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<td>Amendments to Regulations Specifying Enforcement Procedures for the Renewables Portfolio Standard for Local Publicly Owned Electric Utilities</td>
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CALIFORNIA ENERGY COMMISSION

LEAD COMMISSIONER WORKSHOP

In the Matter of: ) Docket No. 16-RPS-03
Modifications to Renewables )
Portfolio Standards (RPS) )
Regulations for Local )
Publicly Owned Electric )
Utilities )

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CALIFORNIA ENERGY COMMISSION (CEC)

CALIFORNIA ENERGY COMMISSION

REMOTE

MONDAY, JUNE 8, 2020
10:03 A.M.

Reported by: Peter Petty
APPEARANCES

CEC COMMISSIONERS (AND COMMISSIONER ADVISORS) PRESENT:

Karen Douglas, Lead Commissioner
Kourtney Vaccaro Advisor to Commissioner Douglas
Eli Harland, Advisor to Commissioner Douglas

CEC STAFF PRESENT:

Renewable Energy Division:
Katharine Larson
Armand Angulo
Gina Barkalow, Office Manager
Natalie Lee, Deputy Director
Malachi Weng-Gutierrez
Gregory Chin
Elisabeth de Jong

Office of the Chief Counsel:
Gabriel Herrera
Mona Badie

STAKEHOLDER Q&A:

Justin Wynne, Braun Legal for California Municipal Utilities Association (CMUA)
David Siao, Roseville Electric Utility
Steve Uhler, Member of the public
Scott Tomashefsky, Northern California Power Agency
Scott Hirashima, Los Angeles Department of Water & Power (LADWP)
Tony Goncalves, Sacramento Municipal Utility District (SMUD)

PUBLIC COMMENT:

Scott Tomashefsky, Northern California Power Agency
James Hendry, San Francisco Public Utilities Commission
Steve Uhler
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JUNE 8, 2020 10:03 A.M.

MS. LARSON: Should we go ahead and get started now? Commissioner Douglas, are you ready?

COMMISSIONER DOUGLAS: Yes, let’s go ahead and get started.

MS. LARSON: Thank you.

COMMISSIONER DOUGLAS: Why don't you kick us off and then I'll start with my opening comments.

MS. LARSON: Great. So thank you all for attending our Lead Commissioner Workshop on Modifications to the RPS Enforcement Regulations for Local Publicly Owned Electric Utilities. My name is Katharine Larson and I'm the staff lead for the update to the RPS regulations.

I'll go over some brief housekeeping and then we'll have opening remarks from Commissioner Douglas. So this workshop is being conducted entirely remotely via Zoom. This means that we're in separate locations and communicating only through electronic means. We're meeting in this fashion consistent with Executive Orders N-25-20 and N-29-20 and the recommendations from the California Department of Public Health to encourage physical distancing to slow the spread of COVID-19.

This is actually our team's first remote-only workshop, as well as our first workshop using Zoom. We've
got multiple staff members on the line to help address any
technical issues that may arise, but please bear with us if
there are any hiccups.

This meeting is being recorded as well as transcribed
by a court reporter. Everyone will be muted during the
presentation and after the conclusion, will have an
opportunity for clarifying questions, and then we'll take
public comments. To ask a clarifying question or make a
public comment, please use the raise hand feature in your
Zoom application to be called on to speak. When you speak,
please provide your name and affiliation. If you've called
in by phone, you'll need to dial Star 9 to raise your hand
and Star 6 to unmute yourself, and spell your name for the
court reporter.

There's also a Q&A window in the Zoom application
which you can use to type your questions. If you want to
provide public comment, but are unable to raise your hand in
the Zoom application, then during the public comment portion
of the workshop, you can type your comment into the Q&A
window and we'll read it out loud, but we request you label
it as a public comment. We'll go over all these instructions
again during the time for clarifying questions and public
comment, and please remember to stay muted until you've been
called on to speak.

We also have a chat function available for logistics

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or tech questions, but please don't use the chat function for Q&A about the content in the workshop or to make public comment. And our written comments must be submitted by Monday, June 22nd, the last day of the public comment period on the express terms — 45-day public comment period on the express terms. We greatly appreciate comments submitted early and we encourage you to submit comments through our e-commenting system, especially when the majority of us are teleworking.

And now I will turn it back to Commissioner Douglas if she'd like to make any opening remarks.

COMMISSIONER DOUGLAS: Thank you, Katharine.

And good morning, everybody. Welcome to the Lead Commissioner Workshop on the Energy Commission’s Proposed Modifications to the Renewables Portfolio Standard Enforcement Regulations for Local Publicly Owned Electric Utilities. The Notice of Proposed Action and other rulemaking documents were posted by the Energy Commission’s staff on May 7th, 2020.

The purpose of today's workshop is to present the proposed modifications to the regulations, answer clarifying questions, and receive public comment. Regarding public comments, thank you to those who were proactive in preparing comments at the workshop today, and we look forward to the extent we can to unpacking all of those comments today.
During our last pre-rulemaking workshop, we emphasized that we would be moving toward having these regulations in place by the end of Compliance Period 3, which closes at the end of 2020. To that end, I'm glad to say that staff is currently on track, even with the challenges brought on by the coronavirus to bring the final regulations for consideration by the Energy Commission at the August 2020 business meeting. We're appreciative, and I'm appreciative, of everyone's engagement to get us to this point.

I would especially like to recognize the Energy Commission staff who've worked hard to get the proposed regulations to where they are today, and to get this workshop on calendar. And from the Renewable Energy Division, Katharine Larson, Gina Barkalow, Gregory Chin, Armand Angulo, and Natalie Lee. And from the Chief Counsel's office, Gabe Herrera and Mona Badie.

At this point, I'll turn this over to Katharine for the remainder of the workshop.

Thanks again.

MS. LARSON: Thank you, Commissioner Douglas.

So for our staff presentation today and the rest of the workshop, I'll begin with a very brief overview of the CEC's RPS Enforcement Regulations, as well as the changes required by recent legislation. Then I'll introduce the proposed regulations and describe in the presentation how
they differ from the pre-rulemaking draft that was posted last December and presented at our January workshop.

I'll then outline the next steps, and immediately following the presentation will pause for clarifying technical or process questions. And after that, we'll open up for public comment. Please do hold any general statements regarding the rulemaking package until public comment.

The first RPS was signed into law in 2002 for retail sales of electricity and targeted 20 percent of retail sales from eligible renewable energy resources by 2017, and then accelerated to 20 percent by 2010. And in this first RPS through 2010, the law required POUs to establish and enforce their own RPS that recognized the intent of the legislature to encourage renewable resources, while also taking into consideration the effect of the standard on rates, reliability, and financial resources, and develop environmental improvement.

In 2011, SB X 1-2, or Senate Bill X 1-2, established new RPS procurement requirements, including a target of 33 percent by 2020 for retail sellers and POUs alike. In bringing POUs into the statewide RPS Program, SB X 1-2 acknowledged the authority of each POU's local governing board, but also required the CEC to adopt RPS enforcement regulations. The CEC's regulations specify how the CEC will assess a POU's procurement actions and determine whether they
meet the RPS requirements. The regulations also specify a process by which CEC may issue a notice of violation and refer noncompliance to the California Air Resources Board, or ARB.

The CEC's regulations were adopted pursuant to Public Utilities Code Section 399.30 in June of 2013 and took effect that October. The CEC subsequently modified the regulations with the amended regulations taking effect in April of 2016. The RPS Enforcement Regulations are specific to POUs. The California Public Utilities Commission establishes RPS rules for retail electricity sellers, as well as oversee their compliance and enforcement.

Since the CEC last amended regulations, these regulations, four pieces of legislation have modified RPS requirements applicable to POUs. These bills affect multiple aspects of the RPS program, including procurement requirements, optional compliance measures, reporting requirements, and special exemptions and exclusions. I'll discuss our proposed implementation of these statutory changes in the following slides.

So as Commissioner Douglas mentioned, Notice of Proposed Action on our proposed regulations was published in the California Regulatory Notice Register on May 8th to initiate the formal rulemaking process and start the 45-day public comment period. The broad objective of this
rulemaking is to implement the statutory changes mentioned on the prior slide in a manner that supports the achievement of the underlining benefits to the RPS and is consistent with statutes, consistent to the extent possible and appropriate with the implementation of parallel requirements for retail sellers, and that it reasonably applies to all POUs.

Proposed regulations, which I'll also refer to as express terms, and additional rulemaking documents were posted on the CEC's website and sent to our LISTSERVs. The proposed regulations are the product of extensive pre-rulemaking activities, including the publication of initial draft regulations that were specific to SB 350 in 2016, and an implementation proposal, draft regulations, and a key topics guide posted at the end of last year.

The proposed express terms are largely consistent with the December 2019 pre-rulemaking draft. The proposed RPS procurement targets for compliance periods after 2020 are the same as those proposed in the December draft, as are most of the proposed changes to excess procurement and optional compliance measures. Two sections, 3205, which is Procurement Plans and Enforcement Programs; and 1240, which is RPS Enforcement, had no additional changes to those proposed in the December draft.

While the overall implementation of the long-term procurement requirements, or the LTRs, as an independent
procurement requirement is the same as in the December 2019
draft, there are multiple revisions in the express terms to
requirements for what actually qualifies long-term
procurement. The proposed express terms also include changes
or clarifications to several requirements for exemptions and
for reporting.

Throughout the express terms, there are formatting
changes, such as numbering and consistent reference,
references for different sections, that have been updated
since the December 2019 draft, and a few corrected typos as
well.

I'll next go through each section of the regulations
for which we've proposed updates in this rulemaking and
summarize the substantive changes since the December 2019
draft. We did receive three sets of comments prior to the
workshop, which included the four numbered proposals, as well
as requests for clarifications and comments on the proposed
implementation. Where possible, I'll seek to speak to those
comments in my presentation.

Section 3201 specifies definitions for various terms
used in regulations. The changes proposed in the rulemaking
include new and revised definitions related to implementation
of the long-term procurement requirements. These include
contract start date, end date, and execution date, ownership
agreement and ownership agreement execution date, long-term
procurement requirement, and RPS procurement requirements.

The changes also include minor updates or clarifications of several existing definitions, compliance period, compliance report, portfolio balance requirement, retail sales, retire, and RPS procurement target.

The definition section in the express terms is largely consistent with the December 2019 draft. Since December, we've added one new definition, Joint Powers Agency, for entity is formed pursuant to the Joint Exercise of Powers Act, to address applicability of aspect of a long-term procurement requirement, ownership requirements for large hydroelectric generation exemptions, and eligibility for a special retail sales calculation.

We also further clarified the definition of compliance period to ensure that it's clearly inclusive of compliance periods established by law through 2030, and the subsequent multiyear compliance period established by the CEC. We also clarified both the definitions of contract execution date and ownership execution date to better identify the action of execution.

We received a preworkshop comment asking for clarification of the difference between the use of retail sales, which is currently a defined term, and total retail sales, which isn’t defined, but is also used in the existing and proposed regulations. Because the two terms are used
interchangeably in the current draft, staff is considering using only retail sales for clarity because it is a defined term, although depending on usage, it may also be appropriate to use other language in the regulations, such as the sum of all retail sales. But we invite further comments on the use of these terms.

Section 3202 specifies eligibility requirements for different types of qualifying electricity products and how each type of electricity product is counted for purpose of RPS procurement requirements -- requirements. The proposed changes in the rulemaking address how each type of electricity product relates to the long-term procurement requirements. The proposed changes also make minor clarifications to existing provisions regarding the effective amendments to PCC 0 contracts, as well as to an existing REC eligibility requirement. Since December, there were no substantive changes to this section. The only additional changes were regarding reference format and consistency.

Section 3204 describes the RPS procurement requirements and special exemptions or adjustments to those requirements. This section covers a lot of material, so I'm going to go through each subdivision separately.

The proposed changes in the rulemaking to subdivision (a), RPS procurement targets, include implementing the new compliance period through 2030 that were established by

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The proposed changes also implement procurement targets for these new compliance periods that are generally based on linearly increasing annual soft targets, except for a slight variation in 2025 and 2026 to address statutory intent language. The proposed changes also implement three-year compliance periods beginning on and after January 1st, 2031, and clarify the variables used in equations to calculate the procurement target. There were no substantive changes to this section since the December 2019 draft, only reference updates for consistency and to reflect updated numbering to various sections.

The new subdivision (e) -- excuse me, (b) proposed in the rulemaking is the location for all special exemptions and adjustments to RPS procurement requirements. Subdivision (b) in the existing regulations was retained and renumbered to subdivision (e). There are quite a few exemptions to cover in this slide, so please hang on.

The proposed changes in the rulemaking to subdivision (b) include moving existing exemptions to this location and implementing statutory changes regarding exemptions from all four bills. The changes from these bills include a new partial procurement target exemption for large hydro generation. This exemption was created by SB 350 and subsequently revised by SB 100.

A revision by SB 1393 and then subsequent repeal by
SB 100 of the existing procurement target exemption for hydro
generation that was originally established by SB 591. A
retail sales reduction established by SB 350 for qualifying
generations from voluntary green pricing or shared renewable
generation program. A partial procurement target exemption
also established by SB 350 for unavoidable procurement of
coal-fired generation under limited circumstances. A partial
procurement target exemption established by SB 1110 for
qualifying generation from gas-fired power plants without
outstanding public indebtedness, again under limited
circumstances. And finally, a revision from SB 350 to
eligibility criteria for an exemption to the portfolio
balance requirement, or PBR, for a POU not connected to a
California balancing authority that meets specified criteria.

In addition to implementing these statutory changes, the
proposed changes in the rulemaking also clarify how certain
exemptions relate to the new long-term procurement
requirement.

The express terms in subdivision (b) are generally
consistent with the December 2019 draft, but there were
several substantive changes. First, in a large hydro
exemption created by SB 350 and modified by SB 100, we
clarified that qualifying generation must actually be applied
to the POU's retail sales, this is based on a fair reading of
a statutory provision that limits the exemption to the
portion of retail sales unsatisfied by the qualifying generation.

We also removed proposed requirements that were effectively duplicative and/or requirements specifying the treatment of renewals or extensions of WAPA contracts for the period between 2016 and 2018, as CEC staff isn't aware of any WAPA contracts expiring during that period.

As in the December 2019 draft, the proposed express terms specify a sunset date of this large hydro exemption as the end of December 2030. We refuse preworkshop comments that this implementation fails to apply the rules of statutory interpretation and prevents POUs with long-term contracts for qualifying hydro from realizing the intended benefits of the exemption. While we understand parties' concerns, the question of a sunset date appears to be a statutory, rather than regulatory issue, as the compliance periods for which the exemption is effective are specified in statute and planned in 2030.

We invite further clarification of the preworkshop comment to make sure that we understand the argument that Public Utilities Code Section 399.30(b) encompassed all compliance periods when the exemption was first adopted. As we understand that prior to SB 350, Section 399.30(c) did require the CEC to establish future compliance periods after those specified in statute. With all that said, though, our
requirements for developing regulations must meet the requirements in review by the Office of Administrative Law and we may not be able to further refine the proposed language.

Moving on. For the Retail Sales Reduction for Green Pricing and Shared Renewable Generation Programs, we changed the term subtract to exclude in the express terms to better align the statute and based on comments received in January. We also revised the definition of monetized for this retail sales reduction to clarify that it includes earning values from the retired RECs, such as through Low Carbon Fuel Standard, or LCFS credits, under current rules for the LCFS Program. This clarification is based on the requirement of Public Utilities Code Section 399.30(c)(4), which specifically requires any RECs associated with electricity credited to a participating customer be retired on behalf of the participating customer and shall not be further sold, transferred, or otherwise monetized for any purpose.

In developing the proposed express terms, staff coordinated with the LCFS team at ARB regarding the prohibition on further monetization of RECs for this retail sales production and determined that use of (indiscernible) green pricing program RECs to substantiate LCFS credits would constitute further monetization of the RECs.

Also related to this provision, we received a comment
stating that a community solar program under the Title 24 energy standard would be precluded from the retail sales reduction. At this time, staff doesn't anticipate changes based on this comment.

A little more on this retail sales reduction in the express terms. We added the definition of reasonable proximity to mean location within a California balancing authority area because that definition provides roughly -- provides equal treatment for POUs, regardless of the size or characteristics of their service territory, and roughly comparable treatment with IOUs that have larger service territories and a similar retail sales reduction. It also provides flexibility to POU governing boards in assessing what resources are cost effective, and it may provide locational benefits to California ratepayers.

The last changes, new changes, for this retail sales reductions were to add limited exceptions regarding the requirement that electricity products meet the criteria of PCC 1, and that POUs seek to procure from resources located in a California balancing authority for those POUs not part of the California balancing authority themselves. These changes, which will allow those POUs to take advantage of the retail sales reduction without needing to procure electricity products located in or scheduled into a different balancing authority area than their own.
Preworkshop comments requested clarification of initial statement of reasons, or ISOR, language explaining the requirement -- explaining this requirement for POUs that are not part of the California balancing authority to seek to procure resources in their own balancing authority area. The intent of the express terms is to allow these POUs to procure outside their balancing authority area if the POU is unable to procure to the extent possible within that area the same standard that's applied for the paralleled requirement for POUs that are part of California balancing authority areas. We do anticipate addressing this clarification in the final statement of reasons.

Moving on from the retail sales reduction for the unavoidable procurement of coal-fired generation, we revised the definition of qualifying coal-fired generation to better align with statute.

For the qualifying gas-fired generation exemption, we added a provision addressing the statutory requirement that additional procurement of RPS eligible or zero-carbon resources resulted in the power plant operating out or below a 20 percent capacity factor. This -- it changes so all requirements for this exemption can be found in one location in the RPS regulations. We also defined resource shuffling for purposes of the exemption based on a cap and trade definition.
The last change to the gas-fired generation exemption was to clarify staff's interpretation of the requirement that a qualifying power plant must be operating at or below 20 percent capacity factor on an annual average during a compliance period to mean this condition must be satisfied each year of the compliance period. This interpretation is to reconcile the fact that the average capacity is typically calculated annually, that the procurement target exemption is structured on a compliance period basis rather than on an annual basement basis, excuse me -- of an annual adjustment as is seen in other RPS exemptions.

We received some preworkshop comments that this interpretation creates an extra obligation that isn't consistent with statutory language. We encourage further comments on how best to reconcile the structure of the procurement target exemptions as a compliance period adjustment with annually evaluated criteria.

And last, the December 2019 draft sought to clarify how the long-term procurement requirement applied to a POU that meets the criteria of Public Utilities Code 399.30(j). The proposed express terms now clarify that if a POU has all its retail sales satisfied by qualifying hydro generation, it'll be deemed in compliance with the LTR, as well as the other procurement requirements. The clarification of how the LTR is calculated when a POU has retail sales unmet by
qualifying generation is now addressed in a new paragraph in Section 3204(d) in the regulations.

So Section 3204(c) specifies portfolio balance requirements, or the PBR. The proposed changes in the rulemaking include clarifying the calculations of the PCC 3 maximum limit and the PCC 1 minimum requirement for Compliance Period 3 and beyond. The proposed changes are intended to ensure that the equations clearly address all possible procurement application scenarios and are easier to follow. However, the proposed changes to the PCC 1 minimum requirement calculation also reflects an update to the CEC's best interpretation of the statutory requirement based on implementation experience.

This clarification would more clearly establish an order of operations in assessing RPS compliance as follows. First, we calculate the PCC 3 maximum limit based on the lesser of the RPS procurement target or total number of RECs applied to the target. Next, we evaluate compliance with the RPS procurement after any PCC 3 RECs, in excess of the maximum limit the POUs sought to apply, were subtracted. And finally, we calculate the PCC 1 minimum based on the lesser of the procurement target or the total number of RECs that are applied and counted toward the target after the subtraction, if any, disallowed PCC 3 RECs.

In many cases, this revised calculation is no
different than the current calculations, but it would affect
POUs that apply both fewer RECs than the RPS procurement
target, as well as retire and attempt to apply more PCC 3
RECs than the allowable maximum limit.

There are actually no substantive changes to this
section since the December 2019 draft, but it does look quite
different because it was restructured to better identify the
relationship between the PCC 1 requirement and PCC 3 maximum
limit and to better accommodate the proposed clarification
for PCC 1 in Compliance Period 3 and going forward.

So subdivision (d) is another new addition in Section
3204 in the rulemaking to implement the long-term procurement
requirement. This is another long slide that covers a lot of
changes, so please try to bear with me.

The proposed additions within this subdivision
implement the LTR as a third RPS procurement requirement with
compliance assessed independently of the procurement target
and the PBR. The proposed additions also include a
definition for long-term procurement and specify how various
changes to agreements for long-term procurement could affect
the long-term status of electricity products procured to the
agreement. The proposed express terms are similar to the
overall implementation proposed in the December 2019 draft,
but reflect multiple revisions or clarifications.

The first change relative to December -- to the
December 2019 draft was to add a provision clarifying how the LTR will be calculated for POU\'s that have a lower RPS procurement target due to a special exemption or adjustment. In those cases, the 65 percent will be assessed on the procurement target after exemptions or adjustments have been applied.

Next, we\'ll discuss changes for the proposed definition of long-term procurement since the December 2019 draft. The express terms clarify the proposed definition of long-term procurement requires a ten-year procurement commitment from one or more RPS-certified facilities. In other words, a ten-year contract between a POU and a third-party supplier would count as long-term only if the POU submits information showing that the third party has a ten-year contract with or ownership of the facilities that are supplying the electricity products.

This revision is necessary to interpret and make specific the requirement that Public Utilities Code 399.13(b) for a contracting scenario in which a ten-year agreement between a POU and third party provides no long-term commitment for any RPS-certified facility and the electricity product for source to portfolio of short-term agreements. This scenario wasn\'t contemplated in the December 2019 draft and the revision is necessary to effectively implement the long-term procurement requirement in a manner that supports a
key purpose and function of the requirement, which we understand stakeholders generally agree upon, which is to provide planning stability for the development and repowering of RPS-certified facilities.

However, preworkshop comments opposed the proposed clarification that long-term contracts must provide a ten-year procurement commitment from RPS-certified facilities, if an argument that its interpretation is inconsistent with Public Utilities Code 399.13(b), inconsistent with the CPUC's implementation to retail seller, and will add administrative complexity. Comments also stated that POUs may not have access to upstream (indiscernible) contract of third parties.

The initial statement of reasons presents CEC staff to rationale for the proposed clarification of the definition of long-term procurement as it applies to POUs. The proposed implementation is not in conflict with the statutory language of Public Utilities Code 399.13(b) or the consistent requirement that applies to POUs through Section 399.30. However, we do invite further comments from stakeholders on how long-term contracts and third-party suppliers that do not provide a ten-year commitment to RPS facilities may support the development and repowering of RPS-eligible resources.

CEC staff's continuing to coordinate with the CPUC RPS team regarding implementation of requirements for long-term procurement in order to identify differences and
similarities in proposed implementation. CEC staff anticipates adjusting and clarifying differences as needed in the final statement of reasons.

In addition to this change to the definition of long-term procurement, the express terms also clarify that if a POU contracts with a third party other than an RPS facility, or the developer of an RPS facility, the POU’s procurement agreement with the third party must be at least ten years in duration, unless that third party is another POU, a joint powers agency on behalf of the POU, or a retail seller. And the resale or packaging of the original contract with the RPS-certified facility doesn't affect the underlying procurement terms of that contract.

This change is intended to provide some additional flexibility to POU governing boards in determining how best to comply with the LTR given practical long-term contracting challenges based on many POUs, and to the somewhat stricter clarification that long-term contracts must demonstrate at least the ten-year procurement commitment to RPS-certified facilities.

Preworkshop comments requested clarification of what constitutes a pro–continuous procurement commitment under different scenarios. In the express terms, continuous procurement commitment refers to the contract or ownership agreement to procure electricity products. Staff believes
this intent is sufficiently clear in the proposed express
terms but will consider suggestions for further clarity.

Based on this meeting, or understanding, failure to
deliver due to a mechanical issue, drought, or other
interruption wouldn't negate the underlying ten-year contract
or ownership agreement. In addition, as currently drafted,
the express terms would allow long-term contracts to change
the procurement quantity or allocation over time if that
change was specified in the contract. Preworkshop comments
also asked for clarification of how a continuous commitment
would be evaluated for long-term PCC 3 contracts in which
RECs were delivered in batches annually or on a compliance
period basis. We are reviewing this for potential additional
clarification, but we certainly request you provide your --
(indiscernible) stakeholders provide your input, further input
and comments.

Preworkshop comments also requested clarification of
what types of amendments would alter a contract such that it
no longer provides a commitment to procure electricity
products for at least ten years. The intent in the express
terms is to address termination and amendments that shorten
the duration of a long-term contract. We'll consider whether
clarification is necessary, but we also request input on
whether there are other types of amendments to consider that
would change the long-term procurement commitment of a long-
term contract.

So moving on from the long-term contracts duration requirements, the express terms now define efficiency improvements for purposes of this requirement as improvement, but allow an RPS-certified facility to make more efficient use of its existing RPS eligible resource or fuel, improve the efficiency of the facility equipment or operations, and/or allow for more efficient use of the facility's generation.

The express terms also clarify that procurement resulting from efficiency improvement to long-term contracts are considered part of the original contract. The express terms also clarify that procurement to amendments that result in an increase in nameplate capacity, except as part of an efficiency improvement, or amendments that increase the quantity of procurement, based on contractual changes only, will be considered as separate agreements, unless they are specified in the original long-term contract.

Preworkshop comments requested clarification of what specifying an expansion would look like in a contract, what level of details needed, and how electricity products may be attributed to an original project versus an expansion. We're reviewing the potential for additional clarifications here, but we encourage further comments on this topic and, as well as suggest some language.
Preworkshop comments also requested addition clarity on how to specify resource substitutions in a long-term contract, such that the substitutions would be considered part of the underlying long-term contract and as third party restrictions apply. The express terms allow substitutions to count as part of the underlying long-term contracts only as explicitly specified in the original contract with the resource identified. However, we encourage further comments from stakeholders on this topic. And we'd also like to clarify that third party as is used in the ISOR refers to entities other than POUs, retail sellers, joint powers agencies, as well as the RPS facilities themselves.

Finally, the express terms clarify that contracting just to jointly negotiated contracts, that reallocate the quantity of electricity products among contract parties are considered part of the original contracts and that assignments of long-term contracts entered into by a retail seller or a POU will be considered long-term only if the assignment maintains the original commitment to procure the same type and quantity of electricity products from the RPS facilities for the remainder of the contract.

Preworkshop comments requested clarification on what constitutes jointly negotiated contracts. The intent of this language was to address procurement agreements entered into by multiple parties as a result of joint negotiations, even
if the individual procurement agreements don't reference the other parties. However, it may be up to the POU to show that the agreement was -- or contract was the outcome of joint negotiations. For example, a jointly held solicitation alone may not be sufficient if three POUs held a solicitation, but only one of them entered into an agreement. We also welcome further input and comments on suggested clarifications that would be helpful.

Section 3205 specifies criteria for a POU's Procurement Plan and Enforcement Program. The proposed changes in the rulemaking included updates implementing statutory changes from SB 1393 that removes certain noticing requirements. Since December, there were no changes to the proposed regulatory language.

Section 3206 specifies optional compliance measures that may be adopted by POU, including measures to accrue excess procurement for use in a future compliance period, delay timely compliance under specified circumstances, establish cost limitations on RPS procurement expenditures, and to reduce the R -- the PCC 1 component of the PBR.

The proposed changes in the rulemaking address statutory changes to excess procurement, delay of timely compliance, and cost limitations, as well as certain clarifications of existing requirements, specifically in the proposed changes to excess procurement, implement new
eligibility requirements beginning January 2021, and propose
a process by which a POU may elect for voluntary early
compliance with the LTR to use the new excess procurement
requirements beginning this compliance period.

The proposed changes also clarify that excess
procurement may be accrued only if all RPS procurement
requirements are met. They also update the equations used to
calculate excess procurement to ensure that the equations
address all procurement scenarios and they're easy to follow.

The proposed changes to cost limitations and delay of
timely compliance address statutory changes and make limited
clarifications to existing requirements for these measures.
There were also limited changes to the PBR reduction measure.

There have been a few substantive changes since the
December 2019 draft. First, regarding excess procurement, we
extended the deadline for applying prior banked PCC 2 excess
procurement, which is no longer eligible under statutory
changes through the end of Compliance Period 5. Second, we
clarified that a POU’s finding that unanticipated curtailment
delayed as timely compliance must include information showing
that it did not result in an increase in greenhouse gas
emissions.

We received a preworkshop comment asking how a POU
would demonstrate curtailment, such as curtailment of a
resource in another utility territory due to a public safety
power shutoff, didn't result in an increase in greenhouse gas emissions. As written, the express terms leave this determination to a POU governing board, but the underlining analyses to be part of a POU finding and supporting materials. We invite further comments on this implementation from stakeholders.

Finally, we clarified that a POU delaying timely compliance due to an unanticipated increase in retail sales because of transportation electrification, may rely on the best forecast information available to the POU, and we also identified several possible examples of forecast that a POU may rely upon.

We received a preworkshop comment requesting clarification of the meaning of best and most recently available information and how to demonstrate that one forecast is better than another. The comment also suggested that the source of information be deemed best and most recently available, once approved by a POU governing board. So it's similar to unanticipated curtailment. As written, we intended the express terms as to let this determination be made by a POU governing board. But we invite additional comments on the suggestion that the governing board's determination should be formally adopted to satisfy this requirement.

Section 3207 specifies reporting requirements for
POUs. The proposed changes in the rulemaking include clarification to existing annual reporting requirements and updates addressing the long-term procurement requirement. The changes also include a revised compliance report process in which POUs make procurement application decisions after the CEC has completed draft verification of the RECs retired.

In addition, the proposed changes include updated reporting requirements for optional compliance measures and exemptions to address statutory changes and needed clarifications. Finally, the proposed changes specify that missing reports are subject to the same process as incorrect or incomplete reports.

The express terms are generally consistent with the December 2019 drafts but there are a few changes. Regarding annual reporting, we received a fair amount of feedback at the January workshop questioning the need for information on electricity procured for other end uses and excluded from retail sales. This information is necessary for the CEC’s verification process to be able to confirm self-reported retail sales with other sources, like EIA data or other program data for which the definition of retail sales may differ from the RPS definition.

Accurate and verifiable information on a POU’s retail sales and exclusions is necessary to ensure that the POUs RPS compliance obligations have been correctly determined. So in
the express terms, we had thought to better identify the type
of information to be reported. We did receive preworkshop
comments that requiring information on upstream contracts as
part of annual reporting on the LTR is an overreach and the
only legitimate inquiry into upstream contracts is to
determine whether the resource is RPS eligible. The CEC’s
staff has presented the basis for this requirement in the
ISOR based on the implementation of the LTR.

We also received a preworkshop comment regarding
guidance for amending annual reports that have already been
submitted based on a different interpretation of statute. So
the CEC staff anticipated this will affect a relatively small
number of POU s and will plan to work with them directly as
needed. However, at this time we don’t anticipate changes in
the regulations regarding this guidance.

Regarding compliance reporting, the express terms now
better identify the information that a POU must include in
compliance reports which is, in effect, the amount of
generation retired, applied, and what the POU intends to bank
as excess, broken down by each portfolio content category and
long-term or short-term classification.

In addition, based on comments submitted, we changed
the deadline for the compliance report to 90 days after the
CEC sends draft verification results. And we specified that
POUs may request extensions following the process identified
in the RPS eligibility guidebook. We also updated reporting requirements for the SB 350 large hydro exemption in effect from 2016 to 2018 and the green pricing program retail sales reduction. These updates were to conform with the changes and proposed implementation of these provisions that I mentioned earlier. And finally, we made minor additional revisions clarifying how the process for incorrect or incomplete reports also apply to missing reports.

Section 3208 specifies reasons that a complaint may be issued for failure to comply with an RPS requirement and that any complaint will follow the process specified in Section 1240. The proposed changes in the rulemaking add failure to comply with the long-term procurement requirement as a reason for issuing a complaint unless excused by delay or timely compliance or cost limitation optional compliance measured.

The proposed changes also update existing provisions specifying failure to comply with the PBR for consistency with the existing requirements in Section 3206. The express terms are consistent with the December 2019 draft. But we did add a subdivision clarifying that for purposes of the CEC complaint process and referral of noncompliance to the ARB, deficits in the RPS procurement target, PBR, and LTR will all be considered equally. While it is ultimately the ARB’s role to assess and collect penalties for noncompliance, the CEC’s
intent is to get the same treatment to a deficit in any RPS procurement requirement.

Section 1240 specifies the process by which the CEC may file a complaint against a POU for noncompliance and provides information regarding issuance of a notice of violation. The proposed changes in the rulemaking update a reference for statute and specifies the CEC will send a notice of violation to the POU in addition to the ARB. And since December, there weren’t any changes to the proposed regulatory language.

So our next steps. Public comments on the express terms and the other materials in the rulemaking package are due on June 22nd, which is the last day of the 45-day comment period on the express terms pursuant to the Administrative Procedures Act, or APA. We anticipate holding the APA public hearing and bringing the proposed regulations to the Commission for adoption at the August 12th CEC business meeting. If we make further modifications to the proposed regulations based on the comments we receive in this comment period, it’s possible this hearing date could be delayed.

When the CEC considers adoption of the proposed regulations, it will also consider the potential environmental impact associated with the proposed regulations in accordance with CEQA. And may at that time consider adoption of a negative declaration if it’s appropriate based
on our review analysis.

We intend to submit the final rulemaking package to the Office of Administrative Law by the end of the third quarter this year and request an urgency effective date once the regulations are approved, anticipated in the December 2020, which is prior to the close of Compliance Period 3. On January 1st, 2021, Compliance Period 4 begins and the long-term procurement requirement, new procurement targets, and new excess procurement requirements will take effect.

July 1st, 2021 is the annual reporting deadline for 2020 and POUs will report based on the updated guidelines and the regulations. And following the new process and the proposed regulations, the compliance report for Compliance Period 3 will be due 90 days after a POU received draft verification results from the CEC.

The rulemaking documents can be obtained online in the Rulemaking Docket Log or on the CEC’s webpage for the rulemaking proceeding. You could also contact me if you have questions about how to access these documents.

This slide has my contact info so for questions about the rulemaking or if you need help accessing rulemaking documents, please contact me or Gina Barkalow who is a backup contact for the rulemaking. For general RPS questions, please contact RPSTrack@Energy.ca.gov and a member of the RPS team will assist you.
So, as I mentioned before, written comments on the proposed regulations and supporting materials in the rulemaking package are due on June 22nd. So we encourage you to use our e-commenting system. You can find instructions for submitting written comments in the Notice of Proposed Action as well as in the updated notice for this workshop.

And this concludes my presentation on the express terms and next steps.

So we’ll now open the floor for clarifying technical or process questions. If you would like to address broader policy issues, please do hold that for the public comment.

To ask a question, please use the raise hand feature in Zoom and we’ll call on you to speak. If you’ve called in by phone, you’ll need to dial Star 9 to raise your hand, and Star 6 to unmute yourself -- mute yourself. Please provide your name and affiliation when we call on you. And if you’ve called in by phone, then please also provide your name for the court reporter, and spell it as well. You can also type your question into the Q&A window, and then one of us will read it out loud.

So I will now turn it over to Gina Barkalow to facilitate the Q&A.

Gina, are you there? Are you able to speak?

MS. BARKALOW: Hello.

MS. LARSON: Hi, I can hear you now.
MS. BARKALOW: Yes. Okay. Sorry about that.

Yes. Hi. So, this is Gina. I’m going to begin with the attendees who have raised their hands. You can see the attendees by clicking on the participant box, which if you move your arrow to the bottom of the slide it highlights the participant box, as well as the chat, and the Q&A box. So we will begin with those.

Again, when I call your name, then I will unmute you. There is a possibility you may need to also unmute yourself. And state your affiliation before you begin your question.

Okay.

Katharine, can you hear me okay?

MS. LARSON: Yes, I can. Thank you, Gina.

MS. BARKALOW: Okay. All right. Well are we ready, Commissioner? Katharine, ready to get started?

COMMISSIONER DOUGLAS: Yes, let’s get going.

MS. BARKALOW: Okay. We will begin with Ren Zhang.

Ren, please state your affiliation, and you may ask your question.

You may have to hit Star 6 to unmute yourself. Or you may have to go to the bottom left-hand side of the presentation and there’s a little phone symbol and unmute yourself there, possibly.

I have allowed you to unmute, so you should be able to unmute yourself, Ren.
Okay. Ren, perhaps you could send us a message in the chat box if you’re having a problem. I notice that your hand was raised from the very beginning, so if you’re unable, I think maybe I’ll move on to the next person and I’ll try to come back to you. But please let us know if you’re having any problems with the chat box, please. Okay.

All right. Justin Wynne, I’m going to allow you to talk.

MR. WYNNE: This is Justin. Can you hear me?

MS. BARKALOW: Yes. Thank you.

MS. LARSON: Yeah.


So first, I just wanted to thank staff and the Commission for all the work that went into these post regulations. I think there are a number of issues that we raised in the pre-rulemaking draft, and I think that we see that you put a lot of effort into addressing a number of those issues and so we greatly appreciate that.

And so CMUA had submitted a list of questions. I think you provided a good response to a number of them. I just wanted to go through and ask a few more clarifying questions just to make sure I understood and maybe have some follow-up questions based off of that.

Well just as an introductory comment on the --
level of detail that I think is appropriate for the regulations. I think I understand that the regulations can’t be bogged down with tons of examples, but particularly considering the long-term procurement requirement, these are contracts of 10, 25 years. And so the financial commitment associated with those is substantial. And so there’s a real need for some regulatory certainty.

And so I think that it doesn’t necessarily have to be in the regulations themselves, but it could even be in the FSOR. But for a number of these example and questions, I think that some level of clarification that we can point back to when we’re executing contracts would be very valuable.

The other part of this is that it’s 2020, communities have been ramping up to this for a long time and so a number of contracts have already been executed without the benefit of these regulations in place. And so as you’re thinking about how rigid and strict these requirements are, I think it’s important to keep in mind that you have, you know, almost nine years of long-term contracts being executed that include a lot of standard provisions. And so it’s -- it’s important to look at how language in existing contracts is structured in making sure that you’re not preventing something that’s a useful, or normal contracting provision.

So the first question I had, just to make sure I understand it, when you were talking about the definition of
continuous for the long-term procurement requirement, there
was the -- I think I understood the discussion about droughts
and mechanical failures, but could you just repeat one more
time for Bucket 3 contracts? If -- if there would be a
strict -- a restriction where if it’s delivered once every
compliance period, that you get everything dumped into your
WREGIS Account, does that still qualify as continuous?

MS. LARSON: So that’s actually one that we are still
reviewing the best way to clarify that. And I think we need
to discuss a little bit more as a team. Certainly understand
the need to better clarify how PPC 3 RECs will be addressed
in a long-term contract and how that requirement will apply.
But I think at this time we’d -- we’d like to hear more from
you all and some other commenters on -- suggested thoughts
for those clarifications.

So I think it’s a really good question that you
brought up in the preworkshop comments and I didn’t -- I
spoke to the fact that I think we’ll need to further consider
clarifications now that we’ve -- when we’ve had more time to
discuss.

MR. WYNNE: Thank you. So the next question I
think -- I think you clarified this, but I think it’d just be
helpful to make sure I understand it. For the definition, or
to understand what a jointly negotiated contract is, I think
what you said was that if -- if there was say a joint
solicitation and then all of the parties executed contracts, 
even if they don’t reference each other that can still be 
jointly negotiated.

I think you -- you gave the example where say one of 
the parties doesn’t actually negotiate a contract or doesn’t 
actually execute. I think I understand that, but -- but if 
there’s a joint solicitation, the parties work together, but 
they have three separate contracts, that can still qualify 
under jointly negotiated.

MS. LARSON: Yeah. That was what I was speaking to 
in the present- in the slide. But I was mentioning that it 
may not always be completely clear, just from a -- submitting 
a joint solicitation itself. Because you could have a 
scenario in which maybe there is a joint solicitation, but 
not all members of the solicitation actually enter into a 
project, maybe only one does. And so that -- that wouldn’t 
maybe be a jointly negotiated contract if only one POU 
actually engages in negotiations and execute the contracts.

Does that make sense?

MR. WYNNE: Yeah. And I think this is an area where 
moving forward with this language, I imagine that it’ll be 
commonplace to just actually have this express language in 
there. But you -- the question would be looking backwards 
for projects that have already gone through this process, 
what do they need to show? And I -- but I understand what
you’re saying that if the contract isn’t executed by one of the parties, they wouldn’t be able to come back five years later and then join into this joint negotiation just because they’ve been a part of a solicitation. I think -- I understand that.

MS. LARSON: Yeah. Okay.

MR. WYNNE: The next question. Under specified requirements for a capacity increase, I think that’s -- this is an area where I would have concerns because if you look at just normal contract language, I don’t think it’s that uncommon where if a increase in the capacities expected in the future, there may actually be very limited reference to that in the contract. It may just say that there’ll be good faith negotiations in the future.

And so this would be one where they -- the contracts that have been executed didn’t have the benefit of knowing what the interpretation potentially would be. And so if there was a very strict requirement said you name the location, the size, and all these -- all these other details, I think that that may restrict the ability of somebody’s expansions to occur, it would severely devalue the benefit of it.

And so when you’re -- it wasn’t clear to me, and I think you said this is something you’re looking for more comments on, but it wasn’t clear to me what the level of
detail you’re looking for, for specified.

MS. LARSON: Yeah. So I did say that we’re -- we
need to further discuss this and would welcome more comments
on this matter. I think -- on some level -- I think
actually, I mean real-world examples that you could provide,
perhaps in your comments on what -- what actually is in
existing contracts, what type of language is in existing
contracts would be helpful for us to see in your comments.
But I think the idea of, sort of fundamentally, is that we
want -- an expansion should be -- get sufficiently considered
if it’s expected, or sufficiently defined if it’s expected,
actually expected as part of a long-term contract.

And so we’d need to further consider what, you know,
that might exactly look like. So I don’t have an answer for
you now, but that’s something we’re certainly looking in to.
And then any -- any like, real specific examples of contract
language that you could provide, or the type -- the
information that’s actually provided in long-term contracts
for expansions now, that would be helpful for us to consider.

MR. WYNNE: Okay. Thank you. And the -- my next
question is on specified for substitution. So I thought what
I heard you say was that for that to not be treated as a new
agreement, the actual resource would need to be specified.
And it wouldn’t be, and I think we had raised the comment, is
it the ability to substitute, or is the actual resource that
would need to be specified? And I thought I heard you say it’s the resource.

MS. LARSON: So I said the resource, but I also said that we’re -- it’s still an area of discussion. And so please continue to address that in your comments as well. And for everyone, I would ask that in comments. That’s still an area that we appreciate the need to clarify and further discuss.

MR. WYNNE: Okay. And then, and it wasn’t clear to me. I thought you said that the -- and we’d raised the question about whether the -- the third-party requirement that you had -- had in the different section about the portfolio contracts where the underlying resources would need to be ten years. Are you asserting that that applies to this such that if there was a substitute resource, so say you needed six months because there was an extended outage, you would only be able to use a resource where that third party also had a ten-year contract with that substitute resource?

MS. LARSON: So I think in principal that would align with our -- our fundamental interpretation of the long-term procurement requirement and the purpose of the requirement which is, again, to provide a continuous long-term commitment to specific facilities. And so I think, and I guess I’m saying a fair amount of the same thing, but these are all really good questions that we felt were raised
in the pre-rulemaking comments. And we’ve started to discuss
but, you know, agree that we still need to further before
coming out with any clarifications.

And so I think, again, additional comments on this
subject, but especially keeping in mind what we see with the
current interpretation of the long-term procurement
requirement and its key function and purpose and how
different resource substitutions for -- with or without the
third-party restrictions to support that requirement is
really a key area that we appreciate seeing in comments.

And again, to the extent you have examples of what
actual contract language might look like, that would be
helpful for us as well in determining how best to clarify.

MR. WYNNE: And then, thank you. And so my last
question was just on the optional compliance mechanism where
there is a delay time to compliance based off curtailment,
and we’d raised the question about what sort of analysis you
need to show to show that there’s not a GHG increase.

And I believe it’s something we talked about in some
of the earlier workshops, and so just to clarify, your
interpretation is you have to show that the curtailment event
did not result in an increase in greenhouse gas emissions.
And it’s not the granting of the waiver that you would have
to show doesn’t result in an increase in greenhouse gas
emissions?
MS. LARSON: Yes. Yes.

MR. WYNNE: And this is one where it’s challenging to think of all of the different analysis that would have to go into this because, I mean things like imports into the system and the effect of the curtailment event on the power that’s being imported and the relative greenhouse gas emissions difference, intensity between out of state versus in state, the dropping of load during the, you know, and the GHG associated with the load that’s lost. Do you need to look at historical baselines?

It seems like a very complicated analysis. And so it -- it’s one that seems challenging to not provide at least some guidance on. And I think -- I think it would be helpful. And I don’t know that it needs to be in the regulations but I think that given how complicated an issue it is, I think it’s something where we would appreciate some more discussion about what the Energy Commission would have in mind for what a POU you would show in that demonstration.

MS. LARSON: Yeah. So, I think as the express terms are written, we would leave it to -- that would leave the determination to a POU’s governing board, including maybe analyses they decided to use in the data they have available.

But I think continuing to follow-up on the -- in comments and we can consider additional clarification, but I think in some ways it doesn’t seem -- it’s not that
dissimilar to the -- the requirement for unanticipated increase in retail sales due to transportation electrification where a POU deciding what the -- what the best forecast to use and their own method for attributing retail sales to transportation electrification. That is also left in the POU’s governing board as well. They have the ability to determine what analysis is appropriate. And so I think there is some similarity there. And so perhaps -- perhaps considering both of those in comments might be helpful.

MR. WYNNE: So those are my clarifying questions. I really appreciate you responding.

And as far as just the workshop, it would be helpful if there are things where you are looking for more feedback because CMUA filed these comments but obviously there was a lot of input from specific POUs. And so individual POUs will have responses, and NCPA and SCPPA all have responses. So I mean, there -- there may be additional points made by other POUs, but it would be helpful if you’re looking for a little bit of a response on some of the issues that were raised, and we haven’t addressed it, if you would raise that so we know that’s something that you’re looking for comment on other than what you’ve already raised. I think that would be helpful.

MS. LARSON: Okay. Great. We will keep that in
MR. WYNNE: Thank you very much.

MS. LARSON: Okay. Thanks, Justin.

MS. BARKALOW: Okay, great. The next person is David Siao. David, feel free to ask your question. And state your affiliation, please.

MR. SIAO: Hi, Gina. Can you hear me?

MS. BARKALOW: Yes, I can. Thanks.

MR. SIAO: Oh, excellent. Hope you’re doing well. And hello Katharine, hope you’re doing well as well.

Let’s see. So as Gina mentioned, my name is David Siao. I’m an analyst for Roseville Electric, POU just to the north of Sacramento. So we’d like to say that we support the State’s climate change goals and expect to comply with all applicable regulations.

But first of all, before I go into my comments, I’d also like to thank staff for all of the help and communication they’ve provided because they’ve been very accommodating and willing to listen to Roseville’s concerns, even when staff doesn’t necessarily agree. So again, I appreciate that.

MS. LARSON: I’m sorry, David. Just to quickly interrupt you and my apology if I’m jumping the gun, but it sounded like you were saying that you had comments to make. We do have a public comments session following this, but
right now we’re doing the Q&A for clarifying questions. So certainly if you have clarifying questions, feel free to ask. But I just wanted to mention that we do have a public comments session following this Q&A.

MR. SIAO: Sure. Thank you, Katharine. And these will be sort of clarifying questions. It’s going to be slightly long because, you know, as Justin alluded to, we have some specific contracts that would be impacted by how these regulations are interpreted.

So I would just say that, you know, we had signed two contracts several years ago in accordance with the regulations that were in place at the time. The first one is a contract that we have with Powerex, which accounts for about 17 percent of our -- meeting our RPS obligation. The other one is with Avangrid, which accounts for about 53 percent of our RPS obligation. 28 percent is Bucket 1, 15 percent would be Bucket 2, and 10 percent would be Bucket 3.

So I just wanted to speak to these specific contracts and ask for clarifications that would affect them. Because depending on how the regulations are clarified or interpreted, Roseville could be close to out of compliance, out of compliance, or ridiculously out of compliance. What this would mean is that Roseville would have to either break the contract with these developers, eat the cost of lost REC values, or basically be out of compliance, which I’m sure is
not the intent of the regulatory changes.

So there is four points that I wanted to seek clarification on. And I’ll just dive into them right now. The first one is not so much a clarification, but just sort of setting the stage. As part of the regulations, it’s pretty clear that the counterparties, third parties must either own the resources or have them under long-term contracts. So I’ve spoken with Powerex and they believe that about 10 percent, which would effectively be 2 percent of our compliance are short-term. So, you know, that’s 2 percent that is against us at this point.

As for the other major resources they have, which are wind resources, they believe that their mother corporation, or parent corporation owns them, but they’re not sure if they can count that as ownership or a long-term contract based on their corporate structure. So it’s something they’ve been looking at for a couple weeks and it’s something that may or may not --

MS. LEE: David, I’m sorry.

MR. SAIO: Uh-huh.

MS. LEE: I’m sorry. This is Natalie Lee. I’m the deputy for Renewable Energy.

In a public meeting of this nature, it’s really not appropriate for us to speak to a specific contract.

MR. SAIO: Sure.
MS. LEE: If you would like to follow up with our staff with written comments on these very specific agreements that you have entered into, we of course will address those comments. But we -- for a public meeting, we really can’t provide a specific answer or, you know, for your specific contract. If you have a general clarifying question that’s appropriate to the overall regulatory language, we’d be more than happy to try to address that. Again, it’s a -- at this point in the webinar we’re looking for technical clarifications of the general regulatory provisions in the --

MR. SIAO: Okay. Sure. I can -- I can summarize my clarifying questions, then. Thank you, Natalie.

So I guess the first question is whether Bucket 3 RECs, if we have signed a long-term contract, whether they can count towards a long-term requirement. You know, that’s a 10 percent impact to Roseville.

And as just mentioned, we’re trying to understand what the exact definition of continuous would be. That would impact about 53 percent of our RPS compliance. So that is an important clarification that we would seek.

The other clarification we’re seeking is whether substitute resources, again I think Katharine had mentioned before that they have to be explicitly mentioned in a contract. However, you know, my understanding of contracting is if something is explicitly mentioned, that’s just going to
be a resource and it’s not going to be specifically
designated as a substitute resource because that’s a bit redundant. Substitute resources are generally something that, you know, would be envisioned in the contract to be added and clarified later.

So I just wanted to say that, you know, depending on how these ambiguities are clarified, Roseville would be out of compliance from the very beginning. This would have a cost impact to our ratepayers, and we could potentially have to look at breaking our contract with these developers and seeking new ones.

So those are the clarifications I was hoping to seek, and I appreciate any input that Energy Commission has on that.

MS. LARSON: Yeah. And thanks, David --

MS. LEE: Natalie again. May I -- may I just say generally because we’ve got a couple of questions that have come in on our chat feature as well along these lines.

So what I’m hearing is that you would like general clarification as to Bucket 3 resource being eligible for long-term designation if the contract terms meet the as-written regulatory language. I think Katharine can speak to that as a clarifying. In some cases though, we’re going to basically thank you for the comment and seek to address that in the future and not be able to answer it in some cases.
today.

But Katharine, please go ahead.

MS. LARSON: Yeah. So the -- regarding PCC 3 contracts. The intent of these was not to preclude PCC 3 from being -- a long-term PCC 3 contract from counting toward the LTR. So I think that’s something that we were not intending to do within the express terms or the ISOR, but we do see that there are some practical questions regarding the form of PCC 3 contracts and how that might interact with the definition, footnote, continuous procurement commitment from an RPS certified facility. And so whether, you know, for a PCC 3 contract, that might look like something like continuous vintages for a ten-year period of RECs. That might be something to consider.

So, I guess, we really would appreciate your further thought on this in comments because we realize that this is an area where it may be very appropriate to have further clarification. And so at this time I can’t speak to particular PCC 3 arrangements, if they would count as long-term or not. But I will say that the, you know, the intent wasn’t to preclude PCC 3 from long-term contracts. But with that said, in your comments, definitely encourage you to consider how those arrangements, different arrangements would support the underlying purpose or function of the long-term procurement requirement. So.
MR. SIAO: Sure. Thank you, Katharine.

MS. LARSON: Definitely appreciate the points you’ve raised, but we really appreciate more comments as well.

MR. SIAO: Sure. And would you also be able to speak to the clarification on continuous, the definition of continuous, as well as the treatment of substitute resources?

I know you spoke with Justin about this before, but just to be clear, your -- I think the current position of the Commission is that substitute resources must be explicitly named within the contract. Is that correct?

MS. LARSON: So I think that was our intent in express terms and ISOR.

MR. SIAO: Okay. And could you speak to the definition of continuous as well, just I believe, was that up in the air, or --

MS. LARSON: Regarding PCC 3 or just in general?

MR. SIAO: Just in general.

MS. LARSON: So I think continuous, again, we see this as referring to the actual agreement, the underlying agreement, the contract, or ownership agreement to procure on a continuous basis. And if there are certain interruptions, then that wouldn’t, you know, negate the underlying ten-year procurement structure.

So. So that -- that’s our general framework for looking at continuous but again, as that applies to PCC 3,
there might be additional considerations, factual considerations we need to think about. And so that, that is where comments -- additional comments would be helpful.

MR. SIAO: Okay. Thank you.

MS. LARSON: Yeah.

MS. BARKALOW: Okay, great. Thank you, David.

Okay, the next person with the hand wave is on the phone, with the last three digits being 385. I’m going to allow you to talk. You may need to hit Star 6 to unmute yourself. You should be able to speak now. Thank you.

MR. UHLER: This is Steve Uhler, U-h-l-e-r, a retail energy customer. Are you reading me?

MS. BARKALOW: We can hear you.

MS. LEE: We hear you.

MR. UHLER: Okay. Particularly to my comment related to 399.30(c)(4) and that you only mentioned the part, it appears you only mentioned the part about Title 24, 10-115. You don’t seem to have enough dynamic range to handle an individual who lives in a home of such who never uses more than the energy produced under that contract that they have, that covenant they have for that power. So those folks would -- some of their power would be sold to somebody else who’s not that retail customer. So I think you need to think a little bit more on that.

And also, simply, are you determining that if a
utility rebate, the cost of the energy use, they can just extract it from their retail sales. If you have a situation you -- kind of the utility drive their retail sales to zero by taking all of their renewable contracts.

MS. LEE: Mr. Uhler. I’m sorry, this is sounding like comment, not a clarifying question. Is there a underlying clarification?

MR. UHLER: A clarifying question. Okay, clarifying question. Why is the -- why do you not see any application of 10-115 to 399.30(c)(4)? And also clarifying question on 399.30(C)(4), the retirement of credits in WREGIS. What happens when credits are retired in other systems? And your compliance with 399.21 to have an accounting system that makes sure that there’s no double counting. So can you clarify that?

MS. LEE: Katharine, do you want -- do you want to address that WREGIS provides service for multiple programs?

MS. LARSON: Sure. Right. So we would -- the credits. The requirement that credits be retired in WREGIS on behalf of a participating customer, WREGIS does, as Natalie was mentioning, it provides -- the accounting system is available and used by multiple programs not just the RPS. And so a POU would need to demonstrate that it is retired RECs in WREGIS on behalf of a participating customer in a different subaccount, not an RPS subaccount that’s, again,
designated for the benefit of a participating customer. And submit that as part of its demonstration that the RECs aren’t -- aren’t being double counted.

So the credits are required to be retired in WREGIS on behalf of the participating customer. For purposes of this exemption, if the credits were not retired in WREGIS on behalf of the participating customer, then they would not be eligible for this retail sales reduction.

MR. UHLER: Okay. So is that -- a customer can go use an account, look up their account and see exactly what they contributed?

MS. LEE: So Mr. Uhler, you’re --

MR. UHLER: Could you clarify, could you -- this is --

MS. LEE: An individual does not -- there’s -- there’s a -- there are requirements and a specific process to participation in WREGIS. That’s for us to describe directly. I think we have spoken about this previously. But instead of focusing on WREGIS, I’d like to turn back to the regulations. We do feel --

MR. UHLER: Okay. So then back to the regulations.

MS. LEE: Okay. So we’re going to --

MR. UHLER: Back to the regulations.

MS. LEE: So as Katharine has stated, we appreciate your comments and we will continue to address those through
the formal rulemaking process. We don’t have any --

MR. UHLER: Okay. Monetization --

MS. LEE: -- further response right now --

MR. UHLER: All right. Clarification on monetization value. What is the Energy Commission term as value? Are they only going to be value to --

MS. LEE: Okay. We’ll take that into consideration that that may need additional clarification in the future. Thank you.

MR. UHLER: I’d like -- okay, so you’re going to expand what value is before you consider submitting these for publication as official regulation?

MS. LEE: My commitment to you is that we will review your comment to identify if additional action is necessary.

MR. UHLER: Okay. So am I to take it that you haven’t put much thought into this part of it?

MS. LEE: Okay. We’re going to be moving on to the next commenter.

MR. UHLER: Um, hang on.

MS. LEE: Sir, I’m sorry, but this is not the appropriate form for this dialog. We’re going to move on to our --

MR. UHLER: Where you’re at or I can --

MS. LEE: -- party.

MR. UHLER: -- I can -- I can further comment. Very
few of my comments and I’ve had a number of written comments prior to meetings have not been answered. And we’re getting closer and closer to when this needs to happen. And -- and -- yeah, so, yeah --

MS. LEE: Okay, sir, again --

MR. UHLER: -- you’re not going to just stop me on this. Because --

MS. LEE: We are going to ask you to hold --

MR. UHLER: -- I would like -- I would like to know why you haven’t mentioned --

MS. LEE: -- additional comment.

MR. UHLER: -- that you’re speaking over the top of me.

MS. LEE: Yes, I’m going to ask you to --

MR. UHLER: I don’t know if it’s a technical issue.

MS. LEE: -- please close --

COMMISSIONER DOUGLAS: This is Commissioner Douglas. We’re going to have to move on. These workshops are an opportunity for you and others to raise clarifying questions to make comments. And I hope that in the public comment if you have additional comment and question, please raise them. This is not a place for staff to do -- conduct responses on its (indiscernible) --

MR. UHLER: Okay.

MS. LEE: Thank you.
MR. UHLER: Okay. I hear what you’re saying. But you’re delaying and reducing ability for a member of the public to make appropriate comments and getting answers.

COMMISSIONER DOUGLAS: This is the clarifying question portion of the workshop. So part of the (indiscernible) --

MR. UHLER: Yeah, and so clarifying questions are addressed.

The one thing that you should consider is you didn’t publish your presentation. So folks who are only using the phone, you have a presenter thing on this slide and I can’t see that slide. So you should publish your presentation. It’s a requirement of Bagley-Keene without delay to provide that.

Because I think -- you’re a commissioner and this is a -- yeah, you’re the body and you’ve been presented with this but the public can’t see that.

So I understand this is your first rodeo in having this online stuff, but make sure that you publish your presentation. I could be far more concise.

COMMISSIONER DOUGLAS: Thank you, Mr. Uhler.

Now this is on my screen. And for those who were able to join more than just by phone, they can see it. But let me just ask staff --

MR. UHLER: But if I walk into the room, I would see
COMMISSIONER DOUGLAS: Uh-huh.

MR. UHLER: That’s not being implemented here. I don’t see anything in any order that says you’re not to provide written, distributed written information.

So please see that that’s presentation is made available. Reschedule the meeting and allow me to follow it and have your presenter not say “on this slide”. Understand?

COMMISSIONER DOUGLAS: Thank you for commenting.

MR. UHLER: Understand what I’m saying?

COMMISSIONER DOUGLAS: Thank you for your comments.

Go on with the presentation.

MR. UHLER: You’re in violation of Bagley-Keene otherwise.

MS. LEE: Okay. We are going to move on to our next commenter now.

MS. BARKALOW: Okay. Our next comment -- person is Scott Tomashefsky.

Scott, can you speak?

MR. TOMASHEFSKY: Yeah, can you hear me?

MS. BARKALOW: Yes.

Ms. LARSON: Yes.

MR. TOMASHEFSKY: All right. Thank you. And appreciate the opportunity to talk here and also I’ll just -- I’ll just flag myself that I’ll be -- I want to make some
public comment as well. So I’ll keep this part short and to the point.

My question, really, for clarification is focused on 3204(b)(11) which is related to the natural gas over generation issue. And just for clarity for purposes of this portion of discussion, could you clarify the relationship between the conclusion you’ve reached in terms of dealing with the compliance period of adjustment with the statutory objective of protecting taxpayers from construction debt?

And I only ask that in the sense that there’s no -- no connection with that in the description in the initial statement of reasons on page 35.

So that’s my question.

MS. LARSON: I’m sorry, I only heard -- I lost the very last bit of what you were saying. You asked to clarify how we reached the conclusion. Can you repeat that part? I’m sorry.

MR. TOMASHEFSKY: Sure, I’d be happy to do that.

What I wanted to see is on -- with the initial statement of reasons on page 35 as it relates to this particular section, what I don’t -- what I see is you come to a conclusion with respect to the 20 percent capacity and how you would calculate it for purposes of a compliance period. What I don’t see in there is any connection between the policy objections of SB 1110 which basically called to
protect taxpayers from construction debt of these power plants.

So that’s my clarifying question on that.

MS. LARSON: Got it. So I can speak to the fact this -- where we wrestled with this provision a little bit is really in where we see the construction of the provision in the statute and the way that it is -- it is structured of a compliance period at target adjustment. Unlike the several other exemptions, hydro exemptions, for instance, that have reductions on an annual basis rather than on a compliance period basis.

So really in the way that the statute was constructed around this exemption is a compliance period adjustment and what’s that meant in the past for RPS exemptions.

That was really driving our -- our understanding, our conclusion that this -- trying to reconcile the compliance period basis in the way that exemption was constructed in statute with different conditions that need to be satisfied annually.

And so that was the primary driver in coming to this conclusion but we certainly welcome further comments on -- on how to connect to the policy. Components are the policy driver but while also keeping in mind what statute says and the form of statute, especially compared to the other RPS exemptions. So.
MR. TOMASHEFSKY: Sure. And I appreciate that. And I’ll elaborate a little bit more on that during public comments so we don’t take time over here. And we’ll certainly provide feedback in written comments as well. So thank you for the opportunity.

MR. LARSON: Thank you, Scott.

MS. BARKALOW: Thank you, Scott.

Okay. The next person we have is Scott Hirashima.

Scott, you should be able to speak. You may need to unmute yourself, Scott.

Try again? It’s not a great connection.

MS. LEE: Scott, it seems --

MS. BARKALOW: Try again.

MS. LEE: -- we don’t have a good connection.

Perhaps you could type in your clarifying question for us and we can read it and respond to it?

Gina, can we move on to the next person and we can always try back to Scott.

MS. BARKALOW: Sure. Sure. Okay. So it doesn’t look like there’s any more raised hands for the Q&A.

We do have one question typed in from Tony Goncalves.

I’ll just go ahead and read that.

Regarding non-PCC 0, pre-June 2010 resources and including in the LTR Section 3202(a)(3)(d), the ISOR states the following: This subparagraph is added to explain how
certain qualifying electricity products are included in the calculation of the long-term procurement requirement consistent with the explanation in subparagraph (b), specifying how these electricity products must be included in the calculation of the portfolio balance requirement.

Section 3202(a)(3)(b) states procurement will not be included in the calculation of the portfolio balance requirement in Section 3204(c). The ISOR language is inconsistent with subparagraph (b). Can you clarify the inconsistency here?

MS. LARSON: Sorry, let me just take another look through this, make sure I’m understanding the correction -- the question correctly.

So the Section 3202(a)(3)(b) states the procurement will not be -- will not be included in the calculation of portfolio balance requirements in Section 320 -- oh, okay, I think I understand the question. Sorry, it took a minute to go through different -- different references.

MS. LEE: Not given that whole thing.

MS. LARSON: So the -- if I’m understanding correctly, there’s -- the question is asking about the difference between the pre-June 2010 procurement that doesn’t meet the requirement of PCC 0 and why that is excluded from the portfolio balance requirement calculation but not excluded from the long-term procurement requirement.
And the difference there is based on the way the requirements are defined. So the -- the portfolio balance requirements are specifically defined, calculated around procurements from contracts that are executed after June 1st, 2010. Whereas the long-term procurement requirement is -- there’s no qualification for when the contracts were entered into or the ownership agreements were entered into. And so there is a different treatment there because pre-June 2010 contracts don’t meet the requirements to count in full would not be included as part of the portfolio balance requirement calculation because that calculation is only for post-June 2010 contract. However, pre-June 2010 contracts that don’t meet the requirement to count in full wouldn’t be excluded from the LTR because the LTR doesn’t provide for that kind of exclusion.

I hope that addressed the question. Please feel free to follow up in the Q&A if I misunderstood.

MS. BARKALOW: Okay. It looks like Tony has raised his hand. I’m going to allow you to talk, Tony. Go ahead.

MR. GONCALVES: Hi, this is Tony Goncalves with SMUD. Can you hear me?

MS. LARSON: Yeah. Great.

MS. BARKALOW: Yes.

MR. GONCALVES: Yeah. So the question really was I
was looking at the ISOR and it just -- the language in the
ISOR seems to infer that this is -- excluding it is
consistent with the way that Section B excludes the resource
from the PBR. And so just seems like it’s maybe was a typo
or maybe I’m misreading that. But that was kind of the
clarification. It just seems to reference B as it’s
excluding these resources from the part including these in
the PBR whereas it excludes. So I just wanted to clarify
whether that is -- if I’m misreading the ISOR or whether that
was just an error or something that got (indiscernible) into
the ISOR.

MS. LARSON: Okay. Well, thank you for the -- the
question. I think we’re going to look a little more
carefully into this but definitely appreciate you raising it
to our attention to make sure we -- we’re clear in the ISOR.

MR. GONCALVES: All right. Thank you.

MS. BARKALOW: Okay. I have another question in the
Q&A box.

This is Scott Hirashima, Los Angeles Department of
Water and Power. Would like to get further clarification on
long-term commitment, specifically with regards to the
treatment of certain power purchase agreements that include
options to own or buyout options after so many years. Say a
POU has a long-term PPA with an ownership option at Year 7.
If the POU exercises the ownership option, our assumption is
that everything prior to that ownership option would be named long-term and everything from the buyout point forward would be considered long-term since ownership is assumed to be permanent.

I wanted to seek clarification that that interpretation is (indiscernible). Additionally, how would the ownership be considered in the event the POU stated -- POU stated by to demo the facility -- demolish the facility after less than ten years of ownership.

MS. LARSON: Okay. I think we can -- it’s an interesting scenario that Scott’s raised. But I think there would be no issue at least for the first part of your question regarding a power purchase agreement with the option to own after a certain number of years if it (indiscernible) the ownership agreement, both ownership and the original long-term contract would meet the requirements of long-term procurement. Or they meet the definition of long-term procurement. So I think what you said is correct in your -- your interpretation.

Regarding if the ownership was considered in the event the POU decides to demolish the facility after ten -- less than ten years of ownership. So this is also an interesting scenario and it may be one for us to think about a little further. But my -- my initial thought is you’re correct when we -- we do say that ownership is seems to be
permanent unless there is something in the ownership agreement that suggests that it’s not permanent or it’s not intended to be permanent.

Though I think the idea of that if a POU entered into an ownership agreement but knew going in or -- and I’m not sure offhand how that might be reflected in the particular agreement. But if the POU was planning to end its ownership through demolishing or simply by transferring ownership to another party, then in that -- that was reflected in the contracted agreement that we wouldn’t necessarily consider that, actually we wouldn’t consider that to be a permanent ownership. So we assume that ownership is permanent unless there’s something that indicates otherwise.

But appreciate the question, that’s an interesting scenario that you’ve raised.

MS. BARKALOW: Okay. So that concludes the Q&A. And now we will move on to the public comment portion.

MS. DE JONG: Hey, this is Elisabeth.

We actually did manage to receive a question from Ren in the chat box. And if you’d like, I can go ahead and read that out.

MS. BARKALOW: Yeah, go ahead.

MS. DE JONG: So this is a clarification on the exemption on qualifying large hydro generation. There’s two parts.
First, what’s the definition of qualifying large hydro generation?

And second is, what does it mean by this type of generation gets exempted?

MS. LARSON: So it’s a good question. There are actually a couple of different versions of a large hydro generation exemption. So there are slightly different eligibility requirements, depending on the specific exemption in place for different years.

So SB 350 created a large hydro exemption that was subsequently modified by SB 100. So there are certain eligibility requirements in place under the SB 350 exemption for 2016 through 2018 but then changed with the effective date from SB 100 going forward.

So regarding what’s actually -- what meets the definition of qualifying hydro generation I can refer to that directly in just a moment, but it’s based on the statutory language that defines what qualifying generation is. So the qualifying large hydroelectric generation meets certain requirements that’s specified in Public Utilities Code Section 339.30(k)(1) and certain requirements for the ownership agreement or contracts to which it’s procured. So procured by -- there for an ownership agreement or contract structures that are allowed.

And what the exemption means is it’s really -- it’s
to adjust the soft target, a POU’s soft target in a given
year. If they have their -- their qualifying generation
which again is qualifying based on the statutory
requirements. If they receive qualifying generation in
excess of 40 percent of their retail sales, they can reduce
what they would have needed to procure for a given year such
that the combination of their large hydro generation and
their RPS procurement doesn’t exceed 100 percent of retail
sales for that year.

So for instance, if a POU RPS procurement annual soft
target for a given year was 33 percent and they had 70
percent large hydro generation, they could reduce the amount
of procurement that they would apply toward the RPS target
from that year to 27 percent such that the combination of
the -- the qualifying large hydro generation and the
procurement RPS procurement doesn’t exceed 100 percent of
retail sales for that year.

And if you have any follow ups, feel free to add them
in the chat.

Were there any other questions, Gina?

MS. BARKALOW: Oh, sorry. No.

So now we’re going to move on to the public comments
portion.

To make a comment, please raise your hand by dialing
Star 9 and Star 6 to unmute yourself. If you’re unable to
make a public comment orally, you may type your comment into the Q&A window and we will read that aloud.

    Public comments will be limited to three minutes per speaker. If you have typed in your comment, that limit will be applied during the reading of your comment.

    Okay. So we will go ahead and, Scott, I will take your comment. Are you ready? I’m going to allow you to speak now.

    MS. LARSON: Sorry, just to interject. Can everyone see the countdown timer?

    MS. BARKALOW: I can.

    MR. TOMASHEFSKY: Can, if that counts.


    MR. TOMASHEFSKY: Thanks for putting that up on the board there. That helps, actually.

    Just as a general matter, I’ll take 15 seconds to just -- just to express our appreciation for all the work that staff has done to get us to this particular point. I know we’ve got a nearly four-year conversation on this. And a lot of the things that we’ve had the greatest concerns about have been addressed with clarifying questions, of course. So I think we’re much further along than we could have been.

    My focus for my comments really on two different areas here. The first one I’ll do shorter since it’s tied to
what you said in terms of the hydro provision. You had made
the comments earlier that it was your -- it was your
interpretation of the statutory requirements would not allow
you to make changes that would go to apply the logic behind
2030, and that you were sort of hamstrung in that regards.

One, I’d like to see that confirmed so that we would
not continue to pursue that particular issue. But putting
that aside, you seem to suggest that there was a need to have
a statutory change to that and I will say that that’s
something that we would pursue given that there’s a little
bit of time to address that. I’d like to have some knowledge
of that in the final statement of reasons if there’s no
change to that. So let me stop at that point.

Now getting back to the natural gas provisions in
3204(b)(11). I wanted to provide a little bit more clarity
in the minute and a half I have left here. What we have here
and I know we’ve had a number of conversations about how you
deal with compliance and the calculation of compliance. And
that of course looks at a -- from a compliance period basis
when you come to that conclusion that you can kind of
reconcile those things over a compliance period basis can do
that.

The problem with that conclusion is that this is tied
to public investment in a project that was built with, you
know, to in response to the energy crisis. So it’s all tied
to debt service. Debt service is something that doesn’t have
the benefit of having to be reconciled over a three-year
period. It is an every year problem and concern. So there
isn’t an opportunity to say in year one we’ve had a major
default on debt payments, but we’ll catch up over three years
and everything will be fine.

This was intended to deal with that type of exact
issue that to the extent that there’s a problem that occurs
in year one, there’s some sort of financial offset that deals
with it. And the regulation here doesn’t address that
particular issue. In fact, it actually doesn’t help until
three or four years out. So it’s potentially problematic and
it’s not consistent with what the legislation said.

I will read one thing in here in terms of the fact
sheet that was initiated by Senator Bradford in 2018.
Basically said that SB 1110 is designed to protect taxpayers
from the construction debt of certain power plants built in
response to the energy crisis. This will not do that.

What I’ll also do is if it’s acceptable, the fact
sheet itself is public so I will be happy to add that to the
docket in addition to the comments that we’ll make going
forward.

MS. BARKALOW: Thank you, Scott.

MR. TOMASHEFSKY: So thanks for the three minutes and
ten seconds on that.
MS. LARSON: Thank you.

MS. BARKALOW: Great. Thank you.

Okay. So we’re going to move next to the caller with the last digits 089. You are allowed to talk. Please state your name and affiliation.

MR. HENDRY: Good after -- good morning, this is James Hendry, H-e-n-d-r-y, with the San Francisco Public Utilities Commission.

Can you hear me okay?

MS. BARKALOW: Yes, we can.

MS. LARSON: Yes.

MR. HENDRY: Great. Thank you very much.

I wanted to focus on the interaction between the green tariff provision and the California Air Resources Board low carbon fuel standard. And I’m worried that there’s going to be a conflict between the two and it will really jeopardize the ability of the low carbon fuel standard program take advantage of green tariff provision.

As we know, the California Energy Commission’s been very active in leading Governor Newsom’s goal of trying to get 5 million electric vehicles on the road by 2030 to meet our AB 32 greenhouse gas reduction goal. And (indiscernible) the interaction between these two programs, particularly the requirement that the renewable energy credit cannot be monetized.
Basically we’d preclude the green tariff as an option to help promote electrical vehicles. The green tariff provision was added to the Public Utilities Code by Section SB -- by (indiscernible) SB 350 and this is the same section added Public Utilities Code Section 740.12 that requires the Energy Commission in any rulemaking dealing with greenhouse gas reduction to look at its effect in transportation electrification.

And so the concern that the interaction between two programs is in 2019. The Air Resources Board significantly expanded -- its revised its low carbon fuel standard program and it looked -- tried to have any green tariff as an option to promote electrical vehicle development. It would give great incentives for electrical vehicle development, it would help promote California’s Renewables Portfolio Standard goals. And so now we have the green tariff’s definitions coming out from the Energy Commission which basically say that if you have green tariff, you can’t use it for the LCSF program.

And this was not raised anywhere in the Air Resources Board rulemaking. It now has the effect of basically requiring that you have to double retire renewable energy credits, one to meet the green tariff eligibility. And then with our second renewable energy credit to meet your CARB low carbon fuel standard requirements. And I’m afraid that given
this double counting, there’ll be very low incentive or
economic feasibility for customers to do that.

I think this comes down to definition of monetized, I
think it ignores the initial regulation, talked about
benefitting the participating customers. And it’s the
customers that’s benefiting by participating in low carbon
fuel standard program just as making it as renewable energy
credit, to claim credit for lead certification to monetize
higher rent. Green-e certification for various products. I
think the focus should be on what’s benefitting the
participating customer and then the further monetization,
there really is no further monetization of the renewable
energy credit, it’s really just recognizing the customers
participating in green tariff program. And we will be
following up with it with staff and in written comments.

But we appreciate the consideration with this issue.

Thank you.

MS. BARKALOW: Thank you. Okay. The next person is
on the phone with the last digits 236. Please state your
name and affiliation. You should be allowed to speak.

Looks like you’re still muted. Okay, go ahead. The
caller on the phone with the last three numbers 236, you
should be able to speak.

Okay. We can’t hear you. So maybe send your
comments in the Q&A box. You should be unmuted now.
Okay. We’re going to move on. The last one we have with the hand raised is Mr. Steve Uhler. I’m going to allow you to talk. Okay, Steve, you should be able to speak.

MR. UHLER: This is Steve Uhler, U-h-l-e-r.

The comment from the PUC on -- in centralizing these renewable energy credits for being used for anything. I totally agree the situation would appear that double counting would have to be required. You don’t seem to have a way to enforce that a customer -- and a customer could be a homebuilder who wishes to sell a house and comply with Title 24 for the community solar. Can sell their house and claim that energy and then also the utility then gets to be in turn claim a reduction in renewable sales for something that apparently made the Commission figures they’re being rebated because there can -- cannot be a bill payment related to the energy that’s used.

You really need to look at this closely. Otherwise, somebody should just post a sign out there and tell people claim that you’re all renewable. We have utility companies that claim they raise their rates to buy more renewables. Where’s the line between a renewable program and you simply you pay for X amount of renewables? How come those credits are then not handled under 399.30(c)(4)?

Basically the way I look at it is, the Commission’s over treating superfluous participation pursuant. There’s
nothing binding utility customers to comply with RPS. So utility customer like a stadium can claim that they are renewably powered even after the utility has claimed it under 399.30(c)(4). They shouldn’t be able to do that. There needs to be these controls. Otherwise there’s no incentive. We just tell everybody hey, don’t -- don’t involve yourself in those programs at all and that reduces the amount of money that we go into renewable.

It’s already as it stands will reduce money because people think they’re buying a renewable and can claim everything about it, but they can’t claim value after the utility takes this credit. Not as a procurement but as a requirement of the RPS in order to reduce their retail sales if they actually show up on their book as retail sale.

So you seriously need to consider how you’re looking at this as far as tracking, the ability to have a customer comply who participates in one of these can no longer claim that they have renewable energy because the utility is claiming it. This removes incentive.

So I really want to hear your term of what you consider value. Because as a person who bought two program and then to find out that they were used -- not only did I get -- not get a power content label, but they were used to comply with RPS. I find this abhorrent that the Energy Commission completely overlooked the retail customer and the
customer who’s trying to reduce carbon, particularly in a
carbon desert like Sacramento County which has only 5 percent
renewable.

MS. BARKALOW: Mr. Uhler -- Mr. Uhler, your time is
up.

MR. UHLER: Okay, thanks. I hope you can get to it.

Bye now.

MS. BARKALOW: Okay. Thank you.

All right. We do have one question in the question
box. It is from Leslie Bryan, utility analyst from Redding
Electric Utility.

Our comment -- our comment addresses the
implementation of SB 1110 and expands on those provided
previously by CMUA and NCPA. We now stress the importance to
our community on implementing the law as intended, evaluating
the 20 percent capacity factor annually rather than over a
compliance period.

Redding Electric Utility is a Northern California
Public Utility -- publicly-owned utility governed by its city
council. We serve over 44,000 customers with an annual
electricity load of over 700 gigawatt hours. As reported in
the 2018 U.S. Census data, Redding is a low-income community
of a population about 92,000 with about 19 percent of its
citizens over the age of 65. Redding’s median household
income in 2017 dollars was just over 46,000 with 18.9 percent
of the population in poverty.

The current COVID-19 crisis is creating significant further economic challenges to our citizens. In response to the energy crisis, city council authorized investments in our natural gas-powered electricity generation plants for the purpose of providing reliable and affordable power for our community. Outstanding debt for the Redding Power Plant is approximately 88 million to being repaid through 2031 with annual payments of approximately $8 million.

To the Redding community, the value of SB 1110 when applied as intended by Senator Bradford is significant, estimated at 450,000 to 750,000 each year. However, under the CEC’s interpretation, the value of SB 1110 has diminished to zero. Redding is not alone in being significantly impacted by the implementation of SB 1110 as Roseville Electric Utility is in a similar situation.

SB 1110 does not in any way impede us from achieving all renewable energy procurement targets as legislated, this bill simply offers Redding customers financial relief through the time the bonds are paid off without the annual average being evaluated on a yearly basis as was the intent of the bill. Redding may be forced to lay off employees, possibly shuttering the facility which will force the burden of the remaining debt to be paid off by the community through increased rates.
At this extraordinarily economically challenging time, we urge the Commission to implement SB 1110 by evaluating the 20 percent capacity factor annually as the law intended.

And that is the end of the comment.

Okay. So it looks like we have concluded the public comment portion of the workshop.

Commissioner Douglas, do you have any questions or follow up before we close?

COMMISSIONER DOUGLAS: Hi, I was looking for my mute button.

I just want to thank everybody for participating and I don’t have any additional comment.


MS. LARSON: Great. Then thank you all, everyone for coming, participating, listening, joining us via Zoom for this very first workshop.

Just as a reminder, please provide your written comments by June 22nd, the end of the 45-day comment period. We certainly appreciate comments submitted earlier, if possible, and really encourage you to provide feedback even on those areas that you’ve asked for further clarification or you raised a need for further clarification. We are reviewing those areas that I mentioned but we certainly appreciate your further thoughts and suggestions on what
clarifications might be appropriate and we rely on your comments.

And with that, thank you all very much for coming. And we really appreciate it and hope you all have a great rest of your Monday.

Thank you.

(Thereupon, the Hearing was adjourned at 12:01 p.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.

And I further certify that I am not of counsel or attorney for either or any of the parties to said hearing nor in any way interested in the outcome of the cause named in said caption.

IN WITNESS WHEREOF, I have hereunto set my hand this 15th day of June, 2020.

PETER PETTY
CER*D-493
Notary Public

TRANScriber'S CERTIFICATE

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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 transcribed by me, a certified transcriber.

And I further certify that I am not of counsel or attorney for either or any of the parties to said hearing nor in any way interested in the outcome of the cause named in said caption.

IN WITNESS WHEREOF, I have hereunto set my hand this 15th day of June, 2020.

Jill Jacoby
Certified Transcriber
AAERT No. CERT**D-633