VALLEY
CLEAN ENERGY

Special Meeting of the Valley Clean Energy Alliance
Board of Directors
Wednesday, November 10, 2021 at 5:00 p.m.
Via Video/Teleconference

Pursuant to Assembly Bill 361 (AB 361), legislative bodies may meet remotely without listing the location of each remote attendee, posting agendas at each remote location, or allowing the public to access each location, with the adoption of certain findings. At the October 14, 2021 meeting, the Board of Directors found that the local health official recommended measures to promote social distancing and authorized the continuation of remote meetings for the foreseeable future. Any interested member of the public who wishes to listen in should join this meeting via teleconferencing as set forth below.

Please note that the numerical order of items is for convenience of reference. Items may be taken out of order on the request of any Board member with the concurrence of the Board. Staff recommendations are advisory to the Board. The Board may take any action it deems appropriate on any item on the agenda even if it varies from the staff recommendation.

Members of the public who wish to listen to the Board of Director's meeting may do so with the teleconferencing call-in number and meeting ID code. Teleconference information below to join meeting:

Join meeting via Zoom:

a. **From a PC, Mac, iPad, iPhone, or Android device with high-speed internet. (If your device does not have audio, please also join by phone.)**
   https://us02web.zoom.us/j/83508632109
   Meeting ID: 835 0863 2109
b. **By phone**
   One tap mobile:
   +1-669-900-9128,,83508632109# US
   +1-346-248-7799,,83508632109# US

   Dial:
   +1- 669-900-9128 US
   +1- 346-248-7799 US
   Meeting ID: 835 0863 2109

Public comments may be submitted electronically or during the meeting. Instructions on how to submit your public comments can be found in the PUBLIC PARTICIPATION note at the end of this agenda.

Board Members: Dan Carson (Chair/City of Davis), Jesse Loren (Vice Chair/City of Winters), Don Saylor (Yolo County), Tom Stallard (City of Woodland), Lucas Frerichs (City of Davis), Wade Cowan (City of Winters), Gary Sandy (Yolo County), and Mayra Vega (City of Woodland)

<u>5:00 p.m. Call to Order</u>

1. **Welcome**
2. **Approval of Agenda**
3. **Public Comment:** This item is reserved for persons wishing to address the Board on any VCE-related matters that are not otherwise on this meeting agenda. Public comments on matters <u>listed</u> on the agenda shall be heard at the time the matter is called. As with all public comment, members of the public who wish to address the Board are customarily limited to two minutes per speaker, electronically submitted comments should be limited to approximately 300 words. Comments that are longer than 300 words will only be read for two minutes. All electronically submitted comments, whether read in their entirety or not, will be posted to the VCE website within 24 hours of the conclusion of the meeting. See below under **PUBLIC PARTICIPATION** on how to provide your public comment.

CONSENT AGENDA

4. **Renew authorization of remote public meetings as authorized by Assembly Bill 361.**
5. **Approve Board Minutes: a) October 14, 2021 regular meeting and b) October 21, 2021 special meeting.**
6. **Receive 2021 Long Range Calendar.**
7. **Receive Financial Update – September 30, 2021 (unaudited) financial statement.**
8. **Receive Legislative Update.**
9. **Receive November 4, 2021 Regulatory Update provided by Keyes & Fox.**
10. **Receive November 3, 2021 Customer Enrollment Update.**
11. **Receive Community Advisory Committee October 28, 2021 Meeting Summary.**
12. **Adopt resolution to change existing fiscal year of July 1st to June 30th to align with calendar year of January 1st to December 31st.**
13. **Update of SACOG Grant – Electrify Yolo.**

REGULAR AGENDA

14. **Receive and accept audited financial statements for the period of July 1, 2020 to June 30, 2021 presented by James Marta & Company.**
15. **Consider adoption of Cost-based Customer Rate Policy and Structure.**
16. **Receive 2022 preliminary operating budget.**
17. **Board Member and Staff Announcements:** Action items and reports from members of the Board, including announcements, AB1234 reporting of meetings attended by Board Members of VCEA expense, questions to be referred to staff, future agenda items, and reports on meetings and information which would be of interest to the Board or the public.
18. **Adjournment:** The Board has scheduled a meeting for Thursday, December 9, 2021 at 5:00 p.m. to held via teleconference.

PUBLIC PARTICIPATION INSTRUCTIONS FOR VALLEY CLEAN ENERGY BOARD OF DIRECTORS SPECIAL MEETING ON WEDNESDAY, NOVEMEBER 10, 2021 AT 5:00 P.M.:

PUBLIC PARTICIPATION. Public participation for this meeting will be done electronically via e-mail ***<u>and</u>*** during the meeting as described below.

Public participation via e-mail: If you have anything that you wish to be distributed to the Board and included in the official record, please e-mail it to VCE staff at Meetings@ValleyCleanEnergy.org. If information is received by 3:00 p.m. on the day of the Board meeting it will be e-mailed to the Board members and other staff prior to the meeting. If it is received after 3:00 p.m. the information will be distributed after the meeting, but within 24 hours of the conclusion of the meeting.

Verbal public participation during the meeting: If participating during the meeting, there are two (2) ways for the public to provide verbal comments:

1) If you are attending by computer, activate the "participants" icon at the bottom of your screen, then raise your hand (hand clap icon) under "reactions".
2) If you are attending by phone only, you will need to press *9 to raise your hand.

VCE staff will acknowledge that you have a public comment to make during the item and will call upon you to make your verbal comment.

Public Comments: If you wish to make a public comment at this meeting, please e-mail your public comment to Meetings@ValleyCleanEnergy.org or notifying the host as described above. Written public comments that do not exceed 300 words will be read by the VCE Board Clerk, or other assigned VCE staff, to the Committee and the public during the meeting subject to the usual time limit for public comments [two (2) minutes]. General written public comments will be read during Item 3, Public Comment. Written public comment on individual agenda items should include the item number in the "Subject" line for the e-mail and the Clerk will read the comment during the item. Items read cannot exceed 300 words or approximately two (2) minutes in length. All written comments received will be posted to the VCE website. E-mail comments received after the item is called will be distributed to the Board and posted on the VCE website so long as they are received by the end of the meeting.

Public records that relate to any item on the open session agenda for a regular or special Board meeting are available for public review on the VCE website. Records that are distributed to the Board by VCE staff less than 72 hours prior to the meeting will be posted to the VCE website at the same time they are distributed to all members, or a majority of the members of the Board. Questions regarding VCE public records related to the meeting should be directed to Board Clerk Alisa Lembke at (530) 446-2750 or Alisa.Lembke@ValleyCleanEnergy.org. The Valley Clean Energy website is located at: https://valleycleanenergy.org/board-meetings/.

Accommodations for Persons with disabilities. Individuals who need special assistance or a disability-related modification or accommodation to participate in this meeting, or who have a disability and wish to request an alternative format for the meeting materials, should contact Alisa Lembke, VCE Board Clerk/Administrative Analyst, as soon as possible and preferably at least two (2) working days before the meeting at (530) 446-2754 or Alisa.Lembke@ValleyCleanEnergy.org.

VALLEY CLEAN ENERGY ALLIANCE

Staff Report - Item 4

TO: Board of Directors

FROM: Mitch Sears, Interim General Manager
Alisa Lembke, Board Clerk/Administrative Analyst

SUBJECT: Renew Authorization to continue Remote Public Meetings as authorized by Assembly Bill 361

DATE: November 10, 2021

Recommendation

VCE Board renew authorization for remote (video/teleconference) meetings, including any standing or future committee(s) meetings and Community Advisory Committee meetings, by finding:

1. Pursuant to Assembly Bill 361 (AB 361), that, (a) the COVID-19 pandemic state of emergency is ongoing, and (b) local officials continue to recommend measures to promote social distancing.

Background/Summary of AB 361

Pursuant to Government Code Section 54953(b)(3) legislative bodies may meet by "teleconference" only if the agenda lists each location a member remotely accesses a meeting from, the agenda is posted at all remote locations, and the public may access any of the remote locations. Additionally, a quorum of the legislative body must be within the legislative body's jurisdiction.

Due to the COVID-19 pandemic, the Governor issued Executive Order N-29-20, suspending certain sections of the Brown Act. Pursuant to the Executive Order, legislative bodies no longer needed to list the location of each remote attendee, post agendas at each remote locations, or allow the public to access each location. Further, a quorum of the legislative body does not need to be within the legislative body's jurisdiction. After several extensions, Executive Order N-29-20 expired on September 30, 2021.

On September 16, 2021, the Governor signed AB 361, which kept some of the provisions of Executive Order N-29-20. Pursuant to Government Code Section 54953(e), legislative bodies may meet remotely and do not need to list the location of each remote attendee, post agendas at each remote locations, or allow the public to access each location.

However, legislative bodies must first find: (1) the legislative body is meeting during a state of emergency and determine by majority vote that meeting in person would present an imminent risk to the health or safety of attendees; or (2) state or local health officials impose or recommend social distancing measures.

On July 29, 2021, the County Health Officer issued the attached Amended Order for Wearing of Face Coverings in Workplaces and Public Settings. Page 3, Section 7 of the Amended Order states that all persons should wear well-fitted face coverings and practice physical distancing. Further, on September 22, 2021, the Health Officer issued the attached memorandum, recommending that all Brown Act bodies continue to meet remotely.

Government Code Section 54953(e)(1). The legislative body must make the required findings every 30 days, until the end of the state of emergency or recommended or required social distancing. Government Code Section 54953(e)(3). On January 1, 2024, Government Code Section 54953(e) is repealed.

Due to the rise in COVID-19 cases caused by the Delta Variant, on July 29, 2021, the Yolo County Health Officer issued an Amended Order for the Wearing of Face Coverings in Workplaces and Public Settings a recommendation that all Brown Act bodies meet remotely. The Amended Order requires the use of face coverings indoors and states that all persons should continue to protect themselves and others by physical distancing (see Page 3, Section 7). Further, on October 20, 2021 the Health Officer issued a memorandum to the Yolo County Board of Supervisors, reaffirmed their September 22, 2021 memorandum to continue to recommend meetings be held remotely whenever possible.

On October 14, 2021, the Board authorized the continuation of remote meetings, pursuant to Assembly Bill 361.

Staff will continue to monitor the situation as part of our emergency operations efforts and will return to the Board every thirty (30) days or as needed with additional recommendations related to the conduct of public meetings.

Attachments:

1. Yolo County Health Officer memorandum dated 10/20/21 to Board of Supervisors

COUNTY OF YOLO

Health and Human Services Agency

Karen Larsen, ***LMFT***
Director

Aimee Sisson, MD, MPH
Health Officer

MAILING ADDRESS
137 N. Cottonwood Street • Woodland, CA 95695
www.yolocounty.org

Date: October 20, 2021

To: All Yolo County Boards and Commissions

From: Dr. Aimee Sisson, Health Officer

Subject: Remote Public Meetings

On September 22, I issued a memo recommending remote meetings. While the case rate in Yolo County has declined over the last month, the current case rate represents substantial community transmission. In the context of substantial community transmission, I continue to recommend meetings be held remotely whenever possible. I am re-issuing that memo with updated COVID-19 case rate data.

In light of the ongoing public health emergency related to COVID-19 and the substantial level of community transmission of the virus that causes COVID-19, the Yolo County Public Health Officer recommends that public bodies continue to meet remotely to the extent possible. Board and Commissions can utilize the provisions of newly enacted AB 361 to maintain remote meetings under the Ralph M. Brown Act and similar laws.

Among other reasons, the grounds for the remote meeting recommendation include:

- The continued threat of COVID-19 to the community. As of October 20, 2021, the current case rate is 11.8 cases per 100,000 residents per day. This case rate is considered “Substantial” under the Centers for Disease Control and Prevention’s (CDC) framework for assessing community COVID-19 transmission; and

- The unique characteristics of public governmental meetings, including the increased mixing associated with bringing together people from across the community, the need to enable those who are immunocompromised or unvaccinated to be able to safely continue to fully participate in public governmental meetings, and the challenges of ensuring compliance with safety requirements and recommendations at such meetings.

Meetings that cannot feasibly be held virtually should be held outdoors when possible, or indoors only in small groups with face coverings, maximal physical distance between participants, use of a portable HEPA filter (unless comparable filtration is provided through facility HVAC systems), and shortened meeting times.

This recommendation is based upon current conditions and available protective measures. The Public Health Officer will continue to evaluate this recommendation on an ongoing basis and will communicate when there is no longer such a recommendation with respect to meetings for public bodies.

VALLEY CLEAN ENERGY ALLIANCE

Staff Report – Item 5

TO: Board of Directors

FROM: Alisa Lembke, Board Clerk / Administrative Analyst

SUBJECT: Approval of Minutes from regular October 14, 2021 meeting and special October 21, 2021 meeting

DATE: November 10, 2021

RECOMMENDATION

Receive, review and approve the attached regular October 14, 2021 meeting and special October 21, 2021 meeting Minutes.

MINUTES OF THE VALLEY CLEAN ENERGY ALLIANCE
BOARD OF DIRECTORS REGULAR MEETING
THURSDAY, OCTOBER 14, 2021

The Board of Directors of the Valley Clean Energy Alliance duly noticed their regular meeting scheduled for Thursday, October 14, 2021 at 5:00 p.m., to be held via Zoom webinar. Chair Carson established that there was a quorum present and began the meeting at 5:01 p.m.

Board Members Present:	Dan Carson, Jesse Loren, Tom Stallard, Don Saylor, Gary Sandy, Wade Cowan, Lucas Frerichs, Mayra Vega
Members Absent:	None

Welcome	Chair Carson welcomed everyone.
Approval of Regular Meeting Agenda	Motion made by Director Don Saylor to approve the October 14, 2021 meeting agenda, seconded by Director Jesse Loren. Motion passed unanimously.
Item 3: Authorize continuation of remote public meetings as authorized by Assembly Bill 361	Chair Carson opened the floor for public comment. There were no verbal or written public comments. Motion made by Director Tom Stallard authorizing the continuation of remote (video/teleconference) meetings, including any standing or future committee(s) meetings and Community Advisory Committee meetings, by finding: 1) pursuant to Assembly Bill 361 (AB 361), that, as a result of the COVID pandemic, there is a proclaimed state of emergency and a local official has recommended measures to promote social distancing and 2) on July 29, 2021, the County Health Officer issued the attached Amended Order for Wearing of Face Coverings in Workplaces and Public Settings. Page 3, Section 7 of the Amended Order states that all persons should wear well-fitted face coverings and practice physical distancing. Further, on September 22, 2021, the Health Officer issued the attached memorandum, recommending that all Brown Act bodies continue to meet remotely. This motion was seconded by Director Lucas Frerichs. Motion passed by the following vote: AYES: Carson, Loren, Saylor, Stallard, Vega, Cowan, Frerichs, Sandy NOES: None ABSENT: None ABSTAIN: None Chair Carson noted that the Board will need to address the continuation of remote meetings every 30 days.

Public Comment – General and Consent	Chair Carson opened the floor for public comment for items not listed on the agenda and items listed on the Consent Agenda. There were no verbal or written public comments.
Approval of Consent Agenda	Motion made by Director Jesse Loren to approve the consent agenda items, seconded by Director Frerichs. Motion passed unanimously. The following items were approved, ratified, and/or received: 5. September 9, 2021 Board meeting Minutes; 6. 2021 Long Range Calendar; 7. Financial Updated – August 31, 2021 (unaudited) financial statements; 8. Legislative Update from Pacific Policy Group; 9. October 7, 2021 Regulatory update provided by Keyes & Fox; 10. October 6, 2021 Customer Enrollment Update; 11. Community Advisory Committee September 23, 2021 meeting summary; and, 12. Customer Dividend and Programs Allocation report.
Item 13: Consider entering into a Power Purchase Agreement for renewable energy and capacity between VCE and Willow Springs Solar 3, LLC / Resolution 2021-020	Interim General Manager Mitch Sears introduced this item. VCE Staff Gordon Samuel reviewed background, RPS compliance need, project, key contract terms, project site, portfolio, and staff recommendation. Mark Osterhold and John Sterling of Leeward were present. Mr. Osterhold thanked those present and mentioned that this project is in its advanced construction phase; projects adjacent to this project are developed by Leeward; Leeward is very familiar with Kern County; and, they are looking forward to moving forward with VCE on this project. Chair Carson opened the floor for written and verbal public comments. The following public comments were given. **Written public comment:** Gerry Braun provided written public comment and an article via email on October 13, 2021. Board Clerk Alisa Lembke read his written public comment into the record and did not read the article into the record. Both items will be posted to the VCE website. **Verbal public comment:** Christine Shewmaker, Community Advisory Committee Chair, thought it would be good to have the CAC review this item since the CAC is looking at VCE's renewable portfolio. The Board asked questions and discussed several topics: state compliance requirements, value of input from the Community Advisory Committee, local projects, Board procurement policy, and renewable portfolio. Chair Carson suggested that the Board and CAC have future discussion(s) on procurement policy. Motion made by Director Saylor to 1) approve the Power Purchase Agreement (PPA) by VCEA for 100% of the output for 15 years of the Willow Springs Solar 3 project under development by Leeward Renewable Energy (Leeward) and 2)

authorize the Interim General Manager to execute the PPA substantially in the form attached and authorizes the Interim General Manager, in consultation with General Counsel, to make minor changes to the PPA so long as the term and price are not changed. This motion was seconded by Lucas Frerichs. Motion passed as Resolution 2021-020 by the following vote:

AYES: Carson, Loren, Saylor, Stallard, Vega, Cowan, Frerichs, Sandy
NOES: None
ABSENT: None
ABSTAIN: None

Item 14: Receive draft Cost-Recovery based Customer Rate Structure.

Mr. Sears reminded the Board that there was no staff report provided on this item. Mr. Sears provided information via slides on the background, preliminary estimates of rate impact, suggested process, and next steps.

The Board discussed several items: financial model and analysis of that model, impact to the customer, Power Charge Indifference Adjustment (PCIA) and Resource Adequacy (RA) costs, and steps moving forward. There were no written or verbal public comments.

Director Loren made a motion to follow staff's recommendation to:

- schedule a Special Board Meeting in late October to consider initial corrective action on cost-recovery based rates for implementation in early November;
- have staff continue analysis of longer-term cost-recovery based rate structure for implementation in early 2022 (Feb);
- have staff present analysis and recommended cost-recovery based rate structure to CAC at October 28th meeting; and,
- staff to bring back analysis and recommended cost-recovery based rate structure/rates for consideration by the Board in November.

This motion was seconded by Director Frerichs. Motion passed by the following vote:

AYES: Carson, Loren, Saylor, Stallard, Vega, Cowan, Frerichs, Sandy
NOES: None
ABSENT: None
ABSTAIN: None

Item 15: Approve CAC At-Large Recruitment and Selection Guidelines and appointment to fill one At-Large seat. / Resolution 2021-021

Mr. Sears provided an overview of the staff report provided to the Board. There were no written or verbal public comments.

Motion made by Director Saylor to:

1. Adopt Resolution reaffirming the Board's September 9, 2021 action amending the structure of the Community Advisory Committee, establishing two seats for each member jurisdiction and three At-Large seats for a total of eleven seats; and establishing selection guidance criteria for the At-Large seats.
2. Update the Community Advisory Committee description and application to reflect the structure and selection guidance criteria for the At-Large seats.

	3. Appoint existing CAC member Lorenzo Kristov to one of the At-Large seats. This motion was seconded by Director Loren. Motion passed as Resolution 2021-021 by the following vote: AYES: Loren, Saylor, Stallard, Vega, Cowan, Frerichs, Sandy NOES: None ABSENT: None ABSTAIN: Carson
Item 16: Receive report on concept to align VCE's Fiscal Year with the Calendar Year.	Director Stallard asked if this item could go directly to public comment and a possible motion, without Staff presenting slides. He felt that Staff presented information well in the staff report. There were no Board members who wished to discuss and/or ask questions. There were no written or verbal public comments. Motion made by Director Frerichs for Staff to proceed with the possible change in accounting year from the current Fiscal Year ending on June 30 to a Calendar Year ending on December 31, seconded by Director Stallard. Motion passed by the following vote: AYES: Carson, Loren, Saylor, Stallard, Vega, Cowan, Frerichs, Sandy NOES: None ABSENT: None ABSTAIN: None
Item 20: Board Member and Staff Announcements	There were no Board or Staff announcements. Chair Carson restated that a special meeting is to be scheduled at the end of October and ask for Board Members to get back promptly to Staff on their availability. Chair Carson announced that the regular meeting scheduled for Thursday, November 11, 2021 is a holiday (Veteran's Day) and has been cancelled. The Board has scheduled a special meeting for Wednesday, November 10, 2021 at 5 p.m.
Adjournment	Chair Carson adjourned the regular Board meeting at 6:32 p.m.

Alisa M. Lembke
VCEA Board Secretary

MINUTES OF THE VALLEY CLEAN ENERGY ALLIANCE
BOARD OF DIRECTORS SPECIAL MEETING
THURSDAY, OCTOBER 21, 2021

The Board of Directors of the Valley Clean Energy Alliance duly noticed their Special meeting scheduled for Thursday, October 21, 2021 at 5:00 p.m., to be held via Zoom webinar pursuant to Assembly Bill 361 and the Board's findings to continue remote meetings. Chair Carson established that there was a quorum present and began the meeting at 5:01 p.m.

Board Members Present:	Dan Carson, Jesse Loren, Don Saylor, Wade Cowan, Mayra Vega, Lucas Frerichs, Gary Sandy
Members Absent:	Tom Stallard

Welcome	Chair Carson welcomed everyone.
Approval of Regular Meeting Agenda	Motion made by Director Sandy to approve the October 21, 2021 special meeting agenda, seconded by Director Vega. Motion passed with Director Stallard absent.
Public Comment – General and Consent	Chair Carson opened the floor for public comment for items not listed on the agenda. Board Clerk informed those present that there were no verbal or written public comments.
Item 4: Consider adoption of a rate adjustment effective November 2021 for VCE customer classes excluding CARE and FERA customers.	Interim General Manager Mitch Sears introduced this item and presented slides highlighting items within the Staff Report. The Board commented that the staff report presented information well and explained the reasons for a rate increase. The Board discussed several aspects of this item, including, effects of increase on customers, messaging, outreach strategy, and next steps moving forward. It was suggested that VCE Staff move forward with speaking with other CCAs on alternate structures of VCE as an organization and at a later meeting have the discussion regarding this topic. Chair Carson opened the floor for public comment. There was no written public comment. There was verbal public comment as follows: **Verbal Public Comment:** Christine Shewmaker commented that there are many outside forces out of the organization's control and supports the suggestion of having further discussion on the organization's structure.

Director Frerichs made a motion to:

1. Approve a 5% average generation rate adjustment (equal to 1.9% total electricity charges) effective November 2021 for VCE customer classes excluding California Alternative Rates for Energy (CARE) and Family Electric Rates Assistance (FERA) customers.
2. Direct staff to bring back a cost-recovery based rate structure and estimated 2022 customer rates for consideration at the November Board meeting.

This motion was seconded by Director Sandy. Motion passed by the following vote:

AYES: Carson, Loren, Saylor, Vega, Cowan, Frerichs, Sandy
NOES: None
ABSENT: Stallard
ABSTAIN: None

Adjournment

The Board has scheduled a special meeting for Wednesday, November 10, 2021 at 5 p.m. Chair Carson adjourned the special Board meeting at 5:36 p.m.

Alisa M. Lembke
VCEA Board Secretary

VALLEY CLEAN ENERGY ALLIANCE

Staff Report - Item 6

TO: Board of Directors

FROM: Alisa Lembke, Board Clerk/Administrative Analyst

SUBJECT: Board and Community Advisory Committee 2021 Long-Range Calendar

DATE: November 21, 2021

Recommendation

Receive and file the 2021 Board and Community Advisory Committee long-range calendar listing proposed meeting topics.

VALLEY CLEAN ENERGY

2021 Meeting Dates and ***Proposed*** Topics – Board and Community Advisory Committee

MEETING DATE		TOPICS	ACTION
~~January 14, 2021~~ Special Meeting January 21, 2021	**Board** ~~WOODLAND~~	• Oaths of Office for Board Members (Annual if new Members) • Approve Updated CAC Charge (Annual) • Approve 2021 Procurement Plan • Treasurer Function / Investment • GHG Free Attributes • Power Purchase Agreement • Arrearage Management Plan	• Action • Action • Action • Action • Action • Action • Action
January 28, 2021	**Advisory Committee** ~~WOODLAND~~	• Formation of 2021 Task Groups (Annual) • Quarterly Power Procurement / Renewable Portfolio Standard Update • Quarterly Strategic Plan update • New Building Electrification • 2021 Marketing Outreach Plan • CA Community Power Agency Joint Powers Authority	• Discussion/Action • Informational • Informational • Informational/Discussion • Action: Recommendation to Board • Action: Recommendation to Board
February 11, 2021	**Board** ~~DAVIS~~	• Update on SACOG Grant – Electrify Yolo • 2021 Marketing Outreach Plan • CA Community Power Agency Joint Powers Authority • Update on January 2021 Rates • Update on Time of Use (TOU) roll out	• Informational • Action • Discussion/Action • Informational • Informational
February 25, 2021	**Advisory Committee** ~~DAVIS~~	• Update on SACOG Grant – Electrify Yolo • 2021 Task Groups – Tasks/Charge (Annual) • New Building Electrification • Legislative Bills • Update on Time of Use (TOU) roll out	• Informational • Discussion/Action • Discussion/Action • Discussion/Action • Informational

March 11, 2021	**Board** ~~WOODLAND~~	• New Building Electrification • Legislative Bills	• Discussion/Action • Action
March 25, 2021	**Advisory Committee** ~~WOODLAND~~	• Draft Programs Plan	• Discussion
April 8, 2021	**Board** ~~DAVIS~~	• Preliminary FY21/22 Operating Budget (Annual)	• Informational/Discussion
April 22, 2021	**Advisory Committee** ~~DAVIS~~	• 2021 and 2022 Power Content Update • Quarterly Strategic Plan update • SMUD 2030 Zero Carbon Plan - presentation • AB 992 (Social Media)/Brown Act - Best Best Krieger presentation • Update on SACOG Grant – Electrify Yolo	• Informational • Informational • Informational • Informational/Discussion • Informational
May 13, 2021	**Board** ~~WINTERS~~	• Update on FY21/22 draft Operating Budget • Update on SACOG Grant – Electrify Yolo • Amendments 22 and 23 to SMUD Agreement Task Order 2 • Execution of Letter Re: SMUD, Resource Adequacy to the Central Procurement District	• Informational • Informational • Action • Action
May 27, 2021	**Advisory Committee** ~~WOODLAND~~	• Power Planning 2022 / Renewable Content • Draft 3-Year Programs Plan	• Discussion/Action • Action: Recommendation to the Board
June 10, 2021	**Board** ~~DAVIS~~	• Approval of FY21/22 Operating Budget (Annual) • Extension of Waiver of Opt-Out Fees for one year (Annual) • Amendment 22 SMUD Agreement Task Order 2 • Draft 3-Year Programs Plan	• Action • Action • Action • Action
June 24, 2021	**Advisory Committee** ~~DAVIS~~	• Prioritizing types of energy (placeholder) • Net Energy Metering (NEM) 3.0 Update	• Discussion/Action • Informational
July 8, 2021	**Board** ~~WOODLAND~~	• Re/Appointment of Members to Community Advisory Committee (Annual) (postponed to September meeting) • Net Energy Metering (NEM) 3.0 Update	• Action • Informational

July 22, 2021	**Advisory Committee** ~~WOODLAND~~	• Quarterly Power Procurement / Renewable Portfolio Standard update • Quarterly Strategic Plan update • Legislative Bills update • Rates Task Group report/update	• Informational • Informational • Informational • Informational
August 12, 2021	**Board** ~~DAVIS~~	**Currently, this meeting is cancelled. A special meeting will be scheduled if an urgent item needs to be addressed.**	
August 26, 2021	**Advisory Committee** ~~DAVIS~~	• Update on SACOG Grant – Electrify Yolo (consent) • Carbon Neutral Task Group report/update • Remote meeting update • CAC Structure discussion	• Informational • Informational • Informational • Discussion/Action
September 9, 2021	**Board** ~~WOODLAND~~	• Re/Appointment of Members to Community Advisory Committee (Annual) • Receive Enterprise Risk Management Report (Bi-annual) • Update on SACOG Grant – Electrify Yolo • FY21/22 Operating Budget / RPS update • Strategic Plan update (Carbon Neutrality) (placeholder) • Certification of Standard and UltraGreen Products (Annual)	• Action • Informational • Informational • Informational /Discussion • Informational • Action
September 23, 2021	**Advisory Committee** ~~WOODLAND~~	• Outreach Task Group report/update • Legislative End of Session Update • Update on FY2020/2021 Allocation of Net Margin (Consent) • FY21/22 Operating Budget // Draft Customer Rate/Policy Structure	• Informational • Informational • Informational • Discussion / Action
October 14, 2021	**Board** ~~WINTERS~~	• Draft Customer Rate/Policy Structure • Customer Dividend and Programs Allocation report (Consent) • CAC Restructuring and appointments	• Discussion/Action • Informational • Action
October 28, 2021	**Advisory Committee** ~~DAVIS~~	• Update on Power Content Label Customer Mailer (Consent) • Review Draft Committee Evaluation of Calendar Year End (Annual) • Community resiliency overview/introduction • Final Draft Customer Rate/Policy Structure	• Informational • Discussion • Informational • Action: Recommendation to the Board

Special Meeting: Wednesday, November 10, 2021	**Board** ~~WOODLAND~~	• FY20/21 Audited Financial Statements (James Marta & Co.) (Annual) • Final Draft Customer Rate/Policy Structure • Update on SACOG Grant – Electrify Yolo	• Action • Action • Informational
November 18, 2021 (3rd Thursday of the month due to Thanksgiving holiday)	**Advisory Committee** ~~WOODLAND~~	• 2022 Power Procurement (Directives/Delegations) (Annual) • GHG Free Attributes • Community resiliency overview/introduction • Quarterly Power Procurement / Renewable Portfolio Standard Update • Update on Cost-based Customer Rates (Policy and Structure) • Update on SACOG Grant – Electrify Yolo • Quarterly Strategic Plan update	• Informational • Action: Recommendation to the Board • Informational • Informational • Discussion • Informational • Informational
December 9, 2021	**Board** ~~DAVIS~~	• Approve Directives and Delegations for 2022 Power Procurement Activities (Annual) • Approve 2022 Calendar Year Budget • GHG Free Attributes • Receive CAC 2021 Calendar Year End Report (Annual) • 2021 Year In Review: Customer Care and Marketing • Election of Officers for 2022 (Annual)	• Action • Action • Action • Receive • Receive • Nominations
December 16, 2021 (3rd Thursday of the month due to Christmas holiday)	**Advisory Committee** ~~DAVIS~~	• 2022 CAC Task Group(s) formation (Annual) • Election of Officers for 2022 (Annual) • Carbon Neutral Task Group report/update (placeholder) • CC Power long duration storage (placeholder)	• Discussion/Action • Nominations • Informational/Discussion • Action: Recommendation to the Board
January 13, 2022	**Board** ~~WOODLAND~~	• Oaths of Office for Board Members (Annual if new Members) • Update on Customer Rate/Policy Structure Implementation • CC Power long duration storage (placeholder)	• Action • Action • Action

January 27, 2022	**Advisory Committee** ~~WOODLAND~~	• Update on Customer Rate/Policy Structure Implementation • Quarterly Power Procurement / Renewable Portfolio Standard Update • Quarterly Strategic Plan update	• Informational • Informational • Informational

Note: CalCCA Virtual Annual Meeting Wednesday, 12/1/21 8:30 a.m. – 4:15 p.m.

VALLEY CLEAN ENERGY ALLIANCE

Staff Report – Item 7

TO: Board of Directors

FROM: Mitch Sears, Interim General Manager
Edward Burnham, Finance and Operations Director

SUBJECT: Financial Update – September 30, 2021 (unaudited) financial statements (with comparative year to date information) and Actual vs. Budget year to date ending September 30, 2021

DATE: November 10, 2021

RECOMMENDATION:
Accept the following Financial Statements (unaudited) for the period of September 1, 2021 to September 30, 2021 (with comparative year to date information) and Actual vs. Budget year to date ending September 30, 2021.

BACKGROUND & DISCUSSION:
The attached financial statements are prepared in a form to satisfy the debt covenants with River City Bank pursuant to the Line of Credit and are required to be prepared monthly.

The Financial Statements include the following reports:

- Statement of Net Position
- Statement of Revenues, Expenditures and Changes in Net Position
- Statement of Cash Flows

In addition, Staff is reporting the Actual vs. Budget variances year to date ending September 30, 2021.

<u>Financial Statements for the period September 1, 2021 – September 30, 2021</u>
In the Statement of Net Position, VCEA as of September 30, 2021, has a total of $4,900,264 in its checking, money market and lockbox accounts, $1,100,000 restricted assets for the Debt Service Reserve account, $1,986,833 restricted assets related to supplier deposits, and $2,207,386 restricted assets for the Power Purchases Reserve account. VCEA has incurred obligations from Member agencies and owes as of September 30, 2021, $55,055. VCEA member obligations are incurred monthly due to staffing, accounting, and legal services.

The term loan with River City Bank includes a current portion of $1,251,856. On September 30, 2021, VCE's net position is $11,302,730.

In the Statement of Revenues, Expenditures, and Changes in Net Position, VCEA recorded $4,834,630 of revenue (net of allowance for doubtful accounts), of which $5,923,082 was billed in September and $1,747,846 represent estimated unbilled revenue. The cost of the electricity for the September revenue totaled $5,328,588. For September, VCEA's gross margin was approximately (18.77%), and operating loss totaled ($907,668). The year-to-date change in net position was ($1,178,660).

In the Statement of Cash Flows, VCEA cash flows from operations were ($628,031) due to September cash receipts of revenues being lower than the monthly cash operating expenses.

<u>Actual vs. Budget Variances for the year to date ending September 30, 2021</u>
Below are the financial statement line items with variances >$50,000 and 5%

- Electric Revenue - $3,563,340 and 23% – variance is due to load being more favorable year-to-date than planned; the continued COVID and recessionary impacts and the weather has been warmer than forecast.
- Purchased Power - $2,023,081 and 12% – variance is due to load being more favorable year-to-date than planned; the COVID and recessionary impacts and the weather has been warmer than forecast.
- SMUD Credit Support - $72,370 and 51% – variance is due to higher load and forward market pricing than budgeted.

Attachments:

1) Financial Statements (Unaudited) September 1, 2021 to September 30, 2021 (with comparative year to date information.)
2) Actual vs. Budget for the year to date ending September 30, 2021

VALLEY CLEAN ENERGY ALLIANCE

FINANCIAL STATEMENTS

(UNAUDITED)

FOR THE PERIOD OF SEPTEMBER 1 TO SEPTEMBER 30, 2021

PREPARED ON OCTOBER 31, 2021

VALLEY CLEAN ENERGY ALLIANCE
STATEMENT OF NET POSITION
September 30, 2021
(UNAUDITED)

ASSETS		
Current assets:		
Cash and cash equivalents	$	4,900,264
Accounts receivable, net of allowance		9,613,952
Accrued revenue		1,747,846
Prepaid expenses		20,629
Other current assets and deposits		1,986,883
Total current assets		18,269,574
Restricted assets:		
Debt service reserve fund		1,100,000
Power purchase reserve fund		2,207,386
Total restricted assets		3,307,386
Noncurrent assets:		
Other noncurrent assets and deposits		
Total noncurrent assets		-
TOTAL ASSETS	$	21,576,960
LIABILITIES		
Current liabilities:		
Accounts payable	$	618,299
Accrued payroll		58,888
Interest payable		2,965
Due to member agencies		55,055
Accrued cost of electricity		5,622,003
Other accrued liabilities		545,482
Security deposits - energy supplies		1,980,000
User taxes and energy surcharges		139,682
Limited Term Loan		1,251,856
Total current liabilities		10,274,230
Noncurrent liabilities		
Term Loan- RCB		
Total noncurrent liabilities		-
TOTAL LIABILITIES	$	10,274,230
NET POSITION		
Restricted		
Local Programs Reserve		224,500
Restricted		3,307,386
Unrestricted		7,770,844
TOTAL NET POSITION	$	11,302,730

VALLEY CLEAN ENERGY ALLIANCE
STATEMENT OF REVENUES, EXPENDITURES AND
CHANGES IN NET POSITION
FOR THE PERIOD OF SEPTEMBER 1, 2021 TO SEPTEMBER 30, 2021
(WITH COMPARATIVE YEAR TO DATE INFORMATION)
(UNAUDITED)

	FOR THE PERIOD ENDING SEPTEMER 30, 2021	YEAR TO DATE
OPERATING REVENUE		
Electricity sales, net	$ 4,834,630	$ 18,829,890
TOTAL OPERATING REVENUES	4,834,630	18,829,890
OPERATING EXPENSES		
Cost of electricity	5,328,588	18,831,601
Contract services	216,291	724,773
Staff compensation	86,087	267,934
General, administration, and other	108,984	177,259
TOTAL OPERATING EXPENSES	5,739,950	20,001,567
TOTAL OPERATING INCOME (LOSS)	(905,320)	(1,171,677)
NONOPERATING REVENUES (EXPENSES)		
Other Revenue		
Interest income	1,376	4,742
Interest and related expenses	(3,724)	(11,725)
TOTAL NONOPERATING REVENUES (EXPENSES)	(2,348)	(6,983)
CHANGE IN NET POSITION	(907,668)	(1,178,660)
Net position at beginning of period	12,210,398	12,481,390
Net position at end of period	$ 11,302,730	$ 11,302,730

VALLEY CLEAN ENERGY ALLIANCE
STATEMENTS OF CASH FLOWS
FOR THE PERIOD OF SEPTEMBER 1 TO SEPTEMBER 30, 2021
(WITH YEAR TO DATE INFORMATION)
(UNAUDITED)

	FOR THE PERIOD ENDING SEPTEMBER 30, 2021	YEAR TO DATE
CASH FLOWS FROM OPERATING ACTIVITIES		
Receipts from electricity sales	$ 6,666,395	$ 18,276,957
Receipts for security deposits with energy suppliers	-	-
Payments to purchase electricity	(6,374,497)	(19,788,409)
Payments for contract services, general, and adminstration	(842,402)	(1,277,703)
Payments for staff compensation	(77,527)	(252,751)
Other cash payments	-	-
Net cash provided (used) by operating activities	(628,031)	(3,041,906)
CASH FLOWS FROM NON-CAPITAL FINANCING ACTIVITIES		
Principal payments of Debt	(32,944)	(98,831)
Interest and related expenses	(3,950)	(12,019)
Net cash provided (used) by non-capital financing activities	(36,894)	(110,850)
CASH FLOWS FROM INVESTING ACTIVITIES		
Interest income	1,376	4,742
Net cash provided (used) by investing activities	1,376	4,742
NET CHANGE IN CASH AND CASH EQUIVALENTS	(663,549)	(3,148,014)
Cash and cash equivalents at beginning of period	8,871,199	11,355,664
Cash and cash equivalents at end of period	$ 8,207,650	$ 8,207,650
Cash and cash equivalents included in:		
Cash and cash equivalents	4,900,264	4,900,264
Restricted assets	3,307,386	3,307,386
Cash and cash equivalents at end of period	$ 8,207,650	$ 8,207,650

VALLEY CLEAN ENERGY ALLIANCE
STATEMENTS OF CASH FLOWS
FOR THE PERIOD OF SEPTEMBER 1 TO SEPTEMBER 30, 2021
(WITH YEAR TO DATE INFORMATION)
(UNAUDITED)

	FOR THE PERIOD ENDING SEPTEMBER 30, 2021	YEAR TO DATE
RECONCILIATION OF OPERATING INCOME TO NET CASH PROVIDED (USED) BY OPERATING ACTIVITIES		
Operating Income (Loss)	$ (905,320)	$ (1,171,677)
(Increase) decrease in net accounts receivable	367,235.00	(1,809,741.00)
(Increase) decrease in accrued revenue	1,446,666	1,187,445.00
(Increase) decrease in prepaid expenses	10,324	(5,486.00)
(Increase) decrease in inventory - renewable energy credits	-	-
(Increase) decrease in other assets and deposits	-	-
Increase (decrease) in accounts payable	(112,242)	134,338.00
Increase (decrease) in accrued payroll	8,560	15,183.00
Increase (decrease) in due to member agencies	20,963	(68,351.00)
Increase (decrease) in accrued cost of electricity	(1,045,909)	(956,808.00)
Increase (decrease) in other accrued liabilities	(436,172)	(436,172.00)
Increase (decrease)security deposits with energy suppliers	-	-
Increase (decrease) in user taxes and energy surcharges	17,864	69,363.00
Net cash provided (used) by operating activities	$ (628,031)	$ (3,041,906)

VALLEY CLEAN ENERGY
ACTUAL VS. BUDGET FYE 6-30-2022
FOR THE YEAR TO DATE ENDING 09/30/2021

GL#	Description	9/30/2021 YTD FY2022 Actuals	9/30/2021 YTD FY2022 Budget	YTD Variance	% under
301.00	Electric Revenue	18,829,890	15,266,550	3,563,340	23%
311.00	Interest Revenues	4,742	14,100	(9,358)	-66%
415.00	Purchased Power	18,831,601	16,808,520	2,023,081	12%
	Labor & Benefits	267,935	292,701	(24,766)	-8%
451.10	Salaries & Wages/Benefits	225,590	244,370	(18,780)	-8%
451.20	Contract Labor	-	14,564	(14,564)	-100%
453.41	Human Resources & Payroll	42,345	33,768	8,577	25%
	Office Supplies & Other Expenses	62,896	47,112	15,785	34%
452.10	Technology Costs	5,333	8,508	(3,175)	-37%
452.15	Office Supplies	394	576	(182)	-32%
452.25	Travel	-	1,524	(1,524)	-100%
452.30	CalCCA Dues	28,730	31,054	(2,324)	-7%
	CC Power	28,440	5,000	23,440	469%
452.35	Memberships	-	450	(450)	-100%
	Contractual Services	690,078	645,939	44,139	7%
453.10	Other Contract Services	-	6,000	(6,000)	-100%
453.15	Don Dame	3,395	2,500	895	36%
453.20	SMUD - Credit Support	215,659	143,289	72,370	51%
453.21	SMUD - Wholesale Energy Services	146,961	146,493	468	0%
453.22	SMUD - Call Center	199,463	196,552	2,910	1%
453.23	SMUD - Operating Services	22,944	15,000	7,944	53%
453.24	Commercial Legal Support	-	-	-	100%
453.25	Legal General Counsel	22,827	37,823	(14,996)	-40%
453.36	Regulatory Counsel	41,420	48,665	(7,245)	-15%
453.37	Joint CCA Regulatory counsel	204	7,880	(7,676)	-97%
453.38	Legislative - (Lobbiest)	20,000	15,000	5,000	33%
453.40	Accounting Services	1,206	6,304	(5,098)	-81%
453.41	Financial Consultant	-	6,250	(6,250)	-100%
453.42	Audit Fees	16,000	14,183	1,817	13%
453.60	PG&E Acquisition Consulting	-	-	-	100%
	Marketing	29,691	58,480	(28,789)	-49%
459.05	Marketing Collateral	29,691	56,917	(27,226)	-48%
459.15	Community Engagement Activities & Sponsorship	-	1,563	(1,563)	-100%
	Programs	-	33,750	(33,750)	-100%
	Program Costs	-	33,750	(33,750)	-100%
	Rents & Leases	3,180	6,030	(2,850)	-47%
457.10	Hunt Boyer Mansion	3,180	6,030	(2,850)	-47%
	Other A&G	113,618	102,016	11,602	11%
459.08	Development - New Members	-	6,000	(6,000)	-100%
459.09	Strategic Plan Implementation	22,401	18,750	3,651	19%
459.10	PG&E Data Fees	66,867	75,018	(8,151)	-11%
459.20	Insurance	4,029	1,933	2,096	108%
459.70	Banking Fees	20,321	315	20,005	6347%
463.10	Miscellaneous Operating Expenses	2,567	1,611	957	0%
463.99	Contingency	-	32,862	(32,862)	-100%
	TOTAL OPERATING EXPENSES	20,001,566	18,029,020	1,972,546	11%
481.10	Interest on RCB loan	11,725	4,018	7,707	192%
	NET INCOME	(1,178,660)	(2,752,388)	1,573,729	-57%

VALLEY CLEAN ENERGY ALLIANCE

Staff Report – Item 8

To: Board of Directors

From: Mitch Sears, Interim General Manager

Subject: Legislative Update – Pacific Policy Group

Date: November 10, 2021

Pacific Policy Group, VCE's lobby services consultant, continues to work with Staff and the Community Advisory Committee's Legislative - Regulatory Task Group on several legislative measures. Below is a summary:

The Legislature concluded the 2021 legislative session with final votes cast on Friday, September 10, 2021. Governor Newsom, after a resounding defeat of the attempted recall, finished the bill signing period on October 10, 2021. Of note, the Governor signed AB 843 (Aguiar-Curry), a bill that VCE supported throughout the legislative session.

The 2022 legislative calendar has been published and January 3, 2022 marks the Legislature's return to Sacramento. As 2022 is the second year of the two-year session, a number of two-year bills must pass their house of origin by January 31, 2022 in order for those legislative vehicles to remain active. SB 612 (Portantino) is a two-year bill but has already passed out of its original house and its next deadline is July 1, 2022 when bills must pass a policy committee of the other house.

The Fall months are a time for legislators work on new bill ideas, manage staff changes, and spend more time in the district connecting with constituents. This Fall has one additional element for the Legislature, packing boxes and moving to a new building. A block north of the Capitol, construction is nearly complete on a new ten-story office building that will house the Legislature and the Governor for the next several years while a new office building is built on the Capitol grounds. It is still an unknown if there will be a "return to normal" in regards to in-person meetings and hearings, but one sure thing is that most conversations will not be taking place in the Capitol building.

VALLEY CLEAN ENERGY ALLIANCE

Staff Report – Item 9

To: Board of Directors

From: Mitch Sears, Interim General Manager

Subject: Regulatory Monitoring Report – Keyes & Fox

Date: November 10, 2021

Please find attached Keyes & Fox's October 2021 Regulatory Memorandum dated November 4, 2021, an informational summary of the key California regulatory and compliance-related updates from the California Public Utilities Commission (CPUC).

Attachment: Keyes & Fox Regulatory Memorandum dated November 4, 2021.

KEYES&FOX LLP

Valley Clean Energy Alliance

Regulatory Monitoring Report

To: Valley Clean Energy Alliance ("VCE") Board of Directors

From: Sheridan Pauker, Partner, Keyes & Fox, LLP
Tim Lindl, Partner, Keyes & Fox LLP
Ben Inskeep, Principal Analyst, EQ Research, LLC

Subject: Regulatory Update

Date: November 4, 2021

Summary

Keyes & Fox LLP and EQ Research, LLC, are pleased to provide VCE's Board of Directors with this monthly informational memo describing key California regulatory and compliance-related updates from the California Public Utilities Commission (CPUC). A Glossary of Acronyms used is provided at the end of this memo.

In summary, this month's report includes regulatory updates on the following priority issues:

- **Ensuring Summer 2021 Reliability:** On October 29, 2021, the CPUC issued a Proposed Decision approving VCE's proposed agricultural irrigation pumping DR pilot, with some modifications.
- **New: Safety Culture Assessments**: The CPUC opened R.21-10-001 and issued a new Order Instituting Rulemaking for developing and adopting safety culture assessments under SB 901. Comments on the preliminary scope and schedule are due November 29, 2021.
- **PG&E's Phase 2 GRC:** On October 18, 2021, the ALJ issued a Proposed Decision in PG&E's Phase 2 GRC regarding revenue allocation and rate design issues.
- **PG&E's Phase 1 GRC:** The Assigned Commissioner issued a Scoping Memo and Ruling establishing a scope and procedural schedule, as well as ruling on various motions. On October 8, 2021, PG&E filed a motion requesting permission to file supplemental testimony, to which TURN replied on October 25, 2021.
- **2022-2023 Wildfire Fund Nonbypassable Charge Rulemaking:** The ALJ issued a Proposed Decision that would adopt a Wildfire Fund NBC of $0.00652/kWh for January 1, 2022, through December 31, 2022.
- **New: RA Rulemaking (2023-2023):** On October 11, 2021, the CPUC issued an Order Instituting Rulemaking, opening this rulemaking as the successor rulemaking to the RA Rulemaking (2021-2022) to consider RA oversight and reforms applicable to LSEs for the 2023 and 2024 compliance years. Parties filed opening comments on the OIR on November 1, 2021.
- **RA Rulemaking (2021-2022):** Workshops were held to develop PG&E's Slice-of-Day proposal and related RA program structural reform. On October 11, 2021, parties filed responses to OhmConnect's Petition for Modification of D.20-06-031, to which OhmConnect responded on

October 25, 2021. The October 11, 2021, Order Instituting Rulemaking in the RA Rulemaking (2023-2024) closed this proceeding, except to resolve OhmConnect's Petition for Modification.

- **RPS Rulemaking:** Parties filed comments and reply comments on the Proposed Decision and Commissioner Rechtschaffen's Alternate Proposed Decision, both of which would significantly modify the RPS program confidentiality rules.
- **IRP Rulemaking:** Parties filed reply comments in response to party comments on the August 17, 2021 ALJ Ruling on a proposed Preferred System Plan. VCE and other LSEs made compliance filings by the October 15, 2021 deadline in response to a September 23, 2021, ALJ Ruling directing LSEs to formally file updated IRP information in the docket that had previously been informally provided to the Energy Division. Parties also filed comments and reply comments, in response to an October 13, 2021, Ruling that requested comments on natural gas issues. On October 26, 2021, California Community Power, of which VCE is a member, issued a Request for Offers for up to 200 MW of Firm Clean Resources (i.e., geothermal or biomass) with deliveries beginning no later than June 1, 2026.
- **PG&E 2022 ERRA Forecast:** PG&E filed rebuttal testimony, and parties filed opening and reply briefs.
- **PG&E's 2019 ERRA Compliance:** Energy Division hosted a workshop on the IOU proposed methodology to calculate the revenue requirement of the estimated unrealized volumetric sales and unrealized revenue resulting from PSPS events.
- **PCIA Rulemaking:** Parties filed comments and reply comments on the September 17, 2021, Ruling requesting comments on ERRA and PCIA issues. PG&E also requested to delay implementation of the line-item presentation of the PCIA on bundled customer bills from December 31, 2021, until October 1, 2023.
- **PG&E's 2020 ERRA Compliance:** Parties filed a Settlement Agreement resolving disputed issues in this proceeding.
- **Provider of Last Resort Rulemaking:** Golden State Power Cooperative filed a Motion to remove the state's electric cooperatives as respondents to the proceeding. A workshop was held on October 29, 2021, to review the operation and expectation of POLR service, registration, and financial security requirements.
- **Investigation into PG&E's Organization, Culture and Governance:** CPUC President Batjer sent a letter to PG&E stating that its execution and communication of its wildfire mitigation device setting known as Fast Trip has been extremely concerning and requires immediate action.
- **PG&E Regionalization Plan**: No updates this month. On September 10, 2021, Parties, including VCE, filed comments on the August 31, 2021, motion for approval of settlement agreements, followed by reply comments on September 17, 2021.
- **Direct Access Rulemaking**: No updates this month. In August, CalCCA filed a response to a July application for rehearing filed by a coalition of parties supporting expansion of Direct Access, who challenged a June CPUC decision that recommended against any re-opening of Direct Access. This proceeding is otherwise closed.
- **RA Rulemaking (2019-2020):** No updates this month. Two applications for rehearing remain the only outstanding items to be addressed in this proceeding, which is now closed.
- **Miscellaneous Updates:**
  - The CPUC, as part of its continued efforts to hold PG&E accountable for its safety performance, will hold a remote (virtual) public workshop on November 8, 2021, to discuss and obtain public feedback on the Corrective Action Plan PG&E submitted after the CPUC placed the company in an Enhanced Oversight and Enforcement Process.
  - The Performance Audit of PG&E Wildfire Mitigation Plan Expenditures Final Report was issued October 11, 2021. It found that PG&E only met one of three objectives. The audit

identified total PG&E questioned costs of $59.8 million (e.g., recommended that PG&E not be able to recover these costs in rates) and nearly $1.5 billion in future potential incrementality concerns for Energy Safety to consider.

- CPUC President Marybel Batjer announced she would resign at the end of 2021. CPUC Deputy Executive Director for Energy and Climate Policy and head of the Energy Division, announced he was stepping down as well.

Ensuring Summer 2021 Reliability

On October 29, 2021, the CPUC issued a Proposed Decision that would approve VCE's proposed agricultural irrigation pumping DR pilot, with some modifications. The PD would also adopt numerous other supply- and demand-side changes to address near-term reliability concerns, although the 2,000-3,000 MW procurement mandate would apply specifically to the IOUs.

- **Background**: CAISO experienced rolling blackouts (Stage 3 Emergency) on August 14, 2020 and August 15, 2020 when a heatwave struck the Western U.S. and there was insufficient available supply to meet high demand. The OIR was issued to ensure reliable electric service in the event that an extreme heat storm occurs in the summer of 2021.

  D.21-03-056 instituted modifications to the planning reserve margin (PRM), effectively increasing the PRM beginning summer 2021 from 15% to 17.5%. For 2021, this results in a minimum target of incremental procurement of 450 MW for PG&E, 450 MW for SCE, and 100 MW for SDG&E. The net costs associated with this incremental procurement would be shared by all customers (including CCA customers) in each IOU's service territory. It also authorized the IOUs to implement a Flex Alert paid media campaign program to encourage ratepayers to voluntarily reduce demand during moments of a stressed grid and adopts modifications and expansions to the Critical Peak Pricing (CPP) program, to be in place for the summer of 2021. D.21-03-056 also established an ELRP to provide emergency load reduction and serve as an insurance policy against the need for future rotating outages. The initial duration of the ELRP pilot program is five years, 2021-2025. After-the-fact pay-for-performance will be made at a prefixed energy-only ELRP Compensation Rate ($1,000/MWh for up to an annual 60-hour limit) applied to incremental load reduction. For PG&E, the budget caps are $3.9 million for administration and $28.6 million for customer compensation.

  On August 10, 2021, the Assigned Commissioner issued an Amended Scoping Memo and Ruling addressing Gov. Newsom's emergency proclamation on accelerating plans for the construction, procurement, and rapid deployment of new clean energy and storage projects to mitigate the risk of capacity shortages and increase the availability of carbon-free energy at all times of day by scoping the current phase of the proceeding to include changes that would increase supply and decrease demand to ensure reliability in the summer of 2022 and 2023.

  VCE's testimony and briefs requested that the CPUC approve VCE's proposal for an Agricultural Demand Flexibility Pilot and approve Polaris' proposal for Demand Flexibility Pilots in IOU territories. VCE's proposed pilot would be made available to 5 MW of customer load on irrigation pumping tariffs. The pilot would include automation of these loads to receive dynamic price signals and implementation of an experimental rate that incorporates dynamic energy and capacity charges in hourly prices. Customers who successfully respond to the price signals and shift load out of expensive hours—typically the ramp hours—will enjoy bill savings and the total cost to serve VCE customers would be reduced.

- **Details**: **VCE Pilot:** The PD would approve VCE's dynamic rate pilot for three years (2022-2024), and direct that it start no later than May 1, 2022. Customers participating in VCE's dynamic rate pilot will receive a "shadow bill." PG&E may bill participating customers based on existing tariffs, but the shadow bill will show the customer savings under the pilot dynamic rate, and VCE will pay customers for the difference between the shadow bill and the existing tariff. For the generation components of the service by VCE, (1) energy costs will be based on CAISO wholesale market prices, and (2) generation capacity and flexible capacity costs will be recovered on an hourly basis using the scarcity pricing concept: more fixed costs are recovered when system utilization is higher relative to the system capacity limit. For the delivery component of the service by PG&E, (1) line losses will be recovered through volumetric rates, which could be time dependent, and (2) distribution capacity costs will also be recovered on an hourly basis using the scarcity pricing concept in lieu of monthly or annual demand charges. Non-generation and non-delivery costs (e.g., transmission rates and non-bypassable charges) of the pilot will be recovered through existing rate structures. The pilot scale will be limited to 5 MW of peak load. The PD would direct PG&E to provide funds to or reimburse VCE for crediting any savings realized by the customers with respect to the delivery component of the VCE dynamic rate pilot in the customers' shadow bills. In response to PG&E's assertion that it is not appropriate to use AutoDR or Public Purpose Program funds for enrolling/integrating loads into the pilot program, the CPUC authorized new funding of $3.25 million for the administration and execution of the three-year pilot. VCE and/or PG&E may engage a service provider with a suitable IT platform to automate dynamic hourly prices and make them accessible to customers and automated agricultural water pumps. The PD would require PG&E to conduct a mid-term and final evaluation of this pilot. The mid-term evaluation report is due December 31, 2023, and a final evaluation is due March 1, 2025.

Procurement Mandate for IOUs: The PD would create an additional procurement mandate of 2,000 MW-3,000 MW for 2023, allocated exclusively to the three large IOUs (900 MW-1,350 MW each for PG&E and SCE, and 200 MW-300 MW for SDG&E). The PD also would require all incremental resources procured as a result of this proceeding to be available during net peak.

Demand-Side Changes: The PD would adopt the following demand-side changes:

- Expands on the Emergency Load Reduction Program (ELRP) adopted in Phase 1 of this proceeding, including removing the eligibility requirement that Group A.1 participants in ELRP not take current service on a critical peak pricing or real-time pricing equivalent tariff. A.2 group is expanded to include non-Base Interruptible Program (non-BIP) aggregators of non-residential, non-BIP customers. Residential Net Energy Metering customers meeting the eligibility standards outlined for Group A.3 participants are eligible to participate in ELRP.
- Modifies the ELRP aimed to increase participation and provide clarity in guidance. Among these modifications, the compensation rate of ELRP is expanded to $2/kWh.
- Adds an ELRP program (ELRP Group A.6) that allows residential customers to opt-in to receive compensation for reductions in energy use during system emergencies, with special outreach to low-income customers and customers in Disadvantaged Communities. Customers may not simultaneously be enrolled in another supply side DR program offered by an IOU, third-party DR provider or CCA. Customers likewise may not be taking service on a critical peak pricing, SmartRate or similar dynamic rate tariff. Finally, a CCA may elect not to participate in the Residential ELRP pilot adopted here, in which case its customers would be ineligible to enroll. The CCA must make its election by January 31 of a new ELRP pilot year.
- Expands on electric vehicle potential by allowing aggregation of vehicle to grid managed charging and discharge to support the grid at net peak.
- Broadens the Flex Alert media campaign to focus on the new Residential ELRP program and continue existing activities into 2022 and 2023.
- Makes changes to existing Demand Response programs, both on a statewide basis and to individual programs that pertain to each major electric Investor-Owned Utility.
- Approves a large smart thermostat incentive program ($75/thermostat incentive) designed to reduce air conditioning a few degrees during emergencies, with special protection for low-income customers that qualify for the Energy Savings Assistance Program.

- Adds pilots to test the effectiveness of dynamic rates that change rapidly in response to grid emergencies. This includes the VCE pilot described above, and an SCE-supported pilot.

Supply-Side Changes: The PD would adopt the following supply-side changes:

- Allows energy storage projects that are not fully deliverable as long as they provide peak and net peak grid reliability benefits in summer 2022 or 2023. IOUs can collect the costs of this procurement through distribution rates until the resource is fully deliverable to CAISO markets; after that, net capacity costs and benefits will be accounted for through the CAM mechanism.
- Expands use of a centralized procurement entity as a means of procuring reliability resources located in local areas. Specifically, it would allow SCE and PG&E to negotiate bilateral contracts for the procurement mandated in the PD in their capacities as Central Procurement Entities.
- Encourages accelerated on-line dates for procurement already ordered. The PD declines to develop a new incentive regime for LSEs or generators to bring IRP procurement on earlier than expected. The PD also declines to introduce penalties for delays to the IOU and LSE procurement ordered in D.19-11-016 and declines to increase penalties already adopted for failures in RA procurement.

- **Analysis**: If adopted, the PD would approve VCE's proposed agricultural pumping DR pilot and direct PG&E to work with VCE on implementation. The PD outlines specific requirements for the pilot, as well as requiring an advice letter compliance filing by VCE. The PD would make numerous other changes designed to increase supply and decrease demand during net peak periods, but it largely focuses on IOUs to achieve its aims, including expanding the Central Procurement Entity function of PG&E and SCE to allow for additional procurement. LSEs are encouraged to accelerate their procurement previously ordered in D.21-06-035, but are not required to do so, and the PD declines to adopt an incentive for LSEs to accelerate procurement.

- **Next Steps**: Comments and reply comments on the PD are due November 10, 2021, and November 16, 2021, respectively. The PD may be considered, at the earliest, at the CPUC's December 2, 2021, Business Meeting.

  If the PD is adopted, VCE (in coordination with PG&E) must submit a Tier 1 Advice Letter no later than 60 days after issuance of the CPUC's final decision that includes the following elements: (1) pilot scope, (2) pilot partners, (3) shadow bill implementation, (4) pilot dates, (5) pilot tariff design, and (6) details of how circuit and system data will be used to calibrate and calculate tariff price curves.

- **Additional Information**: Proposed Decision (October 29, 2021); Ruling taking notice of Revised Summer Stack Analysis (September 30, 2021); D.21-09-045 denying rehearing of D.21-03-056 (September 23, 2021); Ruling providing Staff Concepts Proposal (August 16, 2021); Ruling noticing CEC draft Preliminary 2022 Summer Supply Stack Analysis (August 12, 2021); Amended Scoping Memo and Ruling (August 10, 2021); D.21-06-027 (approved June 24, 2021); Order denying applications for rehearing (May 20, 2021); D.21-03-056 (March 25, 2021); D.21-02-028 directing IOUs to seek additional capacity for summer 2021 (February 17, 2021); Scoping Memo and Ruling (December 21, 2020); ALJ Ruling and Staff Proposal (December 18, 2020); Order Instituting Rulemaking (November 20, 2020); Docket No. R.20-11-003.

New: Safety Culture Assessments

On October 7, 2021, the CPUC opened R.21-10-001 and issued a new Order Instituting Rulemaking for developing and adopting safety culture assessments under SB 901.

- **Background**: IOU safety culture assessments are required as part of AB 1054 and SB 901. AB 1054 directed the CPUC's Wildfire Safety Division, now the Office of Energy Infrastructure Safety, to conduct annual safety culture assessments of each electrical corporation, the first of which will be published in fall 2021. The AB 1054 assessments are specific to wildfire safety efforts and include a workforce survey, organizational self-assessment, supporting documentation, and interviews. SB 901 directs the CPUC to establish a safety culture assessment for each electrical corporation, conducted by an independent third-party evaluator. SB 901 requires that the CPUC set a schedule for each assessment, including updates to the assessment, at least every five years, and prohibit the electrical corporations from seeking reimbursement for the costs of the safety culture assessments from ratepayers. This rulemaking implements SB 901.

- **Details**: This proceeding will implement the statutory requirements of SB 901 relating to the Commission's assessment of safety culture for regulated utilities. It will examine what methodologies should be employed in the safety culture assessments to ensure results are comparable across IOUs and can measure changes in IOU safety culture over time. It will also consider adopting the process and framework to oversee safety culture assessments of gas utilities and gas storage operators, in addition to electrical corporations as required by SB 901. It will consider requiring that IOUs implement specific safety management practices to improve safety culture through adoption of a Safety Management System standard, consider adopting a maturity model to use in safety culture assessments, and determine accountability metrics.
- **Analysis**: This rulemaking will assess the safety culture of PG&E and other IOUs in California. While its direct focus is on IOUs like PG&E, it could impact VCE and its customers to the extent it influences PG&E's safety culture and contributes to the safety of VCE customers, as well as the rates VCE customers pay to PG&E to mitigate or address safety issues (e.g., wildfires caused by PG&E transmission equipment; explosions from PG&E natural gas infrastructure, etc.).
- **Next Steps**: Comments on the preliminary scope and schedule are due November 29, 2021. Reply comments are due December 29, 2021.
- **Additional Information**: Order Instituting Rulemaking (October 7, 2021); Docket No. R.21-10-001.

PG&E's Phase 2 GRC

On October 18, 2021, the ALJ issued a Proposed Decision in PG&E's Phase 2 GRC regarding revenue allocation and rate design issues, which also adopts, without modification, several uncontested settlements on rate design issues (residential rate design settlement; settlement on streetlight rate design issues; EDR settlement; agricultural rate design; C&I rate design) and revenue allocation.

- **Background**: PG&E's 2020 Phase 2 General Rate Case (GRC) addresses marginal cost, revenue allocation and rate design issues covering the next three years. PG&E's pending Phase 1 GRC (filed in December 2018 via a separate proceeding) will set the revenue requirement that will carry through to the rates ultimately adopted in this proceeding.

  In this proceeding, PG&E seeks modifications to its rates for distribution, generation, and its public purpose program (PPP) non-bypassable charge. PG&E proposes to implement a plan to move all customer classes to their full cost of service over a six-year period (the first three years of which are covered by this GRC Phase 2) via incremental annual steps. PG&E proposes to use marginal costs for purposes of revenue allocation and to adjust distribution one-sixth of the way to full cost of service each year over a six-year transition period.

  Of note, PG&E is proposing changes to the DA/CCA event-based fees that were not updated in the 2017 Phase 2 GRC proceeding. In addition, PG&E proposes to remove the PCIA revenue from bundled generation revenue and allocate that cost separately to bundled customers, collecting the PCIA from bundled customers on a non-time differentiated, per-kWh basis (i.e., the same way it is collected from DA/CCA customers). PG&E will continue to display the PCIA with other generation charges on customer bills, but will unbundle the PCIA as part of unbundled charges in each rate schedule.

Five settlement agreements are pending. The **Revenue Allocation Supplemental Settlement Agreement** resolves all of the inter-class revenue allocation issues. Regarding bundled PCIA allocation, the parties agreed to remove PCIA at present rates before allocation and reallocate to the classes in proportion to the adopted generation allocation. The settling parties also agreed to keep in Distribution the revenues for DR programs and EV programs. The settling parties agreed to move Energy Efficiency Incentives revenues from Distribution to Public Purpose Programs and allocate them by the Equal Percentage of Total Revenue method.

The **Agricultural Rate Design Supplemental Settlement Agreement** resolves the agricultural rate design issues in this proceeding, except for the issue of a proposed bill credit for PSPS events. The settling parties agreed to the rate designs proposed by PG&E in its opening testimony, for default Schedules AG-A1, AG-A2, AG-B, and AG-C and opt-in Schedules AG-FA, AG-FB, and AG-FC, as well as the demand charge rate limiter for Schedule AG-C, the elimination of the monthly TOU meter charge, maintaining the status quo for the Optimal Billing Period Program, and Peak Day Pricing provisions. Additionally, settling parties agreed to create new optional rate Schedules AG-A3 and AG-B2 that reduce the summer off-peak energy charges below the electric bundled system average rate. The settling parties agreed that the following four issues should not be decided in this case: A new 10-year legacy TOU period, a springtime rate or balancing account adjustment, daily demand charges, and an account or demand aggregation program.

In the **Economic Development Rate (EDR) Supplemental Settlement Agreement** settling parties reached a settlement agreement to continue the EDR program with program-related rate reductions. PG&E's EDR rate reduces both the transmission, distribution, and the generation portions of customer bills. The settlement would provide that the EDR discount should be set in a way that enables CCAs to offer comparable rates, and PG&E and Joint CCAs agreed to a collaborative process to identify and vet EDR applicants that will make it easier for CCAs to provide a generation rate reduction to CCA customers who qualify for PG&E's EDR. The rate reductions for EDR will be separated between generation and distribution amounts, with the deduction to the generation portion specified in the settlement agreement being substantially less than under the current allocation.

The **Commercial and Industrial Rate Design Supplemental Agreement** resolves Commercial and Industrial rate design issues, apart from the issue of CPUC action on the design of PG&E's transmission rates. The settling parties agreed that PG&E should set bundled PCIA initially equal to the most recent vintage PCIA, but use the adopted allocation for generation to set going forward PCIA rates. PG&E would set SOP rates to recover at least the PCIA. The tariff presentation of the PCIA for bundled generation rates would be modified as set forth in PG&E's rebuttal testimony, which proposed alternative tariff language in response to Joint CCAs' proposals.

The **Residential Rate Design Supplemental Settlement Agreement** resolves all residential rate design issues in the proceeding, including:

- The PCIA will be identified for bundled customers as a flat rate (not differentiated by season or TOU period).
- PG&E's proposal for tiered rate levels for Schedule E-1 should be approved.
- PG&E's proposal to keep the Schedule E-TOU-C (*i.e.,* default residential TOU rate) peak versus off-peak price differentials at their current levels until 12 months after the last cohort of PG&E's customers are migrated to default TOU rates should be approved, and future changes over the following three years are specified in the Settlement Agreement.
- PG&E's Schedule E-ELEC should be approved, with the fixed charge set at $15 per customer per month. Since this new E-ELEC rate requires structural changes to PG&E's billing system, PG&E anticipates that it would take at least twelve months after a final decision is issued in this proceeding before it could be programmed, tested, and implemented.

- PG&E will host two workshops to discuss the collection of key information regarding customers who engage in electrification efforts, and the data collected will be provided to interested stakeholders and the Commission as part of a formal Measurement and Evaluation (M&E) study.

- **Details**: The PD largely adopts PG&E's proposed marginal costs and methodologies for deriving them but adopts marginal connection equipment costs proposed by the Agricultural Energy Consumers Association and marginal transmission capacity costs proposed by the Solar Energy Industries Association. It also adopts, without modification, several uncontested settlements on rate design issues (residential rate design settlement; settlement on streetlight rate design issues; EDR settlement; agricultural rate design; C&I rate design) and revenue allocation.

  With respect to CCA issues, the EDR settlement that would be adopted by the PD notes that PG&E and the Joint CCAs agreed to create a collaborative process "to identify and vet EDR applicants that will make it easier for CCAs to provide a generation rate reduction to CCA customers who qualify for PG&E's EDR." The PD would also approve the agricultural rate design settlement that proposed that the unbundling of the PCIA from the generation component of bundled rates be designed as a flat PCIA rate, not differentiated by season or TOU period, consistent with the PCIA rate design for DA and CCA customers. The PCIA rate for bundled customers would use the most recent vintage of the PCIA rate. Finally, the PD would approve the revenue allocation settlement, including its proposal that before allocating generation revenue, instead of including the PCIA revenue in the overall generation revenue requirement, PCIA revenue will be removed from each customer class's revenue at present rates based on the most recent vintage PCIA rates. Then, PG&E will use the adopted allocation for generation to allocate the PCIA revenue requirement to customer classes.

- **Analysis**: The PD, if adopted, would affect the allocation of PG&E's revenue requirements among VCE's different rate classes and the rate design of PG&E's customers. It will also affect distribution and PPP charges paid by VCE customers to PG&E. PG&E's proposed CCA fee revisions were unopposed, and would increase the cost VCE pays to PG&E for various services, to the extent VCE uses these services.

- **Next Steps**: Comments on the PD are due November 8, 2021, and replies are due November 15, 2021. An evidentiary hearing on RTP issues is scheduled for January 24-26, 2021, followed by opening briefs in February 2022, reply briefs in March 2022, a proposed decision in June 2022, and a decision in July 2022.

- **Additional Information**: Amended Scoping Memo and Ruling (August 25, 2021); Ruling directing PG&E to provide marginal cost scenarios (June 16, 2021); Motion to adopt Commercial and Industrial Rate Design Supplemental Agreement (April 13, 2021); Motion to adopt Revenue Allocation Supplemental Settlement Agreement (April 8, 2021); Motion to adopt Agricultural Rate Design Supplemental Settlement Agreement (April 8, 2021); Motion to adopt Economic Development Rate (EDR) Supplemental Settlement Agreement (April 8, 2021); Motion to adopt residential rate design settlement (March 29, 2021); Notice of Virtual Evidentiary Hearing (March 25, 2021); Scoping Memo and Ruling (February 16, 2021); Ruling bifurcating RTP issues into separate track (February 2, 2021); PG&E Status Report (December 18, 2020); D.20-09-021 on EUS budget (September 28, 2020); Ruling extending procedural schedule (July 13, 2020); Exhibit (PG&E-5) (May 15, 2020); Scoping Memo and Ruling (February 10, 2020); Application, Exhibit (PG&E-1): Overview and Policy, Exhibit (PG&E-2): Cost of Service, Exhibit (PG&E-3): Revenue Allocation, Rate Design and Rate Programs, and Exhibit (PG&E-4): Appendices (November 22, 2019); Docket No. A.19-11-019.

PG&E Phase 1 GRC

The Assigned Commissioner issued a Scoping Memo and Ruling on October 1, 2021. On October 8, 2021, PG&E filed a motion requesting permission to file supplemental testimony, to which TURN replied on October 25, 2021.

- **Background**: Phase 1 GRC applications cover the revenue requirement, including the functionalization of costs into categories such as electric distribution or generation, which impact which customers (bundled, unbundled, or both) pay for the costs through rates. Phase 2 GRC applications cover cost allocation (i.e., assigning costs to customer classes, such as Residential) and rate design issues. PG&E proposes to have a second and third track of this Phase 1 GRC to request reasonableness review of certain memorandum and balancing account costs to be recorded in 2021 and 2022. PG&E will file its next Phase 2 GRC application by September 30, 2021.

  On August 25, 2021, the CPUC Executive Director granted PG&E's request to delay filing its next Phase 2 GRC application until September 30, 2024.

  In their protest of PG&E's application, the Joint CCA parties identified the following list of preliminary issues they plan to examine or address in this proceeding:

  - **Compliance with the Commission's Cost Allocation Directives in D.20-12-005** (PG&E's most recently decided Phase 1 GRC decision), including PG&E's cost functionalization methodology, wildfire costs, and allocation of Customer Care costs.
  - **Reinvestments in and Recovery of Legacy Owned Generation Costs**, including solar contract renewals or the decommissioning of legacy owned assets, which impact Joint CCAs' customers through the PCIA and related vintaging of costs.
  - **Other Issues that May Require Further Investigation and Analysis**, including how costs related to PSPS Events should be tracked and allocated; whether and how any funds that PG&E receives as credits (such as Department of Energy settlement funds) should be allocated to departing load customers; and how PG&E's regionalization proposal impacts its relationship and dealings with CCAs and their customers.

  In August, TURN also filed a Motion requesting a Ruling requiring PG&E to supplement its proposal with an alternative spending plan that limits the growth in proposed spending by the rate of inflation.

- **Details**: The Scoping Memo and Ruling divides the proceeding into two tracks. Track 1 will address the majority of matters, including PG&E's requested revenue requirement together with safety and environmental and social justice issues. Track 2 will address the narrower matters of the reasonableness of the 2019-2021 actual costs recorded in the named memorandum accounts and balancing accounts and, to the extent relevant, also address safety and environmental and social justice.

  In addition to establishing the scope and schedule of the proceeding, the Scoping Memo and Ruling directed PG&E to serve testimony to seek approval for any revisions to the forecasted expenditures for its 10,000-mile undergrounding proposal that fall within the timeframe covered by this proceeding. In addition, in an effort to further explore the available affordability metrics based on a motion by TURN, the Scoping Memo and Ruling directed PG&E to work with Energy Division to prepare an analysis, due one month before intervenor testimony is due. However, TURN's motion requesting a Ruling requiring PG&E to supplement its proposal with an alternative spending plan that limits the growth in proposed spending by the rate of inflation was denied.

  PG&E's supplemental testimony addresses two proposals. The first is PG&E's proposal for a mechanism to allow substantial capital accounting policy changes within the 2023 GRC cycle that would provide rate reductions to customers. The goal of the mechanism would be to return to customers the annual expense revenue requirement for newly capitalized programs exceeding $10 million annually, net of any capital revenue requirement associated with the programs' adopted funding. The second is PG&E's proposal to revise the Transportation Electrification Balancing Account (TEBA) to establish two new two-way subaccounts to record and recover costs of electric distribution capacity additions and new interconnection requests to account for the potential rapid growth in EV adoption and the resulting need for electric infrastructure to support EV charging.

- **Analysis**: This proceeding will set the revenue requirement, and thereby ultimately impact PG&E's rates, for 2023-2026. It will establish how the revenue requirement components will be functionalized, which impact whether the ultimately approved costs will be borne by PG&E bundled customers, unbundled customers like VCE customers, or both. It will also address numerous other issues raised in PG&E's application that could impact rates, policies, and programs implemented by PG&E.
- **Next Steps**: The next steps in Track 1 are public participation hearings in January/February 2022, a PG&E status report in February 2022 regarding changes to its cost forecast for wildfire programs, a PG&E affordability metrics report at least one month before intervenor testimony, PG&E testimony on its 2021 recorded expenditures by March 22, 2022, and intervenor testimony on April 29, 2022. Proposed and final decisions are anticipated in Q2 2023.

  In Track 2, public participation hearings are scheduled for November 2022, and intervenor testimony is due November 14, 2022. A proposed decision is anticipated in Q2 2023, and a final decision is anticipated in Q3 2023.
- **Additional Information**: Motion of PG&E to submit supplemental testimony (October 15, 2021); Scoping Memo and Ruling (October 1, 2021); PG&E Application (June 30, 2021); Docket No. A.21-06-021.

2022-2023 Wildfire Fund Nonbypassable Charge Rulemaking

On October 29, 2021, the ALJ issued a Proposed Decision that would adopt a Wildfire Fund NBC of $0.00652/kWh for January 1, 2022, through December 31, 2022.

- **Background**: This rulemaking continues to implement AB 1054, which extended a non-bypassable charge on ratepayers to fund the Wildfire Fund. The CPUC issued D.20-12-024 in December 2020 that continues the Wildfire Non-Bypassable Charge (NBC) amount of $0.00580/kWh for January 1, 2021, through December 31, 2021. The NBC amount of 2022 and 2023 will be established in this proceeding.
- **Details**: The proposed 2022 Wildfire Fund Non-Bypassable Charge is $0.00652/kWh, up from $0.0058/kWh in 2021. The reason for this proposed increase is that the Department of Water Resources demonstrated a collection shortfall of $13.0 million for 2021 and $85.0 million for 2020 (due largely to a lag in initiating and remitting IOU collections for the Wildfire Fund NBC to DWR at the outset of the Wildfire Fund NBC's existence). Therefore, because of this total $98.0 million under-collection in 2020 and 2021, the 2022 Wildfire Fund NBC is obliged to collect both this 2020-2021 shortfall and the 2022's necessary revenue requirement of $902.4 million.
- **Analysis**: VCE customers will pay the 2022 and 2023 Wildfire Fund Non-Bypassable Charge amounts established in this proceeding. The proposed charge for 2022 is increasing due to an under-collection of the revenue requirement in 2021 that has been added to the revenue requirement for 2022.
- **Next Steps**: Comments and reply comments, respectively, are due November 18, 2021, and November 23, 2021. A Decision is expected to be issued in December. (The same timeline used in 2021 to determine the 2022 Wildfire Fund NBC will also apply in 2022 to establish the 2023 Wildfire Fund NBC amount.)
- **Additional Information**: Proposed Decision on Wildfire NBC for 2022 (October 29, 2021); Ruling requesting comments on 2022 Wildfire Fund NBC (September 8, 20210: Scoping Memo and Ruling (June 8, 2021); Order Instituting Rulemaking (March 10, 2021); Docket No. R.21-03-001.

New: RA Rulemaking (2023-2024)

On October 11, 2021, the CPUC issued an Order Instituting Rulemaking (OIR), opening this rulemaking as the successor rulemaking to R.19-11-009 to consider RA oversight and reforms applicable to LSEs for the 2023 and 2024 compliance years. Parties filed opening comments on the OIR on November 1, 2021.

- **Background**: In Track 3B.2 of the 2021-2022 RA Rulemaking (R.19-11-009), D.21-07-014 rejected CalCCA/SCE's proposal for restructuring the RA program, and instead found that PG&E's "slice-of-day" proposal best addresses the identified principles and the concerns with the current RA framework and if is further developed, is best positioned to be implemented in 2023 for the 2024 compliance year. Therefore, it directed parties to collaborate to develop a final restructuring proposal based on PG&E's slice-of-day proposal through a series of workshops. The PG&E Slice of Day Framework will establish RA requirements based on a "slice-of-day" framework, which seeks to ensure load will be met in all hours of the day, not just during gross peak demand hours. The proposal also attempted to ensure there is sufficient energy on the system to charge energy storage resources. The proposed framework would establish RA requirements for multiple slices-of-day across seasons and would establish a counting methodology to reflect an individual resource's ability to produce energy during each respective slice (e.g., six four-hour periods of the day).
- **Details**: The OIR establishes two tracks to this rulemaking. First, the ongoing major RA structural reforms being considered through a workshop process based on PG&E's "slice-of-day" proposal (previously referred to as "Track 3B.2" in the R.19-11-009 RA rulemaking), is now the "Reform Track" in this rulemaking. All other issues relating to RA procurement obligations and program implementation details will be separated into an "Implementation Track." The Implementation Track will address Local RA requirements for 2023-2026, Flexible RA requirements for 2023-2024, potential modifications to the Central Procurement Entity structure and process, potential modifications to the Planning Reserve Margin, potential modifications to Qualifying Capacity Counting Conventions and Effective Load Carrying Capability (i.e., how different types of resources are counted and credited for RA compliance), and refinements to the RA program.
- **Analysis**: This proceeding will determine VCE's RA obligations and applicable RA rules for the 2023-2024 compliance periods. It will also be the forum for determining major RA structural reforms, such as those being discussed related to PG&E's "slice-of-day" proposal. The workshop process on PG&E's Slice of Day proposal could result in major changes to the RA program structure beginning in the 2024 RA compliance year. The new structure would seek to ensure load (including energy storage charging) will be met in all hours of the day, not just during gross peak demand hours and would move RA from a monthly compliance obligation to a seasonal obligation. The details of the framework would be further fleshed out through the workshop process and need to be approved by the CPUC in 2022.
- **Next Steps**: Reply comments on the OIR are due November 10, 2021, and a prehearing conference is scheduled for November 16, 2021. A scoping memo and ruling is anticipated to be issued in December 2021.

  <u>Implementation Track</u>

  - January 2022: party proposals
  - January/February 2022: Workshop(s)
  - February 2022: Comments on proposals
  - February/March 2022: Reply comments
  - April 2022: CAISO publishes draft LCR and FCR Report
  - May 2022: CAISO publishes final LCR and FCR Report
  - May 2022: Proposed Decision
  - June 2022: Final Decision

Reform Track

- September 2021-January 2022: Workshops. The workshops all to run from 10 a.m. to 3 p.m. and are scheduled for November 3, 2021, November 17, 2021, December 1, 2021, December 15, 2021, January 5, 2022, and January 19, 2022.
- February 2022: Workshop Report
- February/March 2022: Comments/reply comments
- Proposed Decision: Summer 2022

- **Additional Information**: Order Instituting Rulemaking (October 11, 2021); Docket No. R.21-10-002.

RA Rulemaking (2021-2022)

On October 6, 2021, and October 20, 2021, workshops were held to develop PG&E's Slice-of-Day proposal and related RA program structural reform. On October 11, 2021, parties filed responses to OhmConnect's Petition for Modification of D.20-06-031, to which OhmConnect responded on October 25, 2021. The October 11, 2021, Order Instituting Rulemaking in the successor RA rulemaking, R.21-10-002, closed this proceeding, except to resolve OhmConnect's Petition for Modification.

- **Background**: This proceeding is divided into 4 tracks, with the focus in 2021 being on Tracks 3 and 4, described in more detail below. Going forward, a workshop process will be used to generate an RA restructuring proposal in Q1 2022, with the goal of implementing more substantial program changes in 2023 for the 2024 RA compliance year.

  Track 3A (completed): D.20-12-006, issued December 2020, addressed the issues of the financial credit mechanism and competitive neutrality rules for the CPEs. It approved CalCCA's proposed "Option 2," with modifications, which allows the CPE to evaluate the shown resource alongside bid resources to assess the effectiveness of the portfolio. The financial credit mechanism will apply only to new preferred or energy storage resources (i.e., non-fossil-based resources) with a contract executed on or after June 17, 2020. It also adopted PG&E's competitive neutrality proposal for PG&E's service territory. Finally, D.20-12-006 found that the Local Capacity Requirements Working Group should continue to discuss recommendations and develop solutions for consideration in CAISO's 2022 LCR process.

  Track 3B.1 and Track 4 (completed): D.21-06-029, issued June 2021, adopted local capacity requirements for 2022-2024, flexible capacity requirements for 2022, and refinements to the RA program. It adopted a series of changes to the Maximum Cumulative Capacity (MCC) buckets, which function as limits on the amount of RA that may be procured from resources with different characteristics. It required resources in all MCC buckets to have availability on Saturday for the 2022 RA compliance year. This had the effect of modifying the DR and Categories 1 and 2 buckets to add Saturday. DR contracts with an execution date prior to the effective date of D.21-06-029 will be grandfathered and not subject to the new Saturday availability requirement. It also revised the Category 1 availability criteria (4 consecutive hours of availability from 4-9 p.m. from May-September) to increase the monthly minimum availability from 40 hours to 100 hours (and 96 hours for February) and to require year-round availability. D.21-06-029 requested that the CEC launch a stakeholder working group process as part of the 2021 IEPR and make recommendations on several topics intended to support a comprehensive and consistent DR measurement and verification strategy, to be considered for implementation during the 2023 RA compliance year. Finally, D.21-06-029 added a new RA deficiencies penalty structure to the current penalty structure, layering on a penalty multiplier for repeat RA deficiencies based on a point system beginning in the 2022 RA compliance year.

  Track 3B.2 (Ongoing): D.21-07-014 rejected CalCCA/SCE's proposal for restructuring the RA program, and instead found that PG&E's "slice-of-day" proposal best addresses the identified principles and the concerns with the current RA framework and if is further developed, is best positioned to be implemented in 2023 for the 2024 compliance year. Therefore, it directed parties to collaborate to develop a final restructuring proposal based on PG&E's slice-of-day proposal through a series of workshops. The PG&E Slice of Day Framework will establish RA requirements based on a "slice-of-day" framework, which seeks to ensure load will be met in all hours of the day, not just during gross peak demand hours. The proposal also attempted to ensure there is sufficient energy on the system to charge energy storage resources. The proposed framework would establish RA requirements for multiple slices-of-day across seasons and would establish a counting methodology to reflect an individual resource's ability to produce energy during each respective slice (e.g., six four-hour periods of the day).

- **Details**: OhmConnect's Petition for Modification of D.20-06-031 requested that the CPUC raise the demand response Maximum Cumulative Capacity limit of 8.3% to 11.3%. OhmConnect says that the change is needed to create the room for growth envisioned in D.20-06-031 and meet the requirements of the Governor's Emergency Proclamation ordering state energy agencies to expedite and expand DR programs to reduce the likelihood of future rotating power outages.

  A group of CCAs (RCEA, San Diego Community Power, and San José Clean Energy) and EBCE filed responses in support of OhmConnect's Petition for Modification. The group of CCAs said a higher cap would enable more flexibility for them in meeting their RA requirements, and help California meet system reliability needs. EBCE's reasons for supporting the petition were provided in a confidential attachment to its response.

- **Analysis**: If OhmConnect's Petition for Modification is granted, it would allow LSEs like VCE to procure a higher percentage of demand response resources to meet its RA obligations than it is currently allowed under the RA compliance rules.

- **Next Steps**: This proceeding is now closed, except to resolve OhmConnect's Petition for Modification.

- **Additional Information**: OhmConnect's Petition for Modification (September 9, 2021); D.21-07-014 on restructuring the RA program with PG&E Slice of Day proposal (July 16, 2021); D.21-06-029 adopting local capacity obligations for 2022-2024, flexible capacity obligations for 2022, and refinements to the RA program (approved June 24, 2021); 2019 Resource Adequacy Report (March 19, 2021); Scoping Memo and Ruling for Track 3B and Track 4 (December 11, 2020); D.20-12-006 on Track 3.A issues (December 4, 2020); D.20-06-031 on local and flexible RA requirements and RA program refinements (June 30, 2020); Order Instituting Rulemaking (November 13, 2019); Docket No. R.19-11-009.

RPS Rulemaking

On October 6, 2021, and October 11, 2021, parties filed comments and reply comments, respectively, on the Proposed Decision (PD) and Commissioner Rechtschaffen's Alternate Proposed Decision (APD), both of which would significantly modify the RPS program confidentiality rules.

- **Background**: This proceeding addresses ongoing RPS issues. VCE submitted its Final 2021 RPS Procurement Plan on February 19, 2021, its Draft 2021 RPS Procurement Plan on July 1, 2021, and its 2020 RPS Compliance Report on August 2, 2021.

  On September 18, 2020, the ALJ issued a Ruling attaching Staff's Proposed Framework for integrating RPS Procurement Plan requirements into the IRP proceeding uses a two-phased approach that makes a relatively minor change to RPS reporting in the current IRP cycle, while fully integrating all elements of RPS Procurement Plans into the next IRP cycle, proposed to commence in the 2023 calendar year (instead of 2022, under the current two-year cycle, although the issue of a two-year versus three-year cycle is not discussed). It is currently unclear when the CPUC will address this proposal.

- **Details**: Current rules allow LSEs to keep procurement prices confidential for the earlier of 3 years *after* the commercial operation date (COD) or 1 year following the expiration of a contract.

Both the PD and APD find that this current window, which typically results in data being held confidential for 5-10 years from the date of contract execution, should be modified.

- **Contracts Not Requiring CPUC Approval (e.g., VCE's contracts):** The PD would order that contract prices and terms become public **30 days** after *the earlier of* the COD or start of delivery date or 3 years after the contract execution date. The APD makes this information public *6 months after contract execution*.
- **REC-Only Contracts***.* The PD would require contract prices and terms for REC-only contracts to be made public 30 days after contract execution for existing facilities, and 30 days after the COD for new facilities. The APD makes this information public for both new and existing facilities 6 months after CPUC approval, or 6 months after the contract execution date where CPUC approval is not required.
- **Competitive Solicitation Information.** The PD first authorizes the release of information on bids that do not result in RPS contracts and RPS bids that are not shortlisted in aggregated form after the final contracts are submitted for CPUC approval where there are at least 3 bidders in a resource category. Additionally, the PD provides a 3-year confidentiality period for individual bidder information after the close of the solicitation. The APD differs from the PD in that it requires individual bidder information to be made public 1 year after final contracts are submitted for CPUC approval or the close of the solicitation (if no contracts are executed).
- **Claims of Confidentiality for RPS Compliance Reports***.* The PDs apply the same rules for all retail sellers, in a continuation of guidance adopted in D.06-06-066. Essentially, securing confidential status will require a retail seller to demonstrate evidence about the type of data and the harm caused by its release to obtain special confidentiality status where a request falls outside the standard confidentiality matrix.
- **Load Forecast & Renewable Net Short.** Currently, per D.06-06-066 retail sellers may utilize a 4-year confidentiality window composed of 3 future years and 1 past year, where the past year refers to the year in which the compliance report is filed. The PDs would shorten the window to 3 years, composed of 2 future years and 1 past year. Thus for the 2022 RPS filings, this information will be confidential for 2022-2024 but the 2025 data would be public. Further, as data becomes 1 year old, it will also become public, such that for the 2022 forecast, the data for 2023 will become public in 2024 when it is 1 year old (and so forth for 2024 data in 2025).
- **Effective Date & Transition Provisions.** Both PDs specify that the rules will become effective immediately upon their adoption for new contracts executed after the date of a Decision. For contracts approved before the effective date, the existing rules are maintained with the exception of expired contracts, which can be made public immediately. RPS compliance reports and any compliance documents submitted on or after January 1, 2022 must follow the revised confidentiality rules.

CalCCA filed comments in support of the PD, arguing that it ensures expanded public access to RPS procurement information while sufficiently protecting market-sensitive information and not disadvantaging any one market participant over another. CalCCA recommended the CPUC reject the APD because the six-month confidentiality protection for contract pricing beginning from the date of contract execution or approval fails to protect market-sensitive information and disadvantages CCAs as compared to IOUs. Finally, CalCCA recommended the CPUC modify Ordering Paragraph 3 of the PD/APD to clarify that a contract amendment does not reduce the otherwise applicable confidentiality window for contract price information.

- **Analysis**: The PD and APD would significantly reduce the period of time for which VCE and other LSEs could keep RPS data confidential, as detailed above.
- **Next Steps**: The PD/APD are scheduled to be considered at the CPUC's November 4, 2021, meeting.
- **Additional Information**: Ruling allowing R.05-06-040 parties to file comments (September 30, 2021); Proposed Decision and Alternate Proposed Decision on RPS confidentiality (September 16, 2021); Ruling aligning IOU RPS Procurement Plan requirements with PCIA decision (May 26,

2021); Ruling extending deadline for draft 2021 RPS Procurement Plan (May 7, 2021); Ruling establishing issues and schedule for 2021 RPS Procurement Plans (March 30, 2021); D.21-01-005 directing retail sellers to file final 2020 RPS Procurement Plans (January 20, 2021); Ruling on Staff proposal aligning RPS/IRP filings (September 18, 2020); Scoping Ruling (November 9, 2018); Docket No. R.18-07-003.

IRP Rulemaking

On October 11, 2021, parties filed reply comments in response to party comments on the August 17, 2021 ALJ Ruling on a proposed Preferred System Plan. VCE and other LSEs made compliance filings by the October 15, 2021 deadline in response to the September 23, 2021, ALJ Ruling directing LSEs to formally file updated IRP information in the docket that had previously been informally provided to the Energy Division. On October 21, 2021, and October 28, 2021, parties filed comments and reply comments, respectively, in response to an October 13, 2021, Ruling that requested comments on natural gas issues. On October 26, 2021, California Community Power, of which VCE is a member, issued a Request for Offers for up to 200 MW of Firm Clean Resources (i.e., geothermal or biomass) with deliveries beginning no later than June 1, 2026.

- **Background**: On September 1, 2020, LSEs including VCE filed their 2020 IRPs, which included updates on each LSE's progress towards completing additional system RA procurement ordered for the 2021-2023 years under D.19-11-016.

  The September 24, 2020 Scoping Memo and Ruling clarified that the issues planned to be resolved in this proceeding are organized into the following tracks:

  - General IRP oversight issues: This track will consider moving from a two-year to a three-year IRP cycle, IRP filing requirements, and interagency work implementing SB 100.
  - Procurement track: D.21-06-035 establishing the 11,500 MW by 2026 procurement mandate resolved many of the procurement track issues. However, the CPUC will conduct additional quantitative and qualitative analysis in the next few months to help inform the preferred system portfolio (PSP) decision, expected by the end of 2021, where it may consider additional capacity procurement requirements, including the possibility of additional fossil fuel procurement.
  - Preferred System Portfolio Development: The CPUC has aggregated LSE portfolios, analyzed the aggregate portfolio, and proposed a PSP. The next step after party comments and reply comments will be the issuance of a proposed decision and final decision adopting a PSP.
  - TPP: *Completed*. D.21-02-028 transmitted portfolios to the CAISO for use in its TPP analysis.
  - Reference System Portfolio Development: To the extent that a new round of RSP analysis is conducted for the next IRP cycle, this proceeding will be the venue for developing and vetting the resource assumptions associated with that analysis in preparation for the next IRP cycle.

  D.20-12-044 established a backstop procurement process that would apply to LSEs that did not opt-out of self-procuring their capacity obligations under D.19-11-016. It requires LSEs to file bi-annual (due February 1 and August 1) updates on their procurement progress relative to the contractual and procurement milestones defined in the decision. After review of the compliance filings, CPUC Staff will bring a Resolution before the Commission specifying the amount of backstop procurement required for a particular IOU on behalf of each LSE for each procurement tranche (2021, 2022, and 2023).

  D.21-06-035 established a new procurement mandate of 11,500 MW of additional zero-emitting or RPS-eligible net qualifying capacity to be procured by 2026 by LSEs through long-term (10 or more years) contracts. It ordered that the resources from Diablo Canyon be replaced with at least

2,500 MW of zero-emitting resources. In addition, it specifies that 2,000 MW of the procurement mandate required for 2026 must be “long-lead-time” (LLT) resources, with half coming from long-duration storage and the other half from zero-emitting resources with an 80% or greater capacity factor, with the Decision pointing to geothermal and biomass as the resources best-suited to meet this category. VCE is permitted to use resources that were not online or in-development and contracted and approved by its Board as of June 30, 2020 to count towards its procurement requirements (i.e., contracts approved by the VCE Board and executed after June 30, 2020, can count towards VCE’s procurement mandates). LSEs will ***not*** be given the option to opt out up front from providing their proportional share of the capacity required by D.21-06-035. The February 1, 2023 compliance filing will be the first check on the status of LLT resource procurement. VCE’s new obligations and a description of the specific resource requirements for each subcategory of procurement are detailed in the following table.

Table: VCE New & Additional Procurement Obligations Under D.21-06-035

				2026 (Long-Lead Time Resources)		Diablo Replacement	
	2023	2024	2025	Long-Duration Storage	Zero-Emitting Generation Resources	Minimum zero-emitting capacity by 2025 *(subset of 2023, 2024, and 2025 columns)*	Total
VCE Obligation (September NQC MW)	8	23	6	4	4	10	44
Resource Requirements	Zero-emitting or RPS eligible	Zero-emitting or RPS eligible	Zero-emitting or RPS eligible	Must be able to discharge at maximum capacity over at least an eight-hour period from a single resource.	Zero-emitting resources or those that otherwise qualify as eligible under the RPS program and have at least an 80% capacity factor. Must be a generating resource, not storage, able to generate when needed, for as long as needed. Must not be use limited or weather dependent. May not have any on-site emissions, except if the resource otherwise qualifies under the RPS.	(1) Be from a generation resource, a generation resource paired with storage (physically or contractually), or a demand response resource; (2) Be available every day from 5 p.m. to 10 p.m. (the beginning of hour ending 1800 through the end of hour ending 2200), Pacific Time, at a minimum; and (3) Be able to deliver at least 5 megawatt-hours of energy during each of these daily periods for every megawatt of incremental capacity claimed.	

An August 17, 2021 Ruling provided a summary of analysis conducted by CPUC Staff to recommend key elements of the preferred system plan (PSP), including a preferred resource portfolio. The Ruling describes how and why LSEs’ IRPs submitted in September 2020 are expected to fall short of meeting GHG and reliability targets, due to a collective insufficiency of planned new capacity. However, when incorporating the expected impacts of the procurement mandates in D.21-06-035 on mid-term reliability, the Ruling states that reliability and GHG goals are likely to be achieved. The Ruling recommends that the 38 MMT Core Portfolio be adopted by the CPUC as the PSP. This would be a more aggressive GHG target than the 46 MMT by 2030 target previously adopted.

- **Details**: The October 13, 2021 Ruling requested comments and recommendations in response to the CEC’s Mid-Term Reliability Analysis Staff Report and a CPUC staff paper titled “Considering Gas Capacity Upgrades to Address Reliability Risk in Integrated Resource Planning." The analyses could be used to support a CPUC decision allowing or requiring natural gas plant upgrades to meet reliability needs in the mid-term. The CEC Mid-Term Reliability Analysis covered reliability modeling for the years 2023 – 2026, questions associated with the growth of battery energy storage on the grid and the implications for reliability, and options for additional thermal resources. Actions the CPUC could take in response include procurement actions this year as part of consideration a Preferred System Plan (PSP), such as whether gas capacity upgrades at existing sites should be considered as eligible resources for the procurement requirements of D.21-06-035 (i.e., the decision creating a procurement mandate for 11,500 MW of new capacity). The CPUC staff paper found that allowing gas upgrades lowers CAISO system costs in all scenarios and concluded that gas upgrades appeared cost-effective for reliability needs starting in 2024, and in the near-term to meet a higher PRM in 2022 or 2023.

The October 26, 2021 RFO issued by CC Power could result in resource procurement that would allow VCE to meet its compliance obligation for additional clean firm resources under D.21-06-035.

- **Analysis**: The August 17, 2021 Ruling proposing a PSP would accelerate the build-out of clean energy resources by adopting a more aggressive GHG reduction target for the electricity sector over the coming decade. It also posed numerous questions that suggest the CPUC is considering other major changes to procurement mandates that could either result in additional or accelerated procurement requirements for VCE or the imposition of a non-bypassable charge, including on VCE customers, to recover the costs of additional procurement needed for reliability or policy reasons. The October 13, 2021 Ruling on natural gas issues suggests a future CPUC decision could could modify the 11,500 MW procurement mandate under D.21-06-035 to allow certain natural gas capacity upgrades at existing sites to be eligible.
- **Next Steps**: The schedule is as follows:
    - Procurement track: Potential changes to natural gas eligibility under D.21-06-035, and associated procurement actions by the CPUC, apparently will be considered as part of the PSP track (below). It is unclear at this time if other procurement-related issues will be addressed via the PSP decision or through separate CPUC decisions.
    - General IRP oversight issues: A Proposed Decision on the IRP cycle (e.g., possibly moving from every 2 years to a 3-year cycle) is anticipated to be issued soon.
    - Preferred System Portfolio Development: The issuance of a proposed decision, followed by opportunities for comments and reply comments, and the issuance of a final decision are anticipated next.
- **Additional Information**: Ruling requesting comments on natural gas issues (October 13, 2021); Ruling granting IRP confidentiality motions (September 23, 2021); Ruling proposing a PSP (August 17, 2021); Ruling extending procurement compliance filing deadline (July 10, 2021); D.21-06-035 establishing a 11,500 MW by 2026 procurement mandate (June 24, 2021); Ruling Setting August 1, 2021 Procurement Compliance Deadline (April 9, 2021); D.21-02-028 recommending portfolios for CAISO's 2021-2022 TPP (February 17, 2021); D.20-12-044 establishing a backstop procurement process (December 22, 2020); Scoping Memo and Ruling (September 24, 2020); Resolution E-5080 (August 7, 2020); Ruling on IRP cycle and schedule (June 15, 2020); Order Instituting Rulemaking (May 14, 2020); Docket No. R.20-05-003.

PG&E 2022 ERRA Forecast

On October 6, 2021, PG&E filed rebuttal testimony. On October 22, 2021, and November 1, 2021, respectively, parties filed opening and reply briefs.

- **Background**: Energy Resource and Recovery Account (ERRA) forecast proceedings establish the amount of the PCIA and other non-bypassable charges for the following year, as well as fuel and purchased power costs associated with serving bundled customers that utilities may recover in rates.

  On June 1, 2021, PG&E filed its 2022 ERRA Forecast application, requesting a 2022 ERRA forecast revenue requirement for ratesetting purposes of $4.736 billion. After accounting for $2.479 billion of Utility Owned Generation (UOG)-Related Costs and amounts related to capped 2020 departing load PCIA rates addressed in D.20-12-038, PG&E is requesting a revenue requirement request in this application of $2.263 billion.

PG&E preliminarily forecasts that in 2022 the system average bundled service customer rate will increase by 2.4%, the system average DA and CCA rate will decrease by 9.6%, and the departing load rate will increase by 1.7%. VCE's customers' PCIA rates will decrease, on average, by $0.01872/kWh (2017 PCIA Vintage). Consistent with D.21-05-030, PG&E has removed the capping and triggering mechanisms for PCIA rates in this 2022 ERRA Forecast Application. PCIA rates for the 2009 though 2022 customer vintages include PCIA base rates, formerly referred to as uncapped PCIA rates in the 2021 ERRA Forecast Application, plus PUBA rate adders for each vintage. Proposed 2022 PCIA rates, inclusive of the PUBA adder, are shown in the table below.

TABLE 20-4
PROPOSED POWER CHARGE INDIFFERENCE ADJUSTMENT RATES BY CLASS AND VINTAGE APPLICABLE TO POWER CHARGE INDIFFERENCE ADJUSTMENT -ELIGIBLE DEPARTING LOAD CUSTOMERS (WITH DWR FRANCHISE FEE)
($/KWH)

Line No.	Customer Class	2009 Vintage	2010 Vintage	2011 Vintage	2012 Vintage	2013 Vintage	2014 Vintage	2015 Vintage	2016 Vintage	2017 Vintage	2018 Vintage	2019 Vintage	2020 Vintage	2021 Vintage	2022 Vintage
1	Residential	$0.01962	$0.02508	$0.02641	$0.02901	$0.02812	$0.02825	$0.02810	$0.02845	$0.02817	$0.02858	$0.02810	$0.02484	$0.03364	$0.03364
2	Small L&P	$0.01875	$0.02397	$0.02523	$0.02772	$0.02687	$0.02700	$0.02685	$0.02719	$0.02692	$0.02731	$0.02685	$0.02374	$0.03214	$0.03214
3	Medium L&P	$0.02022	$0.02585	$0.02721	$0.02990	$0.02897	$0.02912	$0.02896	$0.02932	$0.02903	$0.02945	$0.02896	$0.02560	$0.03467	$0.03467
4	B19/E19	$0.01880	$0.02403	$0.02530	$0.02780	$0.02694	$0.02707	$0.02692	$0.02727	$0.02699	$0.02739	$0.02693	$0.02380	$0.03224	$0.03224
5	Streetlights	$0.01563	$0.01998	$0.02103	$0.02311	$0.02240	$0.02250	$0.02238	$0.02266	$0.02244	$0.02276	$0.02238	$0.01979	$0.02679	$0.02679
6	Standby	$0.01409	$0.01801	$0.01896	$0.02083	$0.02019	$0.02028	$0.02017	$0.02043	$0.02022	$0.02052	$0.02018	$0.01784	$0.02415	$0.02415
7	Agriculture	$0.01777	$0.02271	$0.02391	$0.02627	$0.02546	$0.02558	$0.02544	$0.02576	$0.02550	$0.02587	$0.02544	$0.02249	$0.03046	$0.03046
8	B20/E20 T (Excluding Fl	$0.01607	$0.02053	$0.02162	$0.02375	$0.02302	$0.02313	$0.02300	$0.02329	$0.02306	$0.02340	$0.02301	$0.02034	$0.02754	$0.02754
9	B20/E20 P (Excluding F	$0.01721	$0.02200	$0.02316	$0.02545	$0.02466	$0.02478	$0.02464	$0.02496	$0.02471	$0.02507	$0.02465	$0.02179	$0.02950	$0.02950
10	B20/E20 S (Excluding Fl	$0.01794	$0.02294	$0.02415	$0.02653	$0.02571	$0.02584	$0.02569	$0.02602	$0.02576	$0.02613	$0.02570	$0.02272	$0.03076	$0.03076
11	BEV1	$0.01597	$0.02042	$0.02150	$0.02362	$0.02289	$0.02300	$0.02287	$0.02316	$0.02293	$0.02326	$0.02288	$0.02022	$0.02738	$0.02738
12	BEV2	$0.01865	$0.02384	$0.02510	$0.02758	$0.02673	$0.02686	$0.02671	$0.02705	$0.02677	$0.02717	$0.02671	$0.02361	$0.03198	$0.03198
13	System Average PCIA Rate by Vintage	$0.01886	$0.02411	$0.02539	$0.02789	$0.02704	$0.02717	$0.02702	$0.02736	$0.02709	$0.02748	$0.02703	$0.02391	$0.03231	$0.03231

- **Details**: Testimony of the Joint CCAs recommends, among other provisions:
  - PG&E should correct the allocation of the gain on sale of its San Francisco headquarters across the ERRA and PCIA vintages to be consistent with the allocation of other common costs included in the PCIA.
  - The 2022 Indifference Amount and 2021 year-end PABA balance should be reduced to remove the above-market cost of solar resources used to supply PG&E's GTSR and DAC-GT programs.
  - PG&E should be required to provide Reviewing Representatives access to confidential data used in prior ERRA Forecasts as part of the existing Master Data Request.
  - PG&E's proposed transfer of the 2021 year-end ERRA balancing account balance to the latest PABA vintage should again be approved as an interim measure until this issue is resolved in the PCIA rulemaking proceeding.
  - PG&E should correct a miscalculation of the RA Charge included in its GTSR and Enhanced Community Renewables rates.
  - PG&E should be required to identify in future ERRA proceedings transactions executed by PG&E as the Central Procurement Entity 22 for Local RA and the effect of CPE procurement on the Cost Allocation Mechanism and PCIA.
- **Analysis**: PG&E has agreed with the Joint CCAs on the SF headquarters allocation. It continues to fight against transparency in its rates, but then caved on providing the prior year's workpapers to the CCAs in each case in its Reply Brief. It also continues to undervalue the GTSR RA charge, which makes its 100% renewable program look more cost competitive than it actually is and creates a cost shift between bundled customers that participate in the program and those that do not. Lastly, PG&E continues to fight against parties being able to analyze its CPE transactions in a transparent manner.
- **Next Steps**: PG&E's update is due November 8, 2021, comments on the PG&E update are due November 18, 2021, a proposed decision will be issued December 1, 2021, and a final decision is anticipated on December 13, 2021.

- **Additional Information**: Scoping Memo and Ruling (August 11, 2021); Notice of Prehearing Conference (July 15, 2021); Application (June 1, 2021); Docket No. A.21-06-001.

PG&E's 2019 ERRA Compliance

Energy Division hosted a workshop on the IOU proposed methodology to calculate the revenue requirement of the estimated unrealized volumetric sales and unrealized revenue resulting from PSPS events.

- **Background**: Phase 1 has been resolved. The September 7, 2021 Ruling consolidated the Phase 2 ERRA compliance proceedings of PG&E, SCE, and SDG&E. The issues scoped for Phase 2 are:
  - What is the appropriate methodology for calculating a utility's unrealized volumetric sales and unrealized revenues resulting from PSPS events in any given record year? Based on this methodology, what are the utilities' (PG&E, SCE, and SDG&E) unrealized volumetric sales and unrealized revenues resulting from 2019 PSPS events?
  - Whether it is appropriate for the utilities to return the revenue requirement equal to the unrealized volumetric sales and unrealized revenue resulting from the PSPS events in 2019.
- **Details**: At the October 26, 2021, workshop hosted by Energy Division, the IOUs (PG&E, SCE, and SDG&E) made a joint presentation of their proposal for a methodology to calculate the revenue requirement of the estimated unrealized volumetric sales and unrealized revenue resulting from PSPS events. CCA representatives pushed back that the IOUs had not considered unrealized revenues from utility-owned generation that had not been bid into the CAISO market. The ALJ requested the CCAs make a motion to clarify whether that issue is in scope in the proceeding.
- **Analysis**: Phase 2 of the proceeding is assessing whether PG&E should be required to return its revenue requirement associated with unrealized sales associated with its 2019 PSPS events, and the methodology and inputs for calculating such disallowance. VCE's customers could benefit from such a CPUC-determined disallowance, e.g., via a bill credit or reduced PG&E charges.
- **Next Steps**: IOU Phase 2 testimony is due November 5, 2021, Intervenor Phase 2 testimony is due January 17, 2022, IOU rebuttal testimony is due February 15, 2022, and a Joint Case Management Statement is due February 25, 2021.
- **Additional Information**: Ruling consolidating ERRA compliance proceedings (September 7, 2021); PG&E Application for Rehearing of D.21-07-013 (August 16, 2021); D.21-07-013 resolving Phase 1 (July 16, 2021); Joint Motion to Adopt Settlement Agreement (October 22, 2020); Amended Scoping Memo and Ruling (August 14, 2020); Scoping Memo and Ruling (June 19, 2020); PG&E's Application and Testimony (February 28, 2020); Docket No. A.20-02-009.

PCIA Rulemaking

On October 1, 2021, and October 8, 2021, respectively, parties filed comments and reply comments on the September 17, 2021, Ruling requesting comments on ERRA and PCIA issues. On October 19, 2021, PG&E requested to delay implementation of the line-item presentation of the PCIA on bundled customer bills from December 31, 2021, until October 1, 2023.

- **Background**: D.18-10-019 was issued on October 19, 2018, in Phase 1 of this proceeding and left the current PCIA in place, maintained the current brown power index, and adopted revised inputs to the benchmarks used to calculate the PCIA for energy RPS-eligible resources and resource adequacy capacity. Phase 2 relied primarily on a working group process to further develop a number of PCIA-related proposals. Three workgroups examined three issues: (1)

issues with the highest priority: Benchmark True-Up and Other Benchmarking Issues; (2) issues to be resolved in early 2020: Prepayment; and (3) issues to be resolved by mid-2020: Portfolio Optimization and Cost Reduction, Allocation and Auction.

D.20-08-004, in response to the recommendations of Working Group 2, (1) adopted the consensus framework of PCIA prepayment agreements; (2) adopted the consensus guiding principles, except for one principle regarding partial payments; (3) adopted evaluation criteria for prepayment agreements; (4) did not adopt any proposed prepayment concepts; and (5) clarified that risk should be incorporated into the prepayment calculations by using mutually acceptable terms and conditions that adequately mitigate the risks identified by Working Group Two.

The Phase 2 Decision, D.21-05-030, addressed the recommendations of PCIA Working Group 3 and removed the cap and trigger for PCIA rate increases, authorized new Voluntary Allocation, Market Offer, and Request for Information processes for RPS contracts subject to the PCIA, and approved a process for increasing transparency of IOU RA resources. However, it did not provide unbundled customers proportional access to system and flexible RA products through the RA voluntary allocation and market offer process proposed by PCIA Working Group 3. Likewise, it declined to provide unbundled customers any access to GHG-Free energy on a permanent basis.

The CCA Parties' Application for Rehearing of D.21-05-030 challenges the Decision's rejection of the RA voluntary allocation and market offer and GHG-free energy allocation. It argues that D.21-05-030 violates Public Utilities Code Section 366.2(g), which guarantees CCA customers the full benefit of the resources for which they bear cost responsibility through the PCIA charge. While CCA customers pay for the RA and GHG-Free products in the PCIA portfolio, the Phase 2 Decision, provides only bundled customers preferential access to RA products and no access to GHG-Free energy on a long-term basis. The CCA Parties argue that since D.21-05-030 effectively requires unbundled customers to pay equally for benefits only bundled customers receive, the Phase 2 Decision also violates the Section 365.2 prohibition against cost-shifting among unbundled and bundled customers.

A Staff Proposal on which the August Ruling requested comments would move the Market Price Benchmark calculation date up by one month – from November 1 to October 1 – to allow for a "normal" proceeding schedule and enable flexibility in addressing last- minute issues. Staff's analysis found that the effects of changes in the forecast RPS and RA adders on PCIA rates are relatively small and concluded that the largest driver of changes to PCIA rates would be the energy index.

Details: The October 19, 2021, PG&E requested an extension of time to comply with Ordering Paragraph 2 of D.20-03-019, which requires PG&E to display a PCIA line item on bundled customer bills. PG&E requests an extension to comply with this requirement from December 31, 2021, to October 1, 2023. PG&E says this is necessary because it is undertaking a multi-year billing system modernization initiative that has required a freeze in any new structural rate changes and billing presentation to PG&E's Advanced Billing System through October 2022. After meeting with CCA, Direct Access, and Energy Division representatives, PG&E also committed to make several additional changes to the bill related to PCIA presentation and rate comparison and to conduct further meetings to discuss how the stakeholders' broader desires for bill presentment might be achieved more efficiently as a package, including showing PCIA as a line item on the back of the bill, within PG&E's billing system modernization initiative timeline. In addition to updating the PCIA definition, PG&E will make the following changes as an interim solution by Q2 2022 to help customers understand that the generation line items on bundled bills include a component for PCIA analogous to the PCIA line item on unbundled customers' bills:

- The definition on the back of the bill will also include a link to www.pge.com/cca which hosts the CCA rate comparison reports and also includes a side-by-side listing of the PCIA charge for bundled customers and unbundled customers by rate class.
- The PCIA component for bundled customers will be included in the CCA annual rate comparison mailer typically sent in July each year, subject to approval by the CPUC Public Advisor's Office.

  - A bill message on bundled customers' service agreement details section of their bill indicating the information regarding the PCIA component of generation and the link to www.pge.com/cca.

- **Analysis**: The issues on which the CPUC requested comments in the September Ruling impact CCAs' ability to gain access to confidential IOU data pertinent to the calculation and implementation of the PCIA, as well as the alignment of ERRA and PCIA proceedings. PG&E's requested extension of time would delay the line-item PCIA on bundled customer bills, but include interim changes such as providing in bills a link to PG&E's website that includes CCA rate comparisons and additional information on the PCIA.

- **Next Steps**: This proceeding remains open to consider (1) Phase 2 issues relating to ERRA proceedings and (2) whether GHG-Free resources are under-valued in the PCIA methodology, and if so, the appropriate way to address this problem.

  D.21-05-030 identified the following next steps:

  - **January 1, 2022**: PCIA cap is removed from rates.
  - **January 2022**: Once the 2021 RFIs are approved, the IOUs may request approval for Contract Assignments and Contract Modifications in response to the RFI by filing Tier 3 advice letters.
  - **February 2022**: After approval of the joint methodology advice letter, IOUs will inform LSEs of their potential Voluntary Allocation shares.
  - **May 2022**: IOUs and LSEs complete the process of determining interest in Allocation elections.
  - **June 2022**: Each IOU confirms Voluntary Allocations and propose Market Offers in their 2022 RPS Procurement Plans. LSEs request approval for Voluntary Allocations in their 2022 RPS Procurement Plans.

- **Additional Information**: Ruling requesting comments (September 17, 2021); Ruling providing Energy Division proposal (August 25, 2021); PG&E AL 6306-E (August 23, 2021); PG&E AL 5973-E-A (August 13, 2021); CalCCA Application for Rehearing of D.21-05-030 (June 23, 20210: D.21-05-030 on PCIA Cap and Portfolio Optimization (May 24, 2021); D.21-03-051 granting petition to modify D.17-08-026 (March 26, 2021); Amended Scoping Memo and Ruling (December 16, 2020); CalCCA/DACC/AReM Protest of PG&E AL 5973-E (November 2, 2020); PG&E AL 5973-E (October 12, 2020); CalCCA/DACC Response to Joint IOU AL on D.20-03-019 (September 21, 2020); Joint IOUs PFM of D.18-10-019 (August 7, 2020); D.20-08-004 on Working Group 2 PCIA Prepayment (August 6, 2020); D.20-06-032 denying PFM of D.18-07-009 (July 3, 2020); D.20-03-019 on departing load forecast and presentation of the PCIA (April 6, 2020); Ruling modifying procedural schedule for working group 3 (January 22, 2020); D.20-01-030 denying rehearing of D.18-10-019 as modified (January 21, 2020); D.19-10-001 (October 17, 2019); Phase 2 Scoping Memo and Ruling (February 1, 2019); D.18-10-019 Track 2 Decisions adopting the Alternate Proposed Decision (October 19, 2018); D.18-09-013 Track 1 Decision approving PG&E Settlement Agreement (September 20, 2018); Docket No. R.17-06-026.

PG&E 2020 ERRA Compliance

On October 15, 2021, parties filed a Settlement Agreement resolving disputed issues in this proceeding.

- **Background**: The annual ERRA Compliance proceeding reviews the utility's compliance with CPUC-approved standards for generation-procurement and cost recovery activity occurring in the preceding year, such as energy resource contract administration, least-cost dispatch, fuel procurement, and balancing account entries.

  PG&E is requesting that the CPUC find it complied with its Bundled Procurement Plan (BPP) in the areas of fuel procurement, administration of power purchase contracts, greenhouse gas compliance instrument procurement, resource adequacy sales, and least-cost dispatch of electric generation resources for the 2020 calendar year. It also seeks a CPUC finding that it managed its utility-owned generation (UOG) facilities reasonably, although it recommends that CPUC review of outages at Diablo Canyon Power Plant related to the Unit 2 main generator be delayed to the 2021 ERRA Compliance review. Of significance to the PCIA, PG&E is requesting the CPUC find that entries in its Portfolio Allocation Balancing Account (PABA), which trues up the above-market forecast of generation resources recovered through the PCIA with actual recorded costs and revenues, are accurate.

PG&E's procurement costs recorded across the portfolio were $158.8 million higher than forecasted, allegedly due to higher-than-forecast RPS-eligible contracts, as offset by higher than forecast retained RPS and retained RA, as well as lower than forecast fuel costs for UOG facilities. Activity recorded in the PABA includes the following categories: Revenues from Customers, RPS Activity, RA Activity, Adopted UOG Revenue Requirements, CAISO Related Charges and Revenues, Fuel Costs, Contract Costs, GHG Costs, and Miscellaneous Costs. PG&E has redacted as confidential its 2020 actual and forecast costs for these categories, so it is unclear from the public filing what the magnitude is regarding the difference between actual and forecast costs for each category.

The Scoping Memo and Ruling specifies the proceeding will be divided into two phases. Phase 1 will address whether PG&E (1) prudently administered and managed Utility-Owned Generation facilities and QF and non-QF contracts, (2) achieved least-cost dispatch of energy resources, (3) had reasonable, accurate, and appropriate ERRA and PABA entries, and (4) administered RA procurement and sales consistent with its Bundled Procurement Plan, among other issues. Phase 2 issues may be amended based on the outcome of Phase 2 of PG&E's 2019 ERRA compliance proceeding. The tentative list of issues include whether sales forecasting methods for adjusting revenue requirement under current decoupling policy should be adjusted to account for power not sold or purchased during a Public Safety Power Shutoff (PSPS) event in 2020, whether it is appropriate for PG&E to return the revenue requirement equal to the estimated unrealized volumetric sales and unrealized revenue resulting from the PSPS events in 2020, and the appropriate methodology for calculating PG&E's unrealized volumetric sales and unrealized revenues resulting from 2020 PSPS events.

In testimony, Joint CCAs recommended a number of accounting adjustments that would reduce PUBA balances by more than $14.3 million. They also recommend the CPUC acknowledge that PG&E's internal audit of its PABA concluded that the processes and controls governing PABA accounting are "Not Adequate," and that PG&E remedy the identified deficiencies. Furthermore, they recommend that the CPUC clarify that future procurement expenses incurred by PG&E acting as the Central Procurement Entity will be reviewable in ERRA Compliance proceedings, and that PG&E should demonstrate the effect of such procurement, if any, on the PABA and ERRA balancing accounts.

PG&E agreed in rebuttal testimony that the accounting for PCIA costs attributed to customers taking service on the GTSR tariff should be adjusted to correctly credit PABA for the 2019 and 2020 record periods, reducing the PABA balance by approximately $5 million. PG&E also agreed to present testimony in its 2021 ERRA Compliance proceeding addressing actions taken in response to the Internal Audit findings that PABA accounting process and controls were inadequate.

- **Details**: In the Settlement Agreement, PG&E agreed with the Joint CCAs' position to a disallowance of $247,500 associated with CAISO penalties for load meter data errors, late submission of Resource Adequacy and Supply Plans and missed deadlines for grid modeling data or telemetry communication for PG&E's utility owned generation and that any future sanctions for missed deadlines for grid modeling data or telemetry communication for PG&E's utility-owned generation will not be recovered from customers. Joint CCAs agreed that CAISO sanctions associated with Power Purchase Agreements (contracted generation) were caused by the counterparty and passed through to the counterparty and should not be disallowed.

PG&E agreed that entries to the PABA for costs associated with the Green Tariff Shared Renewables program should be reduced by $5 million for 2019 and 2020, as Joint CCAs had argued.

PG&E also agreed that certain issues should be in the scope of future ERRA proceedings, resolving the Joint CCA concern regarding its ability to review PG&E's accounting with respect to transactions with the CPE in future ERRA Compliance proceedings.

Finally, PG&E agreed to transfer from PABA to ERRA 2014 and 2017 Diablo Canyon Seismic Studies Balancing Account recorded costs, whereas the 2018 costs were retained in the PABA, which resolved the Joint CCAs concerns about that cost recovery.

- **Analysis**: This proceeding addresses PG&E's balancing accounts, including the PABA, providing a venue for a detailed review of the billed revenues and net CAISO revenues PG&E recorded during 2020. It also determines whether PG&E managed its portfolio of contracts and UOG in a reasonable manner. Both issues could impact the level of the PCIA in 2022 and 2023.
- **Next Steps**: A PD is anticipated for Q1 2022.
- **Additional Information**: Joint Motion for Adoption of Settlement Agreement (October 15, 2021); Scoping Memo and Ruling (June 21, 2021); Application (March 1, 2021); Docket No. A.21-03-008.

Provider of Last Resort Rulemaking

On October 28, 2021, Golden State Power Cooperative filed a Motion to remove the state's electric cooperatives as respondents to the proceeding. A workshop was held on October 29, 2021, to review the operation and expectation of POLR service, registration, and financial security requirements.

- **Background**: A POLR is the utility or other entity that has the obligation to serve all customers (e.g., PG&E is currently the POLR in VCE's territory). In 2019 the Legislature passed SB 520, which defined POLR for the first time in statute, confirmed that each IOU is the POLR in its service territory, and directed the Commission to establish a framework to allow other entities to apply and become the POLR for a specific area (a "Designated POLR"). This rulemaking will implement SB 520.

  The Scoping Memo and Ruling describes the issues that are within scope in the proceeding and the procedural schedule going forward, although most of the procedural dates currently lack specificity. Phase 1 of this OIR will address POLR service requirements, cost recovery, and options to maintain GHG emission reductions in the event of an unplanned customer migration to the POLR. Phase 2 will build on the Phase 1 decision to set the requirements and application process for other non-IOU entities (i.e., a CCA, Energy Service Provider, or third-party) to be designated as the POLR in place of an existing POLR. Phase 3 will address specific outstanding issues not resolved in Phase 1 and 2 of this proceeding.
- **Details**: Golden State Power Cooperative argues in its Motion that the CPUC does not have authority over electric cooperative rate-setting, and as such, issues regarding POLR requirements, cost recovery, or cost allocation are not directly relevant to the electric cooperatives. Since the electric cooperatives are not POLRs and because they do not have CCAs or ESPs providing electricity in their service territories, Golden State Power Cooperative asserts the issues regarding the return of customers to the POLR are not germane to the electric cooperatives and they should be removed as respondents.
- **Analysis**: This proceeding could impact VCE in several ways. First, in establishing rules for existing POLRs, it will address POLR service requirements, cost allocation, and cost recovery issues should a CCA or other LSE discontinue supplying customers resulting in the need for the POLR to step in to serve those customers. Second, in setting the requirements and application process for another entity to be designated as the POLR, it could create a pathway for a CCA or other retail provider to elect to become a POLR for its service area. The preliminary questions

(Appendix B to the OIR) suggest these issues will include examining topics such as CCA financial security requirements, portfolio risk and hedging, CCA deregistration, CCA mergers, and CCA insolvency.

- **Next Steps**: A ruling will be issued in Q4 2021 or Q1 2022 with questions to parties to comment on. Opening and reply comments will be due in Q1 2022.
- **Additional Information**: Golden State Power Cooperative Motion to remove cooperatives as respondents (October 28, 2021); Scoping Memo and Ruling (September 16, 2021); Ruling scheduling prehearing conference (April 30, 2021); Order Instituting Rulemaking (March 25, 2021); Docket No. R.21-03-011.

Investigation into PG&E's Organization, Culture and Governance (Safety OII)

On October 25, 2021, CPUC President Batjer sent a letter to PG&E stating that its execution and communication of its wildfire mitigation device setting known as Fast Trip has been extremely concerning and requires immediate action.

- **Background**: On December 21, 2018, the CPUC issued a Scoping Memo opening the next phase of an ongoing investigation into whether PG&E's organizational culture and governance prioritize safety. This current phase of the proceeding is considering alternatives to current management and operational structures for providing electric and natural gas in Northern California.

  A July 2020 ALJ Ruling described the issues that are potentially still in scope for this proceeding, which include a broad array of issues identified in the December 21, 2018 Scoping Memo, as modified by D.20-05-053 approving PG&E's reorganization plan, plus the ongoing work of NorthStar, the consultant monitoring PG&E. However, the Ruling observed that "it is not clear as a practical matter how many of those issues can be or should be addressed at this time," given PG&E is now implementing its reorganization plan and has filed its application for regional restructuring. Party comments did not explicitly raise the issue of CCA proposals to purchase PG&E electric distribution assets.

  A September 4, 2020 Ruling determined that I.15-08-019 will remain open as a vehicle to monitor the progress of PG&E in improving its safety culture, and to address any relevant issues that arise, with the consultant NorthStar continuing in its monitoring role of PG&E. The Ruling declined to close the proceeding but also declined to move forward with CCAs' consideration of whether PG&E's holding company structure should be revoked and whether PG&E should be a "wires-only company," as well as developing a plan for service if PG&E's CPCN is revoked in the future.

  In April 2021, the CPUC issued Resolution M-4852, placing PG&E into the first of six steps of the Enhanced Oversight and Enforcement process. This six-step process could ultimately result in a revocation of PG&E's certificate of public convenience and necessity if it fails to take sufficient corrective actions. Resolution M-4852 found that PG&E made insufficient progress toward approved safety or risk-driven investments and is not sufficiently prioritizing its Enhanced Vegetation Management (EVM) based on risk. It found that PG&E is not doing the majority of EVM work – or even a significant portion of work – on the highest risk lines.

  On August 18, 2021, CPUC President Batjer sent a letter to PG&E stating that she has directed CPUC staff to investigate whether to advance PG&E further within the Enhanced Oversight and Enforcement process. President Batjer's letter to PG&E identified "a pattern of self-reported missed inspections and other self-reported safety incidents," concluding that "this pattern of deficiencies warrants the fact-finding review." PG&E self-reported missed inspections of hydroelectric substations, distribution poles, and transmission lines. PG&E also reported missing internal targets for enhanced vegetation management and failing to identify dry rot in distribution poles treated with Cellon coating. Many of these issues occurred in High Fire Threat District areas.

- **Details**: The October 25, 2021, letter from President Batjer to PG&E asserts that PG&E's "execution and communication of its wildfire mitigation device setting known as Fast Trip has been extremely concerning and requires immediate action to better support customers in the event of an outage." It finds that since PG&E initiated the Fast Trip setting practice on 11,500 miles of lines in High Fire Threat Districts in late July, it has caused over 500 unplanned power outages impacting over 560,000 customers. It goes on to say that these Fast Trip-caused outages occur with no notice and can last hours or days. The letter goes on to outline near-term and ongoing transparency and accountability actions, as well as cost tracking.
- **Analysis**: The October 25, 2021, letter indicates PG&E's issues with outages extend beyond its execution of PSPS events and include its implementation of Fast Trip. Unlike a PSPS event, by definition, Fast Trip settings do not allow for advance notice to customers of an outage. The letter directs PG&E to make a number of corrective actions and filings related to transparency and accountability.
- **Next Steps**: The proceeding remains open, but there is no procedural schedule at this time.
- **Additional Information**: Letter from President Batjer to PG&E on Fast Trip issues (October 25, 2021); Letter from President Batjer to PG&E (August 18, 2021); Resolution M-4852 (April 15, 2021); Letter from President Batjer to PG&E (November 24, 2020); Ruling updating case status (September 4, 2020); Ruling on case status (July 15, 2020); Ruling on proposals to improve PG&E safety culture (June 18, 2019); D.19-06-008 directing PG&E to report on safety experience and qualifications of board members (June 18, 2019); Scoping Memo (December 21, 2018); Docket No. I.15-08-019.

PG&E Regionalization Plan

No updates this month. On September 10, 2021, Parties, including VCE, filed comments on the August 31, 2021, motion for approval of settlement agreements, followed by reply comments on September 17, 2021.

- **Background**: In D.20-05-051 approving PG&E's reorganization following bankruptcy, PG&E was directed to file a regionalization proposal (Docket No.19-09-016). On June 30, 2020, PG&E filed its regionalization proposal, which describes how it plans to reorganize operations into new regions. PG&E proposes to divide its service area into five new regions. PG&E will appoint a Regional Vice President by June 2021 to lead each region, along with Regional Safety Directors to lead its safety efforts in each region. The new regions would include five functional groups that report to the Regional Vice President encompassing various functions including: (1) Customer Field Operations, (2) Local Electric Maintenance and Construction, (3) Local Gas M&C, (4) Regional Planning and Coordination, and (5) Community and Customer Engagement. Other functions will remain centralized, such as electric and gas operations, risk management, enterprise health and safety, the majority of existing Customer Care and regulatory and external affairs, supply, power generation, human resources, finance, and general counsel.

  In August 2020, parties filed protests and responses to PG&E's application. Of note, South San Joaquin Irrigation District filed a Protest arguing that PG&E's regionalization effort should not create a moratorium or interfere with municipalization efforts. In addition, five CCAs filed responses or protests to PG&E's application, with MCE and EBCE filing protests and City of San Jose, City and County of San Francisco, and Pioneer Community Energy filing responses.

  In February 2021, PG&E submitted its updated regionalization proposal ("Updated Proposal"). In response to feedback, PG&E modified its five regions (renamed North Coast, North Valley & Sierra, Bay Area, South Bay & Central Coast, and Central Valley), <u>including moving Yolo County from Region 1 to Region 2 (North Valley & Sierra), where it would be grouped with the following counties: Colusa, El Dorado, Glenn, Lassen, Nevada, Placer, Plumas, Sacramento, Shasta, Sierra, Solano, Sutter, Tehama, and Yuba</u>. PG&E also provided more information on the new leadership positions that it is creating and its "Lean Operating System" implementation.

Currently, PG&E is in Phase 1 of 3 of its regionalization plan, which is focused on refining regional boundaries, establishing roles and governance for regional leadership, and recruiting and hiring for those positions. In Phase 2 (second half of 2021 through 2022), PG&E will establish and implement the regional boundaries and provide the resources and staffing to support it. In Phase 3 (2023 and after), PG&E will continue to reassess, refine and collaborate with other functional groups to improve efficiencies, safety, reliability and customer service.

On August 31, 2021, PG&E, the California Farm Bureau Federation, the California Large Energy Consumers Association, the Center for Accessible Technology, the Coalition of California Utility Employees, the Public Advocates Office at the California Public Utilities Commission ("Cal Advocates"), the Small Business Utility Advocates, and William B. Abrams filed a motion for approval of their settlement agreement ("Multi-Party Settlement Agreement). A separate settlement agreement is between the South San Joaquin Irrigation District and PG&E. The Multi-Party Settlement Agreement includes a framework within which PG&E will facilitate a stakeholder engagement process for parties to the Multi-Party Settlement Agreement to provide updates and a non-binding forum for input for stakeholders. The proposed settlement would restrict participation in the Regionalization Stakeholder Group to parties or others who agree to the scope, procedures and protocols of the Regionalization Stakeholder group as outlined in the settlement. PG&E will host two public workshops in 2022 and for each year until the completion of Phase III or its regionalization implementation to provide updates to the public about its regionalization implementation progress.

In the separate PG&E/SSJID Settlement Agreement, PG&E clarified and confirmed that its implementation of regionalization as managed by its Regionalization Program Management Office will not include any work to oppose SSJID's municipalization efforts. However, SSJID also acknowledged that PG&E may continue to respond to SSJID's municipalization efforts in other forums and proceedings separate from the regionalization proceeding and/or implementation of the Updated Regionalization Proposal.

- **Details**: VCE filed comments on the settlement jointly with Pioneer Community Energy that were critical of PG&E's Updated Proposal and the settlement. VCE and Pioneer recommended that the CPUC reject the settlement and require changes to PG&E's Updated Proposal, including alignment with the boundaries of regional councils of governments ("COGs") and requirements to coordinate with COGs, the development of metrics to measure PG&E's progress on key safety and customer relations issues, greater coordination between PG&E and CCAs, and improvements to the Regionalization Stakeholder Group to expand its access and efficacy.
- **Analysis**: The implications of PG&E's regionalization plan on CCA operations, customers, and costs are largely unclear based on the information presented in PG&E's application and updated application. PG&E's regionalization plan could impact PG&E's responsiveness and management of local government relations and local and regional issues, such as safety, that directly impact VCE customers. It could also impact municipalization efforts, although the pending SSJID settlement agreement stated that PG&E's regionalization efforts will not be in opposition to SSJID's municipalization. As part of Region 2, VCE would be grouped with several northern counties in central and eastern California.
- **Next Steps**: A Proposed Decision will be issued next.
- **Additional Information**: Joint Motion for approval of Settlement Agreements (August 31, 2021); Ruling granting schedule modification (August 20, 2021); Ruling denying evidentiary hearing (July 28, 2021); PG&E Joint Case Management Statement (July 20, 2021); Amended Scoping Memo and Ruling (June 29, 2021); PG&E Updated Regionalization Proposal (February 26, 2021); Ruling modifying procedural schedule (December 23, 2020); Scoping Memo and Ruling (October 2, 2020); Application (June 30, 2020); A.20-06-011.

Direct Access Rulemaking

No updates this month. On August 13, 2021, CalCCA filed a response to a July application for rehearing filed by a coalition of parties supporting expansion of Direct Access, who challenged a June CPUC decision that recommended against any re-opening of Direct Access. This proceeding is otherwise closed.

- **Background**: In Phase 1 of this proceeding, the CPUC allocated the additional 4,000 GWh of Direct Access load to non-residential customers required by SB 237 (2018, Hertzberg) among the three IOU territories with implementation to begin January 1, 2021.

  In Phase 2, the CPUC issued D.21-06-033 recommending against any further Direct Access expansion at this time based primarily on a concern that doing so "would present an unacceptable risk to the state's long-term reliability goals." It observed that after considering recent reliability events (i.e., the summer 2020 heat storm and resulting rolling blackouts in California and February 2021 outage event and skyrocketing electricity prices in Texas) and IRP forecasts for additional generation, expanded direct access would result in further system fragmentation that raises serious electric system reliability concerns. Further portions of the Decision:

  - Observed that Direct Access providers do not have a track record of relying on long-term contracts to meet their energy needs, which could impede the development of new, needed resources.
  - Noted that allowing expansion could undermine the long-term contracts that LSEs such as CCAs have already entered (i.e., due to load migration) and make it difficult for them to enter new contracts.
  - Stated that currently, the CPUC is not able to ensure that Direct Access expansion would not increase GHG emissions and other pollutants when compared to retaining the current cap, as Direct Access providers have historically relied primarily on unspecified power and lead to a net decline in clean energy procurement.

- **Details**: In their July Application for Rehearing, parties including the Alliance for Retail Energy Markets and the Direct Access Customer Coalition argued that:

  - The CPUC broke the law and abused its discretion when it disregarded the express duties imposed on it by SB 237.
  - D.21-06-033 ignored the substantial evidence in the record as it pertains to: (1) concerns about electric service provider (ESP) procurement performance and (2) the alleged threat to reliability posed by load migration due to an expansion of Direct Access is inaccurate and discriminatory.
  - D.21-06-033 discriminates against non-residential customers and the ESPs that wish to serve them, thereby violating the dormant Commerce Clause of the US Constitution.
  - D.21-06-033 relied on "misrepresentations of facts and speculations."

  CalCCA's August response argued that:

  - The CPUC's interpretation of the statute was consistent with its plain language and legislative history.
  - The Decision is supported by the findings required by statute and is also adequately supported by findings based on the entire administrative record.
  - The dormant Commerce Clause argument fails because the Decision applies equally to both in-state and out-of-state ESPs, and therefore does not unfairly discriminate against out-of-state interests.
  - The argument that the Decision discriminates against both ESPs and their customers and therefore violates their Equal Protection rights fails the "rational basis" test in that the

Decision is based on the findings regarding electric grid reliability and environmental concerns.

- **Analysis**: This proceeding determined the CPUC's recommendations to the Legislature regarding the potential future expansion of DA in California. D.21-06-033 recommending against expansion of Direct Access at this time could reduce the risk of load migration from CCAs (or IOUs) to ESPs.

- **Next Steps**: The only remaining item to be addressed in this proceeding is the Application for Rehearing.

- **Additional Information**: CalCCA Response to Application for Rehearing (August 13, 2021); Application for Rehearing of D.21-06-033 (July 29, 2021); D.21-06-033 recommending against direct access expansion (approved June 24, 2021); Ruling and Staff Report (September 28, 2020); Amended Scoping Memo and Ruling adding issues and a schedule for Phase 2 (December 19, 2019); Docket No. R.19-03-009; *see also* SB 237.

RA Rulemaking (2019-2020)

No updates this month. Two applications for rehearing remain the only outstanding items to be addressed in this proceeding, which is now closed.

- **Background**: This proceeding had three tracks, which have now concluded. Track 1 addressed 2019 local and flexible RA capacity obligations and several near-term refinements to the RA program. D.19-10-020 purported to affirm existing RA rules regarding imports, but adopted a distinction in the import RA compliance requirements for resource-specific and non-resource specific contracts and required, for the first time, that non-resource-specific resources self-schedule (i.e., bid as a price taker) in the CAISO energy market.

  In Track 2, the CPUC previously adopted multi-year Local RA requirements and initially declined to adopt a central buyer mechanism (D.19-02-022 issued March 4, 2019).

  The second Track 2 Decision, D.20-06-002, adopted implementation details for the central procurement of multi-year local RA procurement to begin for the 2023 compliance year in the PG&E and SCE (but not SDG&E) distribution service areas, including identifying PG&E and SCE as the central procurement entities for their respective distribution service areas and adopting a hybrid central procurement framework. The Decision rejected a settlement agreement between CalCCA and seven other parties that would have created a residual central buyer structure (and did not specify the identity of the central buyer) and a multi-year requirements for system and flexible RA. Under D.20-06-002, if an LSE procures its own local resource, it may (1) sell the capacity to the CPE, (2) utilize the resource for its own system and flexible RA needs (but not for local RA), or (3) voluntarily show the resource to meet its own system and flexible RA needs, and reduce the amount of local RA the CPE will need to procure for the amount of time the LSE has agreed to show the resource. Under option (3), by showing the resource to the CPE, the LSE does not receive one-for-one credit for shown local resources. A competitive solicitation (RFO) process will be used by the CPEs to procure RA products. Costs incurred by the CPE will be allocated ex post based on load share, using the CAM mechanism. D.20-06-002 also established a Working Group (co-led by CalCCA) to address: (a) the development of an local capacity requirements reduction crediting mechanism, (b) existing local capacity resource contracts (including gas), and (c) incorporating qualitative and possible quantitative criteria into the RFO evaluation process to ensure that gas resources are not selected based only on modest cost differences.

  In Track 3, D.19-06-026 adopted CAISO's recommended 2020-2022 Local Capacity Requirements and CAISO's 2020 Flexible Capacity Requirements and made no changes to the System capacity requirements. It established an IOU load data sharing requirement, whereby each non-IOU LSE (e.g., CCAs) will annually request data by January 15 and the IOU will be required to provide it by March 1. It also adopted a "Binding Load Forecast" process such that an

LSE's initial load forecast (with CEC load migration and plausibility adjustments based on certain threshold amounts and revisions taken into account) becoming a binding obligation of that LSE, regardless of additional changes in an LSE's implementation to new customers.

On October 30, 2019, CalCCA filed a PFM of D.19-06-026, seeking the creation of an RA waiver process in 2020 for system and flexible RA obligations.

Details: The only two remaining items to be addressed in this proceeding are two applications for rehearing filed by Western Power Trading Forum (WPTF). First, on July 17, 2020, WPTF filed an Application for Rehearing of D.20-06-002, the Track 2 Decision creating a multi-year central procurement regime for local RA capacity. It requested rehearing and reconsideration of the rejected settlement agreement between WPTF, CalCCA, and other parties, arguing that D.20-06-002 will discourage the procurement of local resources by individual LSEs, discriminates against natural gas resources while increasing the need for CAISO backstop procurement, may undermine reliability by making it more difficult to integrate renewables with the larger western grid, and creates a "sale for resale" procurement construct that could place it under FERC's jurisdiction as a wholesale, rather than a retail, transaction.

Second, on August 5, 2020, WPTF filed an Application for Rehearing of D.20-06-028 with respect to the self-scheduling requirements for non-resource specific RA imports.

- **Analysis**: D.20-06-002 established a central procurement entity and mostly resolved the central buyer issues, although several details are being refined through a Working Group. Moving to a central procurement entity beginning for the 2023 RA compliance year will impact VCE's local RA procurement and compliance, including affecting VCE's three-year local RA requirements as part of the transition to the central procurement framework. Eventually, it will eliminate the need for monthly local RA showings and associated penalties and/or waiver requests from individual LSEs, but it also eliminates VCE's autonomy with regard to local RA procurement and places it in the hands of PG&E.

  The Track 1 Decision on RA imports most directly impacted LSEs relying on RA imports to meet their RA obligations by increasing the difficulty of procuring such RA in the future.

- **Next Steps**: The only issues remaining to be addressed in this proceeding are WPTF's Applications for Rehearing. Remaining RA issues will be addressed in the successor RA rulemaking, R.19-11-009.
- **Additional Information**: D.20-09-003 denying PFMs filed by PG&E, CalCCA, and Joint Parties (September 16, 2020); WPTF's Application for Rehearing of D.20-06-028 (August 5, 2020); WPTF's Application for Rehearing of D.20-06-002 (July 17, 2020); D.20-06-028 on Track 1 RA Imports (approved June 25, 2020); D.20-06-002 establishing a central procurement mechanisms for local RA (June 17, 2020); D.20-03-016 granting limited rehearing of D.19-10-021 (March 12, 2020); D.20-01-004 on qualifying capacity value of hybrid resources (January 17, 2020); D.19-12-064 granting motion for stay of D.19-10-021 (December 23, 2019); D.19-10-021 affirming RA import rules (October 17, 2019); D.19-06-026 adopting local and flexible capacity requirements (July 5, 2019); Docket No. R.17-09-020.

Glossary of Acronyms

AB	Assembly Bill
AET	Annual Electric True-up
ALJ	Administrative Law Judge
BioMAT	Bioenergy Market Adjusting Tariff
BTM	Behind the Meter
CAISO	California Independent System Operator

CAM	Cost Allocation Mechanism
CARB	California Air Resources Board
CEC	California Energy Commission
CPE	Central Procurement Entity
CPUC	California Public Utilities Commission
CPCN	Certificate of Public Convenience and Necessity
CTC	Competition Transition Charge
DA	Direct Access
DWR	California Department of Water Resources
ELCC	Effective Load Carrying Capacity
ERRA	Energy Resource and Recovery Account
EUS	Essential Usage Study
GRC	General Rate Case
IEPR	Integrated Energy Policy Report
IFOM	In Front of the Meter
IRP	Integrated Resource Plan
IOU	Investor-Owned Utility
ITC	Investment Tax Credit
LSE	Load-Serving Entity
MCC	Maximum Cumulative Capacity
OII	Order Instituting Investigation
OIR	Order Instituting Rulemaking
PABA	Portfolio Allocation Balancing Account
PD	Proposed Decision
PG&E	Pacific Gas & Electric
PFM	Petition for Modification
PCIA	Power Charge Indifference Adjustment
POLR	Provider of Last Resort
PSPS	Public Safety Power Shutoff
PUBA	PCIA Undercollection Balancing Account
PURPA	Public Utility Regulatory Policies Act of 1978 (federal)
QC	Qualifying Capacity
QF	Qualifying Facility under PURPA
RA	Resource Adequacy
RDW	Rate Design Window
ReMAT	Renewable Market Adjusting Tariff
RPS	Renewables Portfolio Standard

SCE	Southern California Edison
SED	Safety and Enforcement Division (CPUC)
SDG&E	San Diego Gas & Electric
TCJA	Tax Cuts and Jobs Act of 2017
TOU	Time of Use
TURN	The Utility Reform Network
UOG	Utility-Owned Generation
WMP	Wildfire Mitigation Plan
WSD	Wildfire Safety Division (CPUC)

VALLEY CLEAN ENERGY ALLIANCE

Staff Report – Item 10

TO: Board of Directors

FROM: Rebecca Boyles, Director of Customer Care & Marketing

SUBJECT: Customer Enrollment Update (Information)

DATE: November 10, 2021

RECOMMENDATION

Receive and review the attached Customer Enrollment update as of November 3, 2021.

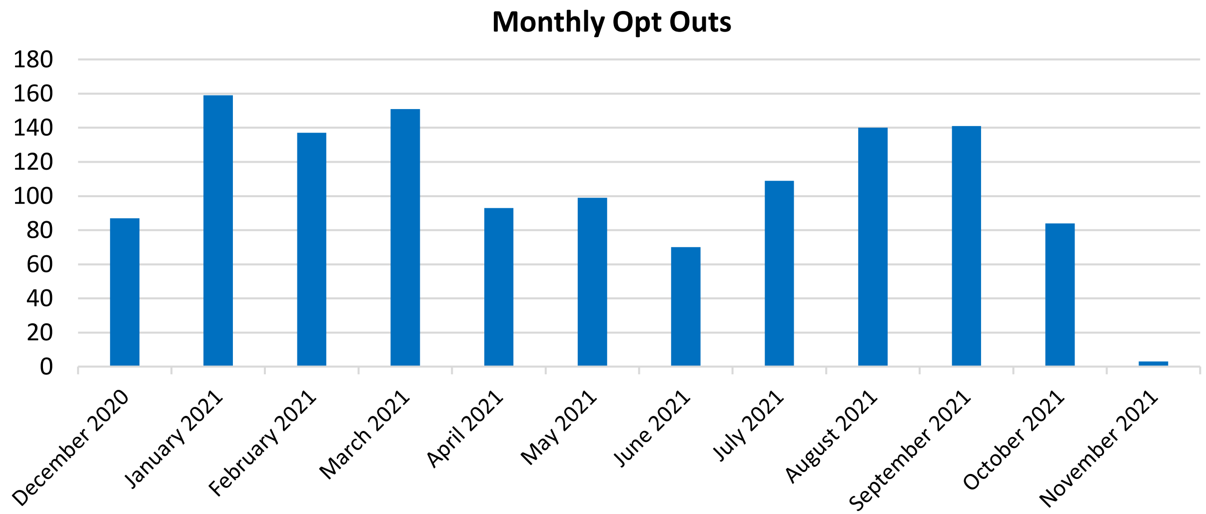
Item 10 - Enrollment Update

	Davis	Woodland	Winters	Yolo Co	Total	Residential	Commercial	Industrial	Ag	NEM	Non-NEM
VCEA customers	28,055	20,633	2,512	10,796	61,996	53,986	6,039	7	1,876	10,517	51,479
Eligible customers	29,340	23,691	2,806	12,364	68,201	59,290	6,647	7	2,153	11,615	56,586
Participation Rate	96%	87%	90%	87%	91%	91%	91%	100%	87%	91%	91%

There are currently 30 Winters customers not included in this table. NEM will enroll throughout 2021.

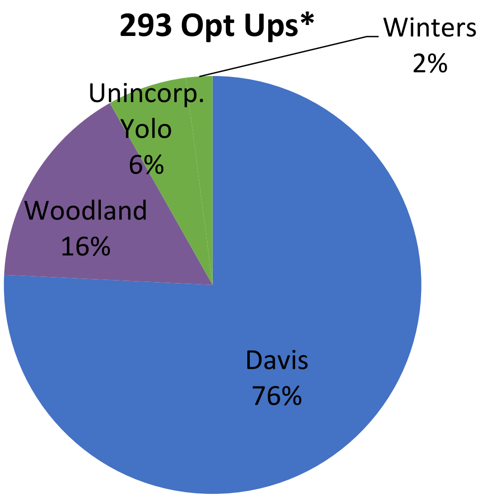
% of Load Opted Out

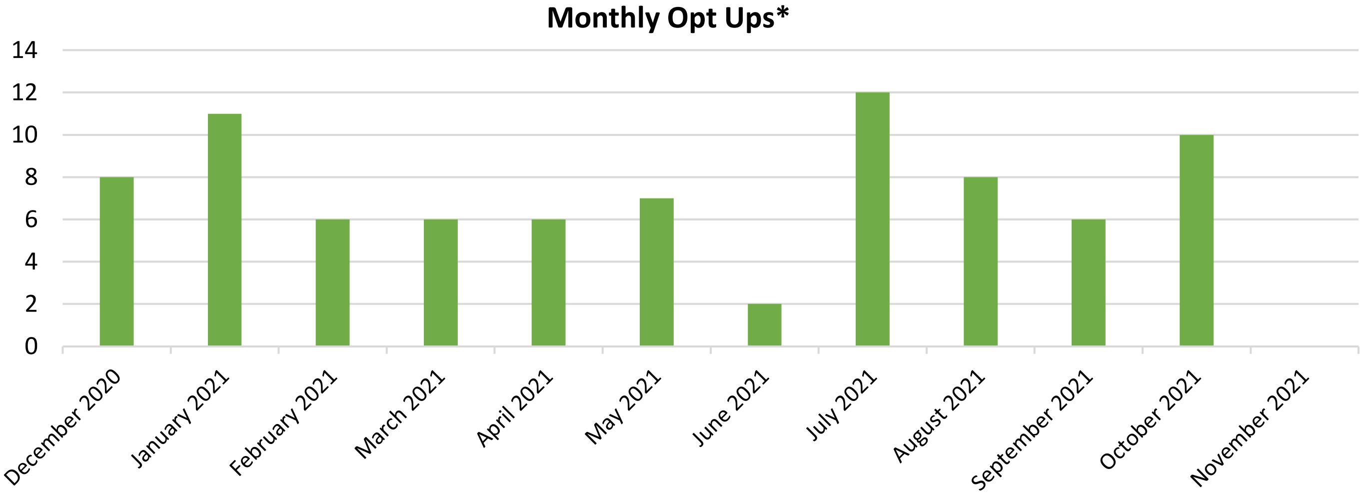
Residential	Commercial	Industrial	Ag	Total
10%	9%	0%	13%	10%



Status Date: 11/3/21

Item 10 - Enrollment Update



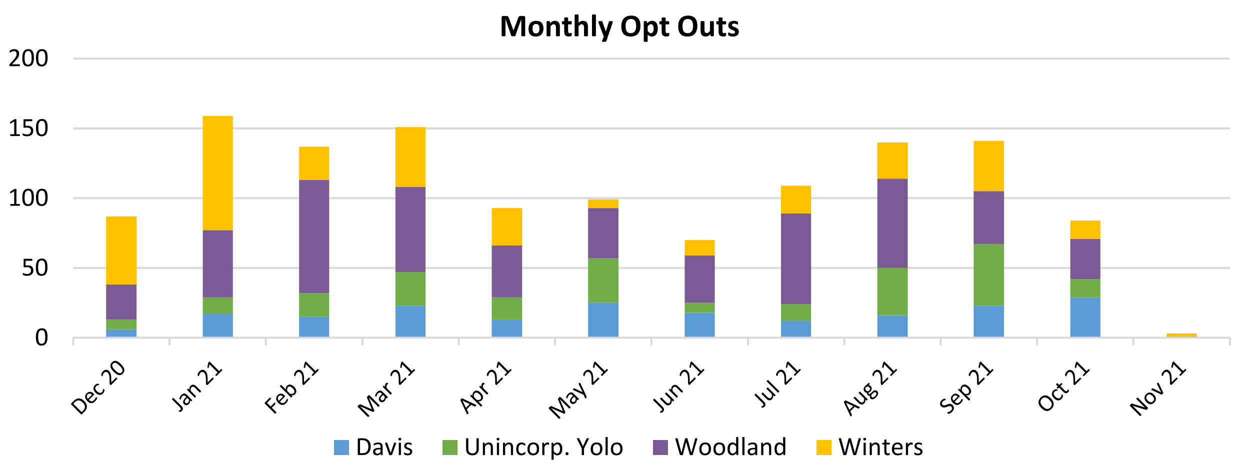


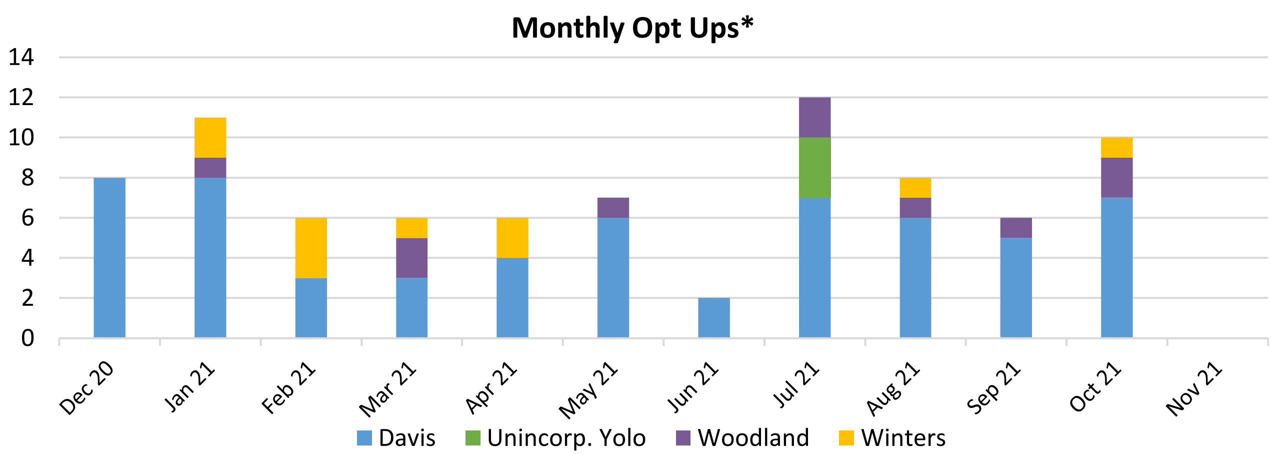
* The numbers in the pie chart represent opt ups for customers who are currently enrolled. The numbers in the bar graph represent opt up actions taken regardless of current enrollment status.

Status Date: 11/3/21

VALLEY CLEAN ENERGY

Item 10 - Enrollment Update



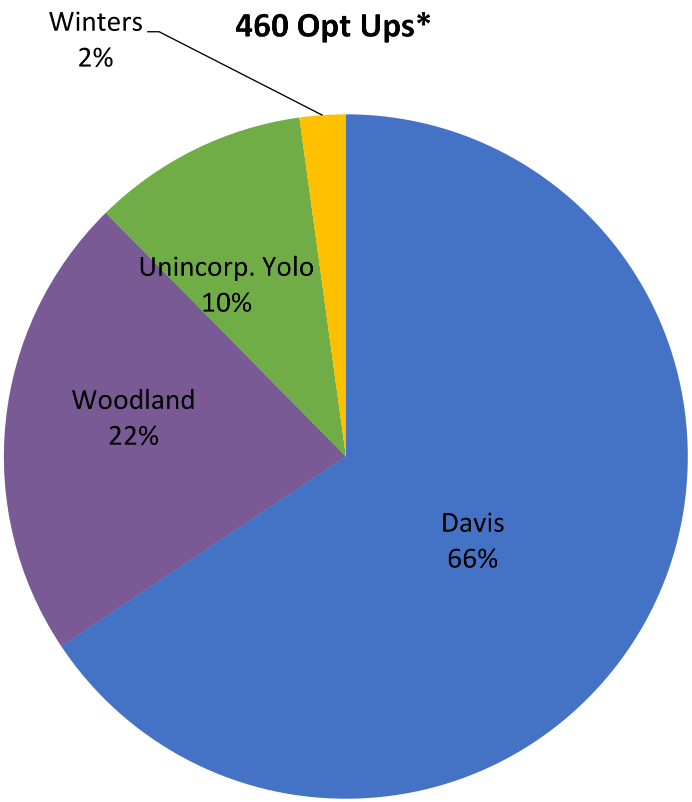


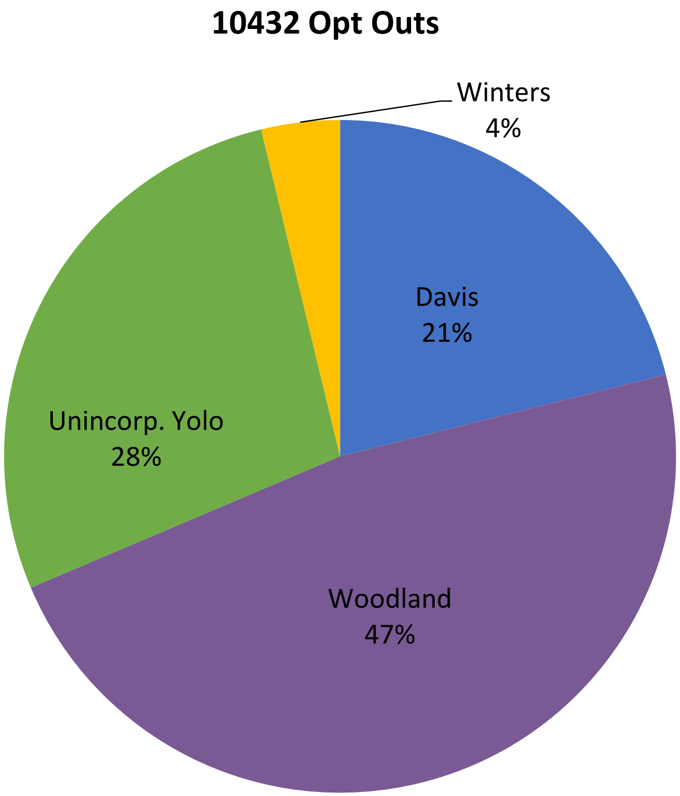
* These numbers represent all opt up actions ever taken regardless of current customer enrollment status.

Status Date: 11/3/21

VALLEY CLEAN ENERGY

Item 10 - Enrollment Update





* These numbers represent all opt up actions ever taken regardless of current customer enrollment status.

Status Date: 11/3/21

VALLEY CLEAN ENERGY ALLIANCE

Staff Report – Item 11

TO:	Board of Directors
FROM:	Alisa Lembke, Board Clerk / Administrative Analyst
SUBJECT:	Community Advisory Committee October 28, 2021 Meeting Summary
DATE:	November 10, 2021

This report summarizes the Community Advisory Committee's meeting held via Zoom webinar on Thursday, October 28, 2021.

A. **Cost-Recovery based Policy and Customer Rate Structure.** The CAC received an update on discussions of VCE's rate policy and customer rate structure consistent with the Board's direction at their special meeting held on October 21, 2021. The CAC discussed financial models, load forecast, resource adequacy costs, rate structure, and possible need for additional policy discussions, Time of Use (TOU) rate changes, and outreach. Staff's recommendation included three basic suggestions: to adopt 1) a cost-recovery based rate policy, 2) a new rate structure with three customer options, and 3) automatically enroll CARE and FERA customers into the newly created Least Cost option. However, the CAC chose to break these into two main issues: the rates policy (1) and the rate structure (2 and 3). A motion to adopt staff recommendation relating to policy "adopt a cost-recovery based rate policy" failed for lack of a second. Rather they chose to address Staff's definition of rate policy: "VCE will set customer rates to collect sufficient revenue from participating customers to fully fund VCE's budget and establish sufficient operating reserve funds." The policy parameters of funding, budget, cap and trigger, and setting rates was discussed in detail. After a thorough discussion, the CAC made a recommendation that the Board adopt:

1) A cost-recovery based rate policy, defined as: VCE will set customer rates to collect sufficient revenue from participating customers to fully fund VCE's budget and establish sufficient operating reserve funds. Changes in rates are to be approved by the Board in consultation with the Community Advisory Committee. (9-0-0);

A shorter discussion on the rate structure then followed. There were concerns by some around making sure there was a significant difference in the Renewable Portfolio Standard (RPS) between the Least-Cost option and the Standard Green option. The CAC then made a recommendation that the Board:

2) Adopt a new rate structure with three customer options: (1) Standard Green (default) and (2) UltraGreen (100% renewable) with rates based on cost-recovery and add a (3) Least-Cost customer rate option; and

3) Automatically enroll California Alternative Rates for Energy (CARE) and Family Electric Rates Assistance (FERA) customers in the newly created least-cost rate option with an enhanced portfolio beginning in 2024. (7-0-2)

Other areas of discussion in general included concern over the impact of the rate increase on certain customers; issues relating to NEM customers; concern over delay in implementing programs, such as EVs; and, desire to optimize, if possible, forecasts for load and budget as VCE goes forward.

B. **Reviewed draft Committee Evaluation of Calendar Year.** The CAC received and reviewed draft 2021 year end reports from the Committee and each Task Group. A few minor modifications to the Committee report are to be made, then all reports are to be presented to the Board for their information. (9-0-0)

VALLEY CLEAN ENERGY ALLIANCE

Staff Report – Item 12

TO: Board of Directors

FROM: Mitch Sears, Interim General Manager
Edward Burnham, Director of Finance and Operations

SUBJECT: Adopt resolution to change existing fiscal year of July 1st to June 30th to align with calendar year (January 1st to December 31st)

DATE: November 10, 2021

RECOMMENDATION
Adopt resolution to change existing fiscal year of July 1st to June 30th to align with calendar year (January 1st to December 31st).

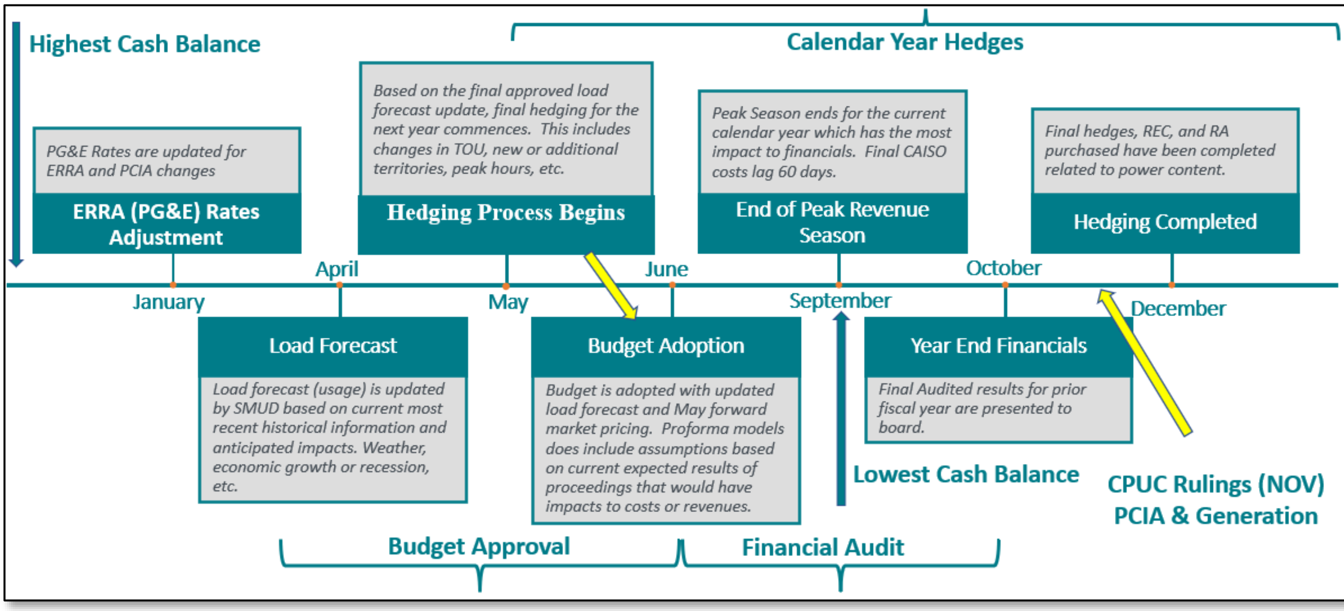
BACKGROUND
Since its formation, Valley Clean Energy has operated with a fiscal accounting year ending on June 30, aligned with the Member Jurisdictions' Fiscal Year. Over the past two years, VCE has experienced high volatility in the energy sector and overall economy, primarily driven by the uncertainty during the COVID-19 pandemic and possible long-term recession. VCE has experienced other financial impacts compared to the adopted budgets driven by forces outside VCE's direct control, including the forward market pricing for energy costs, PG&E generation rate adjustments, and power charge indifference adjustments (PCIA). VCE should consider the optimal timeline of financial milestones to reduce the risks of operating budget performance.

ANALYSIS
As described above, VCE has maintained a Fiscal Year ending June 30. At the October 14 Board Meeting, Staff outlined a comparison timeline of the current Fiscal Year ending June 30 and a Calendar Year ending on December 31 including three options found here. The Accounting Year options were based on a timeline of significant financial milestones incorporated into the budget and audit processes that impact both costs and revenues.

As part of this analysis, VCE did find that the accounting years were not standardized throughout California (including CCA's) and had no regulatory requirements.

Historically, the Fiscal Year timeline presents risks associated with the closeness of VCE's load update, completion of hedging for the adopted budget, and separates the peak energy season (summer) into two Fiscal Years. A Fiscal Year budget incorporates additional assumptions for future regulatory decisions impacting VCE's most significant inputs for generation rate and PCIA rate adjustments increasing the risk of operating budget performance as displayed below.

<u>FISCAL YEAR TIMELINE OF FINANCIAL MILESTONES</u>

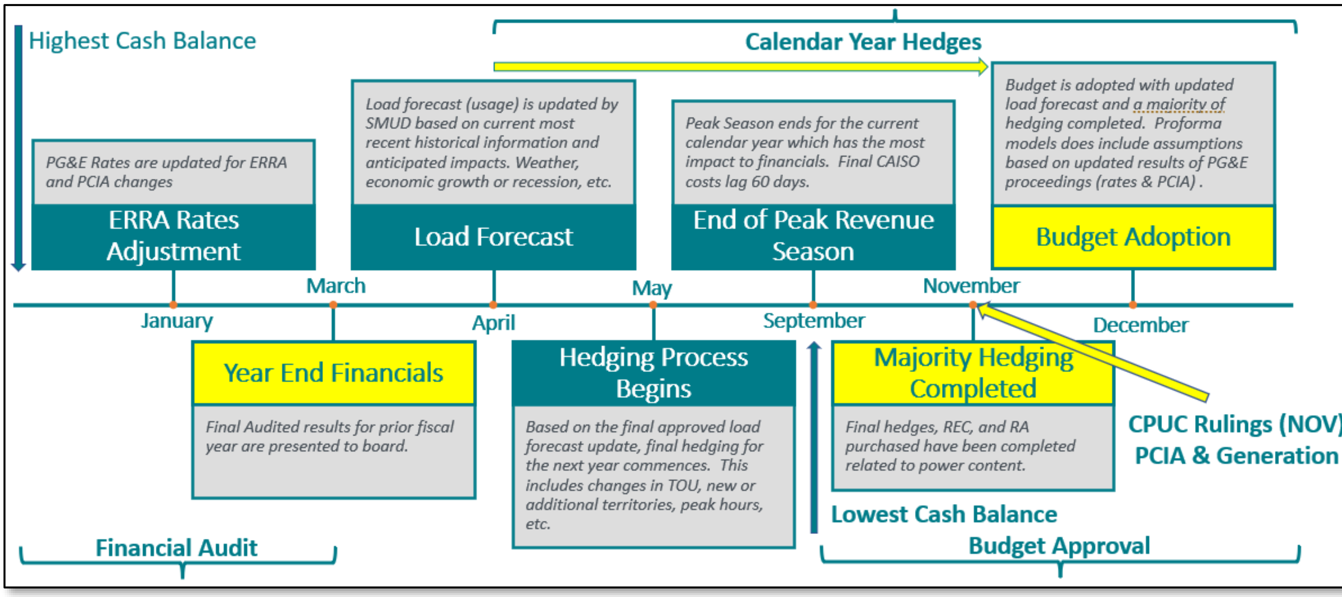


Adoption of a fiscal year aligned with the calendar year ending December 31 would be beneficial by allowing additional time for internal decisions and reviewing the external decisions that impact VCE's operating budget performance, as displayed in the updated timeline below. Internal and external advantages of taking the recommended action include:

- Power Contracts are based on CY (Internal)
- Regulatory Compliance Reporting is based on CY (External)
- Peak Revenue Season (May-September) would not be split (External)
- Increased fixed Power Costs by hedging completion (Both)
- Accuracy of Customer Rates (PG&E filings and VCE costs – External)
- Additional Review Time for Load Update - (Internal)
- Reduced Risks of uncontrollable or variable financial impacts (Internal)

The long-term impact of a fiscal year aligned with the calendar year will also support stabilizing the rate-setting process as decribed in the companion Board item 16. The adoption would require VCE to amend the current Fiscal Year 2021-22 Budget (6 Month) to end as of December 31, 2021 and CY Budget (12 Month) for CY 2022 ending December 31, 2022. The preliminary CY 2022 Budget is being presented in companion item 17. In addition, an audit will be completed in the first quarter of 2022 for the amended 2021-22 Budget (6 Month).

CALENDAR YEAR TIMELINE OF FINANCIAL MILESTONES



*Note: Highlighted headings in the time-line indicate shifts in key budget milestones compared to the existing fiscal year calendar (i.e. July to June)

CONCLUSION

As described above, the transition of our accounting year to a Calendar Year ending December 31 compared to the Fiscal Year ending June 30 reduces the risks of operational budget performance. Therefore, Staff recommends to the Board the adoption of the attached resolution, with an effective date December 31, 2021.

ATTACHMENT

1. Resolution adopting a change in the existing fiscal year of July 1st to June 30th to align with calendar year (January 1st to December 31st) – Effective December 31, 2021.

VALLEY CLEAN ENERGY ALLIANCE

RESOLUTION NO. 2021 - ____

A RESOLUTION OF THE VALLEY CLEAN ENERGY ALLIANCE CHANGING THE FISCAL YEAR (JULY 1 – JUNE 30) TO ALIGN WITH THE CALENDAR YEAR (JANUARY 1 – DECEMBER 31)

WHEREAS, the Valley Clean Energy Alliance ("VCE") is a joint powers agency established under the Joint Exercise of Powers Act of the State of California (Government Code Section 6500 et seq.) ("Act"), and pursuant to a Joint Exercise of Powers Agreement Relating to and Creating the Valley Clean Energy Alliance between the County of Yolo ("County"), the City of Davis ("Davis"), the City of Woodland and the City of Winters ("Cities") (the "JPA Agreement"), to collectively study, promote, develop, conduct, operate, and manage energy programs; and,

WHEREAS, since its establishment, VCE has followed a 12 month fiscal year commencing July 1 and ending June 30; and,

WHEREAS, Section 5.1 <u>Fiscal Year</u> of the JPA Agreement, authorizes the Board to change the fiscal year via resolution.

WHEREAS, a calendar year based fiscal year ending December 31st supports the optimal operational budget performance for the VCE business cycle.

NOW, THEREFORE, the Board of Directors of the Valley Clean Energy Alliance resolves as follows:

1. Adopt Resolution changing the fiscal year commencing July 1 and ending June 30 to a 12 month fiscal year commencing January 1 and ending December 31 with an effective date of December 31, 2021.

PASSED, APPROVED, AND ADOPTED, at a regular meeting of the Valley Clean Energy Alliance, held on the ___ day of _____________ 2021, by the following vote:

AYES:
NOES:
ABSENT:
ABSTAIN:

____
Dan Carson, VCE Chair

____
Alisa M. Lembke, VCE Board Secretary

VALLEY CLEAN ENERGY ALLIANCE

Staff Report – Item 13

TO: Board of Directors

FROM: Mitch Sears, Interim General Manager
Rebecca Boyles, Director of Customer Care and Marketing

SUBJECT: SACOG Grant - Electrify Yolo Update

DATE: November 10, 2021

RECOMMENDATION
Informational item. The purpose of this report is to give an update on the status of the Electrify Yolo (SACOG grant) project.

BACKGROUND
In December 2018, the Sacramento Area Council of Governments (SACOG) authorized the award of a Green Region grant in the amount of $2,912,000, representing the regional "Electrify Yolo" project, with the purpose of installing publicly accessible electric vehicle (EV) charging stations. Originally, only VCE and the City of Davis were involved, and Woodland, Winters and unincorporated Yolo County joined the project prior to submitting the grant application in August 2018. The City of Davis distributed funds to each entity once the Memoranda of Understanding (MOUs) were approved by each jurisdiction. All projects are to be finished by December 31, 2023. VCE is coordinating quarterly meetings among project partners, and the next meeting will be in January 2022.

UPDATE
EV charger installations have been subject to some delays, including impacts from the COVID-19 pandemic. All MOUs were signed (Davis, VCE/Winters, Woodland, unincorporated Yolo County) as of April 2021, and some EV charger installation projects have begun.

The City of Davis and Frontier Energy held a kickoff meeting on June 29 and anticipate moving very quickly on this project. The analysis and design are estimated to take approximately 3 months once the agreement is signed.

The City of Winters finalized a contract with Ample Electric to install the charging infrastructure: two level 2 Blink chargers at the community center and one level 2 and one DC fast charger at the First/Abbey parking lot. The two level 2 Blink chargers have been installed at the community center, and are open for public use. A temporary construction banner has been placed at the site to inform customers of the partnership (including all partner logos), and a permanent sign has been placed as well, displaying VCE, Winters and SACOG logos. The

First/Abbey project (near Winters Hotel) should be completed by Q4 2021, but may be subject to delays.

Due to competing priorities and staffing issues, Woodland has not yet moved forward with their project; however, they remain committed to completing the project on time.

Yolo County is in discussion with ChargePoint about the feasibility of completing the project from beginning to end. There are a number of potential County-owned sites under consideration for charger locations, as well as solar-powered mobile chargers being considered.

VCE Staff is working with each jurisdiction to design banners to be hung at each charging station with logos of all project partners. These banners will inform members of the public that there will be EV chargers coming soon in that location and aim to increase the public's brand association with VCE and electric vehicles.

VALLEY CLEAN ENERGY ALLIANCE

Staff Report – Item 14

TO: Board of Directors

FROM: Edward Burnham, Finance and Operations Director, VCE
Mitch Sears, Interim General Manager, VCE

SUBJECT: Receive and approve audited June 30, 2021 financial statements presented by James Marta & Company

DATE: November 10, 2021

RECOMMENDATIONS:

1. Accept and approve the Audited Financial Statements for the period of July 1, 2020 to June 30, 2021;
2. Accept the Communication with Governance Letter; and
3. Accept the Internal Control Letter

BACKGROUND & DISCUSSION:
The attached financial statements were audited by VCE's Independent Auditor, James Marta & Company. The Financial Statements include the following reports:

- Independent Auditor's Report
- Management's Discussion and Analysis
- Statement of Net Position
- Statement of Revenues, Expenditures and Changes in Net Position
- Statement of Cash Flows
- Notes to the Basis Financial Statements

As part of the accounting Professional standards, the auditors are required to communicate to the VCE Board of Directors various matters relating to the audit as noted in the following:

- Governance letter
- Internal Control Letter

This report and attachments constitute the auditor's communication to the Board.

AUDITOR'S FINDINGS
During the course of the audit, the auditor's found no material concerns over the financial statements or internal controls. Specifically:

- VCE received an unqualified ("clean") audit opinion, meaning the financial statements present VCE's financial position fairly and appropriately
- VCE's internal controls over financial reporting were considered by the auditor, with no material deficiencies in internal controls over financial reporting
- No significant issues were identified in working with our management team or performing the audit

Attachments:

1) Audited Financial Statements for the period of July 1, 2020 to June 30, 2021
2) Communication with Governance Letter
3) Internal Control Letter

VALLEY CLEAN ENERGY ALLIANCE

FINANCIAL STATEMENTS

FOR THE FISCAL YEARS ENDED JUNE 30, 2021 AND 2020

VALLEY CLEAN ENERGY ALLIANCE

TABLE OF CONTENTS

JUNE 30, 2021 AND 2020

	PAGE
Independent Auditor's Report	1
Management's Discussion and Analysis	3
BASIC FINANCIAL STATEMENTS	
Statement of Net Position	6
Statement of Revenues, Expenses and Change in Net Position	7
Statement of Cash Flows	8
Notes to the Basic Financial Statements	9

James Marta & Company LLP
Certified Public Accountants

Accounting, Auditing, Consulting, and Tax

INDEPENDENT AUDITOR'S REPORT

Board of Directors
Valley Clean Energy Alliance
Davis, California

Report on the Financial Statements

We have audited the accompanying financial statements of the governmental activities, the business-type activities, each major fund and the aggregate remaining fund information of Valley Clean Energy Alliance (VCE), as of and for the period ended June 30, 2021, and the related notes to the financial statements, which collectively comprise VCE's basic financial statements as listed in the table of contents.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with accounting principles generally accepted in the United States of America; this includes the design, implementation and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express opinions on these financial statements based on our audit. We conducted our audit in accordance with auditing standards generally accepted in the United States of America and the standards applicable to financial audits contained in *Government Auditing Standards*, issued by the Comptroller General of the United States and the State Controller's Minimum Audit Requirements for California Special Districts. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

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www.jpmcpa.com jmarta@jpmcpa.com

Opinions

In our opinion, the financial statements referred to above present fairly, in all material respects, the respective financial position of Valley Clean Energy Alliance as of June 30, 2021, and the respective changes in financial position and cash flows thereof for the year then ended in conformity with accounting principles generally accepted in the United States of America.

Other Matters

Required Supplementary Information

Accounting principles generally accepted in the United States of America require that the Management's Discussion and Analysis, be presented to supplement the basic financial statements. Such information, although not a part of the basic financial statements, is required by the Governmental Accounting Standards Board who considers it to be an essential part of financial reporting for placing the basic financial statements in an appropriate operational, economic, or historical context. We have applied certain limited procedures to the required supplementary information in accordance with auditing standards generally accepted in the United States of America, which consisted of inquiries of management about the methods of preparing the information and comparing the information for consistency with management's responses to our inquiries, the basic financial statements, and other knowledge we obtained during our audit of the basic financial statements. We do not express an opinion or provide any assurance on the information because the limited procedures do not provide us with sufficient evidence to express an opinion or provide any assurance.

Other Reporting Required by *Government Auditing Standards*

In accordance with *Government Auditing Standards*, we have also issued our report dated November 5, 2021 on our consideration of the VCE's internal control over financial reporting and on our tests of its compliance with certain provisions of laws, regulations, contracts, and grant agreements and other matters. The purpose of that report is to describe the scope of our testing of internal control over financial reporting and compliance and the results of that testing, and not to provide an opinion on internal control over financial reporting or on compliance. That report is an integral part of an audit performed in accordance with *Government Auditing Standards* in considering the VCE's internal control over financial reporting and compliance.

James Marta & Company LLP

James Marta & Company LLP
Certified Public Accountants
Sacramento, California
November 5, 2021

MANAGEMENT DISCUSSION AND ANALYSIS

The Management's Discussion and Analysis provides an overview of Valley Clean Energy Alliance's (VCE) financial activities for the periods ended June 30, 2021 and June 30, 2020. The information presented here should be considered in conjunction with the audited financial statements.

BACKGROUND

The formation of VCE was made possible by the passage, in 2002, of California Assembly Bill 117, enabling communities to purchase power on behalf of their residents and businesses, and creating competition in power generation.

VCE was created as a California Joint Powers Authority (JPA) in January 2017 pursuant to the Joint Exercise of Powers Act and is a public agency separate from its members. Governed by a board of directors consisting of two elected officials representing each of the following local governments: the County of Yolo and the cities of Davis and Woodland. VCE provides electric service to retail customers as a Community Choice Aggregation Program under the California Public Utilities Code Section 366.2.

VCE's mission is to deliver cost-competitive clean electricity, product choice, price stability, energy efficiency, and greenhouse gas emission reductions. VCE provides electric service to retail customers and has the rights and powers to set rates and charges for electricity and services it furnishes, incur indebtedness, and other obligations. VCE acquires electricity from commercial suppliers and delivers it through existing physical infrastructure and equipment managed by the California Independent System Operator (CAISO) and Pacific Gas and Electric Company (PG&E).

In June 2018, VCE began providing service to approximately 56,000 customer accounts as part of its initial enrollment phase. In calendar year 2020, VCE phased in approximately 7,000 Net Energy Metering (NEM) customers. In January 2021, VCE phased in approximately 7,100 customers from its new City of Winters jurisdiction.

Financial Reporting

VCE presents its financial statements in accordance with Generally Accepted Accounting Principles for proprietary funds, as prescribed by the Governmental Accounting Standards Board.

Contents of this Report

This report is divided into the following sections:

- Management's Discussion and Analysis, which provides an overview of operations.
- The Basic Financial Statements, which offer information on VCE's financial results.
- The Statement of Net Position includes all of VCE's assets, liabilities, and net position using the accrual basis of accounting. The Statement of Net Position provide information about the nature and amount of resources and obligations at a specific point in time.
- The Statement of Revenues, Expenses, and Changes in Net Position report all of VCE's revenue and expenses for the period shown.
- The Statement of Cash Flows report the cash provided and used by operating activities, as well as other sources and payments, such as debt financing.
- Notes to the Basic Financial Statements, which provide additional details and information pertaining to the financial statements.

FINANCIAL AND OPERATIONAL HIGHLIGHTS

The following table is a summary of VCE's assets, liabilities, and net position as of June 30:

	2021	2020
Current assets	$21,175,913	$ 22,407,057
Noncurrent assets	3,099,608	2,445,520
Total assets	$24,275,521	$ 24,852,577
Current liabilities	$11,531,607	$ 6,914,208
Noncurrent liabilities	0	1,350,684
Total liabilities	11,531,607	8,264,892
Net position		
Designated – Local Programs	224,500	136,898
Restricted	3,099,608	2,345,520
Unrestricted (deficit)	9,419,806	14,105,267
Total net position	$12,743,914	$16,587,685

Assets

Current assets ended 2021 at approximately 21.2 million, a decrease of approximately $1.2 million as compared to 2020. The contributor to the overall decrease in currents assets was an increase in receivables net of allowance for doubtful accounts of approximately $2.02 million. The net accounts receivable increase was driven by state mandates during COVID-19. Since service to customers began, VCE has operated at a surplus which has resulted in the growth of current assets. Accrued revenue differs from accounts receivable in that it is the result of electricity use by VCE customers before invoicing to those customers has occurred.

Overall, noncurrent assets increased approximately $0.65 million in 2021 due to an increase of in restricted cash for power purchase reserves.

Liabilities

Current liabilities comprised primarily of accrued cost of electricity, accounts payable, other accrued liabilities, security deposits, and current portion of long-term debt. Current liabilities increased by $4.6 million to $11.5 million in 2021. The most significant contributors to the overall increase in current liabilities was an increase of $1M in the outstanding balance to a term loan with an annual renewable requirement, and $1.9M related to the receipt of supplier security deposits for energy supplies. Other significant increases for $2M occurred in accrued cost of electricity.

Non-current liabilities decreased $1.4 million in 2021 related to term loan described above in current liabilities.

The following table is a summary of VCE's results of operations:

	2021	2020
Operating revenues	$ 54,656,880	$55,248,868
Interest income	50,285	102,954
Total income	54,707,165	55,351,822
Operating expenses	58,494,704	45,887,956
Interest and related expenses	56,232	98,613
Total expenses	58,550,936	45,986,572
Change in net position	$ (3,843,771)	$ 9,365,253

Operating Revenues

In fiscal year 2021, VCE's operating revenues decreased by $0.8 million in fiscal year 2021, This decrease was primarily a result of increases in Power Charge Indifference Adjustment (PCIA), as well as slight decreases to generation rates. VCE's operating revenue is from the sale of electricity to its customer base, which mostly consists of residential, commercial, industrial and agricultural customers.

Operating Expenses

In fiscal year 2021, VCE's operating expenses grew by $12.6 million over the prior year of operations in fiscal year 2020. This increase was primarily due to a $12.7 million increase in cost of electricity, driven by increased load, addition of NEM customers and Winters. VCE procures energy from a variety of sources and focuses on purchasing at competitive costs and maintaining a balanced renewable power portfolio. The remaining operating expenses consists of contract services, staff compensation and other general administrative expenses.

ECONOMIC OUTLOOK

As a CCA in its fourth year of operations transitioning out of the COVID-19 pandemic, VCE continues to focus on limiting customer opt outs by keeping rates competitive, increasing brand recognition and providing a superior customer experience. VCE has recently started to procure power through long-term power purchase agreements to assist in stabilizing renewable power costs in the future and help VCE accomplish its mission of providing renewable energy and reducing greenhouse gas emissions. This will help reduce the potential effect of future energy market price volatility and create a stable environment for VCE and its ratepayers. VCE will face significant budgetary pressures over the next two years due to several regulatory and market factors, including rising Power Charge Indifference Adjustment (PCIA) costs and rising market costs to procure resource adequacy supplies.

REQUESTS FOR INFORMATION

This financial report is designed to provide VCE's board members, stakeholders, customers and creditors with a general overview of the VCE's finances and to demonstrate VCE's accountability for the funds under its stewardship.

Please address any questions about this report or requests for additional financial information to Director of Finance and Internal Operations, 604 2nd Street, Davis, CA 95616.

VALLEY CLEAN ENERGY ALLIANCE

STATEMENT OF NET POSITION

JUNE 30, 2021 AND 2020

	2021	2020
ASSETS		
Current assets		
Cash in banks	$ 8,256,056	$ 13,470,486
Accounts receivable, net of allowance	7,982,540	5,960,211
Accrued revenue	2,935,291	2,973,195
Prepaid expenses	15,143	625
Other current assets and deposits	1,986,883	2,540
Total Current Assets	21,175,913	22,407,057
Restricted assets:		
Debt service reserve fund	1,100,000	1,100,000
Power purchase reserve fund	1,999,608	1,245,520
Total Restricted assets	3,099,608	2,345,520
Noncurrent Assets		
Other noncurrent assets and deposits	-	100,000
Total Noncurrent Assets	-	100,000
TOTAL ASSETS	$ 24,275,521	$ 24,852,577
LIABILITIES		
Current Liabilities		
Accounts payable	$ 399,766	$ 642,400
Accrued cost of electricity	6,649,130	4,651,697
Accrued payroll	43,705	11,804
Interest payable	3,259	4,435
Due to member agencies	123,406	116,466
Other accrued liabilities	2,961,654	1,092,084
Line of credit	1,350,687	395,322
Total Current Liabilities	11,531,607	6,914,208
Noncurrent Liabilities		
Line of credit	-	1,350,684
Total Noncurrent Liabilities	-	1,350,684
TOTAL LIABILITIES	$ 11,531,607	$ 8,264,892
NET POSITION		
Net position		
Designated - local program reserves	$ 224,500	$ 136,898
Restricted	3,099,608	2,345,520
Unrestricted	9,419,806	14,105,267
TOTAL NET POSITION	$ 12,743,914	$ 16,587,685

The accompanying notes are an integral part of these financial statements.

VALLEY CLEAN ENERGY ALLIANCE

STATEMENT OF REVENES, EXPENSES AND CHANGES IN NET POSITION

FOR THE YEARS ENDED JUNE 30, 2021 AND 2020

	2021	2020
OPERATING REVENUE		
Electricity sales, net	$ 54,441,240	$ 55,248,868
Other revenue	215,640	-
TOTAL OPERATING REVENUES	54,656,880	55,248,868
OPERATING EXPENSES		
Cost of electricity	54,233,726	41,538,258
Contractors	2,609,080	2,854,222
Staff compensation	1,158,120	1,059,829
General and administrative	493,778	435,647
TOTAL OPERATING EXPENSES	58,494,704	45,887,956
TOTAL OPERATING INCOME (LOSS)	(3,837,824)	9,360,912
NONOPERATING REVENUES (EXPENSES)		
Interest income	50,285	102,954
Interest and related expenses	(56,232)	(98,613)
TOTAL NONOPERATING REVENUES (EXPENSES)	(5,947)	4,341
CHANGE IN NET POSITION	(3,843,771)	9,365,253
Net position at beginning of period	16,587,685	7,222,432
Net position at end of period	$ 12,743,914	$ 16,587,685

The accompanying notes are an integral part of these financial statements.

VALLEY CLEAN ENERGY ALLIANCE

STATEMENT OF CASH FLOWS

FOR THE YEARS ENDED JUNE 30, 2021 AND 2020

	2021	2020
CASH FLOWS FROM OPERATING ACTIVITIES		
Receipts from electricity sales	$ 52,466,863	$ 55,566,575
Payments for security deposits with energy suppliers	100,000	-
Payments to purchase electricity	(52,246,340)	(41,798,319)
Payments for contract services, general, and administration	(1,483,501)	(3,736,336)
Payments for staff compensation	(1,126,219)	(1,051,815)
Other cash payments	(1,768,703)	-
Net Cash Provided (Used) by Operating Activities	(4,057,900)	8,980,105
CASH FLOWS FROM NON-CAPITAL FINANCING ACTIVITIES		
Loans from member agencies	(395,319)	246,006
Draw of line of credit	1,976,610	-
Principal payments of debt	(1,976,610)	(1,976,610)
Interest and related expense	(57,408)	(206,490)
Net Cash Provided (Used) by Non-Capital Financing Activities	(452,727)	(1,937,094)
CASH FLOWS FROM INVESTING ACTIVITIES		
Interest income	50,285	102,954
Net Cash Provided (Used) by Investing Activities	50,285	102,954
NET CHANGE IN CASH AND CASH EQUIVALENTS	(4,460,342)	7,145,965
Cash and cash equivalents at beginning of period	15,816,006	8,670,041
Cash and cash equivalents at ending of period	$ 11,355,664	$ 15,816,006
RECONCILIATION OF OPERATING INCOME TO NET CASH PROVIDED (USED) BY OPERATING ACTIVITIES		
Operating income (loss)	$ (3,837,824)	$ 9,360,912
Adjustments to reconcile operating income to net cash provided (used) by operating activities:		
(Increase) decrease in net accounts receivable	(2,022,329)	(1,007,634)
(Increase) decrease in net accrued revenue	37,904	1,322,518
(Increase) decrease in prepaid expense	(14,518)	(625)
(Increase) decrease in inventory - renewable energy credits	-	207,168
(Increase) decrease in other assets and deposits	(1,884,343)	-
Increase (decrease) in accounts payable	(242,634)	(27,905)
Increase (decrease) in accrued payroll	31,901	8,014
Increase (decrease) in due to member agencies	6,940	(293,843)
Increase (decrease) in accrued cost of electricity	1,987,385	(467,230)
Increase (decrease) in other accrued liabilities	1,869,570	(124,094)
Increase (decrease) in user taxes and energy surcharges	10,048	2,824
Net Cash Provided by Operating Activities	$ (4,057,900)	$ 8,980,105

The accompanying notes are an integral part of these financial statements.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

REPORTING ENTITY

The Valley Clean Energy Alliance (VCE) is a California joint powers authority created on January 1, 2017 and its voting members consist of the following local governments: the County of Yolo and the cities of Davis, Woodland and Winters (collectively, the "Member Agencies"). VCE is governed by an eight-member Board of Directors whose membership is composed of two elected officials representing each of the Member Agencies.

VCE's mission is to address climate change by reducing energy related greenhouse gas emissions through renewable energy supply and energy efficiency at stable and competitive rates for customers while providing local economic and workforce benefits. VCE provides electric service to retail customers as a Community Choice Aggregation Program under the California Public Utilities Code Section 366.2.

VCE began the delivery of electricity in June, 2018. Electricity is acquired from commercial suppliers and delivered through existing physical infrastructure and equipment managed by the California Independent System Operator and Pacific Gas and Electric Company.

BASIS OF ACCOUNTING

VCE's financial statements are prepared in accordance with generally accepted accounting principles (GAAP). The Governmental Accounting Standards Board (GASB) is responsible for establishing GAAP for state and local governments through its pronouncements.

VCE's operations are accounted for as a governmental enterprise fund, and are reported using the economic resources measurement focus and the accrual basis of accounting – similar to business enterprises. Accordingly, revenues are recognized when they are earned and expenses are recognized at the time liabilities are incurred. Enterprise fund type operating statements present increases (revenues) and decreases (expenses) in total net position. Reported net position is segregated into three categories – net investment in capital assets, restricted, and unrestricted.

CASH AND CASH EQUIVALENTS

For purpose of the Statement of Cash Flows, VCE defines cash and cash equivalents to include cash on hand, demand deposits, and short-term investments. Cash and cash equivalents include restricted cash which were the amounts restricted for debt collateral and power purchase reserve.

DEPOSITS

Deposits are classified as current and noncurrent assets depending on the length of the time the deposits will be held. Deposits include those for regulatory and other operating purposes.

OPERATING AND NON-OPERATING REVENUE

Operating revenues consists of revenue from the sale of electricity to customers. Interest income is considered non-operating revenue.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

REVENUE RECOGNITION

VCE recognizes revenue on the accrual basis. This includes invoices issued to customers during the reporting period and electricity estimated to have been delivered but not yet billed. Management estimates that a portion of the billed amounts will not be collected. Accordingly, an allowance has been recorded.

ELECTRICAL POWER PURCHASED

In 2017, VCE entered into a five (5) year contract with the Sacramento Municipal Utility District (SMUD) to provide technical and financial analysis; data management and call center services; wholesale energy services; and operational staff services. As part of the contract, SMUD provides power portfolio purchase services to and on behalf of VCE. Electricity costs include the cost of energy and ancillary services arising from bilateral contracts with energy suppliers as well as generation credits, and load and other charges arising from VCE's participation in the California Independent System Operator's centralized market. The cost of electricity and ancillary services are recognized as "Cost of Electricity" in the Statements of Revenues, Expenses and Changes in Net Position. As of June 30, 2021, $6,578,919 was accrued as payable to SMUD, comprised of $6,578,811 in accrued electricity costs and $108 in accrued contractual services. As of June 30, 2020, $4,913,638 was accrued as payable to SMUD, comprised of $4,591,427 in accrued electricity costs and $322,211 in accrued contractual services

RENEWABLE ENERGY CREDITS

To comply with the State of California's Renewable Portfolio Standards (RPS) and self- imposed benchmarks, VCE acquires RPS eligible renewable energy evidenced by Renewable Energy Certificates (Certificates) recognized by the Western Renewable Energy Generation Information System (WREGIS). VCE obtains Certificates with the intent to retire them, and does not sell or build surpluses of Certificates. An expense is recognized at the point that the cost of the RPS eligible energy is billed by the supplier. VCE is in compliance with external mandates and self-imposed benchmarks.

STAFFING COSTS

VCE pays employees semi-monthly and fully pays its obligation for health benefits and contributions to its defined contribution retirement plan each month. VCE is not obligated to provide post-employment healthcare or other fringe benefits and, accordingly, no related liability is recorded in these financial statements. VCE provides compensated time off, and the related liability is recorded in these financial statements

INCOME TAXES

VCE is a joint powers authority under the provision of the California Government Code, and is not subject to federal or state income or franchise taxes.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

ESTIMATES

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect certain reported amounts and disclosures. Accordingly, actual results could differ from those estimates.

RECLASSIFICATION

Certain amounts in the prior-year financial statements have been reclassified for comparative purposes to conform to the presentation of the current-year financial statements.

NET POSITION

VCE reports net position balances in the following categories: Designated, Restricted, and Unrestricted. Local program reserves are designated funds as approved by the board in support of the VCE's mission and programs plan. Restricted funds are those restricted to a particular purpose, and that restriction is set out in the Contract Agreement. Unrestricted funds support the operating expenses or projects of the organization.

The following are the components of VCE's Net Position at June 30, 2021 and 2020.

	2021	2020
Designated - local program reserves	$ 224,500	$ 136,898
Restricted	3,099,608	2,345,520
Unrestricted	9,419,806	14,105,267
Totals	$ 12,743,914	$ 16,587,685

2. CASH AND CASH EQUIVALENTS

VCE maintains its cash in interest and non-interest-bearing deposit accounts at River City Bank (RCB) of Sacramento, California. VCE's deposits with RCB are subject to California Government Code Section 16521 which requires that RCB collateralize public funds in excess of the FDIC limit of $250,000 by 110%. VCE monitors its risk exposure to RCB on an ongoing basis. VCE's has not adopted its own Investment Policy and follows the investment policy of the County of Yolo.

3. ACCOUNTS RECEIVABLE AND ACCRUED REVENUE

Accounts receivable were as follows:

	June 30, 2021	June 30, 2020
Accounts receivable from customers	$ 9,565,448	$ 7,005,619
Allowance for uncollectible accounts	(1,582,908)	(1,045,408)
Accounts receivable, net	$ 7,982,540	$ 5,960,211

The majority of account collections occur within the first few months following customer invoicing. VCE estimates that a portion of the billed accounts will not be collected. VCE records reserves for its estimated uncollectible accounts as a reduction to the related operating revenues in the Statement of Revenues, Expenses and Changes in Net Position. Charges to reserve for uncollectible accounts for the years ended June 30, 2021 and 2020 were $537,500 and $571,608, respectively. Due to the ongoing pandemic, VCE has elected not to pursue collections, at this time, for old outstanding balances to alleviate the pressure on their customers.

Accrued revenue presented in the Statements of Net Position represents revenue from customer electricity usage that has not been billed at the end of the period. Accrued revenue recognized for the periods ended June 30, 2021 and 2020 was $2,935,291 and $2,973,195, respectively.

4. DEBT

LINE OF CREDIT

In May 2018, VCE entered into a non-revolving, $11,000,000 Credit Agreement (Agreement) with RCB for the purpose of providing working capital to fund power purchases during seasonal differences in cash flow and reserves as needed to support power purchases. RCB requires collateral for the line of credit of $1.1 million which is reported as restricted cash. Interest accrues on the outstanding balance and is payable each month and computed at One-Month LIBOR plus 1.75% per annum, subject to a floor of 1.75% per annum. The Agreement expired on May 15, 2019 with an option to extend the line for another six months. VCE extended the line of credit and the Agreement to November 15, 2019, with continuing extensions granted until August 31, 2020. At the expiration of the Agreement, any outstanding balance can be converted to an amortizing term loan which matures up to five years from conversion date. The Agreement contains various covenants that include requirements to maintain certain financial ratios, stipulated funding of debt service reserves, and various other requirements including the subordination of the member agency loans. As of June 30, 2020 and 2019, $0 and $1,976,610 of the line of credit had been drawn, leaving $7,000,000 and $9,023,390 still available, respectively.

At the October 10, 2019 Board meeting the Board authorized VCE to convert the $1,976,610 Agreement balance to an amortizing 5-year term loan. VCE converted the Agreement to the loan and has paid the loan down to $1,350,687 as of June 30, 2021.

During September, 2020, VCE has agreed in principle to one-year renewals to September 1, 2021, for both the Agreement and the term loan. The Agreement limit will be reduced from $11,000,000 to a line of credit which allows up to $5,000,000 for cash advances and up to $7,000,000 for letters of credit, with the total of both to not exceed $7,000,000. The 5-year term loan has been shortened to a maturity date of September 1, 2021, with the outstanding balance due at that time unless another renewal is agreed upon.

4. DEBT (CONTINUED)

If VCE defaults on the line of credit, RCB may, by notice of the borrower, take any of the following actions:

(a) terminate any obligation to extend any further credit hereunder (including but not limited to Advances) on the date (which may be the date thereof) stated in such notice;
(b) declare all Advances and all indebtedness under the Notes then outstanding (including all outstanding principal and all accrued but unpaid interest), and all other Obligations of Borrower to Lender, to be immediately due and payable without further demand, presentment, protest or notice of any kind; and
(c) exercise and enforce any and all rights and remedies contained in any other Loan Document or otherwise available to Lender at law or in equity.

Debt principal activity and balances for all notes and loans were as follows:

	Beginning	Addition	Payments	Ending
Period Ended June 30, 2020				
River City Bank - Line of Credit	$ 1,976,610	-	$ (1,976,610)	$ -
River City Bank - Loan	-	1,746,006	-	1,746,006
Member Agencies	1,500,000	-	(1,500,000)	-
Total	$ 3,476,610	$ 1,746,006	$ (3,476,610)	$ 1,746,006
Amounts due within one year				(395,322)
Amounts due after one year				$ 1,350,684
Year Ended June 30, 2021				
River City Bank - Loan	1,746,006	3	(395,322)	1,350,687
Total	$ 1,746,006	$ 3	$ (395,322)	$ 1,350,687
Amounts due within one year				(1,350,687)
Amounts due after one year				$ -

5. DEFINED CONTRIBUTION RETIREMENT PLAN

VCE provides retirement benefits to eligible employees through a 401(a) discretionary defined contribution plan and 457(b) deferred compensation plan (Plans). The Plans are administered by International City Management Association Retirement Corporation (ICMA-RC). At June 30, 2021, VCE had 1 plan participant. VCE contributes 7% of covered payroll and up to an additional 3% of covered payroll as a match to employee tax deferred contributions (into the 457(b) deferred compensation plan) into the 401(a) discretionary defined contribution plan.

For the year ended June 30, 2021 and 2020, VCE contributed $45,603 and $7,687, respectively. The Plans' provisions and contribution requirements as they apply to VCE are established and may be amended by the Board of Directors.

6. OPERATING LEASE

In 2018, VCE entered into a nine-month lease for its office space with the City of Davis expiring January 2019. VCE renewed the lease for an additional 12-months expiring January 2021. VCE renewed the lease for an additional 12 months expiring January 2022. Rental expense under this lease was $16,932 and $17,381 for the period ending June 30, 2021 and 2020, respectively. The total for future minimum lease payments is $19,080 for fiscal year ended June 30, 2022.

7. RELATED PARTY TRANSACTIONS

VCE entered into a cooperative agreement with each respective member agency to provide management, legal, accounting and administrative services. The services billed from the Member Agencies to VCE outstanding for the periods ending June 30, 2021 and 2020 totaled $123,406 and $116,466, respectively. In March 2019, VCE began repaying the member agencies for the current year expenditures and repay the outstanding balance at June 30, 2018 over 12 months. The cooperative agreements provide for interest to be accrued on any outstanding balances at an average yield. The balance was paid off during the year ended June 30, 2020.

8. RISK MANAGEMENT

VCE is exposed to various risks of loss related to torts; theft of, damages to, and destruction of assets; errors and omissions; injuries to and illnesses of employees; and natural disasters, for which VCE manages its risk by participating in the public entity risk pool described below and by retaining certain risks.

Public entity risk pools are formally organized and separate entities established under the Joint Exercise of Powers Act of the State of California. As separate legal entities, those entities exercise full powers and authorities within the scope of the related Joint Powers Agreements including the preparation of annual budgets, accountability for all funds, the power to make and execute contracts and the right to sue and be sued. The joint powers authority is governed by a board consisting of representatives from member municipalities. The board controls the operations of the joint powers authority, including selection of management and approval of operating budgets, independent of any influence by member municipalities beyond their representation on that board. Obligations and liabilities of this joint powers authority are not VCE's responsibility.

VCE is a member of the Yolo County Public Agency Risk Management Insurance Authority (YCPARMIA) which provides coverage for general and auto liability and workers' compensation. Once VCE's deductible is met, YCPARMIA becomes responsible for payment of all claims up to the limit. In addition, the California Joint Powers Risk Management Authority (CJPRMA) provide coverage for amounts in excess of YCPARMIA's limits. YCPARMIA provides workers' compensation insurance coverage up to statutory limits, above VCE's self-insurance limit of $1,000 per occurrence, and general and auto liability coverage of $40,000,000, above VCE's self-insurance limit of $1,000 per occurrence. For the period ended June 30, 2021 and 2020, VCE contributed $6,645 and $5,008 for coverage, respectively. Audited financial statements are available from YCPARMIA their website www.ycparmia.org.

9. COMMITMENTS AND CONTINGENCIES

On October 25, 2017, VCE entered into an agreement with SMUD to provide on-going professional services, including, but not limited to: wholesale energy services, customer and data services, billing administration and reporting. As of June 30, 2021, VCE had outstanding non-cancelable commitments to SMUD for professional services to be performed estimated to be $4.1 million.

10. SUBSEQUENT EVENTS

Management has reviewed its financial statements and evaluated subsequent events for the period of time from its year ended June 30, 2021 through November 5, 2021, the date the financial statements were issued. Management is not aware of any subsequent events other than the issuance of refunding bonds described below that would require recognition or disclosure in the accompanying financial statements.

James Marta & Company LLP
Certified Public Accountants

Accounting, Auditing, Consulting, and Tax

COMMUNICATION WITH THOSE CHARGED WITH GOVERNANCE

Board of Directors
Valley Clean Energy Alliance
Davis, California

We have audited the financial statements of Valley Clean Energy Alliance as of and for the year ended June 30, 2021, and have issued our report thereon dated November 5, 2021. Professional standards require that we advise you of the following matters relating to our audit.

Our Responsibility in Relation to the Financial Statement Audit

As communicated in our engagement letter dated June 29, 2018 our responsibility, as described by professional standards, is to form and express an opinion(s) about whether the financial statements that have been prepared by management with your oversight are presented fairly, in all material respects, in conformity with accounting principles generally accepted in the United States of America. Our audit of the financial statements does not relieve you or management of your respective responsibilities.

Our responsibility, as prescribed by professional standards, is to plan and perform our audit to obtain reasonable, rather than absolute, assurance about whether the financial statements are free of material misstatement. An audit of financial statements includes consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control over financial reporting. Accordingly, as part of our audit, we considered the internal control of Valley Clean Energy Alliance solely for the purpose of determining our audit procedures and not to provide any assurance concerning such internal control.

We are also responsible for communicating significant matters related to the audit that are, in our professional judgment, relevant to your responsibilities in overseeing the financial reporting process. However, we are not required to design procedures for the purpose of identifying other matters to communicate to you.

We have provided our findings regarding internal controls and other matters noted during our audit in a separate letter to you dated November 5, 2021.

Planned Scope and Timing of the Audit

We conducted our audit consistent with the planned scope and timing we previously communicated to you.

Compliance with All Ethics Requirements Regarding Independence

The engagement team, others in our firm, as appropriate, our firm, and our network firms have complied with all relevant ethical requirements regarding independence.

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Qualitative Aspects of the Entity's Significant Accounting Practices

Significant Accounting Policies

Management has the responsibility to select and use appropriate accounting policies. A summary of the significant accounting policies adopted by Valley Clean Energy Alliance is included in Note 1 to the financial statements. No matters have come to our attention that would require us, under professional standards, to inform you about (1) the methods used to account for significant unusual transactions and (2) the effect of significant accounting policies in controversial or emerging areas for which there is a lack of authoritative guidance or consensus. However, there are upcoming Governmental Accounting Standards that we have listed in Attachment A.

Significant Accounting Estimates

Accounting estimates are an integral part of the financial statements prepared by management and are based on management's current judgments. Those judgments are normally based on knowledge and experience about past and current events and assumptions about future events. Certain accounting estimates are particularly sensitive because of their significance to the financial statements and because of the possibility that future events affecting them may differ markedly from management's current judgments. The most sensitive accounting estimate affecting the financial statements is the estimate of accounts receivable.

Management's estimate of the allowance for doubtful accounts is based on actual revenues earned for the year which may not be collectible. Management reported increased doubtful accounts for the year due to economic conditions as a result of the COVID-19 pandemic, but will continue to monitor as conditions improve. We evaluated the key factors and assumptions used to develop the estimate of doubtful accounts and determined that it is reasonable in relation to the basic financial statements taken as a whole and in relation to the applicable opinion units.

Management's estimate of the accrued revenue is based on actual revenues earned but not yet billed for June 2021. We evaluated the key factors and assumptions used to develop the estimate of accrued revenue and determined that it is reasonable in relation to the basic financial statements taken as a whole and in relation to the applicable opinion units.

Financial Statement Disclosures

Certain financial statement disclosures involve significant judgment and are particularly sensitive because of their significance to financial statement users. The most sensitive disclosures affecting Valley Clean Energy Alliance's financial statements relate to revenue recognition.

Significant Difficulties Encountered during the Audit

We encountered no significant difficulties in dealing with management relating to the performance of the audit.

Uncorrected and Corrected Misstatements

For purposes of this communication, professional standards require us to accumulate all known and likely misstatements identified during the audit, other than those that we believe are trivial, and communicate them to the appropriate level of management. We did not identify any uncorrected misstatements as a result of our audit procedures.

In addition, professional standards require us to communicate to you all material, corrected misstatements that were brought to the attention of management as a result of our audit procedures. The attached journal entry listing presents adjustments and reclassifications that we identified as a result of our audit procedures, were brought to the attention of, and corrected by, management (Attachment B).

Disagreements with Management

For purposes of this letter, professional standards define a disagreement with management as a matter, whether or not resolved to our satisfaction, concerning a financial accounting, reporting, or auditing matter, which could be significant to Valley Clean Energy Alliance's financial statements or the auditor's report. No such disagreements arose during the course of the audit.

Representations Requested from Management

We have requested certain written representations from management, which are included in the attached letter dated November 5, 2021.

Management's Consultations with Other Accountants

In some cases, management may decide to consult with other accountants about auditing and accounting matters. Management informed us that, and to our knowledge, there were no consultations with other accountants regarding auditing and accounting matters.

Other Significant Matters, Findings, or Issues

In the normal course of our professional association with Valley Clean Energy Alliance, we generally discuss a variety of matters, including the application of accounting principles and auditing standards, operating and regulatory conditions affecting the entity, and operational plans and strategies that may affect the risks of material misstatement. None of the matters discussed resulted in a condition to our retention as Valley Clean Energy Alliance's auditors.

This report is intended solely for the information and use of the Board of Directors, and management of Valley Clean Energy Alliance and is not intended to be and should not be used by anyone other than these specified parties.

James Marta & Company LLP

James Marta & Company LLP
Certified Public Accountants
Sacramento, California
November 5, 2021

The following pronouncements of the Governmental Accounting Standards Board (GASB) have been released recently and may be applicable to Valley Clean Energy Alliance in the near future. We encourage management to review the following information and determine which standard(s) may be applicable to the Valley Clean Energy Alliance. For the complete text of these and other GASB standards, visit www.gasb.org and click on the "Standards & Guidance" tab. If you have questions regarding the applicability, timing, or implementation approach for any of these standards, please contact your audit team.

GASB Statement No. 87, Leases
Effective for the fiscal year ending June 30, 2023

The objective of this Statement is to better meet the information needs of financial statement users by improving accounting and financial reporting for leases by governments. This Statement increases the usefulness of governments' financial statements by requiring recognition of certain lease assets and liabilities for leases that previously were classified as operating leases and recognized as inflows of resources or outflows of resources based on the payment provisions of the contract. It establishes a single model for lease accounting based on the foundational principle that leases are financings of the right to use an underlying asset. Under this Statement, a lessee is required to recognize a lease liability and an intangible right-to-use lease asset, and a lessor is required to recognize a lease receivable and a deferred inflow of resources, thereby enhancing the relevance and consistency of information about governments' leasing activities.

GASB Statement No. 89, Accounting for Interest Cost Incurred Before the End of a Construction Period
Effective for the fiscal year ending June 30, 2022

This Statement establishes accounting requirements for interest cost incurred before the end of a construction period. Such interest cost includes all interest that previously was accounted for in accordance with the requirements of paragraphs 5–22 of Statement No. 62, Codification of Accounting and Financial Reporting Guidance Contained in Pre-November 30, 1989 FASB and AICPA Pronouncements, which are superseded by this Statement. This Statement requires that interest cost incurred before the end of a construction period be recognized as an expense in the period in which the cost is incurred for financial statements prepared using the economic resources measurement focus. As a result, interest cost incurred before the end of a construction period will not be included in the historical cost of a capital asset reported in a business-type activity or enterprise fund.

This Statement also reiterates that in financial statements prepared using the current financial resources measurement focus, interest cost incurred before the end of a construction period should be recognized as an expenditure on a basis consistent with governmental fund accounting principles.

GASB Statement No. 91, Conduit Debt Obligations
Effective for the fiscal year ending June 30, 2023

The primary objectives of this Statement are to provide a single method of reporting conduit debt obligations by issuers and eliminate diversity in practice associated with (1) commitments extended by issuers, (2) arrangements associated with conduit debt obligations, and (3) related note disclosures. This Statement achieves those objectives by clarifying the existing definition of a conduit debt obligation; establishing that a conduit debt obligation is not a liability of the issuer; establishing standards for accounting and financial reporting of additional commitments and voluntary commitments extended by issuers and arrangements associated with conduit debt obligations; and improving required note disclosures.

We do not expect GASB 91 to have any significant impact to Valley Clean Energy Alliance at this time.

GASB Statement No. 92, Omnibus 2020
Effective dates vary

The objectives of this Statement are to enhance comparability in accounting and financial reporting and to improve the consistency of authoritative literature by addressing practice issues that have been identified during implementation and application of certain GASB Statements. This Statement addresses a variety of topics and includes specific provisions about the following:

- The effective date of Statement No. 87, *Leases*, and Implementation Guide No. 2019-3, *Leases*, for interim financial reports – *Effective for the fiscal year ending December 31, 2021*
- Reporting of intra-entity transfers of assets between a primary government employer and a component unit defined benefit pension plan or defined benefit other postemployment benefit (OPEB) plan – *Effective for the fiscal year ending December 31, 2021*
- The applicability of Statements No. 73, *Accounting and Financial Reporting for Pensions and Related Assets That Are Not within the Scope of GASB Statement 68, and Amendments to Certain Provisions of GASB Statements 67 and 68*, as amended, and No. 74, *Financial Reporting for Postemployment Benefit Plans Other Than Pension Plans*, as amended, to reporting assets accumulated for postemployment benefits – *Effective for the fiscal year ending December 31, 2021*
- The applicability of certain requirements of Statement No. 84, *Fiduciary Activities*, to postemployment benefit arrangements – *Effective for the fiscal year ending December 31, 2021*
- Measurement of liabilities (and assets, if any) related to asset retirement obligations (AROs) in a government acquisition – *Effective for the government acquisitions occurring in reporting periods beginning after June 15, 2020*
- Reporting by public entity risk pools for amounts that are recoverable from reinsurers or excess insurers – *Effective for the fiscal year ending December, 2021*
- Reference to nonrecurring fair value measurements of assets or liabilities in authoritative literature – *Effective for the fiscal year ending December 31, 2021*
- Terminology used to refer to derivative instruments. – *Effective for the fiscal year ending December 31, 2021*

Certain provisions of GASB 92 may have a financial statement impact to Valley Clean Energy Alliance. VCE is currently assessing the financial statement impact of GASB 92.

GASB Statement No. 93, Replacement of Interbank Offered Rates
Effective for the fiscal year ending June 30, 2023

The objective of this Statement is to address those and other accounting and financial reporting implications that result from the replacement of an IBOR. This Statement achieves that objective by:

- Providing exceptions for certain hedging derivative instruments to the hedge accounting termination provisions when an IBOR is replaced as the reference rate of the hedging derivative instrument's variable payment
- Clarifying the hedge accounting termination provisions when a hedged item is amended to replace the reference rate
- Clarifying that the uncertainty related to the continued availability of IBORs does not, by itself, affect the assessment of whether the occurrence of a hedged expected transaction is probable
- Removing LIBOR as an appropriate benchmark interest rate for the qualitative evaluation of the effectiveness of an interest rate swap
- Identifying a Secured Overnight Financing Rate and the Effective Federal Funds Rate as appropriate benchmark interest rates for the qualitative evaluation of the effectiveness of an interest rate swap
- Clarifying the definition of reference rate, as it is used in Statement 53, as amended

Providing an exception to the lease modifications guidance in Statement 87, as amended, for certain lease contracts that are amended solely to replace an IBOR as the rate upon which variable payments depend.

GASB Statement No. 94, Public-Private and Public-Public Partnerships and Availability Payment Arrangements
Effective for the fiscal year ending June 30, 2024

The primary objective of this Statement is to improve financial reporting by addressing issues related to public-private and public-public partnership arrangements (PPPs). As used in this Statement, a PPP is an arrangement in which a government (the transferor) contracts with an operator (a governmental or nongovernmental entity) to provide public services by conveying control of the right to operate or use a nonfinancial asset, such as infrastructure or other capital asset (the underlying PPP asset), for a period of time in an exchange or exchange-like transaction. Some PPPs meet the definition of a service concession arrangement (SCA), which the Board defines in this Statement as a PPP in which (1) the operator collects and is compensated by fees from third parties; (2) the transferor determines or has the ability to modify or approve which services the operator is required to provide, to whom the operator is required to provide the services, and the prices or rates that can be charged for the services; and (3) the transferor is entitled to significant residual interest in the service utility of the underlying PPP asset at the end of the arrangement.

This Statement also provides guidance for accounting and financial reporting for availability payment arrangements (APAs). As defined in this Statement, an APA is an arrangement in which a government compensates an operator for services that may include designing, constructing, financing, maintaining, or operating an underlying nonfinancial asset for a period of time in an exchange or exchange-like transaction.

GASB Statement No. 96, Subscription-Based Information Technology Arrangements
Effective for the fiscal year ending June 30, 2024

This Statement provides guidance on the accounting and financial reporting for subscription-based information technology arrangements (SBITAs) for government end users (governments). This Statement (1) defines a SBITA; (2) establishes that a SBITA results in a right-to-use subscription asset—an intangible asset—and a corresponding subscription liability; (3) provides the capitalization criteria for outlays other than subscription payments, including implementation costs of a SBITA; and (4) requires note disclosures regarding a SBITA. To the extent relevant, the standards for SBITAs are based on the standards established in Statement No. 87, Leases, as amended.

Adjusting Journal Entries

Account	Description	Debit	Credit
Adjusting Journal Entries JE # 1			
PBC - to remove old West Village payable.			
22210-0000	ACCOUNTS PAYABLE	84,195	
41510-0000	POWER PURCHASES		84,195
Total		**84,195**	**84,195**
Adjusting Journal Entries JE # 2			
PBC - to adjust billed revenues to agree to aging.			
13710-0000	BILLED REVENUES	178,329	
30120-0000	COMMERCIAL & INDUSTRIAL SALES		178,329
Total		**178,329**	**178,329**

Board of Directors

Dan Carson
VCE Chair
Davis City Council

Wade Cowan
Winters City Council

Lucas Frerichs
Davis City Council

Jesse Loren
VCE Vice Chair
Winters City Council

Gary Sandy
Yolo County Board of Supervisors

Don Saylor
VCE Chair
Yolo County Board of Supervisors

Tom Stallard
Woodland City Council

Mayra Vega
City of Woodland

November 5, 2021

James Marta & Company LLP
Certified Public Accountants
Sacramento, CA 95825

This representation letter is provided in connection with your audit of the Statement of Net Position and the Statement of Revenues, Expenditures and Changes in Net Position and the statement of cash flows of Valley Clean Energy Alliance for the years ended June 30, 2021 and 2020, and the related notes to the financial statements, for the purpose of expressing opinions on whether the basic financial statements present fairly, in all material respects, the financial position, results of operations, and cash flows, where applicable, of the various opinion units of Valley Clean Energy Alliance in accordance with accounting principles generally accepted for governments in the United States of America (U.S. GAAP).

Certain representations in this letter are described as being limited to matters that are material. Items are considered material, regardless of size, if they involve an omission or misstatement of accounting information that, in the light of surrounding circumstances, makes it probable that the judgment of a reasonable person relying on the information would be changed or influenced by the omission or misstatement.

We confirm that, to the best of our knowledge and belief, having made such inquiries as we considered necessary for the purpose of appropriately informing ourselves as of November 5, 2021:

Financial Statements

- We have fulfilled our responsibilities, as set out in the terms of the audit engagement dated June 29, 2018, for the preparation and fair presentation of the financial statements of the various opinion units referred to above in accordance with U.S. GAAP.
- We acknowledge our responsibility for the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.
- We acknowledge our responsibility for the design, implementation, and maintenance of internal control to prevent and detect fraud.
- We acknowledge our responsibility for compliance with the laws, regulations, and provisions of contracts and grant agreements.
- We acknowledge that we are responsible for distributing the issued report as well as the communication with governance letter and internal control letter to all governing board members.
- We have reviewed, approved, and taken responsibility for the financial statements and related notes.
- We have a process to track the status of audit findings and recommendations.
- We have identified and communicated to you all previous audits, attestation engagements, and other studies related to the audit objectives and whether related recommendations have been implemented.

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- Significant assumptions used by us in making accounting estimates, including those measured at fair value, are reasonable.
- Related party relationships and transactions have been appropriately accounted for and disclosed in accordance with the requirements of U.S. GAAP.
- All events subsequent to the date of the financial statements and for which U.S. GAAP requires adjustment or disclosure have been adjusted or disclosed.
- The effects of all known actual or possible litigation and claims have been accounted for and disclosed in accordance with U.S. GAAP.
- We have reviewed and approved the adjusting journal entries reflected in the audit statements and Attachment 1.
- All component units, as well as joint ventures with an equity interest, are included and other joint ventures and related organizations are properly disclosed.
- All funds and activities are properly classified.
- All funds that meet the quantitative criteria in GASB Statement No. 34, *Basic Financial Statements—and Management's Discussion and Analysis—for State and Local Governments*, GASB Statement No. 37, *Basic Financial Statements—and Management's Discussion and Analysis—for State and Local Governments: Omnibus* as amended, and GASB Statement No. 65, *Items Previously Reported as Assets and Liabilities*, for presentation as major are identified and presented as such and all other funds that are presented as major are considered important to financial statement users.
- All components of net position, nonspendable fund balance, and restricted, committed, assigned, and unassigned fund balance are properly classified and, if applicable, approved.
- Our policy regarding whether to first apply restricted or unrestricted resources when an expense is incurred for purposes for which both restricted and unrestricted net position/fund balance are available is appropriately disclosed and net position/fund balance is properly recognized under the policy.
- All revenues within the statement of activities have been properly classified as program revenues, general revenues, contributions to term or permanent endowments, or contributions to permanent fund principal.
- All expenses have been properly classified in or allocated to functions and programs in the statement of activities, and allocations, if any, have been made on a reasonable basis.
- Deposit and investment risks have been properly and fully disclosed.
- Capital assets, including infrastructure assets, are properly capitalized, reported, and if applicable, depreciated.

Information Provided

- We have provided you with:
  - Access to all information, of which we are aware that is relevant to the preparation and fair presentation of the financial statements of the various opinion units referred to above, such as records, documentation, meeting minutes, and other matters;
  - Additional information that you have requested from us for the purpose of the audit; and
  - Unrestricted access to persons within the entity from whom you determined it necessary to obtain audit evidence.
- All transactions have been recorded in the accounting records and are reflected in the financial statements.
- We have disclosed to you the results of our assessment of the risk that the financial statements may be materially misstated as a result of fraud.
- We have no knowledge of any fraud or suspected fraud that affects the entity and involves:
  - Management;

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- Employees who have significant roles in internal control; or
- Others where the fraud could have a material effect on the financial statements.

- We have no knowledge of any allegations of fraud, or suspected fraud, affecting the entity's financial statements communicated by employees, former employees, vendors, regulators, or others.
- We are not aware of any pending or threatened litigation, claims, and assessments whose effects should be considered when preparing the financial statements.
- We have disclosed to you the identity of the entity's related parties and all the related party relationships and transactions of which we are aware.
- There have been no communications from regulatory agencies concerning noncompliance with or deficiencies in accounting, internal control, or financial reporting practices.
- Valley Clean Energy Alliance has no plans or intentions that may materially affect the carrying value or classification of assets and liabilities.
- We have disclosed to you all guarantees, whether written or oral, under which Valley Clean Energy Alliance is contingently liable.
- We have disclosed to you all nonexchange financial guarantees, under which we are obligated and have declared liabilities and disclosed properly in accordance with GASB Statement No. 70, *Accounting and Financial Reporting for Nonexchange Financial Guarantees*, for those guarantees where it is more likely than not that the entity will make a payment on any guarantee.
- For nonexchange financial guarantees where we have declared liabilities, the amount of the liability recognized is the discounted present value of the best estimate of the future outflows expected to be incurred as a result of the guarantee. Where there was no best estimate but a range of estimated future outflows has been established, we have recognized the minimum amount within the range.
- We have disclosed to you all significant estimates and material concentrations known to management that are required to be disclosed in accordance with GASB Statement No. 62 (GASB-62), *Codification of Accounting and Financial Reporting Guidance Contained in Pre-November 30, 1989 FASB and AICPA Pronouncements*. Significant estimates are estimates at the balance sheet date that could change materially within the next year. Concentrations refer to volumes of business, revenues, available sources of supply, or markets or geographic areas for which events could occur that would significantly disrupt normal finances within the next year.
- We have identified and disclosed to you the laws, regulations, and provisions of contracts and grant agreements that could have a direct and material effect on financial statement amounts, including legal and contractual provisions for reporting specific activities in separate funds.
- There are no:
  - Violations or possible violations of laws or regulations, or provisions of contracts or grant agreements whose effects should be considered for disclosure in the financial statements or as a basis for recording a loss contingency, including applicable budget laws and regulations.
  - Unasserted claims or assessments that our lawyer has advised are probable of assertion and must be disclosed in accordance with GASB-62.
  - Other liabilities or gain or loss contingencies that are required to be accrued or disclosed by GASB-62
  - Continuing disclosure consent decree agreements or filings with the Securities and Exchange Commission and we have filed updates on a timely basis in accordance with the agreements (Rule 240, 15c2-12).
- Valley Clean Energy Alliance has satisfactory title to all owned assets, and there are no liens or encumbrances on such assets nor has any asset or future revenue been pledged as collateral, except as disclosed to you.
- We have complied with all aspects of grant agreements and other contractual agreements that would have a material effect on the financial statements in the event of noncompliance.

Mitch Sears, Executive Director

Edward Burnham, Director of Finance & Internal Operations

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Adjusting Journal Entries

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James Marta & Company LLP
Certified Public Accountants

Accounting, Auditing, Consulting, and Tax

REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING AND ON COMPLIANCE AND OTHER MATTERS BASED ON AN AUDIT OF FINANCIAL STATEMENTS PERFORMED IN ACCORDANCE WITH *GOVERNMENT AUDITING STANDARDS*

Independent Auditor's Report

Valley Clean Energy Alliance
Davis, California

We have audited, in accordance with auditing standards generally accepted in the United States of America and the standards applicable to financial audits contained in *Government Auditing Standards* issued by the Comptroller General of the United States, the financial statements of Valley Clean Energy Alliance as of and for the year ended June 30, 2021, and the related notes to the financial statements, which collectively comprise Valley Clean Energy Alliance's basic financial statements, and have issued our report thereon dated November 5, 2021.

Internal Control over Financial Reporting

In planning and performing our audit of the financial statements, we considered Valley Clean Energy Alliance's internal control over financial reporting (internal control) to determine the audit procedures that are appropriate in the circumstances for the purpose of expressing our opinions on the financial statements, but not for the purpose of expressing an opinion on the effectiveness of Valley Clean Energy Alliance's internal control. Accordingly, we do not express an opinion on the effectiveness of Valley Clean Energy Alliance's internal control.

A *deficiency in internal control* exists when the design or operation of a control does not allow management or employees in the normal course of performing their assigned functions, to prevent, or detect and correct misstatements on a timely basis. A *material weakness* is a deficiency, or a combination of deficiencies, in internal control, such that there is a reasonable possibility that a material misstatement of the entity's financial statements will not be prevented, or detected and corrected on a timely basis. A *significant deficiency* is a deficiency, or a combination of deficiencies, in internal control that is less severe than a material weakness, yet important enough to merit attention by those charged with governance.

Our consideration of internal control over financial reporting was for the limited purpose described in the first paragraph of this section and was not designed to identify all deficiencies in internal control over financial reporting that might be material weaknesses or significant deficiencies. Given these limitations, during our audit we did not identify any deficiencies in internal control over financial reporting that we consider to be material weaknesses. However, material weaknesses may exist that have not been identified.

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Compliance and Other Matters

As part of obtaining reasonable assurance about whether Valley Clean Energy Alliance's financial statements are free from material misstatement, we performed tests of its compliance with certain provisions of laws, regulations, contracts, and grant agreements, noncompliance with which could have a direct and material effect on the determination of financial statement amounts. However, providing an opinion on compliance with those provisions was not an objective of our audit and, accordingly, we do not express such an opinion. The results of our tests disclosed no instances of noncompliance or other matters that are required to be reported under Government Auditing Standards

Purpose of this Report

The purpose of this report is solely to describe the scope of our testing of internal control and compliance and the results of that testing, and not to provide an opinion on the effectiveness of the entity's internal control or on compliance. This report is an integral part of an audit performed in accordance with *Government Auditing Standards* in considering the entity's internal control and compliance. Accordingly, this communication is not suitable for any other purpose.

James Marta & Company LLP

James Marta & Company LLP
Certified Public Accountants
Sacramento, California
November 5, 2021

VALLEY CLEAN ENERGY ALLIANCE

Staff Report – Item 15

TO: Board of Directors

FROM: Mitch Sears, Interim General Manager
Edward Burnham, Director of Finance & Internal Operations

SUBJECT: Cost-Based Rate Policy and Customer Rate Structure

DATE: November 10, 2021

RECOMMENDTIONS

1. Approve the attached resolution adopting:
   a. A cost-based rate policy and implementing procedure;
   b. A revised rate structure with three customer options: (1) Standard Green (default) and (2) UltraGreen (100% renewable) with cost-based rates and adding a (3) least-cost customer rate option; and
   c. Automatic enrollment of California Alternative Rates for Energy (CARE) and Family Electric Rates Assistance (FERA) customers in the newly created least-cost rate option with an enhanced portfolio beginning in 2024.

OVERVIEW

Beginning in mid-2020, VCE began exploring the concept of cost-based rates to address financial issues associated with power market and regulatory volatility. Steeply rising Power Charge Indifference Adjustment (PCIA) (+46% for 2021) and power market costs (+57% since May 2021), have required VCE to draw on reserves to stabilize customer rates and maintain its current rate policy of matching PG&E generation rates. In Q3 of 2021, the Board directed staff to develop an expanded and cost-based rate structure to address these issues. In September, staff presented a background report to the Board and CAC that included a draft outline rate structure and development/implementation schedule.

Based on updated power market forecasts and VCE financial model results that corrected an overestimation of the value of VCE's long-term renewable contracts, the Board approved an accelerated rate adjustment of approximately 2% on the average customer bill in mid-October. This cost-based rate adjustment slows the draw on reserves and will be reassessed as final rates for 2022 are set by the Board in December. Note: PG&E's 2022 PCIA and rates are scheduled to be released the 2nd week of November, which will inform the Board's December action to set VCE's rates for 2022.

The Community Advisory Committee considered the proposed cost-based rate policy and structure at its November 28, 2021 meeting and recommended adoption by the Board.

This report and recommendation serve to update VCE's rate policy and customer rate structure consistent with recent Board direction. This policy and structure, if adopted by the Board, will enable VCE to set rates calibrated to actual cost and reserve requirements rather than simply indexed to PG&E's generation rates.

BACKGROUND

In 2017, prior to launch, VCE adopted and registered its Implementation Plan with the California Public Utilities Commission (CPUC). The Plan included a provision that program rates must collect sufficient revenue from participating customers to fully fund VCE's budget, including the need to establish sufficient operating reserve funds. Over the past three years VCE has systematically analyzed policy options and implemented strategies to stabilize customer rates, reduce cost, and manage reserves. This is in keeping with its Strategic Plan goal to maintain financial stability while continuing to offer customer choice, competitive pricing and establishment of local programs. Several of these key financial mitigation strategies have included: discontinuing a rate discount, scaling back voluntary procurement of renewable energy credits (RECs), and signing long-term contracts for fixed price renewable/battery storage projects.

Recognizing that additional steps may be needed to achieve cost recovery objectives, in early 2020 staff began investigating rate related strategies employed by other CCAs designed to address on-going financial pressures outside of a CCA's control (e.g. PCIA, RA, power market prices). Based on general Board direction, research was conducted with input from the CAC Rates Task Group through mid-2021, resulting in a staff concept for an expanded and cost-based customer rate structure. The concept was reviewed by the CAC in September and by the Board in September and October. The staff report related to the concept is at: Item-17-Customer-Rate-Structure-Policy-9-9-21.pdf (valleycleanenergy.org).

Rate Adjustment – October 2021

Additional forecast information on rising power markets, correction of an overestimation of the value of VCE's long-term renewable contracts, and elevated 2021 PCIA rates prompted the Board to approve a rate adjustment on October 21, 2021. The rate adjustment of approximately 2% on the average overall VCE customer bill for the remaining months of 2021 and January 2022 will reduce the draw on VCE's financial reserves. This adjustment went into effect on November 1st and will be evaluated as part of VCE's overall 2022 rate setting action scheduled for December. For reference, the Board staff report related to the accelerated rate adjustment is at: Item-4-Rate-Adjustment-10-21-21.pdf (valleycleanenergy.org).

Updated Financial Factors

On November 8th PG&E's 2022 PCIA and rates will be filed with the CPUC. The information in this filing will allow VCE (and other CCAs), to update assumptions for these key factors that impact rate setting and affect financials. VCE's current budget and forecasts incorporate a 5% PG&E rate increase and 5% PCIA decrease for 2022. Analysists and consultants for CalCCA track PG&E's filings related to these key factors and are continually updating their forecasts for the upcoming year. Recent PG&E filings indicate a greater increase in PG&E's rates and a greater decrease in the PCIA for 2022 than were assumed in VCE's current budget that was adopted in June. Based on these updated forecasts, staff believes that movement of these two factors are likely to improve VCE's financial outlook for 2022 but not eliminate the need to enact rate adjustments for 2022. Due to the timing of the filing, these assumptions are not reflected in this staff report. However, if they are filed on time, staff will include general information in our presentation to the Board on November 10th.

Community Advisory Committee Recommendation

On September 23, 2021 the Community Advisory Committee (CAC) received a background presentation on the rate-based concept and structure. On October 28, 2021 the Committee considered the recommended rate-based policy and structure. The CAC considered the analysis of staff and its own ad-hoc Rates Task Group and ultimately voted 9-0 to recommend adoption of a rate-based policy with one edit as shown in recommendation "a" below (underlined). The Committee also voted in support of the companion motion to recommend adoption of the expanded rate structure (7-0-2). Though understanding of the overall need to adopt a rates-based policy and structure, several Committee members expressed concern that they did not believe there was adequate time for the CAC to fully analyze the policy and therefore abstained from the vote on the cost-based rate structure (Shewmaker and Braun). Note: Staff and the CAC agreed that the rate structure design should incorporate a clear differentiation between the customer rate option portfolios to demonstrate the value of each option.

The CAC recommended that the Board adopt the following:

a. Cost-Based Rate Policy: VCE will set customer rates to collect sufficient revenue from participating customers to fully fund VCE's budget and establish sufficient operating reserve funds. Changes in rates are to be approved by the Board in consultation with the Community Advisory Committee. (9-0-0);

The CAC recommended that the Board also adopt the following:

b. Cost-Based Rate Structure: Adopt a new rate structure with three customer options: (1) Standard Green (default) and (2) UltraGreen (100% renewable) with rates based on cost-recovery and add a (3) least-cost customer rate option.

And,

c. Automatically enroll California Alternative Rates for Energy (CARE) and Family Electric Rates Assistance (FERA) customers in the newly created least-cost rate option with an enhanced portfolio beginning in 2024. (7-0-2)

Under the staff recommended rates policy the Board retains rate setting authority. Staff believes that CAC review of rates in the context of a significant rate restructuring, as in the current case, is appropriate. However, staff has some concern that adding a blanket requirement for CAC review of all rate adjustments may hinder VCE's regular course of business operations (e.g. adjusting rates mid-year to follow a minor PG&E rate change). For these reasons, staff has not incorporated the CAC's additional language in the staff recommended policy shown in the Analysis section of this report, but would suggest that the Board direct staff to work with the CAC to refine the policy language to retain operational flexibility and return with proposed policy changes by mid-2022.

ANALYSIS
As discussed at previous Board and CAC meetings, all electric utilities develop forecasts of cost and revenue requirements based upon informed technical estimates. These forecasts incorporate factors such as future weather, load, market power prices, and other business conditions. Actual outcomes inevitably vary and in extreme instances, like the heat event of August 2020, outcomes may vary significantly. For example, VCE, much like other California utilities, experienced just such variability during August 2020 when excessively hot weather and market price increases impacted the western United States. The net cost impact of this event to VCE was approximately $800K (and would have been closer to $2.5 million absent VCE's risk management and hedging practices). These events continue to “ripple” through the energy sector in the form of higher forward power market prices. During the current period while VCE transitions to longer-term renewable fixed-price power contracts over the next two years, it has relatively high exposure to these rising market prices.

Utilities and CCAs affected by such events must recover costs from customers or draw from reserve funds if available. Under its current rates policy, VCE has been drawing from reserves to stabilize customer rates by matching PG&E generation rates. CCAs in general - and VCE specifically - face two additional revenue impacting uncertainties: PG&E rate revisions and changes to the PCIA. Alterations to these factors result in a corresponding and direct need for VCE to adjust rates (upward or downward) to maintain adopted financial and other Strategic Plan objectives.

As a Community Choice program, VCE’s advantages include local control and the ability to develop and implement revenue structures in a timely manner to meet financial policy goals and objectives. Rate levels forecast and implemented in advance of retail sales, however, inevitably result in actual revenues above or below the cost to serve customers and accomplish business objectives. This is especially true in the electric power business because weather events and corresponding price/load volatility (like the heat storms experienced in August and September of 2020) may result in actual power supply costs substantially in excess of forecast costs. Most utilities have adopted rate stabilization mechanisms to compensate for these types of cost uncertainties in order to more closely balance revenues and costs. As shown in Table 2 below, these factors have also impacted other CCA’s who have taken steps to implement cost-based rates.

Table 2

CCA	IOU Territory	% Difference to IOU (default product)
Clean Power SF	PG&E	+2%
MCE Clean Energy	PG&E	+7%
Pioneer Community Energy	PG&E	+6%
San Jose Clean Energy	PG&E	+8%
Sonoma Clean Power	PG&E	+5%
Clean Power Alliance (Los Angeles area)	SCE	+8%
Desert Clean Energy	SCE	+20%

As discussed at previous meetings, these rate determining factors and rising power market prices have stretched VCE's financials and forced the Board to adopt cost mitigation measures beginning as early as 2018 (e.g. rate increase, multi-year strategy for procurement of renewables, reduced program activity). The volatility of these factors makes it necessary for VCE to now consider a cost-based customer rate structure to augment its existing cost mitigation measures.

<u>Cost-Based Rate Policy</u>

Currently, VCE sets rates for its default product to match PG&E's generation rates, regardless of market movement and/or changing regulatory requirements. While this current approach is simple to calculate and communicate, it requires VCE to draw on reserves to smooth this volatility. Due to the noted scale and variability of these cost drivers, VCE's current rate approach is not aligned with its financial objectives and fiduciary responsibility to collect sufficient revenue from participating customers to fully fund expenditures and establish sufficient operating reserves.

A cost-based rate structure addresses this uncertainty and allows VCE to build a financial foundation that is sustainable, enabling the organization to carry out its mission. In the context of these factors, staff is recommending the following rate policy update and associated implementing procedure:

> **Policy:** VCE will set customer rates to collect sufficient revenue from participating customers to fully fund VCE's budget and establish sufficient operating reserve funds.
>
> **Implementing Procedure** (budget years 2022 and 2023): Over the next two budget years set customer rates to fully fund VCE's budget, as may be amended from time to time, and rebuild a minimum operating reserve of 30 days cash by the end of 2023; with a targeted operating reserve of 60 days cash by the end of 2023. Beginning in 2024, higher operating reserve targets will be established to support Strategic Plan goals including achieving an investment grade credit rating.

The recommended policy and implementing procedure are designed to collect adequate revenue to meet VCE's expenditures and build reserves at a moderate pace over the next several years to manage customer rate impacts. This approach will allow VCE to effectively transition into its fixed-price long term renewable contracts over the next several years, thereby significantly reducing exposure to short-term power market volatility.

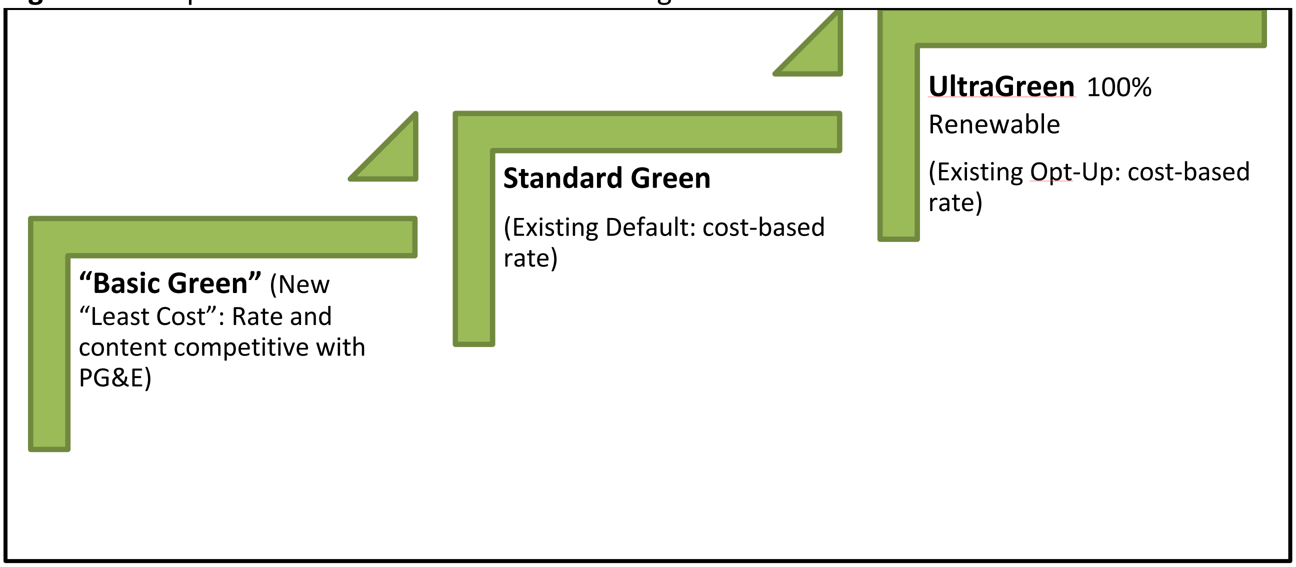
In summary, with this action VCE's longer-term financial outlook (2024+) includes increased stability and cost certainty due to its long-term PPA's and cost-based rate structure, allowing VCE to rebuild reserves and re-establish positive margins going forward. See companion agenda item 16 (2022 Preliminary Budget), for additional information on budget forecasts.

<u>Recommended Customer Rate Structure</u>

The recommended customer rate structure serves to implement the recommended rate-based policy by introducing two key elements to VCE's existing rate structure. First, it increases customer choice by adding a new least-cost customer option that would continue to be directly indexed to PG&E's rates. This new option is designed in recognition that many VCE customers have been impacted by the pandemic and that rising utility bills have further strained family and business finances. Second, the existing default (Standard Green) and opt-up (UltraGreen) options would incorporate cost-based rates. The modification to VCE's existing two options would enable VCE to set rates calibrated on actual cost and reserve requirements.

Figure 1 below summarizes the proposed structure.

Figure 1 – Proposed Customer Rate Structure Design



Note: Name of new customer option TBD.

The proposed customer rate structure detail is listed below and shown in Table 2.

1. Rate Structure
   a. Three customer rate options – (1) Basic (new), (2) Standard (existing default), and (3) UltraGreen (existing opt-up)

2. Customer Distribution
   a. All CARE/FERA customers automatically opted down (approx. 27% of VCE load)
   b. Assumed additional customer load opt-down/out: 5%

3. Portfolio/Price (renewable/GHG content)
   a. Basic Green rate (new): competitive with PG&E generation rate net of PCIA and Franchise Fees (+/- 2%) and maintain minimum portfolio to comply with regulatory requirements; ineligible for customer dividend program.
      i. CARE/FERA customers maintain existing VCE multi-year portfolio mix for Standard default through 2023; shift to enhanced portfolio in 2024: PG&E renewable content plus a minimum of 5%.
   b. Standard (existing default): cost-based rate and maintain existing VCE multi-year portfolio mix.
   c. UltraGreen (existing opt-up): cost-based rate and maintain existing 100% renewable mix.

Table 2 below shows the recommended cost-based rate structure information listed above in table form.

Table 2 – VCE Cost-based Rate Structure

Customer Rate Option	Rate	Portfolio	Notes
Basic (new)	Competitive with PG&E (+/- 2%)	• Minimum portfolio for VCE to comply with regulatory requirements	• Not eligible for customer dividend program • CARE/FERA customers maintain existing VCE multi-year portfolio mix for Standard default through 2023; shift to enhanced portfolio in 2024
Standard Green - Default (existing)	Cost-based	• Maintain existing VCE multi-year portfolio mix	• Portfolio minimum percent renewable content above Basic • Eligible for customer dividend program
UltraGreen – Opt-up (existing)	Cost-based	• Maintain existing 100% renewable portfolio	• Eligible for customer dividend program

The recommended cost-based rate policy and structure are included in the attached resolution. If approved, the cost-based rate policy and structure is scheduled to be implemented in February 2022.

Communications

One of the key considerations of the proposed rate policy and structure change is how it is communicated to VCE's customers, as well as to the general public. Based on feedback from other CCAs and VCE's consultants, staff recommends a measured, transparent customer outreach strategy with an emphasis on the additional choices to be offered. This approach would also be designed to acknowledge that VCE is in the competitive energy business and that rate adjustments driven by market forces are not uncommon or unexpected.

A key focus of the communications strategy will be emphasizing VCE's success in procuring electricity for approximately 25% less than PG&E, but that the PCIA eliminates that competitive advantage by "eating up" any potential savings customers would have realized. Communications will focus on easily understandable language (and graphics), that highlight the overriding impact of the PCIA as a cost driver. VCE's additional benefits such as more choice in electricity supply, local control, and community reinvestment through energy contracts and programs will also be emphasized.

Recommended outreach actions would include listing the changes on VCE's website with an introductory message from the Board Chair and Vice-Chair. This piece would recognize the PCIA's role in keeping electricity rates high, and VCE's success so far in keeping our rates low, protecting our customers from paying too much.

Because of the current uncertainty around changes to PG&E's 2022 rates and PCIA, staff recommends measured direct outreach to key accounts (including agricultural) beginning in Q1 2022, after there is more certainty in how VCE's rates compare. Based on information gathered from other CCAs undertaking similar rate actions, staff does not anticipate significant opt-down or opt-out customer activity in response to the new rate structure – especially if additional choice of a competitive customer rate is offered as recommended. To confirm similar outcomes, analysis of opt-up/down/out activity is planned to track VCE's results so corrective action can be taken if necessary. The communications strategy will be finalized after Board and CAC feedback in November 2021 and will encompass the time period November 2021-March 2022.

Updated Schedule

The schedule developed for consideration of the expanded and cost-based rate structure has been updated to include the special Board meeting in October, PG&E 2022 rates/PCIA information release, the CAC review of 2022 rates at its November meeting and the December Board meeting adopting 2022 VCE rates.

- *Sept: Board direction; Based on Board direction, staff + CAC Task Group finalize draft rate policy and expanded and cost-based customer rate structure.*
- *Sept: CAC examination/feedback on draft rate policy and expanded and cost-based customer rate structure; input on customer outreach strategy.*
- *October: Board update/direction; draft policy/rate structure.*
- *October: Board special meeting; approved accelerated rate adjustment for Nov 2021 – Jan 2022.*
- *October 28: CAC consideration/recommendation on final draft policy/rate structure.*
- *Nov 8: PG&E 2022 rates and PCIA update released.*
- **Nov 10 (Current): Board** consideration/action on final draft rate policy/structure.
- Nov 18: CAC update on 2022 PCIA and PG&E rates.
- Dec 9: Board adoption of calendar based fiscal year and budget; set 2022 VCE rates.
- Nov-Jan 2022: Execute customer outreach strategy.
- Jan 2022: Rates update report to Board/CAC.
- Feb 2022: Implement expanded and cost-based customer rates and structure.
- Post-implementation: Monitoring/reporting customer opt-out/opt-down activity.

CONCLUSION/NEXT STEPS

Staff is recommending adoption of an expanded and cost-based customer rate structure similar to those implemented by other CCA's. Staff recognizes that the recommended action is a shift from VCE's current rate structure but also that it is driven by forces outside of VCE's direct control. Staff is making the recommendation because it maintains local control, customer choice, cost competitiveness and the ability to execute local programs.

If the expanded and cost-based customer rate structure is approved, staff will bring recommended 2022 customer rates to the Board for consideration at the December meeting.

ATTACHMENT

1. Resolution adopting Cost-Based Rate Policy and Revised Customer Rate Structure

VALLEY CLEAN ENERGY ALLIANCE

RESOLUTION NO. 2021 - ____

A RESOLUTION OF THE VALLEY CLEAN ENERGY ALLIANCE ADOPTING A COST-BASED RATE POLICY, IMPLEMENTATION PROCEDURE AND REVISED RATE STRUCTURE

WHEREAS, on June 19, 2019, the Board adopted via Resolution 2019-007 a New Rate Structure and Dividend Program Guidelines, which outlined the purpose of setting a new rate structure and set program guidelines, including matching PG&E electric generation rates less Power Charge Indifference Adjustment (PCIA) exit fee; and,

WHEREAS, in mid-2020, VCE began exploring the concept of cost-based rates to address financial issues associated with power market and regulatory volatility; and,

WHEREAS, steeply rising PCIA, Resource Adequacy (RA) and power market costs have required VCE to draw on reserves to stabilize customer rates to maintain its current rate policy of matching PG&E generation rates; and,

WHEREAS, to address rising power markets, correction of an overestimation of the value of VCE's long-term renewable contracts, and elevated 2021 PCIA rates prompted the Board on October 21, 2021 to approve a rate adjustment effective November 1, 2021 for the remaining months of 2021 and January 2022 to reduce the draw on VCE's financial reserves; and,

WHEREAS, there is a need to update VCE's rate policy and customer rate structure consistent with recent Board direction and to set rates calibrated to actual cost and reserve requirements rather than simply indexed to PG&E's generation rates.

NOW, THEREFORE, the Board of Directors of the Valley Clean Energy Alliance resolves as follows:

1. VCE adopts a cost-based rate policy and implementing procedure as shown Attachment 1;
2. VCE adopts a revised rate structure with three customer options: (1) Standard Green (default) and (2) UltraGreen (100% renewable) with cost-based rates and add a (3) least-cost customer rate option as shown in Attachment 2;
3. VCE will automatically enroll California Alternative Rates for Energy (CARE) and Family Electric Rates Assistance (FERA) customers in the newly created least-cost rate option with an enhanced portfolio beginning in 2024.

PASSED, APPROVED, AND ADOPTED, at a regular meeting of the Valley Clean Energy Alliance, held on the ___ day of _____________ 2021, by the following vote:

AYES:
NOES:
ABSENT:
ABSTAIN:

____
Dan Carson, VCE Chair

____
Alisa M. Lembke, VCE Board Secretary

Attachments:

1. VCE Cost-based rate policy and implementing procedure
2. VCE Revised rate structure

Attachment 1 - VCE Cost-based rate policy and implementing procedure

Policy: VCE will set customer rates to collect sufficient revenue from participating customers to fully fund VCE's budget and establish sufficient operating reserve funds.

Implementing Procedure (budget years 2022 and 2023): Over the next two budget years set customer rates to fully fund VCE's budget, as may be amended from time to time, and rebuild a minimum operating reserve of 30 days cash by the end of 2023; with a targeted operating reserve of 60 days cash by the end of 2023. Beginning in 2024, higher operating reserve targets will be established to support Strategic Plan goals including achieving an investment grade credit rating.

Attachment 2 - VCE Revised rate structure

1. Rate Structure
   a. Establish three customer rate options – (1) "Basic[1]" Green (new), (2) Standard Green (existing default), and (3) UltraGreen (existing opt-up)

2. Customer Distribution
   a. All CARE/FERA customers automatically opted down to "Basic" rate (approx. 27% of VCE load)

3. Portfolio/Price (renewable/GHG content)
   a. "Basic Green" rate (new): competitive with PG&E generation rate net of PCIA and Franchise Fees (+/- 2%) and maintain minimum portfolio to comply with regulatory requirements; ineligible for customer dividend program.
      i. CARE/FERA customers maintain existing VCE multi-year portfolio mix for Standard default through 2023; shift to enhanced portfolio in 2024: PG&E renewable content plus a minimum of 5%.
   b. Standard (existing default): cost-based rate and maintain existing VCE multi-year portfolio mix.
   c. UltraGreen (existing opt-up): cost-based rate and maintain existing 100% renewable mix.

Table below shows the VCE revised rate structure information listed above in table form.

VCE Cost-based Rate Structure

Customer Rate Option	**Rate**	**Portfolio**	**Notes**
Basic Green (new)	Competitive with PG&E (+/- 2%)	• Minimum portfolio for VCE to comply with regulatory requirements	• Not eligible for customer dividend program • CARE/FERA customers maintain existing VCE multi-year portfolio mix for Standard default through 2023; shift to enhanced portfolio in 2024
Standard Green - Default (existing)	Cost-based	• Maintain existing VCE multi-year portfolio mix	• Portfolio minimum percent renewable content above Basic • Eligible for customer dividend program
UltraGreen – Opt-up (existing)	Cost-based	• Maintain existing 100% renewable portfolio	• Eligible for customer dividend program

[1] "Basic" Green name to be determined.

VALLEY CLEAN ENERGY ALLIANCE

Staff Report – Item 16

TO:	Board of Directors
FROM:	Mitch Sears, Interim General Manager Edward Burnham, Director of Finance & Internal Operations
SUBJECT:	Preliminary Draft Operating Budget Calendar Year 2022
DATE:	November 10, 2021

RECOMMENDATION
Receive informational report and provide direction on development of final budget for 2022.

OVERVIEW
This update is the first of two discussions leading to Board adoption of the calendar year 2022 budget (2022 Budget) ending December 31, 2022. The basis for the staff preparing a CY 2022 budget is a result of the companion agenda Item 13, adopting a resolution to change the current fiscal year (July 1 to June 30) to align with the calendar year (January 1 to December 31).

The purpose of this staff report is to: (1) provide an update on the FY2020-21 and 2021-22 Operating Budgets, (2) provide an overview of key factors influencing the operating budgets, (3) present an analysis of three draft budget scenarios for the Board discussion and feedback.

As detailed in the body of this report, the previous FY 2020-21 has resulted in a net loss of $3.8M for a total loss of $.3M more than budgeted. The current FY 2021-22 for the first six months is anticipated to be approximately $1.6M net more favorable than the approved Budget. The three 2022 budget scenarios outlined in the analysis section of this report range between $0.3M net income to $3.8M net loss based on net rate increases due to rising power costs and resource adequacy costs as VCE transitions to its fixed price long-term renewable power purchase agreements.

VCE's short-term outlook (2022 and 2023) indicates continued volatility in market prices and PCIA with associated financial challenges which requires corrective action on rate setting to ensure cost recovery. The longer-term outlook (2024+), indicates increased stability and cost certainty due to long-term PPA's coming on-line and cost-based rate structure allowing VCE to rebuilt reserves and achive positive margins.

BACKGROUND
As discussed in staff reports leading to the adoption of the FY 2021-22 Budget and budget monitoring process in June, the past two years have seen high volatility in the energy sector

and overall economy primarily driven by the uncertainty during the COVID-19 pandemic and possible long-term recession. In addition, the increases in 2021 Power Charge Indifference Adjustment (PCIA), resource adequacy, and power market costs have required VCE to draw against reserves to stabilize customer rates and maintain its current rate policy of matching PG&E generation rates. As part of the budget adoption and monitoring process, VCE has taken the following key actions:

- In June 2020, the Board adopted a FY 2020-21 budget that included the fiscal mitigation policy adjustments starting in fiscal year 2019-20 that reduced the net loss from over $5M to $2.8M. The policy adjustments scaled back VCE's near-term acquisition of renewable energy credits (RECs) and GHG-free power content. This policy was adopted by the Board to address: (1) the objective of aligning VCE's short and long-term power procurement efforts, (2) the increasing/unpredictable PCIA, and (3) volatility in Resource RA power pricing, which have created uncertainty for CCA programs across the State. The policy adjustments placed VCE in a better position to maintain competitive rates and clean power content for its customers while meeting its baseline compliance obligations.

- In October 2020, staff presented a mid-year budget update to monitor actual customer load demand, revenue, and expenses during the pandemic. The June 2020 forecasted net deficit for FY 2022 was approximately $6.0M; the follow-up mid-year update in October 2020 showed a net $7.1M deficit due to rising RA, power, and PCIA costs.

- In May 2021, in conjunction with SMUD, staff provided a budget update, including the annual electricity demand forecast for VCE for a projected net income loss of approximately $7.70M for FY 2022. The primary fiscal drivers included: (1) a load increase of 0.5% as the predicted dampening effects of an ongoing recession from COVID were no longer anticipated, (2) 7% increase in market power costs compared to FY 2021 due primarily to the hot 2020 summer and its impacts on forward market power prices, and (3) Time of Use (TOU) rate transitions for non-residential customers were lower than anticipated due to the methodology applied by PG&E. Based on the best information available at the time, the budget model incorporated assumptions of a 5% increase in PG&E's generation rates and a 5% decrease for the PCIA in 2022. As noted below, these assumptions are in the process of being revised to reflect updated information indicating a larger increase in PG&E's rates and a larger decrease in PCIA for 2022.

- In June 2021, the Board extended the policy strategy adjustments described in the bullet point above one year to reduce procurement of short-term renewable resources (RECs) to partially mitigate current financial impacts. The Board approved the FY 2021-22 Operating Budget with $51.2M of operating revenues and $58.1M of operating expenses for a net loss of $6.9M.

- In October 2021, the Board received updated power market forecasts and VCE financial model results that corrected an overestimation of the value of VCE's long-term renewable contracts of approximately $13M over the next 2 years. The Board approved an accelerated rate adjustment of approximately 2% on the average customer bill in mid-October to reduce pressure on reserves; additional information on this action is included in the companion board item 16.

Long-term Fixed Price Power Purchase Agreements

VCE renewable power and storage resource deliveries resulting from our contracted long-term power purchase agreements (PPAs) began in 2021 and will significantly increase over 2022 and 2023. The PPAs are fixed-price contracts and are projected to cover over 80% of VCE's annual load by 2024 to reduce VCE costs compared to current RPS and RA market costs and significantly reduce volatility as VCE moves forward. As discussed with the Board leading up to the FY 2021-22 budget adoption in June, the undesirable but necessary RPS policy adjustments and utilization of cash reserves have helped VCE stabilize customer rates and partially bridge the gap until the long-term PPAs begin full delivery in the 2021-24 timeframe.

ANALYSIS

This report updates the information provided to the Board in September 2021 and provides the basis for the presented budget scenarios. The sections below provide updates on: (1) the FY2020-21 and 2021-22 Operating Budgets, (2) provide an overview of key factors influencing the operating budgets, and (3) present an analysis of three budget scenarios for discussion and Board feedback.

1. Operating Budget Update – FY 2020-21 & FY 2021-22 (6 Month)

As presented to the Board in September, VCE has faced financial challenges associated with power market and regulatory volatility, requiring VCE to draw on reserves to stabilize customer rates and maintain its current policy of matching PG&E generation rates.

FY 2020-21 (July 2020-June 2021) – The audited financials presented in the companion Board agenda item 15 increased losses by approximately $300K.

- NEM revenues unfavorable $800K related to reporting for the annual true-up process.
- Rugged Solar PPA performance deposit of $220K was forfeited by the developer to VCE, resulting in additional other revenue
- The receivables account was reconciled for an increase of $180K
- VCE released accrued expenses of $90K as reconciled

FY 2021-22 (6 Month) – The unaudited financials for the six months of July-2021 to December-2021 are currently forecasted to be net favorable to Budget by $1.6M for a forecasted loss of $3.5M. The key factors that resulted in the $1.6M difference include:

- PCIA. A net 46% increase in the PCIA from 2020/21 continues to have significant revenue erosion for approximately $23M total paid for the 9-months of the current calendar through September.
- Power Prices. Average forward market power prices have increased 57% since May 2021.
- Customer Rate Increase of 2% - The Board approved an accelerated rate adjustment of approximately 2% on the average customer bill in mid-October for $300K.

The following table summarizes the FY 2021-22 (6 Month) actuals vs. approved Budget.

FY 2021-22	APPROVED BUDGET FY 2021 (6 MO)	Actual YTD Sept. 30 (3 MO) + Forecast (3 MO)	Variance
Revenue	$ 25,043	$ 28,606	$ 3,564
Power Cost	$ 27,592	$ 29,616	$ (2,023)
Other Expenses	$ 2,509	$ 2,469	$ 41
Net Income	$ (5,059)	$ (3,478)	$ 1,581

Staff will continue to monitor the FY 2021-22 (6 Month) Operating Budget, including October and November results in the December CY 2022 Budget adoption.

2. Key factors – Operating Budgets

The VCE financial outlook for CY 2022 and CY 2023 has changed significantly since the Board approved the current fiscal year budget in June 2021. PG&E's rates are forecast to increase in while PCIA is forecast to decrease significantly in 2022. These forecasted changes, in combination with VCE cost-based rate adjustments will off-set higher forecasted power costs as VCE transitions into its long-term fixed price renewable PPA's scheduled to come on-line in 2022 and 2023. The budget scenarios shown in Tables 2 though 4 below incorporate these factors in the short and longer-term forecasts.

Key baseline factors that influenced the development of the budget options presented in Section 3 below include:

- Power Prices. Average forward market power prices have increased by approximately 57% since the April-2021 preliminary draft budget. This impacts the Budget directly since VCE buys forward energy price hedges to manage energy price risk. Based on the Board approved procurement policy, SMUD is in the process of completing hedge purchases for 2022. Speculation in the energy markets on the potential for a repeat of the heat storm event of last summer 2020 pushed forward market power prices significantly higher in 2021. Beyond 2022, a significant portion of these short-term energy costs and the associated price volatility will be mitigated by the commencement of VCE's long-term PPA agreements.
- Financial Power Cost Model - Total difference between adopted and corrected forecasts is approximately $13M over the three FYs 2022 to 2024, resulting from a modeling error that overestimated the financial benefits of VCE's long-term renewable power purchase contracts.
- PCIA. A net 39% increase in the PCIA from 2020/21 continues to have significant revenue erosion for approximately $21M for the 6-months of the current calendar through July.
- Fiscal Year and Budget adoption timing. As described in October and in the proposed adoption of companion agenda item 13 (revised fiscal year), the budget adoption

process occurs during the load forecast updates and the beginning of the hedging process for the following calendar year.

Based on information provided by CalCCA forecast analysts, the results of various regulatory, legislative and market factors are expected to lead to a more significant normalization of PCIA and RA power costs in 2023 and beyond and are factored into VCE's long-term outlooks. These factors, in combination with VCE's fixed-rate longer term PPA's, indicate some moderation in financial volatility for VCE going forward. Staff will continue to monitor and update the Board should conditions change. The CY 2022 Draft Budget options shown below are inclusive of the above factors.

3. FY 2022 Draft Budget Scenarios

Staff developed three budget scenarios to test the sensitivity of two key variables that drive financial outcomes for VCE: PCIA and PG&E generation rates – all scenarios incorporate the same power cost assumptions based on the best available market information from SMUD and so are consistent in each scenario. The scenarios represent a best, worst, and most likely scenario that serve to bookend the analysis while offering a third "most likely" scenario that incorporates the best available information and forecasts for the PCIA and PG&E generation rates. In addition to consistent power cost assumptions, each budget option includes the same PCIA scenario based on the October 2021 CPUC filings, as shown in Table 1 below.

Rate Forecasts and Revenue

VCE, along with all other California CCAs, receives PG&E PCIA and generation rate forecasts modeling information produced by financial analysts under contract with CalCCA. The latest forecast from the consultant (Oct 2021) predicts significant increases in PG&E's generation rates and decreases in PCIA over the CY 2022 time period. These changes are based on information from separate filings to the CPUC and are scheduled to be finalized in November 2021.

Table 1 – Rates Scenarios

		RATES		
	PCIA	Scenario 1	Scenario 2	Scenario 3
CY2022	-30%	12%	10%	15%
CY2023	5%	-7%	-7%	-7%
CY2024	-2%	2%	2%	2%
CY2025	2%	1%	1%	1%

- **Generation rate changes (1% change approximately $650K Net Annual Impact to VCE) -** Generation rate changes are related to PG&E's 2022 Annual Consolidated Rate Change and request to recover costs recorded in its Catastrophic Event Memorandum Account (CEMA). PG&E implements several rate changes at the start of each year to reflect the consolidation of authorized and pending revenue changes and recovery of balances in various balancing accounts.

- **PCIA (1% change approximately $300K net annual impact to VCE) -** The PCIA is calculated from the utility's Indifference Amount, updated annually in each IOU's rate setting proceeding. The Indifference Amount is the difference in the target year between the cost of the IOU's supply portfolio and the market value of the IOU's supply portfolio. Since the PCIA is a backwards look, higher market power prices in 2021 would result in a lower 2022 PCIA.

As with the volatility in costs, forecasted PCIA and Generation rate changes impacting CY 2022 are included in the budget options ranging from 10% to 15% net increase that includes PG&E's rate increase for 2022 plus any rate adjustment by VCE (not in addition to the rate increase adopted in October 2021).

The budget options detailed below incorporate these rate forecasts as follows:

- Scenario 1: Moderately discounted forecast of PG&E generation rate increases.
- Scenario 2: Highly discounted forecast of PG&E generation rate increases.
- Scenario 3: Low discounted forecast of PG&E generation rate increases.

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Budget Scenario 1: CY 2022

Budget Scenario 1 incorporates net rate changes of 12%; the net impact for CY 2022 is a loss of $2.2M. This option includes a moderately reduced rate increase from the CalCCA consultant, which is considered by staff as a solid possible outcome based on additional customer cost burdens during the assumed period of recovery from the pandemic.

Table 2 – Budget Scenario 1 (12% net rate increase - moderately discounted from forecast)

VALLEY CLEAN ENERGY DRAFT BUDGET SUMMARY 2022 - BUDGET SCENARIO 1	APPROVED BUDGET FY 2021 (6 MO)	ACTUAL YTD SEP (3 MO) + FORECAST (3 MO) FY 2021 (6 MO)	DRAFT BUDGET CY 2022
Energy - Megawatt Hours			
OPERATING REVENUE	$ 25,043	$ 28,606	$ 69,700
OPERATING EXPENSES:			
Cost of Electricity	27,592	29,616	66,990
Contract Services	1,369	1,413	2,640
Outreach & Marketing	117	90	247
Programs	68	34	138
Staffing	580	554	1,175
General, Administration and other	382	374	754
TOTAL OPERATING EXPENSES	**30,107**	**32,080**	**71,945**
TOTAL OPERATING INCOME	**(5,064)**	**(3,474)**	**(2,245)**
NONOPERATING REVENUES (EXPENSES)			
Interest income	28	19	56
Interest expense	(23)	(23)	(42)
TOTAL NONOPERATING REV/(EXPENSES)	**5**	**(4)**	**15**
NET MARGIN	**$ (5,059)**	**$ (3,478)**	**$ (2,230)**
NET MARGIN %	**-20.2%**	**-12.2%**	**-3.2%**

As shown in Table 5 below – Budget Scenario Comparison, this scenario forecasts stabilization of VCE's financials and a return to positive net margins in 2023. Scenario 1 is a relatively cautious scenario that demonstrates the short and long-term impacts of PG&E rate changes.

Budget Scenario 2: CY 2022

Budget Scenario 2 incorporates net rate changes of 10%; the net impact for CY 2022 is a loss of $3.8M. Given the rate increases experienced in actual and forward power costs and the best available forecasting information from the CalCCA consultant, staff believes this increase would be understated and represents an unlikely outcome for this budget cycle.

Table 3 – Budget Scenario 2 (10% net rate increase - highly discounted from forecast)

VALLEY CLEAN ENERGY DRAFT BUDGET SUMMARY 2022 - BUDGET SCENARIO 2	APPROVED BUDGET FY 2021 (6 MO)	ACTUAL YTD SEP (3 MO) + FORECAST (3 MO) FY 2021 (6 MO)	DRAFT BUDGET CY 2022
Energy - Megawatt Hours			
OPERATING REVENUE	**$ 25,043**	**$ 28,606**	**$ 68,100**
OPERATING EXPENSES:			
Cost of Electricity	27,592	29,616	66,990
Contract Services	1,369	1,413	2,640
Outreach & Marketing	117	90	247
Programs	68	34	138
Staffing	580	554	1,175
General, Administration and other	382	374	754
TOTAL OPERATING EXPENSES	**30,107**	**32,080**	**71,945**
TOTAL OPERATING INCOME	**(5,064)**	**(3,474)**	**(3,845)**
NONOPERATING REVENUES (EXPENSES)			
Interest income	28	19	56
Interest expense	(23)	(23)	(42)
TOTAL NONOPERATING REV/(EXPENSES)	**5**	**(4)**	**15**
NET MARGIN	**$ (5,059)**	**$ (3,478)**	**$ (3,830)**
NET MARGIN %	**-20.2%**	**-12.2%**	**-5.6%**

As shown in Table 5 below – Budget Option Comparison, this option forecasts a more significant net loss for VCE in FY 2022 but is a less likely outcome. In this unlikely scenario, VCE would be required to take a more aggressive rate setting posture for 2022 to stabilize its finances before returning to positive net margins in 2023 and beyond.

Budget Scenario 3: CY 2022

Budget Scenario 3 incorporates net rate changes of ~15%; the impact for CY 2022 is a minor net gain. This option includes a slightly reduced rate increase from the CalCCA consultant, which is considered by staff as a possible outcome based on additional customer cost burdens during the assumed period of recovery from the pandemic.

Table 4 – Budget Scenario 3 (15% net rate increase - low discount from forecast)

VALLEY CLEAN ENERGY DRAFT BUDGET SUMMARY 2022 - BUDGET SCENARIO 3	APPROVED BUDGET FY 2021 (6 MO)	ACTUAL YTD SEP (3 MO) + FORECAST (3 MO) FY 2021 (6 MO)	DRAFT BUDGET CY 2022
Energy - Megawatt Hours			
OPERATING REVENUE	**$ 25,043**	**$ 28,301**	**$ 72,200**
OPERATING EXPENSES:			
Cost of Electricity	27,592	29,467	66,990
Contract Services	1,369	1,413	2,640
Outreach & Marketing	117	90	247
Programs	68	34	138
Staffing	580	554	1,175
General, Administration and other	382	374	754
TOTAL OPERATING EXPENSES	**30,107**	**31,931**	**71,945**
TOTAL OPERATING INCOME	**(5,064)**	**(3,631)**	**255**
NONOPERATING REVENUES (EXPENSES)			
Interest income	28	19	56
Interest expense	(23)	(23)	(42)
TOTAL NONOPERATING REV/(EXPENSES)	**5**	**(4)**	**15**
NET MARGIN	**$ (5,059)**	**$ (3,634)**	**$ 270**
NET MARGIN %	**-20.2%**	**-12.8%**	**0.4%**

As shown in Table 5 below – Budget Option Comparison, this option forecasts a net income for VCE in FY 2022 of approxiemently $300K. In this scenario, VCE shows robust net margins beginning in 2023 as long-term renewable PPA's begin full delivery.

Table 5 – Budget Scenario Comparison

	Actuals			Actual YTD Sept. 30 (3 MO) + Forecast (3 MO)	Budget Scenarios	Forecasted		
Scenario 1	FY2019	FY2020	FY2021*	FY2022	CY2022	CY2023	CY2024	CY2025
Revenue	51,035	55,249	54,657	28,606	69,700	62,600	65,500	66,600
Power Cost	38,540	41,538	54,234	29,616	66,990	52,400	47,100	48,400
Other Expenses	3,850	4,346	4,267	2,469	4,940	5,140	5,269	5,400
Net Income	8,646	9,365	(3,844)	(3,478)	(2,230)	5,060	13,132	12,800
Scenario 2	FY2019	FY2020	FY2021*	FY2022	CY2022	CY2023	CY2024	CY2025
Revenue	51,035	55,249	54,657	28,606	68,100	61,100	63,900	64,900
Power Cost	38,540	41,538	54,234	29,616	66,990	52,400	47,100	48,400
Other Expenses	3,850	4,346	4,267	2,469	4,940	5,140	5,269	5,400
Net Income	8,646	9,365	(3,844)	(3,478)	(3,830)	3,560	11,532	11,100
Scenario 3	FY2019	FY2020	FY2021*	FY2022	CY2022	CY2023	CY2024	CY2025
Revenue	51,035	55,249	54,657	28,606	72,200	65,000	67,900	69,000
Power Cost	38,540	41,538	54,234	29,616	66,990	52,400	47,100	48,400
Other Expenses	3,850	4,346	4,267	2,469	4,940	5,140	5,269	5,400
Net Income	8,646	9,365	(3,844)	(3,478)	270	7,460	15,532	15,200

* Based on preliminary audit results presented in companion item 15.

Note: 2023, 2024, and 2025 forecasted financials are based on the most current available data and assumptions, as displayed in Table 1 - Rates Scenarios. These scenarios rely the on the use of future rate adjustments, reserves, or both to mitigate future power cost volitility.

CONCLUSION

The draft FY 2022 operating budget scenarios do not meet VCE's 5% minimum annual net margin goal. Staff has prepared the draft FY 2022 operating budget scenarios based on the best available information on PG&E generation rates and PCIA as of October 2021 CPUC filings. PG&E's 2022 PCIA and rates are scheduled to be released the 2nd week of November, allowing VCE to set 2022 rates at the December Board meeting. The continued use of existing reserves for customer rate stabilization allows VCE to maintain rate competitiveness with PG&E and bridge the gap until long-term renewable contracts come on-line in 2023 and beyond as indicated in Table 5.

Based on the Board's feedback and direction, staff will return with an updated Operating Budget recommendation for CY 2022 in December.