



Board of Directors Regular Meeting Agenda

Wharfinger Building, Bay Room (downstairs)
1 Marina Way, Eureka, CA 95501

Thursday, October 22 2026
3:30 PM

Meeting Information

Meeting Reports and Comments

Pursuant to Government Code section 54957.5, all writings or documents relating to any item on this agenda which have been provided to a majority of the Board, including those received less than 72 hours prior to the Board's meeting, will be made available to the public at redwoodenergy.org.

Speakers wishing to distribute materials to the Board at the meeting must provide 13 copies to the Board Clerk.

How to Participate

This is a hybrid in-person and virtual meeting. When technical difficulties arise that prevent members of the public from offering comments, or if broadcasting is disrupted due to matters out of RCEA's control, this meeting will be discontinued unless otherwise allowed by law.

To participate in the meeting online, go to <https://us02web.zoom.us/j/81972368051>.

To participate by phone, call (669) 900-6833 or (253) 215-8782. Enter webinar ID: 819 7236 8051.

To speak during the public comment periods, raise your hand in the online Zoom webinar, or press star (*) 9 on your phone to raise your hand. Staff will ask you to unmute your phone or computer when it is your turn. You will have 3 minutes to speak.

Email written comments to PublicComment@redwoodenergy.org. Identify the agenda item number in the subject line. Comments will be included in the meeting record but not read aloud during the meeting.

Accessibility

Need help with accessibility? Any member of the public needing special accommodation to participate in this meeting or access the meeting materials should email LTaketa@redwoodenergy.org or call (707) 269-1700 at least 3 business days before the meeting. Assistive listening devices are available.

Open Session (Call to Order)

1. Roll Call | Remote Director Participation

- 1.1. Brown Act Teleconference Participation Rules

2. Reports from Member Entities

3. Oral & Written Communications

This time is provided for people to address the Board or submit written communications on matters not on the agenda. At the conclusion of all oral communications, the Board may respond to statements. Any request that requires Board action will be set by the Board for a future agenda or referred to staff.

4. Staff Reports

- 4.1. Executive Director's Report

5. New Business

- 5.1. Financial Audit Reports for Fiscal Years Ending 2026 and 2025

Accept and Approve Redwood Coast Energy Authority Financial Statements June 30, 2026, and 2025 and Associated Independent Auditors' Report by Baker Tilly US, LLP.

6. Presentations

- 6.1. Overview of Distributed Energy Resources and Virtual Power Plants (Information only)

7. Consent Calendar

All matters in the Consent Calendar section are considered routine by the Board and are enacted in one motion. There is no separate discussion of any of these items; if discussion is required, that item is removed from the Consent Calendar and considered separately. At the end of the reading of the Consent Calendar, Board members or members of the public can request that an item be removed for separate discussion.

- 7.1. Approve Minutes of September 24, 2026, Board Meeting.
- 7.2. Accept Disbursement Report for August 2026, and Financial Reports for This Fiscal Year Through August 2026.
- 7.3. Receive Regulatory and Legislative Platform Engagement Report.

8. Items Removed from Consent Calendar

Items removed from the Consent Calendar section will be heard under this section.

9. Old Business – None

10. New Business (continued)

10.1. Energy Risk and Rates Ad Hoc Subcommittee Formation

Approve the formation of an Energy Risk and Rates Ad Hoc Subcommittee through the end of Fiscal Year 2027-28 to receive regular risk updates and make recommendations to the Board, and appoint no more than 5 board members to serve on the committee.

11. Future Agenda Items

Any request that requires Board action will be set by the Board for a future agenda or referred to staff.

12. Adjournment

Next Regular Meeting (Third Thursday)

Thursday, November 19, 2026 | 3:30 PM

Wharfinger Building Bay Room (downstairs), 1 Marina Way, Eureka, CA 95501
Online and phone participation is available via Zoom.

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Staff Report

Agenda Item # 1.1

Information

Agenda Date	October 22, 2026
To	Board of Directors
Prepared by	Eileen Verbeck, Deputy Executive Director
Subject	Revised Member Teleconference Participation Rules

Background

When emergency Brown Act meeting law changes went into effect in 2020 due to the COVID-19 public health emergency, the RCEA Board of Directors, Community Advisory Committee (CAC) and the subcommittees of those bodies met online via teleconference using the Zoom platform with no physical, public meeting location. Since the pandemic, the Brown Act has been amended to codify modern teleconference meeting practices both during and outside of declared states of emergency. SB 707 (Durazo, 2025) sets out the latest Brown Act revisions which were signed into law on October 3, 2025.

Summary

RCEA Board Directors may attend up to two meetings per year from a remote location without making the location accessible to the public for the following, revised, “just cause” reasons:

1. Childcare or caregiving to child, parent, grandparent, grandchild, sibling, spouse, domestic partner;
2. Contagious illness that prevents in person attendance;
3. Mental or physical need not subject to reasonable accommodation provisions;
4. Travel while on official business of RCEA or another state or local agency;
5. Immunocompromised child, parent, grandparent, grandchild, sibling, spouse, or domestic partner that requires remote participation;
6. Physical or family medical emergency; or
7. Military service obligations.

A vote is not necessary to request remote attendance for just cause, including for medical emergency remote attendance per SB 707 revisions. A brief description, protecting the Director’s (or family member’s) medical privacy, must be provided and the Director must publicly disclose whether anyone 18 years of age or older is present in the room at the remote location, and the general nature of the individual’s relationship with the Director.

At a future meeting, staff will recommend Board adoption of a revised Teleconferencing Policy capturing the latest Brown Act revisions and provide the Board an opportunity to pass a resolution enabling remote meeting participation for members who must travel at least 20 miles to the Wharfinger Building.



Staff Recommendation

None. Information only.

Required Distribution Information

The **Revised** Ralph M. Brown Act

[Link to California Government Code Sections 54950 - 54963¹](#), revised October 3, 2025, by SB 707 (Durazo, 2025).

Redwood Coast Energy Authority List of Physical Meeting Locations

Body	Date	Time	Location
Board of Directors	4 th Thursday of each month	3:30 p.m.	Wharfinger Building, 1 Marina Way, Eureka, CA 95501
Community Advisory Committee	2 nd Tuesday of odd-numbered months	6 p.m.	Jefferson Community Center Auditorium, 1000 B Street, Eureka, CA 95501
Finance Committee	As needed, dates TBD	TBD	RCEA Offices, 633 Third Street, Eureka, CA 95501

¹ [The Revised Ralph M. Brown Act, California Code, GOV 54950.5 - 54963:](https://leginfo.legislature.ca.gov/faces/codes_displayText.xhtml?lawCode=GOV&division=2.&title=5.&part=1.&chapter=9.&article=)
https://leginfo.legislature.ca.gov/faces/codes_displayText.xhtml?lawCode=GOV&division=2.&title=5.&part=1.&chapter=9.&article=



Staff Report

Agenda Item # 4.1

Information

Agenda Date	October 22, 2026
To	Board of Directors
Prepared by	Elizabeth Burks, Executive Director
Subject	Executive Directors' Report

Summary

Executive Director Elizabeth Burks will provide updates on topics as needed.

RCEA Updates

September Call Log Summary

In September 2026, there were 99 customer-initiated interactions. The top categories across all interaction types were:

- **Billing and Related Inquiries: 39 (39%)**
- **Rebates / Customer Programs Inquiries: 26 (26%)**
- **General Information: 15 (15%)**

Customers contacted RCEA staff with general questions about their statements and energy costs, as well as detailed questions about rates, solar generation, and to discuss late payment or collection notices they have received. In September 50% of the rebate inquiries were regarding E-Bike vouchers and 15% were regarding EV rebates. Other rebate and customer programs inquiries were from customers and contractors interested in our home appliance electrification incentives. There were 8 total opt outs in September.

NREN Update

In September, the RCEA Northern Rural Energy Network team completed 11 home energy assessments, gave out 83 efficiency kits, and paid out \$6,787 in rebates to Humboldt County customers.

NREN Partner	Rebates		Efficiency Kits		Energy Assessments	
	September	YTD	September	YTD	September	YTD
RCEA	\$6,787	\$94,016	83	301	11	69
LAPC	\$100	\$8,445	151	521	3	40
MCOG	\$1,230	\$7,733	36	210	7	33
SBC	\$21,731	\$90,136	81	497	11	61
Total	\$29,847	\$200,330	351	1529	32	203



Staff Recommendation

None. Information only.

Attachments

1. Community Outreach Events Summary
2. LEAN/Community Choice Energy Alliance Federal Activity Report - September 2026

Redwood Coast Energy Authority – Community Outreach & Events Summary

Each month, RCEA connects with community members across Humboldt County through events, presentations, and outreach efforts that build awareness of our programs and services. This summary provides a snapshot of our outreach reach, engagement highlights, and upcoming opportunities to connect with the community.

October 2026

AT A GLANCE

Events

We participated in a variety of community events, including the Fortuna Apple Harvest Festival, Natural Science Day in Garberville, Walk to End Alzheimer's, Trinidad Resilience Fair, and Arcata Farmers Market.

Community members appreciated the opportunity to connect with us and learn about the many resources that are available.

Next Month

In November, we'll staff education tables at the McKinleyville Resource Center's Open House, Arcata Chamber of Commerce's Sip & Shop event, and at Loleta and Rio Dell's Community Resource Centers.



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Federal Affairs Updates

Monthly Policy Report



The National Voice for Affordable, Clean, & Reliable Power

September 2026
By Community Choice Energy Alliance

[Download PDF Version](#)

Executive Summary

Congress returned from August recess with numerous priorities to accomplish ahead of the midterm elections.

The House, which began its pre-election recess two weeks earlier than planned, passed a suite of energy related bills, including the Ratepayer Protection Act (H.R. 9340), the “High-Capacity Grid Act” (H.R. 6633), the “Load Forecasting Enhancement Act” (H.R. 9332), and “Affordable Innovation for the Grid Act” (H.R. 9339).

The House Energy and Commerce Subcommittee on Energy held a hearing on the proposed Nuclear Lifecycle Innovation Campuses (NLIC), hearing from Department of Energy (DOE)

Assistant Secretary for Nuclear Energy Theodore Garrish on the administration's legislative requests.

The SEEC Institute also released its "Thriving Economy Project," which included CCEA policy recommendations.

In the Senate, discussions were dominated by permitting reform negotiations, as the legislative text, the "Bipartisan American Affordability and Jobs Act," was released on Sept. 30. Outside of this, the Senate Energy and Natural Resources Committee also held a hearing on NLICs, and a bipartisan group of Senators wrote a letter urging the timely release of Low Income Home Energy Assistance funding.

The administration likewise remained active throughout September, as the DOE issued a Request for Information seeking input on the recent Executive order "Declaring a National Emergency to Secure the United States Bulk-Power System."

The DOE also announced the latest round of SPARK funding to bolster grid resiliency and capacity through transmission upgrades.

Finally, the Environmental Protection Agency issued a repeal of Biden-era carbon capture and storage requirements for coal and some new-gas fired power plants, as well as releasing new draft regulations that would bar future attempts at regulating power plant pollution using the Clean Air Act.

CCEA FEDERAL ADVOCACY

CCEA staff visited Washington, D.C., September 28–30 for its Fall Advocacy Days, meeting with 10 congressional offices from various CCA-enabled states. Our goal was to strengthen relationships and build bipartisan support for Community Choice Aggregation. The trip continued CCEA's work to raise awareness of community-led energy solutions and explore opportunities for ongoing bipartisan collaboration on Capitol Hill.



CONGRESSIONAL ACTIONS

1. Senate Permitting Deal Text Unveiled

Senate negotiators released the legislative text of a permitting reform deal, titled the “Bipartisan American Affordability and Jobs Act of 2026.” The final bill includes measures to ease the siting of interstate transmission lines by removing the Department of Energy from the national transmission planning process and imposing a cost allocation model that will only require ratepayers to pay for transmission if they benefit from the line. **The bill also includes permitting certainty measures to prevent the Executive branch from revoking or altering permits, with some exceptions such as court orders or requests from the permit holder,** and would speed the interconnection of projects by requiring grid operators to study power generation and load together. The bill features a new 150-day statute of limitations for National Environmental Policy Act (NEPA) and National Historic Preservation Act lawsuits and shortens review timelines under both policies. States would also face restrictions in their ability to block projects under Section 401 of the Clean Water Act by prohibiting states from imposing conditions on projects unless they are needed for compliance with water quality requirements. **The bill also addresses issues around the costs of AI data centers by indicating that data centers should be assigned all embedded and incremental costs of transmission service, directing the Federal Energy Regulatory Commission (FERC) to revise its rules accordingly, and it allows states to conduct “a market-based approach to data center interconnection.”** The comprehensive package also includes provisions to ease reconductoring and other transmission upgrades under NEPA, streamlines hydropower and geothermal energy development, and requires rulemakings for ensuring behind-the-meter generation can access wholesale markets.

The Senate entered recess shortly after the bill was released and will not vote on the legislation until after the midterm elections. House Natural Resources Committee Ranking Member Jared Huffman has already warned that he believes the Senate bill will not receive support from House Democrats and urged negotiations to resume after the upcoming elections.

2. House Passes Energy Bills Before Adjourning for Recess

On Sept. 16, the **House passed the “Ratepayer Protection Act” (H.R. 9340) by a nearly unanimous vote of 417-3.** H.R. 9340 seeks to codify President Trump’s Ratepayer Protection Pledge and ensure data centers pay for new generation and transmission upgrades they require by creating a PURPA “must consider” requirement. Despite the bipartisan vote in the House, the **Senate failed to reach the 60-vote threshold needed to pass the bill on Sept. 30 after Democrats argued the bill does not go far enough to protect ratepayers.** The House bill’s passage comes a day after the House passed three grid improvement bills unanimously. This included the “High-Capacity Grid Act” (H.R. 6633) from Rep. Julie Fedorchak (R-ND), which would require the use of best-available transmission conductors for all new and rebuilt interstate transmission lines, with the goal of increasing transmission capacity and reliability within existing rights-of-ways. The House also passed the “Load Forecasting Enhancement Act” (H.R. 9332) from Rep. Troy Balderson (R-OH), which directs the Federal Energy Regulatory Commission (FERC) to establish regional boards to study and recommend best practices for electric load forecasting, as well as requiring FERC to report these findings to Congress and encourage states to utilize the forecasting procedures. The “Affordable Innovation for the Grid Act” (H.R. 9339) from Rep. Diana Harshbarger (R-TN) which also passed, would direct the Energy Secretary to assess the use of AI and other technologies for strengthening grid capacity, reliability, and efficiency.

3. Senate and House Committees Hold Nuclear Waste Hearings

On Sept. 23, the Senate Environment and Public Works (EPW) Committee held a hearing to discuss updates to nuclear waste management policies, and the Department of Energy's proposed Nuclear Lifecycle Innovation Campuses (NLIC), which would be designed to support nuclear activities such as fuel fabrication, enrichment, reprocessing, and final disposition of spent fuel. While the panel demonstrated broad support for finding a permanent solution for spent nuclear fuel, EPW Chair **Shelley Moore Capito (R-WV) emphasized the long-term commitments of such waste management.** Dr. Kathryn Huff, professor and department chair, at the University of Wisconsin-Madison, testified before the panel and **warned that such campuses will require authorization and appropriations from Congress, as well as sustaining public support through transparency and accountability.** The EPW hearing followed a Sept. 15 hearing from the House Energy and Commerce Subcommittee on Energy held the hearing on the same subject. DOE Assistant Secretary for Nuclear Energy Theodore Garrish testified before the panel, where he reiterated the administration's legislative requests to support NLICs, such as removing Yucca Mountain's status as the sole site for long-term spent nuclear fuel storage, reinstate the Nuclear Waste Fund, and authorize DOE to negotiate with states for NLIC sites. **Assistant Secretary Garrish also stated that these NLIC cannot be temporary, and that this disposal method would provide nuclear waste storage for millennia.** Six states, Idaho, Louisiana, Oklahoma, Tennessee, Utah, and West Virginia, are DOE finalists to host the NLICs.

4. SEEC Institute Releases its Thriving Economy Project

On Sept. 15, a group of House Democrats led by Rep. Kathy Castor (D-FL) released hundreds of energy and environmental policy proposals as part of the Sustainable Energy and Environment Coalition (SEEC) Institute's "Thriving Economy Project." The SEEC Institute was formed in 2024 to complement the leadership of SEEC, a caucus in the U.S. House of Representatives founded in 2009 and composed of 100+ Members of Congress committed to advancing durable and effective environmental policy. The collection of Thriving Economy Project proposals covers four broad policy objectives, such as "Flourishing Lands, Communities and Resources," "Secure American Energy Future," "Financing the Energy Future," and "Building Government for Today." The proposals include ways to increase energy generation, support emerging energy technologies, reduce ratepayer costs, and increase certainty around federal funding.

Chapter five of the report, "Cheap, Abundant, and Clean Energy for All" includes three proposals focused on Community Choice Aggregators (CCA), ensuring CCAs are eligible for federal grant funds, providing incentives to encourage states to authorize CCAs, and conducting a national study on the benefits of community-led energy procurement. Last December, CCEA submitted recommendations to be included in the report. The list of proposals could provide insight into policy priorities for the next Congress, should House Democrats win the majority. House Minority Leader Hakeem Jefferies (D-NY) has not endorsed the proposals but previously launched an affordability working group focused on energy issues led by Reps. Nikki Budzinski (D-IL) and Mike Levin (D-CA), who both contributed to the SEEC Institute report.

5. Senators Sign Letter Supporting Timely Release of LIHEAP Funding

On Sept. 17, a bipartisan group of 31 Senators sent a letter to Department of Health and Human Services (HHS) Secretary Robert Kennedy Jr. urging the release of funds for the Low Income Home Energy Assistance Program (LIHEAP). The group, led by Sens. Susan Collins (R-ME), Jack Reed (D-RI), and Lisa Murkowski (R-AK), remind Sec. Kennedy that the recently passed stopgap funding bill **requires HHS to distribute at least 90% of LIHEAP funds by Nov. 1**. The letter emphasizes the importance of LIHEAP in the winter months, providing assistance with energy bills for low income and senior households. The group states that timely release of the **funds will be important due to extraordinary pressures consumers will face this winter and that many state agencies and tribes have already begun activating their LIHEAP programs.**

ADMINISTRATION ACTIONS

6. DOE Issues RFI for President Trump's Executive Order on Bulk-Power System Equipment

The Department of Energy (DOE) published a Request for Information (RFI) in the Federal Register on Sept. 9, regarding President Trump's recent Executive order (EO) "Declaring a National Emergency to Secure the United States Bulk-Power System." **The RFI seeks input from industry stakeholders in eight areas to guide the DOE's implementation of the EO's prohibition on importation and installation of some foreign-produced bulk-power system electrical equipment.** This request includes information on what categories within the EO's definition of bulk-power system electrical equipment need further clarification, how foreign ownership or influence can be determined for equipment and its sub-tier supply chains, how DOE should conduct risk assessment, and what DOE should assess in deciding to remove or disconnect existing equipment. The RFI also requests information on licensing applications, domestic manufacturing for replacing prohibited equipment, the one-time and recurring cost implications of compliance with the EO and its implementation, and what technical assistance or pilot programs would help asset owners prepare for implementation.

7. DOE Announces \$2 Billion in SPARK Funding

On Sept. 24, the Department of Energy's (DOE) Office of Electricity announced nearly \$2 billion in federal funding for grid improvement projects through the Speed to Power through Accelerated Reconductoring and other Key Advanced Transmission Technology Upgrades (SPARK) initiative. SPARK redirects remaining Biden-era grid resilience funds under the Infrastructure Investment and Jobs Act's Grid Resilience and Innovation Program (GRIP). **31 projects, across 26 states, will use \$1.9 billion in federal funding, matched by \$3.35 billion in recipient cost-share funding, to rebuild or reconductor over 1,500 miles of transmission lines and deploy Grid-Enhancing Technologies across another 21,000 miles.** DOE states that by eliminating bottlenecks and maximizing existing rights-of-way, the projects will add an additional 23 gigawatts of electricity capacity to the nation's grid without building new transmission corridors while reducing permitting bottlenecks and lowering electricity costs.

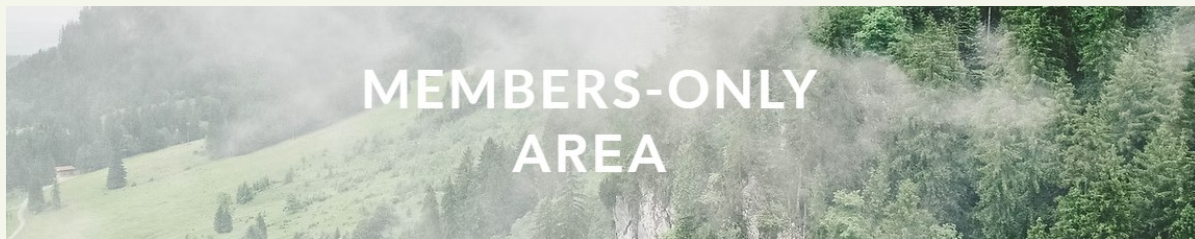
8. EPA Announces Repeal of Carbon Rules for Fossil Fuel Plants

Environmental Protection Agency (EPA) Administrator Lee Zeldin announced the repeal of carbon rules for fossil-fueled power plants at the Group of Twenty (G20) “Energy Abundance Ministerial” on Sept. 14. The **repeal includes the 2024 carbon capture and storage requirements for coal and some new gas-fired power plants**, which had been expected for some time. Administrator Zeldin also announced **new draft regulations that would prevent future administrations from using the Clean Air Act (CAA) to regulate pollution from power plants**. The EPA is using similar arguments as used when repealing the 2009 endangerment finding, primarily that CAA does not grant EPA a role in controlling such emissions. The repeal has been under Office of Management and Budget review since May and could undermine upcoming arguments in a separate case before the Supreme Court in which the Justice Department contends EPA is the primary regulator of greenhouse gas emissions, rather than states and cities.

Additional Resources

Log in to **CCEA's Members-Only Portal** to access:

- A detailed Members Directory
- Federal Policy Committee documents and materials (*log in to read all weekly and monthly reports, policy briefs, and additional resources*)
- CCEA's curated national CCA database (*for Terawatt members only*)



Community Choice Energy Alliance partners with Meguire Whitney to advance federal policy and advocacy for CCAs.

Visit our Website





Staff Report

Agenda Item # 5.1

Information

Agenda Date	October 22, 2026
To	Board of Directors
Prepared by	Lori Biondini, Business Planning and Finance Director
Subject	Financial Audit Reports for Fiscal Years Ending 2026 and 2025

Summary

RCEA engaged Baker Tilly US, LLP to prepare audited financial statements for the fiscal years ending June 30, 2026, and June 30, 2025. Jodi Dobson, Partner at Baker Tilly US, LLP, will present the statements and a report on the audit process and results.

Audited financial statements for the fiscal year ending June 30, 2025, were accepted and approved by the Board of Directors in September 2025. However, RCEA adopted the provisions of Governmental Accounting Standards Board (GASB) Statement No. 103, Financial Reporting Model Improvements on July 1, 2025, and as required by GASB, certain prior year amounts have been restated to conform to the current year presentation. The restatement had no effect on RCEA's 2025 net position as previously reported.

Staff Recommendation

Accept and Approve Redwood Coast Energy Authority Financial Statements June 30, 2026, and 2025 and Associated Independent Auditors' Report by Baker Tilly US, LLP.

Attachments

1. Reporting and insights from 2026 and 2025 audit: Redwood Coast Energy Authority
2. Redwood Coast Energy Authority Financial Statements June 30, 2026, and 2025

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Reporting and insights from 2026 audit:

Redwood Coast Energy Authority

June 30, 2026

Executive summary

September 25, 2026

To the Board of Directors
Redwood Coast Energy Authority
633 3rd Street
Eureka, CA 95501

We have completed our audit of the financial statements of Redwood Coast Energy Authority (the Authority) for the year ended June 30, 2026, and have issued our report thereon dated September 25, 2026. This letter presents communications required by our professional standards.

Your audit should provide you with confidence in your financial statements. The audit was performed based on information obtained from meetings with management, data from your systems, knowledge of the Authority's operating environment and our risk assessment procedures. We strive to provide you clear, concise communication throughout the audit process and of the final results of our audit.

Additionally, we have included information on key risk areas Redwood Coast Energy Authority should be aware of in your strategic planning. We are available to discuss these risks as they relate to your organization's financial stability and future planning.

If you have questions at any point, please connect with us:

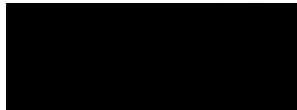
- Jodi Dobson, Principal: jodi.dobson@bakertilly.com or +1 (608) 240 2469
- Ryan Theiler, Senior Manager: ryan.theiler@bakertilly.com or +1 (608) 240 2571

Sincerely,

Baker Tilly US, LLP



Jodi Dobson, Principal, CPA



Ryan Theiler, Senior Manager, CPA

THIS COMMUNICATION IS INTENDED SOLELY FOR THE INFORMATION AND USE OF THOSE CHARGED WITH GOVERNANCE, AND, IF APPROPRIATE, MANAGEMENT, AND IS NOT INTENDED TO BE AND SHOULD NOT BE USED BY ANYONE OTHER THAN THESE SPECIFIED PARTIES.

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Responsibilities

Our responsibilities

As your independent auditor, our responsibilities include:

- Planning and performing the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement. Reasonable assurance is a high level of assurance.
- Assessing the risks of material misstatement of the financial statements, whether due to fraud or error. Included in that assessment is a consideration of the Authority's internal control over financial reporting.
- Performing appropriate procedures based upon our risk assessment.
- Evaluating the appropriateness of the accounting policies used and the reasonableness of significant accounting estimates made by management.
- Forming and expressing an opinion based on our audit about whether the financial statements prepared by management, with the oversight of the Board of Directors:
 - Are free from material misstatement
 - Present fairly, in all material respects and in accordance with accounting principles generally accepted in the United States of America
- Performing tests related to compliance with certain provisions of laws, regulations, contracts and grants, as required by *Government Auditing Standards*
- Our audit does not relieve management or the Board of Directors of their responsibilities.

We are also required to communicate significant matters related to our audit that are relevant to the responsibilities of the Board of Directors, including:

- Internal control matters
- Qualitative aspects of the Authority's accounting practice including policies, accounting estimates and financial statement disclosures
- Significant unusual transactions
- Significant difficulties encountered
- Disagreements with management
- Circumstances that affect the form and content of the auditors' report
- Audit consultations outside the engagement team
- Corrected and uncorrected misstatements
- Other audit findings or issues

Audit status

Significant changes to the audit plan

There were no significant changes made to either our planned audit strategy or to the significant risks and other areas of emphasis identified during the performance of our risk assessment procedures.

Audit approach and results

Planned scope and timing

Audit focus

Based on our understanding of the Authority and environment in which you operate, we focused our audit on the following key areas:

- Key transaction cycles
- Areas with significant estimates
- Implementation of new accounting standards

Our areas of audit focus were informed by, among other things, our assessment of materiality. Materiality in the context of our audit was determined based on specific qualitative and quantitative factors combined with our expectations about the Authority's current year results.

Key areas of focus and significant findings

Significant risks of material misstatement

A significant risk is an identified and assessed risk of material misstatement that, in the auditor's professional judgment, requires special audit consideration. Within our audit, we focused on the following areas below.

Significant risk areas	Testing approach	Conclusion
Management override of controls	Incorporate unpredictability into audit procedures, emphasize professional skepticism and utilize audit team with industry expertise	Procedures identified provided sufficient evidence for our audit opinion
Improper revenue recognition due to fraud	Confirmation or validation of certain revenues supplemented with detailed predictive analytics based on non-financial data and substantive testing of related receivables	Procedures identified provided sufficient evidence for our audit opinion
Potential for inaccurate billing data from Pacific Gas & Electric (PG&E)	Review Calpine SOC report and perform walkthrough to assess the procedures established to validate the data	Procedures identified provided sufficient evidence for our audit opinion

Other areas of emphasis

We also focused on other areas that did not meet the definition of a significant risk, but were determined to require specific awareness and a unique audit response.

Other areas of emphasis		
Cash and investments	Revenues and receivables	General disbursements
Payroll	Long-term debt	Capital assets including infrastructure
Net position calculations	Financial reporting and required disclosures	

Internal control matters

We considered the Authority's internal control over financial reporting as a basis for designing our audit procedures for the purpose of expressing an opinion on the financial statements. We are not expressing an opinion on the effectiveness of the Authority's internal control.

Our consideration of internal control was for the limited purpose described in the preceding paragraph and was not designed to identify all deficiencies in internal control that might be material weaknesses or significant deficiencies and, therefore, material weaknesses or significant deficiencies may exist that were not identified.

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 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. We identified the following deficiencies as material weaknesses:

- **Financial statement close process**

Properly designed systems of internal control provide your organization with the ability to process and record accurate monthly and year-end transactions and annual financial reports.

Our audit includes a review and evaluation of internal controls relating to financial reporting. Common attributes of a properly designed system of internal control for financial reporting are as follows:

- There is adequate staffing to prepare financial reports throughout the year and at year-end.
- Material misstatements are identified and corrected during the normal course of duties.
- Complete and accurate financial statements, including footnotes, are prepared.
- Financial reports are independently reviewed for completeness and accuracy.

Our evaluation of the internal controls over financial reporting has identified control deficiencies that are considered material weakness surrounding the preparation of financial statements and footnotes, adjusting journal entries identified by the auditors, and an independent review of financial reports.

Management has not prepared financial statements that are in conformity with generally accepted accounting principles. In addition, we have recommended material adjusting journal entries.

Other comments and recommendations

During our testing, we noted compliance-related control deficiencies regarding the entity's obligations under Rural Utility Service (RUS) requirements. Specifically, relied on the auditor to prepare the financial statements, which included material journal entries. While this deficiency is not expected to result in material misstatements, it reflects gaps in the entity's compliance processes and documentation controls. We recommend that the Authority should evaluate whether internal resources can be allocated to prepare financial statements independently.

Required communications

Qualitative aspect of accounting practices

- **Accounting policies:** Management is responsible for the selection and use of appropriate accounting policies. In accordance with the terms of our engagement letter, we have advised management about the appropriateness of accounting policies and their application. The significant accounting policies used by Authority are described in Note 1 to the financial statements. As described in Note 10, the Authority changed accounting policies by adopting GASB Statement No. 103 in 2026. Accordingly, the accounting change has been retrospectively applied to the prior period presented. We noted no transactions entered into by the Authority during the year for which accounting policies are controversial or for which there is a lack of authoritative guidance or consensus or diversity in practice.
- **Accounting estimates:** Accounting estimates, including fair value estimates, are an integral part of the financial statements prepared by management and are based on management's 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, the degree of subjectivity involved in their development and because of the possibility that future events affecting them may differ significantly from those expected. The following estimates are of most significance to the financial statements:

Estimate	Management's process to determine	Baker Tilly's conclusions regarding reasonableness
Allowance for doubtful accounts	Evaluation of historical revenues and loss levels with the analysis on collectability of individual amounts	Reasonable in relation to the financial statements as a whole
Unbilled Revenue	Evaluate the July Calpine monthly usage report and calculation of the estimated portion related to June	Reasonable in relation to the financial statements as a whole

There have been no significant changes made by management to either the processes used to develop the particularly sensitive accounting estimates, or to the significant assumptions used to develop the estimates noted above.

- **Financial statement disclosures:** The disclosures in the financial statements are neutral, consistent and clear.

Significant unusual transactions

There have been no significant transactions that are outside the normal course of business for the Authority or that otherwise appear to be unusual due to their timing, size or nature.

Significant difficulties encountered during the audit

We encountered no significant difficulties in dealing with management and completing our audit.

Disagreements with management

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 that could be significant to the financial statements or the auditors' report. We are pleased to report that no such disagreements arose during the course of our audit.

Audit report

There have been no departures from the auditors' standard report.

Audit consultations outside the engagement team

We encountered no difficult or contentious matters for which we consulted outside of the engagement team.

Uncorrected misstatements and corrected misstatements

Professional standards require us to accumulate misstatements identified during the audit, other than those that are clearly trivial and to communicate accumulated misstatements to management. Management is in agreement with the misstatements we have identified, and they have been corrected in the financial statements. The schedule within the attachments summarizes the material corrected misstatements, that, in our judgment, may not have been detected except through our auditing procedures. In our judgment, none of the misstatements that management has corrected, either individually or in the aggregate, indicate matters that could have had a significant effect on the Authority's financial reporting process.

Other audit findings or issues

We encountered no other audit findings or issues that require communication at this time.

We generally discuss a variety of matters, including the application of accounting principles and auditing standards, with management each year prior to retention as the Authority's auditors. However, these discussions occurred in the normal course of our professional relationship and our responses were not a condition to our retention.

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 or accounting matters.

Written communications between management and Baker Tilly

The attachments include copies of other material written communications, including a copy of the management representation letter.

Compliance with laws and regulations

We did not identify any non-compliance with laws and regulations during our audit.

Fraud

We did not identify any known or suspected fraud during our audit.

Going concern

Pursuant to professional standards, we are required to communicate to you, when applicable, certain matters relating to our evaluation of the Authority's ability to continue as a going concern for a reasonable period of time but no less than 12 months from the date of the financial statements, including the effects on the financial statements and the adequacy of the related disclosures, and the effects on the auditor's report. No such matters or conditions have come to our attention during our engagement.

Independence

We are not aware of any relationships between Baker Tilly and the Authority that, in our professional judgment, may reasonably be thought to bear on our independence.

Related parties

We did not have any significant findings or issues arise during the audit in connection with the Authority's related parties.

Nonattest services

The following nonattest services were provided by Baker Tilly:

- Financial statement preparation
- Adjusting journal entries
- Grant advisory services
- Advisory services for the Inflation Reduction Act Credit

None of these nonattest services constitute an audit under generally accepted auditing standards, including *Government Auditing Standards*.

Audit committee resources

Our business is to know every aspect of yours and to maintain a constant lookout for what's next. We invite you to learn about some of the trending challenges and opportunities for public sector organizations like yours and how Baker Tilly can help.

To explore more trending topics and regulatory updates, visit our resource page at <https://www.bakertilly.com/insights/audit-committee-resource-page>.



Capital project oversight

Public sector capital projects face increasing pressure from cost escalation, supply chain disruption, regulatory complexity and heightened scrutiny around transparency and accountability. Strong planning, governance and controls are critical across the full project life cycle, from feasibility and funding strategy through execution and closeout.

Independent oversight helps chart a clear course from planning to delivery. Our teams work alongside leadership to strengthen governance, establish financial and contractual controls, align funding with project goals and monitor performance throughout execution, helping projects stay on schedule, within budget and aligned with community priorities.



Succession planning

An aging workforce, rising retirement rates and competition for specialized talent make succession planning a fiscal and operational a priority for public sector organizations.

By identifying critical roles, assessing workforce risk, building internal talent pipelines and integrating succession planning with broader workforce strategies, Baker Tilly helps organizations preserve institutional knowledge and maintain continuity, today and into the future.



Economic development

Successful economic development depends on disciplined planning, sound financial analysis and coordinated execution. Public sector leaders must balance incentives, infrastructure investment, funding opportunities and stakeholder priorities while maintaining fiscal responsibility.

Baker Tilly's supports local governments with strategic and financial planning, incentive structuring and negotiation, tax increment financing administration, project financing, grant strategy, and economic and fiscal impact analysis. This integrated approach helps leaders move from vision to action, strengthening communities and advancing sustainable, long-term growth.

Management representation letter



REDWOOD COAST Energy Authority

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September 25, 2026

Baker Tilly US, LLP
4807 Innovate Lane
P.O. Box 7398
Madison, WI 53711

Dear Baker Tilly US, LLP:

We are providing this letter in connection with your audit of the financial statements of Redwood Coast Energy Authority (RCEA) as of June 30, 2026 and 2025 and for the years then ended for the purpose of expressing an opinion as to whether the financial statements present fairly, in all material respects, the financial position of the Redwood Coast Energy Authority and the respective changes in financial position and cash flows, in conformity with accounting principles generally accepted in the United States of America (GAAP). We confirm that we are responsible for the fair presentation of the previously mentioned financial statements in conformity with accounting principles generally accepted in the United States of America. We are also responsible for adopting sound accounting policies, establishing and maintaining internal control over financial reporting, and preventing and detecting fraud.

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. An omission or misstatement that is monetarily small in amount could be considered material as a result of qualitative factors.

We confirm, to the best of our knowledge and belief, the following representations made to you during your audit.

Financial Statements

- 1) We have fulfilled our responsibilities, as set out in the terms of the audit engagement letter dated December 19, 2024, including our responsibility for the preparation and fair presentation of the financial statements in accordance with U.S. GAAP.
- 2) The financial statements referred to above are fairly presented in conformity with accounting principles generally accepted in the United States of America. We have engaged you to advise us in fulfilling that responsibility. The financial statements include all properly classified funds of the RCEA required by accounting principles generally accepted in the United States of America to be included in the financial reporting entity.
- 3) 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.



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- 4) We acknowledge our responsibility for the design, implementation, and maintenance of internal control to prevent and detect fraud.
- 5) Significant assumptions we used in making accounting estimates, including those measured at fair value, if any, are reasonable in accordance with accounting principles generally accepted in the United States of America U.S. GAAP.
- 6) All events subsequent to the date of the financial statements and for which accounting principles generally accepted in the United States of America require adjustment or disclosure have been adjusted or disclosed. No other events, including instances of noncompliance, have occurred subsequent to the financial statement date and through the date of this letter that would require adjustment to or disclosure in the aforementioned financial statements.
- 7) All material transactions have been recorded in the accounting records and are reflected in the financial statements.
- 8) We are in agreement with the adjusting journal entries you have proposed, and they have been posted to the appropriate accounts.
- 9) There are no known or possible litigation, claims, and assessments whose effects should be considered when preparing the financial statements. There are no unasserted claims or assessments that our lawyer has advised us are probable of assertion and must be disclosed in accordance with accounting principles generally accepted in the United States of America.
- 10) Guarantees, whether written or oral, under which RCEA is contingently liable, if any, have been properly recorded or disclosed.

Information Provided

- 11) We have provided you with:
 - a. Access to all information, of which we are aware, that is relevant to the preparation and fair presentation of the financial statements, such as financial records and related data, documentation, and other matters.
 - b. Additional information that you have requested from us for the purpose of the audit.
 - c. Unrestricted access to persons within the entity from whom you determined it necessary to obtain audit evidence.
 - d. Minutes of the meetings of the Board of Directors or summaries of actions of recent meetings for which minutes have not yet been prepared.
- 12) We have disclosed to you results of our assessment of the risk that the financial statements may be materially misstated as a result of fraud.



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- 13) We have no knowledge of any fraud or suspected fraud that affects the entity and involves:
 - a. Management,
 - b. Employees who have significant roles in internal control, or
 - c. Others where the fraud could have a material effect on the financial statements.
- 14) We have no knowledge of any allegations of fraud or suspected fraud affecting the entity received in communications from employees, former employees, regulators, or others.
- 15) We have no knowledge of known instances of noncompliance or suspected noncompliance with provisions of laws, regulations, contracts, or grant agreements, or abuse, whose effects should be considered when preparing financial statements.
- 16) There are no related parties or related party relationships and transactions, including side agreements, of which we are aware.

Other

- 17) There have been no communications from regulatory agencies concerning noncompliance with, or deficiencies in, financial reporting practices.
- 18) We have a process to track the status of audit findings and recommendations.
- 19) We have identified to you any investigations or legal proceedings that have been initiated with respect to the period under audit.
- 20) We have provided our views on reported findings, conclusions, and recommendations, as well as our planned corrective actions, for our report.
- 21) RCEA has no plans or intentions that may materially affect the carrying value or classification of assets, deferred outflows of resources, liabilities, deferred inflows of resources or fund balance or net position.
- 22) We are responsible for compliance with federal, state, and local laws, regulations, and provisions of contracts and grant agreements applicable to us, including tax or debt limits, debt contracts, and IRS arbitrage regulations; and we have identified and disclosed to you all federal, state, and local laws, regulations and provisions of contracts and grant agreements that we believe have a direct and material effect on the determination of financial statement amounts or other financial data significant to the audit objectives, including legal and contractual provisions for reporting specific activities in separate funds.
- 23) There are no:



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- a) Violations or possible violations of budget ordinances, federal, state, and local laws or regulations (including those pertaining to adopting, approving and amending budgets), provisions of contracts and grant agreements, tax or debt limits, and any related debt covenants whose effects should be considered for disclosure in the financial statements or as a basis for recording a loss contingency, or for reporting on noncompliance, except those already disclosed in the financial statement, if any.
 - b) Other liabilities or gain or loss contingencies that are required to be accrued or disclosed by accounting principles generally accepted in the United States of America.
 - c) Rates being charged to customers other than the rates as authorized by the applicable authoritative body.
- 24) As part of your audit, you assisted with the preparation of the financial statements. We acknowledge our responsibility as it relates to those non-audit services, including that we assume all management responsibilities; oversee the services by designating an individual, preferably within senior management, who possesses suitable skill, knowledge, or experience; evaluate the adequacy and results of the services performed; and accept responsibility for the results of the services. We have reviewed, approved, and accepted responsibility for those financial statements.
- 25) We have made all management decisions and performed all management functions in relation to the nonattest services provided by Baker Tilly US, LLP or Baker Tilly Advisory Group, LP, as identified in the engagement letter or an addendum to the engagement letter. We have designated Lori Biondini, an employee with suitable skill, knowledge, and/or experience to oversee the services received. Furthermore, we have established and maintained internal controls, including monitoring activities related to the nonattest services provided by Baker Tilly US, LLP or Baker Tilly Advisory Group, LP, and we have evaluated and accepted responsibility for the adequacy and results of the nonattest services received.
- The nonattest services provided by Baker Tilly US, LLP or Baker Tilly Advisory Group, LP, are listed below.

- a) Financial statement preparation
 - b) Adjusting journal entries
 - c) Grant advisory services
 - d) Advisory services for the Inflation Reduction Act Credit
 - e) None of these nonattest services constitute an audit under generally accepted auditing standards, including *Government Auditing Standards*.
- 26) RCEA has satisfactory title to all owned assets, and there are no liens or encumbrances on such assets nor has any asset been pledged as collateral.
- 27) RCEA has complied with all aspects of contractual agreements that would have a material effect on the financial statement in the event of noncompliance.



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- 28) The financial statements include all component units as well as joint ventures with an equity interest, and properly disclose all other joint ventures and other related organizations, if any. Component units have been properly presented as either blended or discrete.
- 29) Components of net position (net investment in capital assets; restricted; and unrestricted) are properly classified and, if applicable, approved.
- 30) RCEA has no derivative financial instruments such as contracts that could be assigned to someone else or net settled, interest rate swaps, collars or caps.
- 31) Provisions for uncollectible receivables, if any, have been properly identified and recorded.
- 32) Deposits and investments are properly classified, valued, and disclosed (including risk disclosures, collateralization agreements, valuation methods, and key inputs, as applicable).
- 33) Provision, when material, has been made to reduce excess or obsolete inventories to their estimated net realizable value.
- 34) Capital assets, including infrastructure and intangible assets, are properly capitalized, reported, and, if applicable, depreciated/amortized. Any known impairments have been recorded and disclosed.
- 35) We have appropriately disclosed RCEA's 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 are available and have determined that net position were properly recognized under the policy.
- 36) We have reviewed our long-term debt agreements and believe that all terms related to significant events of default with finance-related consequences, termination events with finance-related consequences and subjective acceleration clauses have been properly identified and disclosed.
- 37) Unused lines of credit, collateral pledged to secure debt and direct borrowings and private placements have been properly identified and disclosed.
- 38) We have previously implemented GASB Statement No. 87, *Leases*, and believe that all required disclosures and accounting considerations have been identified and properly classified in the financial statements in compliance with the Standard.
- 39) We have identified any leases or other contracts that are required to be reported as leases and are in agreement with the key assumptions used in the measurement of any lease related assets, liabilities or deferred inflows of resources.
- 40) We have assessed the impact of GASB Statement No. 96, *Subscription-Based Information Technology Arrangements* and determined the impact of the statements to be immaterial.
- 41) As a member of California Community Choice Financing Authority (CCCFA), RCEA does not have an obligation for CCCFA's outstanding debt.



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- 42) We have implemented GASB Statement No. 103, *Financial Reporting Model Improvements*, and believe that all required disclosures and accounting considerations have been identified and properly classified in the financial statements in compliance with this Standard.
- 43) We have implemented GASB Statement No. 104, *Disclosure of Certain Capital Assets*, and believe that all required disclosures and accounting considerations have been identified and properly classified in the financial statements in compliance with this Standard.
- 44) The auditing standards define an annual report as "a document, or combination of documents, typically prepared on an annual basis by management or those charged with governance in accordance with law, regulation, or custom, the purpose of which is to provide owners (or similar stakeholders) with information on the entity's operations and the financial results and financial position as set out in the financial statements." Among other items, an annual report contains, accompanies, or incorporates by reference the financial statements and the auditors' report thereon. We confirm that we do not prepare and have no plans to prepare an annual report.

Sincerely,

Redwood Coast Energy Authority

Signed: [REDACTED]

Lori Biondini, Director of Business Planning and Finance

Signed: [REDACTED]

Elizabeth Burks, Executive Director

Client service team



Jodi Dobson, CPA
Principal

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Accounting changes relevant to Redwood Coast Energy Authority

Future accounting standards update

GASB statement number	Description	Potentially impacts you	Effective date
105	Subsequent Events		6/30/27

Further information on upcoming [GASB pronouncements](#).

Updated guidance for the financial reporting of subsequent events

GASB Statement No. 105, *Subsequent Events*, which supersedes GASB Statement No. 56, is intended to enhance consistency in the application of requirements for subsequent events.

The Statement defines subsequent events as transactions or other events that occur after year end but before the date the financial statements are available to be issued. The date the financial statements are available to be issued is the date at which (a) the financial statements are complete in a form and format that complies with generally accepted accounting principles (GAAP) and (b) approvals necessary for issuance have been obtained, or typically the opinion date. The definition of subsequent events in this Statement modifies the subsequent events time frame throughout the GASB literature.

The Statement also clarifies:

- The different types of subsequent events (recognized and nonrecognized events)
- When note disclosures are required
- The information that should be included in those note disclosures

Normal adjusting journal entries

Redwood Coast Energy Authority

Year End: June 30, 2026

Normal adjusting journal entries

Date: 7/1/2025 To 6/30/2026

Account No: A01 To A99

310

Associate	Sr. Associate	Manager
Partner Review	IR/CDR	RT18036 8/24/2026

Number	Date	Name	Account No	Reference	Annotation	Debit	Credit
A01	6/30/2026	Accrued Sick Leave	2103 EF	QQ.101			118,128.71
A01	6/30/2026	Fund Balance	3900 EF	QQ.101		118,128.71	
To record prior year entry related to accrued sick leave under GASB 101 that was not recorded prior to providing the FYE 2026 trial balance							
A02	6/30/2026	Fixed Asset	1500 EF	U.930			582,953.00
A02	6/30/2026	Land	1520 EF	U.930		582,953.00	
To move the portion of the office building purchase that relates to land from the fixed asset account to the land account							
A03	6/30/2026	Nonprofit Organization Grants	4250 EF	U.940			40,000.00
A03	6/30/2026	HSU-SPF	5429 EF	U.940		40,000.00	
To adjust capital contribution revenue by moving payment #2 received from Humboldt State University for the TERAS project to other operating revenue							
A04	6/30/2026	Fixed Asset	1500 EF	U.930			37,707.00
A04	6/30/2026	Accumulated depreciation	1600 EF	U.930		37,707.00	
To retire capital assets (telephone system, copy machine, and BEAM software)							
A05	6/30/2026	Accounts Receivable-Other	1103 EF	C.303.1		1,831,694.49	
A05	6/30/2026	Electricity Sales	5510 EF	C.303.1			1,831,694.49
To reverse "FYE26 Unbilled Revenue" entry and correct June 2026 billing							
A06	6/30/2026	Accrued Vacation	2102 EF	CC.400			1,981.82
A06	6/30/2026	Accrued Sick Leave	2103 EF	CC.400			21,960.68
A06	6/30/2026	Accrued Sick Leave	2103 EF	CC.400		29,484.54	
A06	6/30/2026	Accrued Sick Leave	2103 EF	CC.400			1,679.99
A06	6/30/2026	Accrued Sick Leave	2103 EF	CC.400		2,255.57	
A06	6/30/2026	Payroll Taxes Etc.	7250 EF	CC.400		1,679.99	
A06	6/30/2026	Payroll Taxes Etc.	7250 EF	CC.400			2,255.57
A06	6/30/2026	Payroll Taxes Etc.	7250 EF	CC.400		1,981.82	
A06	6/30/2026	Paid Time Off- Holiday	7262 EF	CC.400			29,484.54
A06	6/30/2026	Paid Time Off - Sick	7263 EF	CC.400		21,960.68	
To true up compensated absences (provided by Lori and Nicole Marie)							
A07	6/30/2026	Unearned Revenue	2013 EF	CC.300			515,315.39
A07	6/30/2026	CPUC NREN	5031 EF	CC.300		515,315.39	
To accrue fourth quarter unearned revenue from PG&E.							
A08	6/30/2026	State contracts	5030 EF	C.400		142,517.76	
A08	6/30/2026	HSU-SPF	5429 EF	C.400			142,517.76
To move the ARV- California Energy Commission EV Grant from noncapital subsidy to its' own GL account for capital contributions.							
A09	6/30/2026	Accounts Receivable	1100 EF	C.401		2,930,582.00	
A09	6/30/2026	IRA tax credits	5032 EF	C.401			2,930,582.00

Redwood Coast Energy Authority
Year End: June 30, 2026
Normal adjusting journal entries
Date: 7/1/2025 To 6/30/2026
Account No: A01 To A99

		310-1
Associate	Sr. Associate	Manager
Partner Review	IR/CDR	RT18036 8/24/2026

Number	Date	Name	Account No	Reference	Annotation	Debit	Credit
To recognize the IRA tax credit revenue and the corresponding receivable as the eligibility requirements have been met.							
						6,256,260.95	6,256,260.95
Net Income (Loss)			4,670,763.89				

Two-way audit communications

As part of our audit of your financial statements, we are providing communications to you throughout the audit process. Auditing requirements provide for two-way communication and are important in assisting the auditor and you with more information relevant to the audit.

As this past audit is concluded, we use what we have learned to begin the planning process for next year's audit. It is important that you understand the following points about the scope and timing of our next audit:

- a. We address the significant risks of material misstatement, whether due to fraud or error, through our detailed audit procedures.
- b. We will obtain an understanding of the five components of internal control sufficient to assess the risk of material misstatement of the financial statements whether due to error or fraud, and to design the nature, timing and extent of further audit procedures. We will obtain a sufficient understanding by performing risk assessment procedures to evaluate the design of controls relevant to an audit of financial statements and to determine whether they have been implemented. We will use such knowledge to:
 - Identify types of potential misstatements
 - Consider factors that affect the risks of material misstatement
 - Design tests of controls, when applicable and substantive procedures
- c. We will not express an opinion on the effectiveness of internal control over financial reporting or compliance with laws, regulations and provisions of contracts or grant programs.
- d. The concept of materiality recognizes that some matters, either individually or in the aggregate, are important for fair presentation of financial statements in conformity with generally accepted accounting principles while other matters are not important. In performing the audit, we are concerned with matters that, either individually or in the aggregate, could be material to the financial statements. Our responsibility is to plan and perform the audit to obtain reasonable assurance that material misstatements, whether caused by errors or fraud, are detected.

Our audit will be performed in accordance with auditing standards generally accepted in the United States of America.

We are very interested in your views regarding certain matters. Those matters are listed here:

- a. We typically will communicate with your top level of management unless you tell us otherwise.
- b. We understand that the governing board has the responsibility to oversee the strategic direction of your organization, as well as the overall accountability of the entity. Management has the responsibility for achieving the objectives of the entity.
- c. We need to know your views about your organization's objectives and strategies, and the related business risks that may result in material misstatements.
- d. We anticipate that the Authority will receive an unmodified opinion on its financial statements.
- e. Which matters do you consider warrant particular attention during the audit, and are there any areas where you request additional procedures to be undertaken?

- f. Have you had any significant communications with regulators or grantor agencies?
- g. Are there other matters that you believe are relevant to the audit of the financial statements?

Also, is there anything that we need to know about the attitudes, awareness and actions of the governing body concerning:

- a. The entity's internal control and its importance in the entity, including how those charged with governance oversee the effectiveness of internal control?
- b. The detection or the possibility of fraud?

We also need to know if you have taken action in response to developments in financial reporting, laws, accounting standards, governance practices or other related matters, or in response to previous communications with us.

With regard to the timing of our audit, here is some general information. If necessary, we may do preliminary financial audit work during the months of April-June, and sometimes early in July. Our final financial fieldwork is scheduled during the summer to best coincide with your readiness and report deadlines. After fieldwork, we wrap up our financial audit procedures at our office and may issue drafts of our report for your review. Final copies of our report and other communications are issued after approval by your staff. This is typically 6-12 weeks after final fieldwork but may vary depending on a number of factors.

Keep in mind that while this communication may assist us with planning the scope and timing of the audit, it does not change the auditor's sole responsibility to determine the overall audit strategy and the audit plan, including the nature, timing and extent of procedures necessary to obtain sufficient appropriate audit evidence.

We realize that you may have questions on what this all means or wish to provide other feedback. We welcome the opportunity to hear from you.



Baker Tilly Advisory Group, LP and Baker Tilly US, LLP, trading as Baker Tilly, are members of the global network of Baker Tilly International Ltd., the members of which are separate and independent legal entities. Baker Tilly US, LLP is a licensed CPA firm that provides assurance services to its clients. Baker Tilly Advisory Group, LP and its subsidiary entities provide tax and consulting services to their clients and are not licensed CPA firms. ©2026 Baker Tilly Advisory Group, LP⁴⁵

Redwood Coast Energy Authority

Financial Statements

June 30, 2026 and 2025

Redwood Coast Energy Authority

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June 30, 2026 and 2025

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Independent Auditors' Report

To the Board of Directors of
Redwood Coast Energy Authority

Report on the Audit of the Financial Statements

Opinion

We have audited the accompanying financial statements of Redwood Coast Energy Authority (RCEA), as of and for the years ended June 30, 2026 and 2025, and the related notes to the financial statements, which collectively comprise the RCEA's basic financial statements as listed in the table of contents.

In our opinion, the accompanying financial statements referred to above present fairly, in all material respects, the financial position of RCEA as of June 30, 2026 and 2025, and the changes in financial position and cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America.

Basis for Opinion

We conducted our audit in accordance with auditing standards generally accepted in the United States of America (GAAS) and the standards applicable to financial audits contained in *Government Auditing Standards* issued by the Comptroller General of the United States (*Government Auditing Standards*). Our responsibilities under those standards are further described in the Auditors' Responsibilities for the Audit of the Financial Statements section of our report. We are required to be independent of the RCEA and to meet our other ethical responsibilities, in accordance with the relevant ethical requirements relating to our audits. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Emphasis of Matter

As discussed in Note 10, RCEA adopted the provisions of GASB Statement No. 103, effective July 1, 2025. Accordingly, the accounting changes have been retroactively applied to prior periods presented. Our opinion is not modified with respect to this matter.

Responsibilities of Management for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with accounting principles generally accepted in the United States of America; and 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.

In preparing the financial statements, management is required to evaluate whether there are conditions or events, considered in the aggregate, that raise substantial doubt about the RCEA's ability to continue as a going concern for twelve months beyond the financial statement date, including any currently known information that may raise substantial doubt shortly thereafter.

Auditors' Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditors' report that includes our opinion. Reasonable assurance is a high level of assurance but is not absolute assurance and therefore is not a guarantee that an audit conducted in accordance with GAAS and *Government Auditing Standards* will always detect a material misstatement when it exists. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations or the override of internal control. Misstatements are considered material if there is a substantial likelihood that, individually or in the aggregate, they would influence the judgment made by a reasonable user based on the financial statements.

In performing an audit in accordance with GAAS and *Government Auditing Standards*, we:

- Exercise professional judgment and maintain professional skepticism throughout the audit.
- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, and design and perform audit procedures responsive to those risks. Such procedures include examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements.
- Obtain an understanding of internal control relevant to the audit 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 RCEA's internal control. Accordingly, no such opinion is expressed.
- Evaluate the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluate the overall presentation of the financial statements.
- Conclude whether, in our judgment, there are conditions or events, considered in the aggregate, that raise substantial doubt about the RCEA's ability to continue as a going concern for a reasonable period of time.

We are required to communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit, significant audit findings and certain internal control-related matters that we identified during the audit.

Required Supplementary Information

Management has omitted the Management Discussion and Analysis that accounting principles generally accepted in the United States of America require to be presented to supplement the basic financial statements. Such missing 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. Our opinion on the basic financial statements is not affected by this missing information.

Other Reporting Required by *Government Auditing Standards*

In accordance with *Government Auditing Standards*, we have also issued our report dated September 25, 2026 on our consideration of RCEA'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 solely 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 the effectiveness of RCEA's 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 RCEA's internal control over financial reporting and compliance.

Baker Tilly US, LLP

Madison, Wisconsin
September 25, 2026

Redwood Coast Energy Authority

Statements of Net Position

June 30, 2026 and 2025

	<u>2026</u>	<u>2025</u>
Assets and Deferred Outflow of Resources		
Current Assets		
Cash and cash equivalents	\$ 40,433,388	\$ 37,635,310
Restricted assets:		
Security reserve fund	262,917	-
Accounts receivable, net of allowance	4,742,424	6,132,604
Unbilled revenue	1,831,694	3,050,773
Other receivable	3,173,976	438,195
Prepaid expenses	24,698	24,840
Inventory	19,835	21,822
Deposits	<u>795,553</u>	<u>682,699</u>
Total current assets	<u>51,284,485</u>	<u>47,986,243</u>
Noncurrent Assets		
Restricted assets:		
Reserve fund	372,608	383,271
Decommissioning fund	196,000	-
Plant in service	14,240,110	812,562
Accumulated depreciation	(782,769)	(399,830)
Construction work in progress	<u>337,651</u>	<u>9,399,476</u>
Total noncurrent assets	<u>14,363,600</u>	<u>10,195,479</u>
Total assets	<u>65,648,085</u>	<u>58,181,722</u>
Deferred Outflows of Resources		
Asset retirement obligation	<u>196,000</u>	<u>-</u>
Total deferred outflow of resources	<u>196,000</u>	<u>-</u>
Total assets and deferred outflow of resources	<u>\$ 65,844,085</u>	<u>\$ 58,181,722</u>

See notes to basic financial statements

Redwood Coast Energy Authority

Statements of Net Position

June 30, 2026 and 2025

	<u>2026</u>	<u>2025</u>
Liabilities and Net Position		
Current Liabilities		
Accounts payable	\$ 3,742,295	\$ 1,540,637
Accrued cost of electricity	3,042,876	5,394,365
Accrued wages	170,596	167,666
Accrued compensation	371,072	349,559
Security deposits	1,573,470	1,049,170
Current liabilities payable from restricted assets:		
Current portion of revenue bonds	<u>276,378</u>	<u>276,378</u>
Total current liabilities	<u>9,176,687</u>	<u>8,777,775</u>
Noncurrent Liabilities		
Revenue bonds	5,112,987	5,389,364
Asset retirement obligation	196,000	-
Advances from grantors	<u>7,075,981</u>	<u>4,402,909</u>
Total noncurrent liabilities	<u>12,384,968</u>	<u>9,792,273</u>
Total liabilities	<u>21,561,655</u>	<u>18,570,048</u>
Net Position		
Net investment in capital assets	8,778,235	4,529,737
Unrestricted	<u>35,504,195</u>	<u>35,081,937</u>
Total net position	<u>44,282,430</u>	<u>39,611,674</u>
Total liabilities and net position	<u>\$ 65,844,085</u>	<u>\$ 58,181,722</u>

See notes to basic financial statements

Redwood Coast Energy Authority

Statements of Revenues, Expenses and Changes in Net Position
Years Ended June 30, 2026 and 2025

	2026	Restated 2025
Operating Revenues		
Charges for service	\$ 55,660,828	\$ 67,883,895
Other operating revenue	768,994	5,545,217
Total operating revenues	56,429,822	73,429,112
Operating Expenses		
Purchased power	47,734,259	63,809,443
Operation and maintenance	10,355,954	9,017,157
Depreciation	423,041	80,564
Total operating expenses	58,513,254	72,907,164
Operating income (loss)	(2,083,432)	521,948
Noncapital Subsidies		
Program revenue	11,362,145	3,595,529
Program expenses	(5,962,401)	(1,915,157)
Total noncapital subsidies	5,399,744	1,680,372
Total operating income (loss) and noncapital subsidies	3,316,312	2,202,320
Nonoperating Revenues (Expenses)		
Investment income	1,318,877	504,793
Interest expense	(106,951)	(111,797)
Capital contributions	142,518	-
Total nonoperating revenues	1,354,444	392,996
Change in net position	4,670,756	2,595,316
Net Position, Beginning	39,611,674	37,016,358
Net Position, Ending	\$ 44,282,430	\$ 39,611,674

See notes to basic financial statements

Redwood Coast Energy Authority

Statements of Cash Flows

Years Ended June 30, 2026 and 2025

	2026	Restated 2025
Cash Flows From Operating Activities		
Received from customers	\$ 59,758,182	\$ 75,548,637
Paid to suppliers for goods and services	(53,138,370)	(60,910,207)
Paid to employees for operating payroll	(5,187,955)	(5,004,699)
Net cash flows from operating activities	<u>1,431,857</u>	<u>9,633,731</u>
Cash Flows From Capital and Related Financing Activities		
Acquisition and construction of capital assets	(4,405,825)	(374,855)
Capital contributions received	142,518	-
Debt retired	(276,378)	(276,378)
Interest paid	(106,951)	(111,797)
Net cash flows from capital and related financing activities	<u>(4,646,636)</u>	<u>(763,030)</u>
Cash Flows From Noncapital and Related Financing Activities		
Received from programs	11,104,635	7,998,438
Paid to programs	(5,962,401)	(1,915,157)
Net cash flows from noncapital and related financing activities	<u>5,142,234</u>	<u>6,083,281</u>
Cash Flows From Investing Activities		
Interest income	<u>1,318,877</u>	<u>504,793</u>
Net cash flows from investing activities	<u>1,318,877</u>	<u>504,793</u>
Net change in cash and cash equivalents	3,246,332	15,458,775
Cash and Cash Equivalents, Beginning	<u>38,018,581</u>	<u>22,559,806</u>
Cash and Cash Equivalents, Ending	<u>\$ 41,264,913</u>	<u>\$ 38,018,581</u>
Noncash Capital and Financing Activities		
Noncapital subsidy revenue accrued	<u>\$ 2,930,582</u>	<u>\$ -</u>

See notes to basic financial statements

Redwood Coast Energy Authority

Statements of Cash Flows

Years Ended June 30, 2026 and 2025

	2026	Restated 2025
Reconciliation of Operating Income to Net Cash Flows From Operating Activities		
Operating income	\$ (2,083,432)	\$ 521,948
Noncash items in operating income:		
Depreciation	423,041	80,564
Changes in assets and liabilities:		
Accounts receivable	1,390,180	972,063
Unbilled revenue	1,219,079	683,020
Other receivables	194,801	361,817
Inventory	1,987	822
Deposits	(112,854)	3,518,705
Prepaid expenses	142	40,973
Accounts payable	2,201,659	650,819
Accrued cost of electricity	(2,351,489)	2,513,614
Accrued compensation and wages	24,443	186,761
Security deposits	524,300	102,625
Net cash flows from operating activities	<u>\$ 1,431,857</u>	<u>\$ 9,633,731</u>
Reconciliation of Operating Income to Net Cash Flows From Operating Activities		
Cash and cash equivalents	\$ 40,433,388	\$ 37,635,310
Security reserve	262,917	-
Reserve fund	372,608	383,271
Decommissioning fund	196,000	-
Cash and cash equivalents	<u>\$ 41,264,913</u>	<u>\$ 38,018,581</u>

See notes to basic financial statements

Redwood Coast Energy Authority

Notes to Basic Financial Statements
June 30, 2026 and 2025

1. Summary of Significant Accounting Policies

Reporting Entity

The Redwood Coast Energy Authority (RCEA) is a joint powers authority formed in 2003 under California Government Code Section 6500 to develop and implement sustainable energy initiatives that reduce energy demand, increase energy efficiency and advance the use of clean, efficient and renewable resources available in the Humboldt County region of California. The member agencies of RCEA are the County of Humboldt, the Humboldt Bay Municipal Water District, the cities of Arcata, Blue Lake, Eureka, Ferndale, Fortuna, Rio Dell and Trinidad. RCEA is governed by a Board of Directors comprised of representatives of the member agencies.

RCEA began the delivery of electricity in May 2017. RCEA provides electric service to retail customers as a Community Choice Aggregation Program (CCA) under the California Public Utilities Code Section 366.2. Electricity is acquired from commercial suppliers and delivered through existing physical infrastructure and equipment managed by the California Independent System Operator and PG&E.

Basis of Accounting

RCEA'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.

RCEA'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.

When both restricted and unrestricted resources are available for use, it is RCEA's policy to use restricted resources first, then unrestricted resources as they are needed.

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 the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Cash and Cash Equivalents

For purposes of the statement of cash flows, RCEA has defined cash and cash equivalents to include cash on hand, demand deposits and short-term investments with an original maturity of three months or less.

Restricted Assets

Mandatory segregations of assets are presented as restricted assets. Such segregations are required by bond agreements and other external parties. Current liabilities payable from these restricted assets are so classified. The restricted assets included relate to the debt service for the USDA loan, the decommissioning fund for the asset retirement obligation, and the security reserve fund required by Pacific Gas and Electric Company related to RCEA's Community Choice Aggregator financial security requirement.

Redwood Coast Energy Authority

Notes to Basic Financial Statements

June 30, 2026 and 2025

Accounts Receivable

Accounts receivable represent program revenues which have been earned for which the related cash has not been received. Accounts receivable was as follows:

	2026	2025
Accounts receivable from customers	\$ 11,679,372	\$ 14,888,075
Allowance for uncollectible accounts	(6,936,948)	(8,755,471)
Total	<u>\$ 4,742,424</u>	<u>\$ 6,132,604</u>

The majority of account collections occur within the first few months following customer invoicing. RCEA estimates that a portion of the billed amounts will not be collected. The allowance for uncollectible accounts at the end of a period includes amounts billed during the current and prior fiscal years.

Unbilled Revenue

RCEA records an estimate for unbilled revenues earned from the dates its customers were last billed to the end of the fiscal year. On June 30, 2026 and 2025, unbilled revenues were \$1,831,694 and \$3,050,773, respectively.

Other Receivables

Other receivables consist of amounts due to RCEA that are not related to retail electricity sales, including grant and program receivables, retention amounts withheld by grantors, and tax credits. During 2026, other receivables also included an amount due under provisions of the Inflation Reduction Act. Grant and program receivables are recognized when applicable eligibility requirements are met, and tax credit receivables are recognized when the applicable requirements for the credit have been satisfied and the amount is measurable and expected to be realized.

Inventory

Inventory is generally used for construction, operation and maintenance work, not for resale. Inventory is valued at the lower of cost or market utilizing the average cost method and charged to construction or expense when used.

Deposits

Various energy contracts entered into by RCEA require RCEA to provide a supplier with a security deposit. These deposits are generally held for the term of the contract. Deposits are classified as current or noncurrent depending on the length of the time the deposits are expected to be held.

Capital Assets and Depreciation

Capital assets are generally defined by RCEA as assets with an initial, individual cost of more than \$2,000 and an estimated useful life in excess of one year.

Capital assets of RCEA are recorded at cost or the estimated acquisition value at the time of contribution to RCEA. Major outlays for capital assets are capitalized as projects are constructed. Depreciation is computed according to the straight-line method over estimated useful lives of five to ten years for equipment. Leasehold improvements are depreciated over the shorter of 1) the useful life of the leasehold improvement or 2) the remaining years of the lease.

Advances From Grantors

RCEA received grant funding from various grantors. The amount in this category represents funds received by RCEA, but not yet expended to carry out specific goals as required by the terms and conditions of the grant agreement. Grant revenue will be recognized as the objectives of the grant agreement are carried out.

Asset Retirement Obligation

The Authority's asset retirement obligation relates to the decommissioning and restoration requirements associated with its microgrid facility located on property leased from the County of Humboldt. Under the terms of the agreement, the Authority is financially responsible for decommissioning the microgrid facility and restoring the leased premises at the end of the facility's 25-year operating life or upon earlier termination of the agreement. Upon commercial operation, the Authority is required to reserve \$196,000 in a designated account and contribute 2.5% of the then-current reserve balance annually over the term of the agreement. The agreement estimates that the reserve will total approximately \$363,000 at the end of the 25-year term, representing the estimated cost of decommissioning the facility. The Authority recognized the related asset retirement obligation upon the commencement of commercial operations.

The Authority recognizes liabilities for legal obligations associated with the retirement of tangible capital assets in accordance with GASB Statement No. 83, *Certain Asset Retirement Obligations*. The asset retirement obligation is measured based on the best estimate of the current value of expected future retirement costs, with a corresponding deferred outflow of resources recognized upon initial measurement. The deferred outflow is amortized over the remaining useful life of the related asset, and the liability is adjusted annually for the effects of inflation or deflation.

Long-Term Obligations

Long-term debt and other obligations are reported as liabilities. Bond premiums and discounts are amortized over the life of the bonds using the straight-line method. Gains or losses on prior refundings are amortized over the remaining life of the old debt or the life of the new debt, whichever is shorter. The balance at year end for premiums and discounts is shown as an increase or decrease in the liability section of the statement of net position. The balance at year end for the loss on refunding is shown as a deferred outflow in the statement of net position.

Accrued Compensation and Accrued Wages

RCEA pays employees bi-weekly and fully pays its obligation for health benefits and contributions to its defined contribution retirement plan each month. RCEA provides compensated time off, and the related liability is recorded in these financial statements. Under terms of employment, employees are granted sick leave and vacations in varying amounts. Vacation and sick leave pay is accrued when earned in the financial statements. RCEA is not obligated to provide postemployment healthcare or other fringe benefits and, accordingly, no related liability is recorded in these financial statements.

Security Deposits

Various energy contracts entered into by RCEA require the supplier to provide RCEA with a security deposit. These deposits are generally held for the term of the contract or until the completion of certain benchmarks. Deposits are classified as current or noncurrent depending on the length of time the deposits will be held.

Net Position

Net position is presented in the following components:

Net Investment in Capital Assets - This component of net position consists of capital assets, net of accumulated depreciation and is reduced by outstanding borrowings that are attributable to the acquisition, construction or improvement of those assets.

Restricted - This component of net position consists of net assets subject to external constraints on their use imposed by creditors (such as through debt covenants), grantors, contributors or laws or regulations of other governments or constraints imposed by law through constitutional provisions or enabling legislation.

Unrestricted - This component of net position consists of net position that does not meet the definition of "investment in capital assets" or "restricted".

Revenue and Expenses

RCEA classifies operating revenues and expenses, nonoperating revenues and expenses and noncapital subsidies in accordance with GASB Statement No. 103, *Financial Reporting Model Improvements*. Operating revenues and expenses generally result from providing services and producing and delivering goods in connection with RCEA's principal ongoing operations. The principal operating revenues of RCEA are revenues derived from the provision of electricity to retail customers. Operating expenses include purchased power, administrative and other operating expenses, and depreciation on capital assets.

Revenue Recognition

RCEA recognizes revenue on an 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 be uncollectible. Accordingly, an allowance for uncollectible accounts has been recorded. RCEA's methodology used to calculate the allowance for doubtful accounts considers the impacts of the recession and the suspension of customer electricity disconnections.

Noncapital Subsidies

The Authority receives and provides subsidies in connection with certain programs and activities that are not restricted for capital purposes. Noncapital subsidies received are recognized as program revenues when eligibility requirements are met and the amounts are earned. Amounts provided by the Authority under such programs are recognized as program expenses in the period in which the related obligations are incurred. Noncapital subsidies are reported separately from operating revenues and expenses in the statement of revenues, expenses and changes in net position.

Capital Contributions

Cash and capital assets are contributed to RCEA from customers or external parties. The value of property contributed to the RCEA is reported as revenue on the statements of revenues, expenses and changes in net position.

Electrical Power Purchased

During the normal course of business, RCEA purchases electrical power from numerous suppliers. Electricity costs include the cost of energy and capacity arising from bilateral contracts with energy suppliers as well as wholesale sales and generation credits, and load and other charges arising from RCEA's participation in the CAISO's centralized market. The cost of electricity and capacity is recognized as "Purchased Power" in the Statements of Revenues, Expenses and Changes in Net Position.

Income Taxes

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

The Governmental Accounting Standards Board (GASB) Has Approved the Following

GASB has approved GASB Statement No. 105, *Subsequent Events*. When it becomes effective, application of this standard may result in restating of these financial statements. Management is evaluating the effects of this new pronouncement.

2. Cash and Cash Equivalents

As of June 30, 2026 and 2025, RCEA maintains its cash in both interest-earning and noninterest-earning bank accounts with Umpqua Bank.

California Government Code Section 16521 requires banks to collateralize amounts of public funds in excess of the FDIC limit of \$250,000 in an amount equal to 110% of deposit balances.

The California Cooperative Liquid Assets Securities System (California CLASS) is a joint powers authority established under California law to provide California public agencies with pooled investment programs. California CLASS is governed by a Board of Trustees, and Public Trust Advisors, LLC, an investment adviser registered with the U.S. Securities and Exchange Commission, provides investment advisory services to California CLASS. California CLASS investments are marked to market daily and are reported at fair value. The fair value of RCEA's position in California CLASS is the same as the value of its investment in the pool.

Investment Policy

RCEA has adopted an investment policy. That policy follows state statutes for allowable investments.

Redwood Coast Energy Authority

Notes to Basic Financial Statements

June 30, 2026 and 2025

3. Capital Assets

A summary of changes in capital assets for 2026 follows:

	Balances July 1, 2025	Increases	Decreases	Balances June 30, 2026
Capital assets, not being depreciated:				
Land and land rights	\$ 286,880	\$ 582,953	\$ -	\$ 869,833
Total capital assets not being depreciated	286,880	582,953	-	869,833
Capital assets being depreciated:				
Leasehold improvements	45,972	-	-	45,972
Equipment	479,710	12,884,697	(40,102)	13,324,305
Total capital assets being depreciated	525,682	12,884,697	(40,102)	13,370,277
Total capital assets	812,562	13,467,650	(40,102)	14,240,110
Less accumulated depreciation:				
Leasehold improvements	(25,119)	(2,299)	-	(27,418)
Equipment	(374,711)	(420,742)	40,102	(755,351)
Total accumulated depreciation	(399,830)	(423,041)	40,102	(782,769)
Construction in progress	9,399,476	587,165	(9,648,990)	337,651
Capital assets, net	\$ 9,812,208	\$ 13,631,774	\$ (9,648,990)	\$ 13,794,992

Redwood Coast Energy Authority

Notes to Basic Financial Statements

June 30, 2026 and 2025

A summary of changes in capital assets for 2025 follows:

	Balances July 1, 2024	Increases	Decreases	Balances June 30, 2025
Capital assets, not being depreciated:				
Land and land rights	\$ 286,880	\$ -	\$ -	\$ 286,880
Total capital assets not being depreciated	286,880	-	-	286,880
Capital assets being depreciated:				
Leasehold improvements	45,972	-	-	45,972
Equipment	414,440	65,270	-	479,710
Total capital assets being depreciated	460,412	65,270	-	525,682
Total capital assets	747,292	65,270	-	812,562
Less accumulated depreciation:				
Leasehold improvements	(22,821)	(2,298)	-	(25,119)
Equipment	(296,445)	(78,266)	-	(374,711)
Total accumulated depreciation	(319,266)	(80,564)	-	(399,830)
Construction in progress	9,089,891	309,585	-	9,399,476
Capital assets, net	\$ 9,517,917	\$ 294,291	\$ -	\$ 9,812,208

4. Long-Term Obligations

The following bonds have been issued:

Date	Purpose	Final Maturity	Interest Rate	Original Amount	Outstanding Amount 6/30/2026	Outstanding Amount 6/30/2025
6/1/2021	To finance the construction of electric distribution facilities, United States Department of Agriculture (USDA), Rural Utilities Service (RUS)	1/2/2046	1.79%	\$ 6,287,592	\$ 5,389,365	\$ 5,665,742*

* The debt noted is directly placed with a third party.

Redwood Coast Energy Authority

Notes to Basic Financial Statements

June 30, 2026 and 2025

Revenue bonds debt service requirements to maturity follow:

Years Ending June 30:	Principal	Interest	Total
2027	\$ 276,378	\$ 96,268	\$ 372,646
2028	276,378	91,494	367,872
2029	276,378	86,629	363,007
2030	276,378	81,135	357,513
2031	276,378	76,184	352,562
2032-2036	1,381,890	307,605	1,689,495
2037-2041	1,381,890	183,249	1,565,139
2042-2046	1,243,695	58,066	1,301,761
Total	\$ 5,389,365	\$ 980,630	\$ 6,369,995

All RCEA revenues net of specified operating expenses are pledged as security of the above revenue bonds until the bonds are defeased. Principal and interest paid for 2026 and 2025 were \$383,328 and \$388,175, respectively. Total customer gross revenues as defined for the same periods were \$56,429,822 and \$73,429,112. Annual principal and interest payments are expected to require 0.7% and 0.5% of gross revenues on average, respectively.

Debt Coverage

Under the terms of the resolutions providing for the issue of revenue bonds, revenues less operating expenses must exceed 1.25 times the annual debt service of the bonds in 2026 and 2025. The coverage only includes revenue debt and does not include general obligation or other debt. The coverage requirement was met in 2026 and 2025.

Long-Term Obligation Summary

Long-term obligation activity for the year ended June 30, 2026 is as follows:

	July 1, 2025	Additions	Reductions	June 30, 2026	Due Within One Year
Revenue bonds	\$ 5,665,742	\$ -	\$ 276,377	\$ 5,389,365	\$ 276,378
Advances from grantors	4,402,909	9,930,671	7,257,599	7,075,981	-
Total	\$ 10,068,651	\$ 9,930,671	\$ 7,533,978	\$ 12,465,346	\$ 276,378

Long-term obligation activity for the year ended June 30, 2025 is as follows:

	July 1, 2024	Additions	Reductions	June 30, 2025	Due Within One Year
Revenue bonds	\$ 5,942,120	\$ -	\$ 276,378	\$ 5,665,742	\$ 276,378
Advances from grantors	-	4,402,909	-	4,402,909	-
Total	\$ 5,942,120	\$ 4,402,909	\$ 276,378	\$ 10,068,651	\$ 276,378

5. Grants

RCEA administers various grants from the California Public Utilities Commission (CPUC), California Energy Commission and other sources. Grant revenues are recognized when applicable eligibility requirements are met, which generally occurs when the corresponding eligible expenditures are incurred. Grants that meet the definition of a subsidy under GASB Statement No. 103 are reported as noncapital subsidies or capital contributions, as applicable.

6. Defined Contribution Retirement Plan

The Redwood Coast Energy Authority Plan (Plan) is a defined contribution 401(a) retirement plan established by RCEA to provide benefits upon retirement to its employees. The Plan is administered by Ascensus, LLC. As of June 30, 2026, there were 37 plan members. RCEA is required to contribute a flat rate of \$4,000 per year plus 4% of annual covered payroll to the Plan and up to an additional 3% of salary as match contribution. RCEA contributed \$383,950 and \$361,500 during the fiscal years ended June 30, 2026 and 2025, respectively. Plan provisions and contribution requirements are established and may be amended by the Board of Directors.

7. Deferred Compensation Plan

RCEA offers a deferred compensation plan to eligible employees under Internal Revenue Code (IRC) Section 457(b). This plan allows employees to voluntarily defer a portion of their compensation on a pre-tax basis, thereby reducing their current taxable income and allowing for tax-deferred growth of retirement savings. The plan is designed to supplement other retirement benefits and provide employees with additional financial security in retirement. Participation in the plan is optional and available to all full-time employees. In addition to employee contributions, the employer makes discretionary contributions to the plan. For the fiscal years ended June 30, 2026 and June 30, 2025, the employer contributions totaled \$376,934 and \$322,279, respectively.

8. Risk Management

RCEA is covered for general business, liability, automobile and errors and omissions through the Special Districts Risk Management Authority (SDRMA), a public entity risk pool. As a member of a public entity risk pool, RCEA is responsible for appointing an employee as a liaison between RCEA and SDRMA, implementing all policies of the SDRMA and promptly paying all contributions. SDRMA is responsible for providing insurance coverage as agreed upon, assisting RCEA with implementation, providing claims adjusting and defending any civil action brought against an officer of RCEA.

RCEA is exposed to various insurable risks of loss related to torts; theft of, damage to and destruction of assets; and errors and omissions. During the year, RCEA purchased insurance policies from investment-grade commercial carriers to mitigate risks that include those associated with earthquakes, theft, general liability, errors and omissions and property damage. Settled claims have not exceeded the commercial liability in any of the past three years. There were no significant reductions in coverage compared to the prior year.

On July 12, 2018, RCEA's Board adopted the Energy Risk Management Policy (ERMP). The ERMP establishes RCEA's Energy Risk Program and applies it to all power procurements and related business activities that may impact the risk profile of RCEA. The ERMP documents the framework by which RCEA staff and consultants will identify and quantify risk, develop and execute procurement strategies, develop controls and oversight and monitor and measure and report on the effectiveness of the ERMP. Risks covered by the ERMP include market price risk, credit risk, volumetric risk, operational risk, opt-out risk, legislative and regulatory risk and other risks arising from operating as a Community Choice Aggregation and participating in California energy markets. The Board approved updates to the ERMP in July 2019, July 2020, July 2021, June 2025, and January 2026.

Redwood Coast Energy Authority

Notes to Basic Financial Statements

June 30, 2026 and 2025

RCEA maintains other risk management policies, procedures and systems that help mitigate and manage credit, liquidity, financial, regulatory and other risks not covered by the ERMP.

Credit guidelines include a preference for transacting with investment-grade counterparties, evaluating counterparties' financial condition and assigning credit limits as applicable. These credit limits are established based on risk and return considerations under terms customarily available in the industry. In addition, RCEA enters into netting arrangements whenever possible and where appropriate obtains collateral and other performance assurances from counterparties.

9. Purchase Commitments

Power and Electric Capacity

In the ordinary course of business, RCEA enters into various power purchase and energy storage agreements in order to acquire renewable and other energy and electric capacity. The price and volume of purchased power may be fixed or variable. Variable pricing is generally based on the market price of electricity at the date of delivery. Variable volume is generally associated with contracts to purchase energy from as-available resources such as solar, wind and hydro-electric facilities.

RCEA enters into power purchase and energy storage agreements in order to comply with state law and elective targets for renewable and greenhouse gas (GHG) free products and to ensure stable and competitive electric rates for its customer.

The following table represents the expected, undiscounted, contractual commitments for energy storage, power and electric capacity outstanding as of June 30, 2026:

Years Ending June 30:

2027	\$ 21,557,851
2028	21,927,883
2029	22,360,559
2030	22,668,163
2031	22,012,015
2032-2036	57,010,032
2037-2041	31,381,855
2042-2046	<u>3,810,150</u>
Total	<u>\$ 202,728,508</u>

Redwood Coast Energy Authority

Notes to Basic Financial Statements

June 30, 2026 and 2025

10. Change in Accounting Principle

The Authority adopted the provisions of Governmental Accounting Standards Board (GASB) Statement No. 103, *Financial Reporting Model Improvements*, during the current fiscal year. As required by the standard, certain prior year amounts have been restated to conform to the current year presentation. The restatement had no effect on the Authority's net position as previously reported.

Statement of Revenues, Expenses and Changes in Net Position	Balance as Previously Reported at June 30, 2025	Implementation of GASB 103	Balance as Adjusted June 30, 2025
Operating Revenues			
Grant revenue	\$ 9,090,996	\$ (9,090,996)	\$ -
Other operating revenue	554,543	4,990,674	5,545,217
Operating Expenses			
Operation and maintenance	(10,932,314)	1,915,157	(9,017,157)
Noncapital Subsidies			
Program revenue	-	3,595,529	3,595,529
Program expenses	-	(1,915,157)	(1,915,157)
Nonoperating Revenues (Expenses)			
Investment income	-	504,793	504,793
	<u>\$ (1,286,775)</u>	<u>\$ -</u>	<u>\$ (1,286,775)</u>
Statement of Cash Flows	Balance as Previously Reported at June 30, 2025	Implementation of GASB 103	Balance as Adjusted June 30, 2025
Cash Flows From Operating Activities			
Received from customers	\$ 70,557,963	\$ 4,990,674	\$ 75,548,637
Paid to suppliers for goods and services	(62,825,364)	1,915,157	(60,910,207)
Cash Flows From Noncapital Financing Activities			
Received from programs	-	7,998,438	7,998,438
Paid to program	-	(1,915,157)	(1,915,157)
Received from grants	13,493,905	(13,493,905)	-
Cash Flows From Investing Activities			
Interest Income	-	504,793	504,793
Total	<u>\$ 21,226,504</u>	<u>\$ -</u>	<u>\$ 21,226,504</u>

11. Subsequent Events

In September 2026, RCEA and Desert Community Energy participated in an energy prepayment transaction through the California Community Choice Financing Authority (CCCFA). In connection with the transaction, CCCFA issued \$659.2 million of Clean Energy Project Revenue Bonds, Series 2026H (Green Bonds), the proceeds of which were used to finance the prepayment of electricity to be delivered over approximately 30 years. RCEA entered into a Clean Energy Purchase Contract with CCCFA and related agreements under which certain rights and obligations associated with existing power purchase agreements were assigned to J. Aron & Company LLC. The transaction is structured to provide RCEA with electricity at a discount to the prices it would otherwise pay under the assigned power purchase agreements. Electricity deliveries under the transaction are scheduled to commence in February 2027. The bonds are special, limited obligations of CCCFA and do not constitute indebtedness of RCEA.

**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 Auditors' Report

To the Board of Directors of
Redwood Coast Energy Authority

We have audited, in accordance with the 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 (*Government Auditing Standards*), the financial statements of Redwood Coast Energy Authority (the RCEA), which comprise RCEA's statement of net position as of June 30, 2026, and the related statements of revenues, expenses, and changes in net position, and cash flows for the year then ended, and the related notes to the financial statements, and have issued our report thereon dated September 25, 2026. Our report includes an emphasis of matter paragraph because of the adoption of the provisions of GASB Statement No. 103, *Financial Reporting Model Improvements*, effective July 1, 2025. Our report is not modified because of this matter.

Report on Internal Control Over Financial Reporting

In planning and performing our audit of the financial statements, we considered RCEA's internal control over financial reporting (internal control) as a basis for designing audit procedures that are appropriate in the circumstances for the purpose of expressing our opinion on the financial statements, but not for the purpose of expressing an opinion on the effectiveness of the RCEA's internal control. Accordingly, we do not express an opinion on the effectiveness of RCEA'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 was for the limited purpose described in the first paragraph of this section and was not designed to identify all deficiencies in internal control that might be material weaknesses or significant deficiencies and therefore, material weaknesses or significant deficiencies may exist that were not identified. We identified certain deficiencies in internal control, described in the accompanying schedule of findings and questioned costs as items 2026-001, that we consider to be material weaknesses.

Report on Compliance and Other Matters

As part of obtaining reasonable assurance about whether RCEA'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 financial statements. 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*.

RCEA's Response to Finding

Government Auditing Standards requires the auditor to perform limited procedures on RCEA's response to the finding identified in our audit and described in the accompanying schedule of findings and questioned costs. RCEA's response was not subjected to the other auditing procedures applied in the audit of the financial statements and, accordingly, we express no opinion on the response.

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.

Baker Tilly US, LLP

Madison, Wisconsin
September 25, 2026

**Independent Auditors' Report on
Compliance With Aspects of Contractual Agreements and
Regulatory Requirements for Electric Borrowers**

To the Board of Directors of
Redwood Coast Energy Authority

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 accompanying financial statements of Redwood Coast Energy Authority (RCEA), as of June 30, 2026 and the related notes to the basic financial statements, which collectively comprise RCEA's financial statements as listed in the table of contents and have issued our report thereon dated September 25, 2026. In accordance with *Government Auditing Standards*, we have also issued our report dated September 25, 2026, on our consideration of RCEA'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. No reports other than the reports referred to above have been furnished to management.

In connection with our audit, other than the item noted below, nothing came to our attention that caused us to believe that RCEA failed to comply with the terms, covenants, provisions or conditions of their loan, grant and security instruments as set forth in 7 CFR Part 1773, *Policy on Audits of Rural Utilities Service Borrowers*, §1773.33 and clarified in the RUS policy memorandum dated February 7, 2014, insofar as they relate to accounting matters as enumerated below. However, our audit was not directed primarily toward obtaining knowledge of noncompliance. Accordingly, had we performed additional procedures, other matters may have come to our attention regarding the RCEA's noncompliance with the above-referenced terms, covenants, provisions or conditions of the contractual agreements and regulatory requirements, insofar as they relate to accounting matters. In connection with our audit, other than the finding 2026-001 noted below, we noted no matters regarding RCEA's accounting and records to indicate that RCEA did not:

- Maintain adequate and effective accounting procedures;
- Utilize adequate and fair methods for accumulating and recording labor, material and overhead costs and the distribution of these costs to construction, retirement and maintenance or other expense accounts;
- Reconcile continuing property records to the controlling general ledger plant accounts;
- Clear construction accounts and accrue depreciation on completed construction;
- Record and properly price the retirement of plant;
- Seek approval of the sale, lease or transfer of capital assets and disposition of proceeds for the sale or lease of plant, material or scrap;
- Maintain adequate control over materials and supplies;

- Prepare accurate and timely Financial and Operating Reports;
 - See finding 2026-001
- Obtain written RUS approval to enter into any contract for the management, operation or maintenance of the borrowers' system if the contract concerns all or substantially all of the electric system;
- Disclose material related-party transactions in the financial statements, in accordance with requirements for related parties in generally accepted accounting principles;
- Record depreciation in accordance with RUS requirements (See RUS Bulletin 183-1, Depreciation Rates and Procedures);
- Comply with the requirements for the detailed schedule of deferred debits and deferred credits; and
- Comply with the requirements for the detailed schedule of investments.

This report is intended solely for the information and use of the Board of Directors, management and the RUS and supplemental lenders and is not intended to be and should not be used by anyone other than these specified parties. However, this report is a matter of public record and its distribution is not limited.

Baker Tilly US, LLP

Madison, Wisconsin
September 25, 2026

**Financial Statement Findings Required to Be Reported in Accordance With
Government Auditing Standards**

Finding 2026-001: Material Weakness - Internal Control Over Financial Reporting

Criteria: Management is responsible for establishing and maintaining effective internal control over financial reporting, including controls over the preparation and fair presentation of financial statements in accordance with accounting principles generally accepted in the United States of America. A material weakness is a deficiency, or combination of deficiencies, in internal control such that there is a reasonable possibility that a material misstatement of the financial statements will not be prevented, or detected and corrected, on a timely basis.

Condition: RCEA does not currently have internal resources sufficient to prepare a complete set of annual financial statements, including the related note disclosures, in accordance with generally accepted accounting principles. Accordingly, we assisted with the preparation of RCEA's annual financial statements and related notes. In addition, material adjusting entries were identified and proposed during the audit.

Cause: RCEA's current staffing resources do not provide sufficient capacity and financial-reporting expertise to prepare a complete set of GAAP financial statements and related disclosures and to ensure that material year-end adjustments are identified prior to the audit.

Effect: The absence of effective controls over the year-end financial reporting process increases the risk that a material misstatement or required disclosure could be omitted from the financial statements and not be detected and corrected on a timely basis.

Recommendation: We recommend that RCEA evaluate its year-end financial reporting process and determine whether additional internal or external resources are appropriate to assist management in preparing and reviewing a complete set of GAAP financial statements and related disclosures. We also recommend that RCEA strengthen its review of year-end general ledger balances and significant financial statement adjustments to reduce the risk of material misstatements remaining unidentified prior to the audit.

Management's Response: RCEA's Finance Manager prepares monthly budget to actual reports for Department managers. The Director of Business Planning and Finance prepares monthly financial reports for the RCEA Board of Directors, including a year-to-date actual report compared to budget. The Director of Business Planning and Finance also prepares a quarterly Budget Update Report that includes a summary of revenues and expenditures and calls out any significant deviations. The Board takes action to approve the financial and budget reports at its monthly meeting. Due to staffing constraints, we anticipate continued assistance from RCEA's auditors to prepare the complete annual financial statements based on information provided by RCEA staff.



Staff Report

Agenda Item # 6.1

Information

Agenda Date	October 22, 2026
To	Board of Directors
Prepared by	Stephen Kullmann, Director of Customer Programs Richard Engel, Director of Power Resources
Subject	Overview of Distributed Energy Resources and Virtual Power Plants

Summary

In response to interest expressed by Board members, staff will provide a presentation on distributed energy resources and virtual power plants, and potential opportunities for RCEA in this topic area.

Equity Impacts

None - this item is information only.

Alignment with RCEA's Strategic Plan

This topic relates to numerous strategies in RCEA's strategic plan. Chief among them:

2.1.5 Integrate Distributed Energy Resources. Develop and implement customer programs that support, promote and integrate distributed energy resources, including but not limited to grid-connected generation, energy storage, energy efficiency, electric vehicle and demand response technologies.

2.1.6 Integrate a Distributed Energy Resource Management System. Support the development and installation of systems needed for effective and responsive management of distributed energy resources. Evaluate the potential integration of distributed energy resources into a unified system that would allow RCEA to aggregate and automate demand response activities

2.3.1 Implement Demand Response and Distributed Energy Resource Programs. Support and prioritize demand response programs that offer customers a role in balancing energy usage with the availability of electricity on the grid. Demand response programs and offerings will, where possible, integrate with distribution-connected efficiency systems and controls, renewable energy generation, and energy storage measures. Where feasible, energy technologies will be controllable and integrated as a distributed resource; any such efforts will require customer education and approval and will be implemented with a commitment to respecting and protecting customers' rights to privacy.



2.3.2 Support Reduced Energy Use During Peak Hours and Peak Event Days. Notify, support, and enable action from customers who choose to participate by shifting energy usage to off-peak hours, reduce daily energy usage during peak hours, and/or reduce energy usage during peak event days.

2.3.3 Enable Automated Demand Response. Install communicable controls with electrification, efficiency, and storage technologies that automatically reduce energy use during demand response events. Implement building demand response systems that allow for the curtailment of loads without major impacts to occupants and operations.

Financial Impact

As no board action is requested on this item, there is no associated financial impact.

Staff Recommendation

None – information only.

Attachments

- *The ABCs of VPPs: An Introduction to Virtual Power Plants* from Clean Energy States Alliance

Informational slides on this topic will be presented to the Board at the meeting.



The ABCs of VPPs

An Introduction to Virtual Power Plants

Adam Warren | Clean Energy States Alliance
September 2026



ABOUT THIS REPORT

This paper was produced by the Clean Energy States Alliance (CESA) to help state officials, as well as other stakeholders, understand what virtual power plants (VPPs) are and how they can be optimally designed.

This report was produced by CESA as part of the VPP Acceleration Initiative. The Initiative helps states, local governments, communities, and financial institutions deploy and scale VPPs—advancing affordability, strengthening resilience and grid reliability, and supporting decarbonization. This initiative is led by CESA, Clean Energy Group (CEG), and World Resources Institute (WRI). For more information about this effort and to browse related resources, visit www.cesa.org/projects/vpp.

ABOUT THE AUTHOR

This report was written by Adam Warren, PhD, for CESA. Adam serves as a Senior Advisor at Luminate LLC, a management consultancy providing engineering, commercial, and environmental services to the power, energy, and renewables markets. Previously, he was a Center Director at the National Renewable Energy Laboratory (NREL), where he worked to address technical and policy barriers to the energy transition. He also served as the founding co-Director of the Advanced Energy Systems graduate program at the Colorado School of Mines, a joint initiative with NREL that has graduated more than 100 MS and PhD students. He has a PhD in chemical engineering from McMaster University.

ACKNOWLEDGEMENTS

Review and input for this paper was provided by Bernard Birikorang, Bekenstein Climate Leaders Scholar, Yale University; Nate Hausman, Warren Leon, Todd Olinsky-Paul, and Samantha Donalds of CESA; Marriele Mango, Clean Energy Group; Sonali Razdan, Voltus; Jennifer Tribble, WRI US Polsky Energy Center; and Kyle Wallace, Sunrun.

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GLOSSARY OF TERMS

Advanced distribution management system (ADMS)

Utility software used to monitor and manage distribution grid operations.

Aggregator

An entity that enrolls and coordinates many distributed resources to provide grid services.

Application programming interface (API)

A defined way for software systems to exchange information.

Baseline

An estimate of what electricity use would have been without a VPP event, often used to measure load reduction.

CTA-2045 / EcoPort

A standardized appliance communication interface, often discussed for water heaters and other controllable appliances.

Demand response

An energy management strategy where electricity consumers reduce or shift their power use during periods of high demand or grid stress.

Demand response management system (DRMS)

Software used to manage demand response programs.

Distributed energy resource (DER)

A small-scale resource connected to the distribution system or located behind a customer meter, such as solar, storage, EV charging, or flexible load.

Distributed energy resource management system (DERMS)

Software used to monitor, forecast, dispatch, and measure distributed energy resources.

Dispatch

An instruction to use enrolled devices to provide a grid service at a particular time.

Feeder

A distribution circuit that delivers electricity from a substation to customers.

Gateway

Hardware or software that bridges two systems or networks that do not naturally communicate with each other.

Home energy management system (HEMS)

Hardware or software that coordinates energy devices in a home.

Interoperability

The ability of different devices, platforms, and systems to exchange information and work together.

Measurement and verification

The process of determining what a VPP actually delivered during an event or market interval.

Non-wires alternative

A resource or program, such as storage or demand flexibility, used to defer or avoid traditional wires-based grid upgrades.

OEM cloud

A cloud platform operated by the original equipment manufacturer of a device.

OpenADR

A standard for automated demand response event messaging.

Opt-out

A customer's ability to decline participation in a specific event or withdraw from a program under defined rules.

Override authority

The utility's ability to limit, cancel, or modify a VPP dispatch to protect safety or reliability.

Reserve margin/backup reserve

The portion of a battery kept available for customer backup power rather than discharged during a VPP event.

Supervisory control and data acquisition (SCADA)

Utility systems used to monitor and control grid equipment.

Settlement

The process of calculating payments or credits after performance has been measured.

Site controller

Hardware or software at a site that translates VPP instructions into device-level actions.

Telemetry

Operational data sent from devices or platforms, such as load, output, availability, and state of charge.

Virtual power plant (VPP)

A coordinated portfolio of distributed energy resources that can be operated together to provide grid services.

INTRODUCTION

The electric grid is changing more quickly than it has in decades. Rising demand, rapid electrification, distributed energy adoption, reliability concerns, and cost pressures are forcing states and utilities to look for new ways to expand grid capability. Virtual power plants (VPPs)—aggregations of small, behind-the-meter energy resources—can help support rapid, economic, reliable, and equitable grid growth by coordinating customer-sited resources so they can reduce demand, shift energy use, integrate and optimize renewable energy, and support the grid when needed, all while providing cost savings and backup power to businesses and residences. The U.S. Department of Energy (DOE) has framed VPPs as a near-term resource for meeting load growth and reducing grid costs. Based on the idea that VPPs could serve 10-20 percent of projected future U.S. peak demand, DOE estimates VPP capacity could grow from roughly 33 GW today to 80 to 160 GW by 2030.¹

A VPP becomes a dependable grid resource when its benefits become visible, dispatchable, measurable, monetizable, secure, customer-protective, and useful to the grid.

This paper explains how VPPs operate and why communications and standards are central to their success. VPPs are not simply collections of distributed energy resources. They are coordinated operating systems for flexible demand, storage, and distributed generation. Their value depends on whether customers, devices, aggregators, utilities, and markets can communicate reliably, protect customer choices, verify performance, and operate under clear rules. For state energy agencies, a central challenge is to help create the technical, regulatory, and programmatic conditions that allow VPPs to develop, access markets, and realize their potential as dependable grid resources.

A VPP helps the grid by coordinating many smaller customer-sited (behind-the-meter) resources so they can act together as a flexible grid resource. These customer-sited resources may include batteries, electric vehicles and chargers, smart thermostats, water heaters, rooftop solar paired with storage, building controls, and flexible commercial loads, among others. These technologies are often called distributed energy resources (DERs) because they are located at homes and businesses rather than at a central power station.

¹ Sonali Razdan, Jennifer Downing, and Louise White, *Pathways to Commercial Liftoff: Virtual Power Plants—2025 Update*, U.S. Department of Energy, January 2025, www.smartenergydecisions.com/wp-content/uploads/2025/04/liftoff_doe_virtualpowerplants2025update.pdf.



VPPs can provide valuable services to a utility or wholesale energy market. These services may include reducing peak demand, shifting energy use, discharging stored energy, relieving local grid constraints, providing ancillary market services such as frequency regulation, and deferring traditional grid investments such as poles-and-wires or substation expansion. Importantly, VPPs can benefit the enrolled customers, providing revenue and energy cost savings during business-as-usual conditions, and in many cases, backup power during grid outages; and they reduce costs for ratepayers by providing lower-cost grid services that displace higher-priced resources.

To achieve all this, VPPs require clear operating rules. Before a single customer is enrolled, some basic questions need to be answered. These include who enrolls customers, who sends dispatch instructions, who controls the enrolled devices, who measures performance, who pays whom and on what basis, and who can override dispatch for reliability or safety, or to accommodate resiliency needs. Program design choices such as resource ownership, compensation, eligible technologies, contract duration, dispatch methods, and affordability provisions strongly shape the operating model.²

The main takeaways for state energy agencies are straightforward: VPP scale depends less on technology breakthroughs than on trusted communication among devices, customers, aggregators, utilities, markets, and regulators. Standards can reduce integration costs and make programs more repeatable. Embedding equity components in VPP program rollout and design can help ensure public support and widespread adoption. VPPs also need customer protections, cybersecurity plans, performance measurement, data governance, and compensation rules that are clear enough for customers, utilities, aggregators and market operators to rely on.

2 Todd Olinsky-Paul, *Program Design for Battery-Based Virtual Power Plants*, Clean Energy States Alliance, February 2026, www.cesa.org/resource-library/resource/bvpp-program-design.

The basics: what a VPP is and why it matters

WHAT IS A VIRTUAL POWER PLANT?

A virtual power plant is a coordinated group of distributed energy resources that can be operated together to provide grid services. It is “virtual” because the resources are spread across many homes, businesses, buildings, vehicles, and devices rather than located at a single power plant. The word “plant” can be misleading because a VPP is less a physical facility than an operating model: software, communications, customer agreements, and control systems allow many small resources to respond as one coordinated portfolio, a single “virtual power plant.”

VPPs build on the long history of demand response (DR), but they are not limited to traditional DR programs, which typically pay large utility customers to reduce load during a limited number of peak events. A VPP can do that, but it may also provide more active, measured, and coordinated services; in some cases, VPPs export power to the grid. As VPP programs grow in sophistication, they become more automated, more location-responsive, and more tightly integrated with utility operations.³

Table 1: **DR, DERs, and VPPs Are Related but Distinct Concepts**

	Demand Response (DR)	Distributed Energy Resources (DERs)	Virtual Power Plants (VPPs)
What is it?	A program, service, or strategy that changes electricity consumption in response to grid conditions or price signals	Physical technologies that generate, store, manage, or shift electricity use at customer sites or on the distribution system	A coordinated aggregation of DERs that can be managed and dispatched as a single grid resource
Examples	Smart thermostat programs, managed electric vehicle (EV) charging, commercial load curtailment, peak demand programs	Rooftop solar, battery storage, EVs, smart thermostats, water heaters, backup generators	Networks of batteries, EVs, thermostats, water heaters, and other DERs operating together
Physical asset?	No	Yes	No
Shifts the timing of electricity use?	Yes	Sometimes	Often
Can generate electricity?	No	Sometimes	Sometimes (through participating DERs)

CONTINUED

3 Angela Long, Ryan Long, and Natalie Mins Frick, *Virtual Power Plant Profiles and Inventory*, Lawrence Berkeley National Laboratory, January 2025, https://eta-publications.lbl.gov/sites/default/files/2025-03/vpp_profiles_and_inventory_singl-pgs_fnl_3-25_rev.pdf.

Table 1: **DR, DERs, and VPPs Are Related but Distinct Concepts** (CONTINUED)

	Demand Response (DR)	Distributed Energy Resources (DERs)	Virtual Power Plants (VPPs)
Can reduce or shift demand?	Primary purpose	Sometimes	Common capability
Requires coordination across many customers?	Sometimes	Not necessarily	Yes
Can provide grid services?	Yes	Potentially	Primary purpose
Can participate in wholesale markets?	Limited	Generally not on its own	May be designed to do so
Primary value proposition	Provides flexible demand that can help balance the grid	Produces, stores, or manages energy at a specific location	Combines many distributed resources into a reliable, dispatchable grid resource
What it is NOT	Not a technology or device	Not necessarily coordinated with other resources	Not a single technology or device

DR refers to programs that change electricity consumption; DERs are the underlying technologies that can produce, store, or manage energy; and VPPs coordinate multiple DERs to provide services to customers, utilities, grid operators, and wholesale markets.

WHY DO VPPS MATTER NOW?

States, utilities and grid operators are facing multiple pressures at once: rising electricity demand, electrification, data center growth, distribution system investment needs, reliability concerns, increasing extreme weather events and associated grid outages, and the need to integrate more variable renewable generation. VPPs offer an important way to expand grid capability without relying only on new centralized infrastructure. They can use resources that customers are already installing for bill savings, backup power, mobility, or comfort, and coordinate those resources to provide value to the wider grid. VPPs can support equity goals too, since resource investment and associated savings can support customers and communities experiencing high energy burdens. And investing in VPPs means investing in the community rather than utility- or corporate-owned infrastructure.

A VPP is a coordinated portfolio of customer-sited resources that can reduce, shift, store, or supply electricity when the grid needs help.



Over the past decade, VPP programs have spread rapidly. Battery-based VPPs are now active in the majority of U.S. states and Puerto Rico, and more are being developed by state energy agencies and utilities.⁴

Notable active VPP programs include:⁵

- In Vermont, utility Green Mountain Power has created one of the most successful VPP programs, with more than 10,000 batteries behind residential meters to provide peak demand reduction and frequency regulation.
- The California CalReady program aggregates more than 56,000 residential customers, with 75,000 batteries and solar+storage systems providing peak demand reduction, resource adequacy, and emergency reliability support; this system provides up to 375 MW of peak capacity.
- Also in California, the Peak Power Rewards program aggregates 8,500 residential solar and storage customers of the utility PG&E for peak demand reduction and summer reliability. This program provided 27 MW over more than 90 consecutive days and instantaneous peak output near 32 MW during the first season.
- The North Carolina PowerPair program aggregates up to 6,000 residential solar+storage systems in Duke Energy's territory for peak demand reduction, grid support, and emissions reduction.
- The Arizona SRP Battery Partner program aggregates up to 5,000 residential customers for peak demand reduction and emergency demand response.
- In Texas, the ERCOT Aggregate Distributed Energy Resource Pilot aggregates batteries, solar+storage, electric vehicle (EV) chargers, smart thermostats, flexible commercial loads, and distributed generation for wholesale market participation, energy, ancillary services, and grid support.
- In Massachusetts, the ConnectedSolutions VPP program was recently expanded; in addition to tapping behind-the-meter (BTM) batteries, thermostats, water heaters, EV chargers and other connected devices for peak demand reduction,

VPPs sit at the intersection of technology, utility regulation, customer programs, energy equity, cybersecurity, and market design. State energy agencies can help make those aspects understandable and actionable.

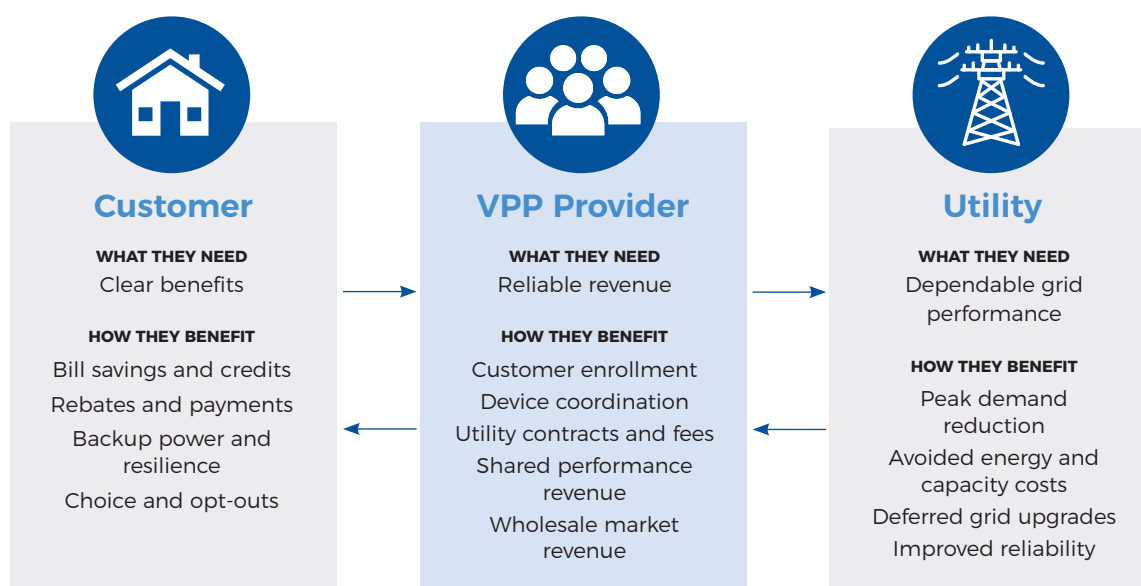
4 "Virtual Power Plant Programs Summary Table," Clean Energy States Alliance, accessed September 2026, www.cesa.org/resource-library/resource/virtual-power-plant-programs-summary-table.

5 Ibid.

the program now includes locational adders for enrollees that can provide local distribution grid benefits (distribution investment deferral).

Clearly, VPPs are no longer theoretical—they're up and running in at least 30 states. Given the rapid spread of VPPs, the questions state energy agencies developing a program need to ask are increasingly concrete: what services should VPPs provide in their state, who will be able to participate, how will participants be compensated, how will performance be measured, and what rules are needed to make the program scalable?⁶

Figure 1: **How VPP Value Can Flow Between Participants**



VPPs create optimal value when benefits and obligations are aligned across customers, providers, and utilities.

6 Olinsky-Paul, *Program Design for Battery-Based Virtual Power Plants*.

Who participates and what happens when a VPP operates

WHO PARTICIPATES IN A VPP?

A working VPP depends on coordinated action among several groups. Customers provide access to BTM energy resources and receive value through payments, bill savings, backup power, resilience, or participation in a community reliability effort. Device manufacturers and installers provide the hardware, software, apps, and cloud interfaces that make devices controllable. Aggregators or VPP providers enroll customers, connect devices, forecast available flexibility, dispatch resources, measure performance, and manage compensation. For some VPP programs, utilities aggregate

Figure 2: **Who is Involved in a VPP and What Do They Do?**

Role	Who They Are	What They Do
 VPP Provider/Aggregator	The entity that coordinates distributed resources into a single, dispatchable resource	- Recruit and enroll resources - Forecast availability and grid needs - Dispatch resources and optimize performance - Settle payments and manages incentives
 Resource Owner	The individual or organization that owns the DER (such as solar, storage, EVs, or smart thermostats)	- Own and maintain the DER - Authorize participation of the DER in the VPP - Receive incentives or bill savings in return
 Host Customer	The customer site or facility where the DER is located	- Host the DER on their premises (e.g., home business, or community facility) - Agree to allow the VPP to dispatch the DER when needed - Experience reliability and cost benefits from participation
 Device/Asset Manufacturers (OEMs)	Companies that design and manufacture DER technologies and equipment	- Build reliable, secure, and interoperable DER devices - Ensure product performance, safety, and standards compliance - Enable integration with VPP platforms and systems
 Software/Platform Providers	Companies that provide the software platforms, controls, and analytics that enable VPPs	- Provide VPP platforms, controls, and data analytics - Ensure secure communication and interoperability - Support operations, optimizations, and reporting
 Utility/Grid Operator	Entities responsible for operating the grid and serving customers	- Procure VPP services (e.g., capacity, peak reduction, reliability) - Integrate VPPs into grid operations and planning - Ensure reliability, safety, and compliance

CONTINUED

Figure 2: **Who is Involved in a VPP and What Do They Do?** (CONTINUED)

Role	Who They Are	What They Do
 Regulators/ Policymakers	State and federal agencies that set rules, policies, and market frameworks	- Establish rules for participation and compensation - Ensure consumer protection and equitable access - Enable innovation through policy and regulatory frameworks
 Financiers/ Investors	Lenders, investors, and financing institutions that fund DERs and VPPs	- Provide capital for DERs and VPP platforms - Assess risk and support bankable project structures - Enable innovative financing models

resources; in other programs, device manufacturers or installers serve as aggregators; in still others, aggregators are third parties.

Utilities identify grid needs, define operating limits, request events, verify performance, and may require visibility or override authority to protect the distribution system. Depending on the market and regulatory structure, utilities may procure VPP services, operate or coordinate with VPP aggregators, and integrate VPP resources into distribution system planning and operations. They can manage peak demand, provide capacity and other grid services, defer or avoid infrastructure investments, and improve system reliability and resilience with VPPs. Market operators may enable qualified aggregations to participate in energy, capacity, ancillary service, or other markets. State energy offices, regulators, and program administrators shape program design, customer protections, eligibility rules, incentives, reporting, and equity requirements.

The more clearly the different roles are defined, the easier it is for VPP programs to succeed and grow.

WHAT HAPPENS WHEN A VPP IS DISPATCHED?

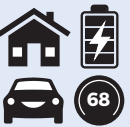
A VPP becomes useful to the grid when it can respond to a specific need. That need may be a summer peak, a winter reliability concern, a local distribution constraint, a high wholesale price period, or an emergency generation shortfall. Dispatch is the process of activating the VPP to respond to a grid need through coordinated action across many enrolled devices.⁷

A typical event begins when a utility, market operator, program administrator, or VPP provider identifies a system or market need and sends a request to the VPP provider

7 VPPs can also add grid value when they are not being dispatched. For example, some VPPs compensate enrolled customers for maintaining devices in a “ready” state. This is similar to a traditional peaking generator that is paid for capacity, even if it is not called upon to deliver electricity.

or aggregator. Depending on the VPP program, these events may be predefined and automated or up to the discretion of the utility or market operator. The VPP platform then checks which devices are available and applies practical limits: customer opt-outs, battery reserve settings, thermostat comfort bands, electric vehicle charging needs,

Figure 3: **What Happens During a VPP Event?**

	What Happens	When Does This Happen
1  Forecast and Planning	The utility identifies an upcoming grid event, such as a summer peak, local reliability issue, or emergency shortage, which means the grid needs support.	 Days or hours ahead of the grid event
2  Event Call	The utility or grid operator sends a dispatch request to the VPP aggregator, with details about the timing, location duration, and requested response.	 Pre-dispatch
3  Availability Check	The VPP aggregator checks which devices are available, with regard to customer opt-outs, device settings, and comfort settings.	 Pre-dispatch
4  Device Response	Devices support the grid by reducing demand or providing power during the grid event (e.g., batteries discharge, EV charging shifts, thermostats adjust, water heaters pause).	 During the grid event (high demand, grid instability)
5  Telemetry and Monitoring	Operational data shows whether the portfolio is responding as expected.	 During and after grid event
6  Measurement and Verification	Performance is measured and results are tracked, reported, and used to determine payments.	 After event
7  Settlement Period	Participating customers, aggregators, or providers receive payments, bill credits, or other compensation.	 After event
8  Program Review	Program administrators review outcomes, customer experience, equity metrics, and operational lessons.	 After event

A VPP event is a step-by-step process of coordinating customer-hosted devices to respond to grid needs while ensuring consumer protections and performance verification.

and device operating constraints. Dispatch instructions move through the communication chain to devices. This can mean discharging batteries, slowing the charging of EVs, adjusting thermostats, pausing water heating, or shifting flexible building loads. After the event, telemetry and meter data are used to verify performance and settle payments.

A VPP dispatch event is a chain of actions: request, availability check, customer protections, device control, telemetry, verification, and payment.

Most VPPs follow a similar sequence of activities before, during, and after a dispatch event. The timeline in Figure 3 illustrates the typical operational flow, from customer enrollment and event forecasting through dispatch, performance verification, compensation, and program evaluation.

VPP CASE STUDY

Puerto Rico's Customer Battery Energy Sharing Program

Puerto Rico's Customer Battery Energy Sharing program provides a concrete example of how dispatch works. LUMA, the company responsible for operating Puerto Rico's electric grid, forecasts grid events based on expected capacity shortfalls, notifies aggregators, and participating customer batteries discharge stored energy first to the customer's home or business to reduce demand, and then to the grid to supplement supply. Aggregators manage customer enrollment and event communications, and customers retain important choices such as backup reserve settings and the ability to opt out of individual events. Participating customers are compensated through their aggregator. LUMA pays each aggregator \$1.25 per kilowatt-hour based on the amount of energy delivered during a grid event, but each aggregator determines customer compensation. LUMA tries to provide day-ahead dispatch, but sometimes the dispatch signal is sent only hours or minutes ahead; fast and accurate communications are essential to allow the VPP to respond.⁸ The Customer Battery Energy Sharing program grew from 3,440 customers in March 2024 to more than 90,000 customers providing an average of 75 MWs of grid support during events two years later. Currently, seven aggregators have been approved by LUMA to participate in the program.⁹ This case study shows why customer communication is part of VPP operations, not an optional add-on.

8 Hanna Jones, *Lessons Learned from Puerto Rico's First Virtual Power Plant*, Clean Energy States Alliance, February 2026, www.cesa.org/resource-library/resource/puerto-rico-virtual-power-plant.

9 "Customer Battery Energy Sharing," LUMA Energy, accessed August 2026, <https://lumapr.com/battery-demand-response/?lang=en>.



The VPP technology stack

WHAT ARE THE MAIN TECHNOLOGY LAYERS IN A VPP?

VPPs are easier to understand when they are broken into layers. Although not all programs use exactly the same architecture, most include four basic layers: the grid-edge asset layer, the site or gateway layer, the aggregation and orchestration layer, and the utility or market interface layer.

Grid-edge or asset layer

The grid-edge layer is made up of the physical resources that actually change electricity use, generate or store energy, or export power. Examples include home batteries, EV chargers, smart thermostats, water heaters, solar inverters, building controls, and flexible commercial or industrial loads. This is where value is created: a battery discharges, an EV charger slows, a thermostat adjusts, or a building reduces demand.

Site, gateway, or device-cloud layer

The site or gateway layer translates VPP instructions into device-specific actions. This layer may include a home energy management system, a building energy management system, an inverter platform, a charger management system, a communications gateway, or a manufacturer's cloud platform. It is also where customer preferences are often enforced, including thermostat comfort bands, battery backup reserve settings, charging needs, and opt-out choices.

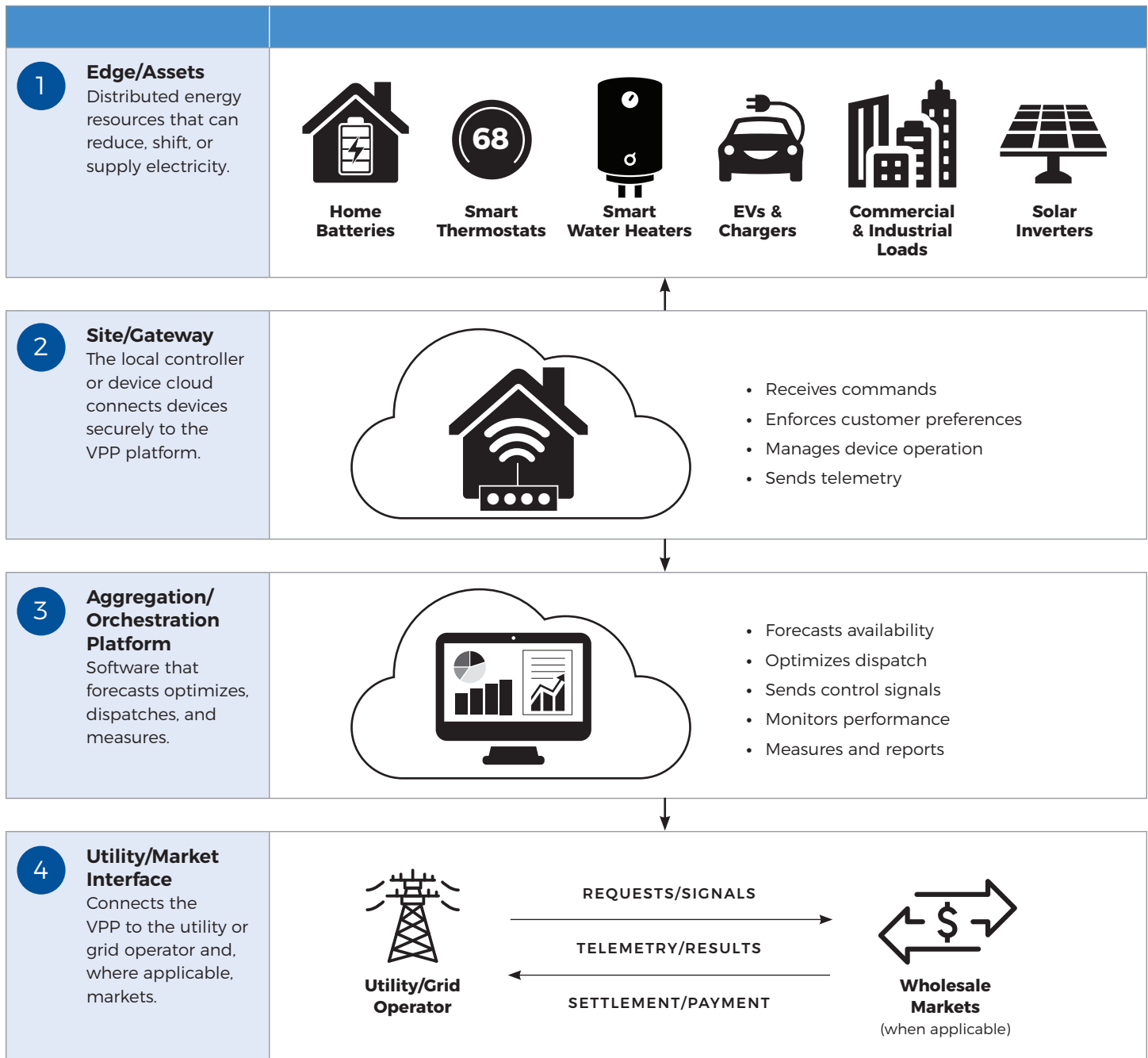
Aggregation and orchestration layer

The aggregation and orchestration layer is the software layer that turns many separate devices into a coordinated portfolio. It forecasts availability, estimates response uncertainty, decides which resources to dispatch, sends control signals, monitors performance, and performs measurement and verification. This layer is often called a VPP platform or a distributed energy resource management system (DERMS).

Utility and market interface layer

The utility and market interface layer is where the VPP interacts with the utility or aggregator. Utility-facing functions may include managing distribution constraints, issuing event calls, exercising override authority, providing operational visibility, and reporting performance. Market-facing functions may include submitting bids, receiving dispatch instructions, exchanging telemetry and metering data, and supporting settlement.

Figure 4: **What Are the Main Components of a VPP?**



Most VPPs can be explained as four connected layers, supported by cybersecurity, privacy, and interoperability.



WHAT INFORMATION IS SHARED IN A VPP?

VPPs depend on trusted information exchange. Customer and enrollment information establishes who is participating, which devices are enrolled, what the customer has agreed to, and how the customer can withdraw or opt out. Device information may include battery state of charge, inverter status, charger availability, thermostat settings, water heater status, reserve preferences, or other operating data. Grid and market information may include event calls, price signals, feeder constraints, dispatch instructions, operating limits, telemetry requirements, and settlement rules.

Performance and financial information are also essential. Utilities, aggregators, and market operators need to know how much load was reduced, how much energy was exported, whether the resource followed the dispatch instruction, and whether customers opted out. Settlement then depends on the terms of the customer contract or tariff, and the performance of the enrolled resources.

Different parties need different data. Customer data should be shared only with the parties that need it, and only to the degree necessary for them to perform their defined role. A utility may need enough visibility to operate safely and verify performance, but that does not mean every party needs full customer-level data.



Communications, standards, and trust

HOW DO DEVICES ENROLLED IN VPPS COMMUNICATE?

VPP communication is layered and often hybrid. A device may communicate through a manufacturer app or cloud, a site controller, a gateway, a charger network, an aggregator platform, a utility demand response system, or a DERMS. Some communication is direct, but much of it passes through vendor clouds or aggregators.

The utility usually does not send a command directly to every enrolled thermostat, battery, or EV charger in a VPP. Instead, the utility or market signal moves through a chain of systems that translate the grid need into device-level action. Performance data then flows back through the chain for monitoring, measurement, verification, and settlement.

Effective device communication enables a VPP to respond quickly and accurately during emergencies, allows performance to be measured, and is key to making the VPP a reliable and responsive resource for the utility, aggregator or grid operator to call upon.

WHAT ARE STANDARDS, AND WHY DO THEY MATTER?

A standard is a shared specification for how technologies or organizations interact. Standards do not make every device the same; they make it easier for different devices, platforms, utilities, and markets to work together. They also enable competition, allow for a variety of products to enter the marketplace, simplify troubleshooting, and reduce administrative burdens. A simple analogy is a common phone charger. The charger does not make every phone identical, but it reduces friction by making connection safer, more predictable, and less expensive.

Similarly, VPP communications benefit from standardization. A VPP may include batteries, EV chargers, thermostats, water heaters, inverters, commercial building systems, manufacturer clouds, aggregator platforms, utility systems, and wholesale market systems. If every connection is custom, costs go up, reliability goes down, and the program becomes harder to replicate. Standards can reduce integration costs, improve interoperability, support cybersecurity, make performance easier to verify, and allow more vendors to participate. With standards, VPPs become more repeatable, financeable, interoperable, and scalable.



The standards landscape is not a single solution; it is a mix of interconnection rules, communications protocols, information models, EV charging standards, distribution services contracts, certification efforts, and cybersecurity frameworks. No single standard governs the full VPP stack. Instead, near-term VPP deployment depends on a layered standards ecosystem. Some standards govern DER behavior at the grid edge. Some structure communications between utilities, aggregators, gateways, and devices. Some support demand response or EV charging. Others address the operating and commercial relationship between utilities and aggregators. The most important standards and coordination efforts are summarized in Figure 5 (p. 20).

WHAT MAKES A VPP LOOK LESS RISKY TO UTILITIES?

Because utilities are charged with the very important job of providing safe, reliable power to millions of customers—and because blackouts can be costly and life-threatening—utility managers tend to be risk-averse. New technologies, especially those not under the utility's direct ownership and control, can seem risky. Utilities may also have financial concerns about resources such as rooftop solar, which can reduce demand for utility-supplied electricity and alter traditional revenue and investment patterns. For these reasons and others, utilities have historically been slow to embrace innovative DERs such as DR, rooftop solar, and combined-heat-and-power (CHP) as solutions to grid constraints. Because VPPs have historically needed utility participation in order to function, a risk-averse utility posture can be a significant impediment to VPP development.¹⁰

To reduce utility perception of VPP risk, three concepts are especially important:

- **Visibility:** Can the utility see what the VPP is doing before, during, and after dispatch? This depends on telemetry quality, reporting speed, and integration with utility systems.
- **Schedulability:** Can the VPP respond when and how it is asked? A more mature VPP can follow shaped schedules, not just simple start-and-stop events.
- **Availability:** Can the VPP be counted on often enough to matter for planning and operations? A resource limited to a few hours on summer afternoons has less value than one available across seasons and longer event windows.¹¹

¹⁰ With the implementation of FERC Order 2222, which requires ISOs and RTOs to open wholesale energy markets to DER participation, VPP aggregators will increasingly be able to bypass utilities and bid VPP services directly into wholesale energy markets. However, much of the country operates outside of regional wholesale markets; and even within such markets, a utility contract for services may be a better deal for VPP participants than a wholesale market contract. Therefore, de-risking VPPs for utilities remains critical to VPP scale-up.

¹¹ *Building Trustworthy Virtual Power Plants: The VPP Market Maturity Model*, EnergyHub, 2026, www.energyhub.com/resource/building-trustworthy-power-plants-vpp-maturity-model

Figure 5: **The VPP Standards Mix**

Standard/Framework	Where It Applies	What It Does/Why It Matters for VPPs
 IEEE 1547	Grid interconnection point	Sets functional requirements for how DERs behave at the distribution grid interface , including voltage, frequency, ride-through, and interoperability. It helps ensure resources behave predictably when connected to the grid.
 IEEE 2030.5	DER communications	Provides a standardized internet-based communications protocol between utilities and DERs , especially smart inverters and gateways. It can reduce reliance on one-off integrations, though implementation still varies by utility and vendor.
 OpenADR	Demand response communications	Standardizes automated demand-response event messages from electricity providers to customers , including event timing, duration, and requested response. It is useful for event-based VPP programs, but is typically one part of a broader technology stack.
 IEC 61850-7-420	Utility operational systems	Provides standardized communication and information models for DERs, controllable loads, and energy-management systems. It is an international standard especially relevant to more complex, utility-grade integration.
 OCPP	EV charger network communications	Standardizes communication between EV chargers and charging-management systems . It supports managed EV charging and can reduce vendor lock-in at the charger-to-network interface.
 ISO/IEC 15118	EV-to-charger communications	Governs communication between the EV and charging equipment , including Plug & Charge and capabilities relevant to bidirectional charging. Unlike OCPP, it focuses on the vehicle-to-charger interface. This is an international standard.
 DOE/NAESB contract work	Utility/market contracting and coordination	Helps standardize contractual and business arrangements among aggregators, utilities, and other parties . It complements technical standards by addressing the commercial rules needed for VPP participation. Standardized contracting can help reduce soft costs.

VPPs rely on a variety of standards, which create a common language that lets different devices, aggregators, utilities, and markets work to communicate in different ways.

De-risking VPPs requires cybersecurity, performance verification, customer protections, operational testing, and clear rules for utility override authority. Aggregators can further reduce risk for the utility by bringing proprietary DERMS and experience with VPP operations. VPP value increases as programs move from simple event-based demand response toward more visible, schedulable, and grid-aware resources. Within the VPP technology stack, some technologies may be lower risk than others. For example, thermostats may carry relatively more risk because customer behavior is related to comfort.



If a house gets too hot, residents may turn up the air conditioning even though the utility has called a peak demand event. By comparison, batteries do not reduce customer comfort when they discharge, so customers are usually indifferent to whether the utility is discharging the battery.¹²

What makes a VPP look less risky to participants and other ratepayers?

Utility customers may also have a perception of risk when considering a VPP program. Customers may be hesitant to enroll for several reasons. Here are questions potential customers may have:

- **Economic risk:** What assurance is there that promised VPP program revenues will really materialize? Will revenues and cost savings add up to pay back my initial investment?
- **Trust and control issues:** If I enroll in a VPP, am I giving up control of my enrolled devices to the utility or aggregator? Will I really be able to opt out of events if I want to?
- **Knowledge gaps:** How does the VPP work? Are there hidden risks?

De-risking VPPs for participants requires information and transparency. Utilities, aggregators and developers all have a role to play, as do state policymakers and regulators, who are in a position to require consumer protections as part of VPP program development. Making enrollment contracts clear and easy to understand, providing examples of program economics, and answering customer questions can help reduce the perception of risk. In addition, utility regulators should ensure customers are getting a fair shake economically from VPP programs—both customers who enroll, and other ratepayers, who should not bear additional costs.

To reduce ratepayer risk perception, it is important to ensure the VPP will be cost-effective, and to identify and mitigate potential cost shifts from one group of ratepayers to another. Among the common cost-effectiveness tests used by states, the Ratepayer Impact Measure (RIM) test is useful to identify cost shifts between participating and non-participating customers.¹³

12 An exception to this is when a natural disaster, such as a winter storm, is anticipated and may cause grid power outages. In these cases, most VPP programs avoid calling on customer batteries, since customers will want fully charged batteries to help them ride through a grid outage.

13 For more information on cost-effectiveness tests, see: *Energy Storage Benefit-Cost Analysis: A Framework for State Energy Programs*, Applied Economics Clinic for the Clean Energy States Alliance, December 2022. www.cesa.org/resource-library/resource/energy-storage-benefit-cost-analysis-a-framework-for-state-energy-programs.



Program development implications for states

WHAT SHOULD STATE ENERGY AGENCIES ASK WHEN REVIEWING OR DEVELOPING A VPP PROGRAM?

VPP program development involves both technical and program design choices. Technical choices determine how efficiently and cost-effectively the VPP will function, how well it integrates with or supplements other resources, and how it minimizes risk. Program design choices determine what benefits and services the VPP provides, who participates, and how it interacts with other state energy programs. There will inevitably be some overlap between the technical and program design choices.

To make **technical choices**, state energy policymakers and regulators do not need to become protocol engineers. But they do need to ensure that a proposed VPP will meet minimum standards of performance, cost effectiveness, safety and security. Program design choices, such as device ownership, may have practical considerations for participants and other ratepayers. Some useful questions to ask include:

- How will cost-effectiveness be measured?
- Which resources and customers will be eligible to enroll?
- How will the system be dispatched?
- What telemetry will be used?
- What measurement & verification and settlement data are required?
- Are interfaces standards-based?
- Who is responsible for authentication, encryption, updates and incident response?
- What compensation/settlement mechanisms will be used?

Generally, **program design choices** depend on what the VPP is intended to accomplish. For this reason, CESA recommends that state agencies first set policy goals the VPP will support. Program design will then follow from those goals.

This is important because VPP programs will look different depending on what they are supposed to achieve. For example, if the policy goal is grid modernization and resilience, the VPP program may include proactive distribution grid planning, locational



incentives to advance non-wires solutions, and an emphasis on back-up power and community resilience hubs. If the goal is peak demand reduction, the program may include peak demand dispatch and incentives for longer-duration discharge. If the goal is decarbonization, the dispatch signal may be based on emissions peaks rather than demand peaks, may be coordinated with electrification programs, and may include mechanisms to support retirement of fossil fueled peaker plants.

Once the goals are clear, VPP program design involves answering a set of practical questions. These include:

- What grid services will the VPP provide?
- How will customer incentives be structured?
- How will customer contracts be structured?
- Who should own VPP assets, and who should have a voice in how they are used?
- How will equity/affordability be ensured?
- How will the economic and environmental benefits and burdens be shared across communities?
- What will be the role of third-party aggregators?
- Will the VPP export power to the grid, or just reduce load behind the meter?

These and other VPP program design elements, and emerging best practices, are discussed in CESA's publications *Program Design for Battery-Based Virtual Power Plants*¹⁴ and *Energy Storage Program Design for Peak Demand Reduction*.¹⁵ A summary table of VPP programs across the nation, with links to program pages and documents, can be found on CESA's website.¹⁶

VPP program design should flow from state policy goals, incorporating emerging best practices from existing programs.

14 Olinsky-Paul, *Program Design for Battery-Based Virtual Power Plants*.

15 Todd Olinsky-Paul and Olivia Tym, *Energy Storage Program Design for Peak Demand Reduction*, Clean Energy States Alliance, December 2024, www.cesa.org/resource-library/resource/energy-storage-program-design-for-peak-demand-reduction.

16 "Virtual Power Plant Programs Summary Table," Clean Energy States Alliance, accessed September 2026, www.cesa.org/resource-library/resource/virtual-power-plant-programs-summary-table.

Barriers and what comes next

WHAT TECHNICAL AND INSTITUTIONAL BARRIERS STILL SLOW VPP DEPLOYMENT?

Although VPP deployment is no longer limited by whether flexible devices exist, it remains limited by whether the ecosystem can operate them reliably at scale. Persistent barriers include fragmented device interfaces, proprietary application programming interfaces, inconsistent telemetry, limited distribution-system visibility, bespoke utility-aggregator contracts, unclear performance measurement and settlement rules, cybersecurity and data governance gaps, customer enrollment and retention challenges, equity and affordability barriers, gaps in institutional coordination, and uncertain rules for value stacking.

Distribution visibility is especially important. Many VPPs can reduce system peak, but fewer can reliably deliver distribution-level value on a specific feeder, substation, or transformer because locational mapping and real-time constraint data may be limited. This is one reason the field is moving from simple event-based portfolios toward more grid-aware VPPs.¹⁷

WHAT NEW DEVELOPMENTS SHOULD STATES MONITOR?

Several developments suggest that the field is becoming more mature. DOE's VPP Liftoff work frames VPPs as a near-term resource for load growth and grid cost management. Berkeley Lab's VPP profiles and inventory work provides a useful vocabulary for distinguishing basic, integrated, and more orchestrated VPP models. DOE and North American Energy Standards Board (NAESB) distribution services contract work is moving standardization beyond device protocols and into the utility-aggregator operating relationship.¹⁸

New technologies are also emerging. Key among these are plug-in solar, permissionless batteries, bidirectional EVs, and more sophisticated EV chargers. These technologies help to expand access to VPP participation—for example, by getting around the need for participants to own a home in order to install rooftop solar and residential-scale

17 Long et al, *Virtual Power Plant Profiles and Inventory*.

18 Razdan et al, *Pathways to Commercial Liftoff: Virtual Power Plants - 2025 Update*; Saumil Patel and Paul De Martini, *Standard Distribution Services Contract*, U.S. Department of Energy, November 2023, www.energy.gov/sites/default/files/2023-11/2023-11-15%20Standard%20Distribution%20Services%20Contract_optimized.pdf; Long et al, *Virtual Power Plant Profiles and Inventory*.



batteries—and also offer other benefits, such as portability and lower capital costs. As distributed energy technologies continue to advance, states should remain alert to opportunities to expand the VPP technology stack.

States should also watch the Mercury Consortium, IEEE P2030.14, OpenADR 3 and broader distributed energy coordination efforts; EV standards such as OCPP and ISO/IEC 15118; and stronger cybersecurity expectations. The common theme is that standardization is moving from device-level communication toward whole-program coordination: enrollment, consent, dispatch, telemetry, measurement, cybersecurity, contracts, and settlement.¹⁹

One big change underway in the VPP space is the implementation of Federal Energy Regulatory Commission (FERC) Order 2222 in ISO and RTO markets. Issued by FERC on September 17, 2020, Order 2222 requires regional grid operators to revise their market rules so that aggregated DERs can participate alongside traditional power plants in wholesale energy, capacity, and ancillary services markets. The primary goal of the order is open wholesale markets to DERs by removing longstanding participation barriers and enabling them to earn revenue through market participation, often as part of a VPP. While all ISOs and RTOs have submitted compliance filings to FERC, implementation remains uneven across regions, with market rules still being refined and rollout timelines extending over several years. Some regions have already begun opening wholesale market participation pathways for DERs, while others are still developing the market rules and processes needed to comply with Order 2222.

States should understand that, although Order 2222 is intended to open wholesale energy markets to aggregated distributed resources, this is not necessarily a sufficient replacement for state-designed and regulated VPPs. State-designed VPPs may provide a different set of benefits than DERs enrolled in wholesale market programs (for example, distribution grid support), may enroll a different set of technologies, and may offer different types of incentives and support to participating customers. From the customer perspective, contracting to provide services to their utility may be more beneficial and offer more protections than contracting to provide services in a regional market. Most importantly, wholesale energy markets are not designed to support state policy goals. For these reasons, when developing a VPP within a wholesale market, it will be important for state policymakers and regulators to determine how the program design should (or should not) align with changing wholesale market rules.

19 “FERC Order No. 2222: Fact Sheet,” Federal Energy Regulatory Commission, September 2020, www.ferc.gov/media/ferc-order-no-2222-fact-sheet; “Mercury Consortium,” Electric Power Research Institute, accessed August 2026, <https://msites.epri.com/mercury-consortium>.



CONCLUSION

Virtual power plants will scale faster when technical standardization and policy best practices combine to streamline program development and de-risk program operations. The decisive challenge is whether utilities, aggregators, device manufacturers, customers, regulators, and market operators can rely on repeatable technical and operational rules.

The goal is not just to enroll more devices. The goal is to make those devices visible, dispatchable, measurable, secure, customer-protective, and useful to the grid. This goal is advanced by the development and adoption of standards, certification profiles, emerging coordination efforts, emerging best practices, and DOE and NAESB utility-aggregator contract work. The next phase of VPP deployment will depend on connecting these pieces into a coherent model that is adoptable and adaptable to meet the needs of state policymakers, utilities, aggregators, and customers.



Row 1 (L-R): CESA; Resonant Energy; CESA; Bigstockphoto/DavidM199. Row 2 (L-R): Portland General Electric; CESA; Murray Carpenter/Maine Public. Row 3 (L-R): Orsted (US Offshore Wind); CESA; Solara/California Energy Commission; iStockphoto/Fotomax. Row 4 (L-R): Tom Piorkowski; CESA; Shutterstock/Soonthorn Wongsaita

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ABOUT CESA

The Clean Energy States Alliance (CESA) is a national, nonprofit coalition of public agencies and organizations working together to advance clean energy. CESA members—mostly state agencies—include many of the most innovative, successful, and influential public funders of clean energy initiatives in the country. CESA works with state leaders, federal agencies, and other stakeholders to develop and promote clean energy programs and markets, with an emphasis on renewable energy, energy equity, financing strategies, and economic development. CESA facilitates information-sharing, provides technical assistance, coordinates multi-state collaborative projects, and communicates the views and achievements of its members.

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Board of Directors Draft Meeting Minutes

Wharfinger Building, Bay Room (downstairs)
1 Marina Way, Eureka, CA 95501

Thursday, September 24 2026
3:30 PM

Attendance

Present

Carlos Diaz	Sarah Schaefer, Vice Chair (arrived 3:46 p.m.)
Michael Gerace, Chair	Jack Tuttle
Skip Jorgensen	Frank Wilson
Elise Scafani	Mike Wilson (remote, just cause - agency travel, left at 3:49 p.m.)

Absent

Scott Bauer	Jason Ramos
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Staff and Others Present

Name	Title
Mike Avcollie	Capital Assets Manager
Ken Beals	Information Technology Technician
Elizabeth Burks	Executive Director
Nancy Diamond	RCEA Legal Counsel
Richard Engel	Power Resources Director
Eileen Verbeck	Deputy Executive Director
Lori Taketa	Board Clerk

Open Session (Call to Order)

Chair Gerace called a meeting of the Board of Directors of the Redwood Coast Energy Authority to order at the above location and date at 3:35 p.m. Notice of this meeting was posted on September 19, 2026. Director Mike Wilson participated remotely with just cause due to travel for County business. There was no one 18-years old or older with him while he teleconferenced.

4. Staff Reports

4.1. Executive Director's Report

Executive Director Burks reported that RCEA achieved 100% renewable/carbon-free resources in its power portfolio for the first time in 2025. The Board-approved bond prepay agreement will result in \$2.65 million in savings per year during its initial 10-year pricing period, exceeding the projected \$2 million estimate. The California Supreme Court ordered the Appellate Court to hear CalCCA's appeal contesting the CPUC's change in calculating the Market Price Benchmark. This calculation affects the Power Charge Indifference Adjustment, which caused the large increase in electricity bills this year. RCEA will participate in ex parte communications contesting the CPUC's preliminary decision to eliminate North Coast offshore wind development from its electricity grid development plans. There were no public comments.

5. Consent Calendar

- 5.1. Approve Minutes of August 27, 2026, Board Meeting.
- 5.2. Accept Disbursement Report for July 2026, and Financial Reports for This Fiscal Year Through July 2026.

There were no requests to remove items from the consent calendar.

M/S: M. Scafani, Jorgensen: Approve Consent Calendar items.

The motion passed with a unanimous roll call vote. Ayes: Diaz, Gerace, Jorgensen, Scafani, Tuttle, F. Wilson, M. Wilson. Noes: None. Absent: Bauer, Ramos, Schaefer. Abstain: None.

Community Choice Energy (CCE) Business

7. CCE Business Consent Calendar

- 7.1. Adopt Resolution 2026-10 Approving and Attesting to the Veracity of RCEA's 2025 Power Source Disclosure Report.

There were no requests to remove this item from the CCE Business Consent Calendar.

M/S: Scafani, Diaz: Approve CCE Business Consent Calendar item.

The motion passed with a unanimous roll call vote. Ayes: Diaz, Jorgensen, Scafani, Schaefer, Tuttle, F. Wilson, M. Wilson. Noes: None. Absent: Bauer, Ramos. Abstain: None. Non-Voting: Gerace.

End of CCE Business | Resume RCEA Board Business

11. Old Business

11.1. Annual Humboldt Sawmill Company Alternative Biomass Use Report (Information only)

Power Resources Director Engel presented the Annual Humboldt Sawmill Company Alternative Biomass Use Report, providing history of the agreement with Humboldt Sawmill Company to provide requested information annually during the contract term through 2031. HSC received no new notices of violation from the Air District this year. RCEA Legal Counsel confirmed that conditions do not exist to indicate a default of power purchase agreement terms. A draft health risk assessment report triggered by previous HSC plant emissions data found that cancer risks in the surrounding Scotia area fall below public notification and remediation thresholds. Humboldt Sawmill Company continues to evaluate a potential small-scale biomass plant in Ukiah, despite the end of BioMAT program incentives. Current economics do not support project investment. The Community Advisory Committee expressed continued concern about particulate matter emissions but acknowledged that the annual HSC report increased transparency about the plant's operations and environmental impact. There were no public comments on this agenda item.

11.2. Grid Resilience Innovation Partnership (GRIP) Program Funds for Tribal Energy Resilience and Sovereignty Project Final Award Execution and Staffing

Chair Gerace recused himself from this discussion due to a potential conflict of interest. The Yurok Tribe is a recipient of the GRIP grant and Chair Gerace is the vice president of a Yurok-owned construction corporation which may build infrastructure funded by this grant. Chair Gerace left the meeting room at 4:05 p.m. Vice Chair Schaefer facilitated the discussion.

Deputy Executive Director Verbeck described the history of the RCEA partners' GRIP 2 award for microgrids grant application with the Department of Energy from the initial \$87 million award in 2024, informal project termination in 2025, and resumed 2026 negotiations resulting in a \$65 million grant that required removal of solar energy and community benefit components. The remaining partners (Yurok and Hoopa Tribes, the Blue Lake Rancheria, and RCEA) have secured match funds as required by the federal award. If the partners continue to build solar, it will have to be done with funds outside the federal award. There was no public comment on this item.

M/S: Scafani, Tuttle: Authorize RCEA Executive Director to execute the Department of Energy Grid Resilience Innovation Partnership Program Funds for Tribal Energy Resilience and Sovereignty Project GD-0000967 Final Award and Unfreeze the Contracts and Grants Manager Upon Execution of Final Award.

The motion passed with a unanimous voice vote. Ayes: Diaz, Jorgensen, Scafani, Schaefer, Tuttle, F. Wilson. Noes: None. Absent: Bauer, Gerace, Ramos, M. Wilson. Abstain: None.

Chair Gerace returned to the meeting room at 4:15 p.m. after the vote and resumed meeting facilitation.

12. New Business

12.1. Regional Climate Action Plan: Establishing RCEA as Host Agency

Executive Director Burks reported on approval progress for the Memorandum of Understanding establishing RCEA as the host agency for the Regional Climate Action Plan implementation. The MOU will go into effect after jurisdiction governing councils representing 85% of Humboldt County's population sign the agreement. The MOU includes cost-sharing for a Regional Climate Program Manager position, establishes the RCEA Board with additional representatives from Humboldt County Association of Governments, Humboldt Transit Authority, and Humboldt Waste Management Authority, as the Regional Climate Committee, along with an RCAP Technical Advisory Committee comprised of staff from RCAP member entities.

Daniel Chandler, member of the 350 Humboldt Steering Committee, supported the memorandum of understanding and RCEA's role as Regional Climate Action Plan implementation host.

Colin Fiske of the Coalition for Responsible Transportation Priorities also supported the memorandum of understanding, noting that the climate crisis continues to intensify.

M/S: Schaefer, Tuttle: Approve the Memorandum of Understanding establishing RCEA as the host agency for the Regional Climate Committee and Climate Program Manager Position to coordinate the implementation of the Regional Climate Action Plan.

The motion passed with a unanimous voice vote. Ayes: Diaz, Gerace, Jorgensen, Scafani, Schaefer, Tuttle, F. Wilson. Noes: None. Absent: Bauer, Ramos, M. Wilson. Abstain: None.

12.2. Approval of Fifth Lease Amendment Between GHD, Tenant, and RCEA, Landlord, for 718 3rd Street, Eureka, CA

Deputy Executive Director Verbeck reported on a lease amendment where tenant GHD relinquishes finished office space in exchange for a one-time \$300,000 tenant incentive allowance. RCEA would perform work to separate and secure the office spaces. The amendment would provide the RCEA office space needed at a significantly lower cost than building a partial second story in the adjoining warehouse. Staff also anticipate cost savings from acquiring office furniture GHD gives up during the move, and from ending RCEA's lease at the 917 Third Street building. There were no public comments on this agenda item.

M/S: Jorgensen, Schaefer: Approve Fifth Amendment to Commercial Lease Agreement between Redwood Coast Energy Authority, Landlord, and GHD Inc., Tenant, for 718 3rd Street and Authorize the Executive Director to execute all applicable documents pending review by RCEA Legal Counsel.

The motion passed with a unanimous voice vote. Ayes: Diaz, Gerace, Jorgensen, Scafani, Schaefer, Tuttle, F. Wilson. Noes: None. Absent: Bauer, Ramos, M. Wilson. Abstain: None.

12.3. Recommended Design-Build Procurement for 718 3rd Street Office Remodel

Capital Assets Manager Avcollie described work that will be needed to renovate the 718 Third Street warehouse to become RCEA's office, and the benefits of a design-build public contracting process. Staff anticipate more efficient management of a single design-build contract and pointed to the benefits of using best value contractor selection criteria. The directors discussed how the proposed procurement process differs from the previous, halted procurement for developing RCEA's empty parking lot at the

corner of Third and I Streets. For that project, RCEA received estimates exceeding the agency's budget just for project design. Estimates for construction at that time were over \$8 million, making new-build office plans unfeasible.

There were no public comments on this agenda item. Director Diaz and Chair Gerace volunteered to serve on an ad hoc Building Remodel Solicitation Committee.

M/S: Scafani, Diaz: Authorize RCEA's Executive Director to utilize the design-build process to procure design and construction of the commercial remodel and improvements to 718 3rd St. Eureka; and initiate the first step by developing and issuing a Request for Qualifications.

Create an Ad Hoc Building Remodel Solicitation Committee comprised of five or fewer RCEA Board members.

Delegate authority to the Building Remodel Solicitation Ad Hoc Committee to: 1) approve the short list of qualified design build contractors, and 2) authorize the Executive Director to issue a Request for Proposals for construction of the commercial remodel/improvements at 718 and 720 3rd St. Eureka.

The motion passed with a unanimous voice vote. Ayes: Diaz, Gerace, Jorgensen, Scafani, Schaefer, Tuttle, F. Wilson. Noes: None. Absent: Bauer, Ramos, M. Wilson. Abstain: None.

12.4. Overview of Distributed Energy Resources and Virtual Power Plants (Information only)

This agenda item was postponed to the October Board meeting.

There were no requests for future agenda items. Chair Gerace adjourned the meeting at 4:52 p.m.

Lori Taketa, Clerk of the Board

The author used Zoom AI to generate a draft of these minutes. After using this tool, the author reviewed, edited and takes full responsibility for the content of these minutes.

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Staff Report

Agenda Item # 7.2

Information

Agenda Date	October 22, 2026
To	Board of Directors
Prepared by	Lori Biondini, Business Planning and Finance Director
Subject	Profit & Loss, Balance Sheet and Monthly Disbursements Reports

Summary

The attached Disbursements Report lists RCEA's checks, debits, and electronic payments made during the period identified on the report. The Business Planning and Finance Director certifies that the disbursements were drawn in payment of demands conforming to RCEA's adopted Financial Policy and budget.

The Financial Reports (Profit & Loss Budget vs. Actual and Balance Sheet) are presented to keep the Board apprised of current agency receipts and spending relative to budget line items.

Alignment with RCEA's Strategic Plan

Agency financial tracking and reporting are necessary administrative functions supporting RCEA strategic plan goal implementation.

Financial Impact

The disbursements presented were drawn in payment of demands included within the adopted budget.

Staff Recommendation

Approve Disbursement Reports for August 2026, and Financial Reports for This Fiscal Year Through August 2026.

Attachments

1. Disbursements Report for August 1 through August 31, 2026
2. Profit & Loss Budget vs. Actual Report, August 2026
3. Balance Sheet as of August 31, 2026

Redwood Coast Energy Authority
Disbursements Report
As of August 31, 2026

Type	Date	Num	Name	Memo	Amount
Bill Pmt -Check	08/03/2026	ACH	The Energy Authority	Weekly CISO072926	-78,461.47
Bill Pmt -Check	08/10/2026	ACH	The Energy Authority	Weekly CISO080526	-31,849.95
Liability Check	08/14/2026	ACH	Ascensus	Paydate 8/14/26	-15,405.81
Liability Check	08/14/2026	ACH	EDD	Paydate 8/14/26	-9,570.30
Liability Check	08/14/2026	ACH	Internal Revenue Service	Paydate 8/14/26	-40,256.06
Liability Check	08/14/2026	ACH	Ascensus	Paydate 8/14/26	-14,127.08
Bill Pmt -Check	08/14/2026	ACH	CA Community Power	June 2026 Tumbleweed Monthly Capacity	-50,404.63
Bill Pmt -Check	08/14/2026	ACH	Humboldt Sawmill Co.	July 2026 Electricity Charges	-809,207.48
Bill Pmt -Check	08/14/2026	ACH	Leapfrog Power, Inc	July 2026 RA	-37,180.00
Bill Pmt -Check	08/14/2026	ACH	Resolv Systems Inc.	NREN Rebate App Platform & Finder Tool	-22,492.00
Bill Pmt -Check	08/14/2026	ACH	Sonoma Clean Power Authority	July 2026 Flex RA	-261,000.00
Bill Pmt -Check	08/14/2026	ACH	Choice Digital Corp	June 2026 NEM Cash Outs Client Fees	-730.30
Bill Pmt -Check	08/14/2026	WIRE	Sierra Business Council	NREN partner payment Q3 2026	-750,109.00
Check	08/14/2026	22715	NEM Customer	2026 NEM Yearly Payout	-197.06
Check	08/14/2026	22716	NEM Customer	2026 NEM Closeout	-79.43
Bill Pmt -Check	08/14/2026	22717	Adventures Edge	July 2026 e-bike vouchers	-1,600.00
Bill Pmt -Check	08/14/2026	22718	AM Conservation Group, Inc.	NREN Res Kits - Qty 104	-11,296.30
Bill Pmt -Check	08/14/2026	22719	AT&T	RCAM Router charges 06/19-07/18/26	-163.00
Bill Pmt -Check	08/14/2026	22720	Bishop, M.	Mileage reimbursement July 2026	-32.12
Bill Pmt -Check	08/14/2026	22721	Braun Blaising & Wynne, P.C.	Regulatory & Procurement June 2026	-1,091.58
Bill Pmt -Check	08/14/2026	22722	City of Arcata	June 2026 Excessive Electricity Use Tax	-228.98
Bill Pmt -Check	08/14/2026	22723	City of Arcata	June 2026 Utility User Tax	-8,662.97
Bill Pmt -Check	08/14/2026	22724	Developed Employment Services, LLC.	633 3rd St. Yard work	-164.04
Bill Pmt -Check	08/14/2026	22725	Donald Dame	CCE Consulting services July 2026	-336.00
Bill Pmt -Check	08/14/2026	22726	EAN Services, LLC	Staff travel vehicle rentals July 2026	-99.27
Bill Pmt -Check	08/14/2026	22727	Humboldt Bay Coffee Co.	Office Coffee: 633 3rd St.	-64.10
Bill Pmt -Check	08/14/2026	22728	Humboldt HyCycle	Aug 2026 E-Bike Vouchers	-1,000.00
Bill Pmt -Check	08/14/2026	22729	Law Offices of Nancy Diamond	July 2026 legal services	-8,058.50
Bill Pmt -Check	08/14/2026	22730	McKinleyville Chamber of Commerce	Mega Mixer Feature Fee	-25.00
Bill Pmt -Check	08/14/2026	22731	Mission Linen & Uniform Service	July 2026 janitorial supplies	-226.12
Bill Pmt -Check	08/14/2026	22732	CCE Customer	July 2026 E-Bike Voucher direct to customer	-600.00
Bill Pmt -Check	08/14/2026	22733	North Coast Cleaning Services, Inc.	July 2026 services	-1,090.00
Bill Pmt -Check	08/14/2026	22734	Premier Financial Group, Inc.	Advisory Fee for Q3 2026	-6,876.81
Bill Pmt -Check	08/14/2026	22735	Public Sector HR Association	Public Sec HR-Cert Renewal Fee- K. Siino	-300.00
Bill Pmt -Check	08/14/2026	22736	Quest	Veeam Data Platform Essentials & Backup	-1,175.80
Bill Pmt -Check	08/14/2026	22737	Revolution Bicycles, Inc.	July 2026 E-Bike Voucher	-600.00
Bill Pmt -Check	08/14/2026	22738	Stephens Electrical, Inc	July 2026 RRG design/build services	-18,430.00
Bill Pmt -Check	08/14/2026	22739	The Engine is Red	June 2026 NREN Graphic Design & Art Direction	-15,325.00
Bill Pmt -Check	08/14/2026	22740	Times Printing Company	July 2026 printing and mailing services	-1,482.89
Bill Pmt -Check	08/14/2026	22741	Ubeo Business Services	633+ 917 3rd St Printer Charges: 7/6-8/5/26	-260.55
Bill Pmt -Check	08/14/2026	22742	Mission Linen & Uniform Service	Janitorial Supplies 633 3rd St	-51.55
Paycheck	08/14/2026	ACH	Employees	Payroll	-98,684.21
Bill Pmt -Check	08/17/2026	ACH	The Energy Authority	Monthly TEA Invoice #TEA72026 July 2026	-843,255.14
Bill Pmt -Check	08/17/2026	ACH	The Energy Authority	Weekly CISO081226	-56,668.07
Check	08/17/2026	ACH	VISA- Commercial Card	Statement Date 07/31/26	-13,535.79
Check	08/20/2026	Debit	Columbia Bank	Service Charge	-300.64

Redwood Coast Energy Authority
Disbursements Report
As of August 31, 2026

Type	Date	Num	Name	Memo	Amount
Check	08/20/2026	Debit	Columbia Bank	Service Charge	-248.28
Liability Check	08/28/2026	ACH	Ascensus	Paydate 8/28/26	-15,489.17
Liability Check	08/28/2026	ACH	EDD	Paydate 8/28/26	-9,328.07
Liability Check	08/28/2026	ACH	Internal Revenue Service	Paydate 8/28/26	-39,481.52
Liability Check	08/28/2026	ACH	Ascensus	Paydate 8/28/26	-14,158.51
Liability Check	08/28/2026	ACH	CICCS Coalition for Controlling Insurance	Aug 2026 Premiums	-68.68
Liability Check	08/28/2026	ACH	Colonial Life	Sept 2026 Premiums	-4,126.73
Liability Check	08/28/2026	ACH	Keenan	Sept 2026 Premiums	-56,698.80
Liability Check	08/28/2026	ACH	Principal Life Insurance Company	Sept 2026 Premiums	-133.74
Bill Pmt -Check	08/28/2026	ACH	Baker Tilly US, LLP	Accounting services through 07/31/26	-3,150.00
Bill Pmt -Check	08/28/2026	ACH	CalPine Corporation	July 2026 Data Management	-77,455.30
Bill Pmt -Check	08/28/2026	ACH	Choice Digital Corp	June 2026 NREN rebate client fees	-103.20
Bill Pmt -Check	08/28/2026	ACH	EDPR CA Solar Park LLC II	July 2026 contract Energy	-826,396.44
Bill Pmt -Check	08/28/2026	ACH	North Coast Highway Solar 1, LLC	June & July 2026 contract energy	-31,276.97
Bill Pmt -Check	08/28/2026	ACH	North Coast Highway Solar 2, LLC	June 2026 contract Energy	-12,198.73
Bill Pmt -Check	08/28/2026	ACH	Sandrini BESS Storage LLC	July 2026 Contract Energy Storage	-1,242,000.00
Bill Pmt -Check	08/28/2026	ACH	Choice Digital Corp	NREN CPUC survey rewards, qty 14	-700.00
Bill Pmt -Check	08/28/2026	WIRE	Foster Clean Power A, LLC	July 2026 Contract Energy	-30,562.90
Bill Pmt -Check	08/28/2026	WIRE	Foster Clean Power B, LLC	July 2026 Contract Energy	-49,297.81
Bill Pmt -Check	08/28/2026	WIRE	PG&E Voluntary Allocation	Apr 2026 Forecast Price- VA	-75,814.30
Liability Check	08/28/2026	22743	Ameritas Life Insurance Corp.- Vision	Sept 2026 Premiums	-519.68
Liability Check	08/28/2026	22744	Ameritas Life Insurance Corp. - Dental	Sept 2026 Premiums	-3,096.20
Bill Pmt -Check	08/28/2026	22745	Adventures Edge	Aug 2026 E-Bike Voucher	-400.00
Bill Pmt -Check	08/28/2026	22746	Amazon.com	Office and IT supplies July 2026	-58.76
Bill Pmt -Check	08/28/2026	22747	AT&T	RCAM router and data charges	-1,008.06
Bill Pmt -Check	08/28/2026	22748	Bithell, M.	Mileage Reimbursement Aug 2026	-117.45
Bill Pmt -Check	08/28/2026	22749	Carter Properties	917 3rd Street Office Sept 2026	-2,450.00
Bill Pmt -Check	08/28/2026	22750	City of Eureka-Water	917 & 633 3rd. St. 06/25/26-7/25/26	-361.80
Bill Pmt -Check	08/28/2026	22751	Fortuna Chamber of Commerce	Fortuna Apple Harvest Festival Booth 10/03/26	-25.00
Bill Pmt -Check	08/28/2026	22752	Frontier Energy, Inc.	NREN Program Consulting July 2026	-17,117.25
Bill Pmt -Check	08/28/2026	22753	Humboldt Bay Coffee Co.	Office Coffee: 633 3rd St.	-64.10
Bill Pmt -Check	08/28/2026	22754	Humboldt HyCycle	Aug 2026 E-Bike Vouchers	-1,600.00
Bill Pmt -Check	08/28/2026	22755	iPROMOTEu.com, Inc	RCEA Promo: Qty 150 LED Magnetic Bracelets	-574.98
Bill Pmt -Check	08/28/2026	22756	John Winzler	633 3rd St. Sept 2026	-8,144.97
Bill Pmt -Check	08/28/2026	22757	Kilowatt Engineering, Inc.	NMEC Program Support Services July 2026	-21,035.00
Bill Pmt -Check	08/28/2026	22758	Lake County/City Area Planning Council	2025-2026 True-Up TO 15-21	-29,656.44
Bill Pmt -Check	08/28/2026	22759	Lake County/City Area Planning Council	NREN Partner payment Task Orders15-21	-189,525.21
Bill Pmt -Check	08/28/2026	22760	Marc Malfatti Electric	EV Charging Station electrical work: DMV site	-30,808.03
Bill Pmt -Check	08/28/2026	22761	Mission Linen & Uniform Service	Aug 2026 janitorial supplies	-185.50
Bill Pmt -Check	08/28/2026	22762	North Coast Journal, Inc.	Eureka Chamber 2026 Impact Mag. Ad	-975.00
Bill Pmt -Check	08/28/2026	22763	Northern CA Safety Consortium	CPR & First Aid Training: H. Baker & K. Martin	-180.00
Bill Pmt -Check	08/28/2026	22764	NYLEX.net, Inc.	July & Aug 2026 onsite IT support	-12,102.00
Bill Pmt -Check	08/28/2026	22765	Optimum Business-633	633 3rd St: Phone & Internet 08/01-08/31/26	-1,103.78
Bill Pmt -Check	08/28/2026	22766	PG&E- EV	REVNet electricity usage	-3,157.07
Bill Pmt -Check	08/28/2026	22767	PG&E-Office Utility	Office electricity usage	-317.10
Bill Pmt -Check	08/28/2026	22768	PG&E - ACV	ACV site charges	-317.54

Redwood Coast Energy Authority
Disbursements Report
As of August 31, 2026

Type	Date	Num	Name	Memo	Amount
Bill Pmt -Check	08/28/2026	22769	PG&E CCA	July 2026 CCE billing services charges	-21,932.54
Bill Pmt -Check	08/28/2026	22770	Pierson Building Center	Safety device for on-site assessments	-37.47
Bill Pmt -Check	08/28/2026	22771	Reider, S	Mileage Reimbursement Aug 2026	-76.42
Bill Pmt -Check	08/28/2026	22772	Shred Aware	Shredding services Aug 2026	-68.95
Bill Pmt -Check	08/28/2026	22773	Signorelli, Giovanna	Per Diem 2026 CalCCA Leg Com Mtg	-135.00
Bill Pmt -Check	08/28/2026	22774	Sport & Cycle	Aug 2026 E-Bike Voucher	-400.00
Bill Pmt -Check	08/28/2026	22775	Tripepi Smith and Associates, Inc.	M1 of General Counsel Recruitment	-7,000.00
Bill Pmt -Check	08/28/2026	22776	Witte, M.	Mileage Reimbursement Aug 2026	-36.98
Bill Pmt -Check	08/28/2026	22777	Yakovleva, Vera A.	Per Diem 2026 CalCCA Leg Com Mtg	-135.00
Paycheck	08/28/2026	ACH	Employees	Payroll	-97,055.30
Bill Pmt -Check	08/31/2026	ACH	Choice Digital Corp	NREN Residential Rebate Prefunding	-40,000.00
Bill Pmt -Check	08/31/2026	ACH	CLEAResult	NREN consulting July 2026	-27,171.91
Bill Pmt -Check	08/31/2026	ACH	Special District Risk Managment P&L	FY26-27 Property & Liability, Cyber Risk	-290,282.98
Bill Pmt -Check	08/31/2026	ACH	The Energy Authority	Weekly CISO082626	-108,146.52
TOTAL					<u>-6,618,824.14</u>

Redwood Coast Energy Authority
Profit & Loss Budget vs. Actual
July through August 2026

	<u>Jul - Aug 26</u>	<u>Budget</u>	<u>% of Budget</u>
Ordinary Income/Expense			
Income			
Total 4 GRANTS AND DONATIONS	20,865.17		
5 REVENUE EARNED			
Total 5000 · Revenue - government agencies	2,518,068.25	17,548,342.00	14.35%
Total 5100 · Revenue - program related	18,425.74	152,404.00	12.09%
Total 5300 · Revenue - interest earned	210,299.90	600,000.00	35.05%
Total 5400 · Revenue- other contracts	100,454.25	515,532.00	19.49%
Total 5500 · Revenue - electricity sales	7,311,134.66	51,359,098.00	14.24%
Total 5 REVENUE EARNED	10,158,382.80	70,175,376.00	14.48%
Total Income	10,179,247.97	70,175,376.00	14.51%
Gross Profit	10,179,247.97	70,175,376.00	14.51%
Expense			
Total 6 WHOLESALE POWER SUPPLY	8,175,549.09	53,053,147.00	15.41%
Total 7 PERSONNEL EXPENSES	850,657.30	6,848,843.00	12.42%
Total 8.1 FACILITIES AND OPERATIONS	612,712.65	1,412,926.00	43.37%
Total 8.2 COMMUNICATIONS AND OUTREACH	12,876.44	383,463.00	3.36%
8.4 PROFESSIONAL & PROGRAM SRVS			
8400 · Regulatory	35,053.00	400,101.00	8.76%
Total 8410 · Contracts - Program Related Ser	1,535,159.91	9,067,655.00	16.93%
8419 · Organization Dues & Memberships	0.00	468,839.00	0.0%
8420 · Accounting	28,350.00	123,000.00	23.05%
8430 · Legal	21,356.47	211,500.00	10.1%
8450 · Wholesale Services - TEA	204,549.46	1,146,894.00	17.84%
8470 · Data Management - Calpine	147,973.20	774,452.00	19.11%
8480 · Customer Billing - PG&E	43,898.68	254,994.00	17.22%
Total 8.4 PROFESSIONAL & PROGRAM SRVS	2,016,340.72	12,447,435.00	16.2%
Total 8.6 INCENTIVES & REBATES	138,407.58	4,454,047.00	3.11%
Total 9 NON OPERATING COSTS	1,181.55	129,300.00	0.91%
Total Expense	11,807,725.33	78,729,161.00	15.0%
Net Ordinary Income	-1,628,477.36	-8,553,785.00	19.04%
Net Income	-1,628,477.36	-8,553,785.00	19.04%

Redwood Coast Energy Authority
Balance Sheet
As of August 31, 2026

	<u>Aug 31, 26</u>
ASSETS	
Current Assets	
Checking/Savings	
1010 · Petty Cash	300.00
1060 · Umpqua Checking Acct 0560	-170,454.81
1071 · Umpqua Deposit Cntrol Acct 8215	1,312,743.57
1075 · Umpqua Reserve Account 2300	21,639,393.24
1077 · JP Morgan Chase Act 74999	386,207.84
1078 · CA CLASS Reserve Fund 0001	13,569,085.12
Total Checking/Savings	<u>36,737,274.96</u>
Total Accounts Receivable	3,029,771.74
Other Current Assets	
1101 · Allowance for Doubtful Accounts	-7,011,254.91
1103 · Electricity Receivable	13,946,188.06
1120 · Inventory Asset	19,835.15
1205 · Prepaid Insurance	20,179.08
1210 · Retentions Receivable	113,433.87
Total Other Current Assets	<u>7,088,381.25</u>
Total Current Assets	46,855,427.95
Total Fixed Assets	13,897,630.29
Other Assets	
1700 · Security Deposits	795,719.47
1800 · Deferred Outflow of Resources	196,000.00
Total Other Assets	<u>991,719.47</u>
TOTAL ASSETS	<u><u>61,744,777.71</u></u>
LIABILITIES & EQUITY	
Liabilities	
Current Liabilities	
Total Accounts Payable	4,179,921.12
Total Credit Cards	8,943.17
Other Current Liabilities	
2002 · Deposits Refundable	1,573,470.01
2011 · NEM Escrow Liability	270,847.89
2013 · Unearned Revenue	7,075,981.22
Total 2100 · Payroll Liabilities	<u>371,072.69</u>
Total 2200 · Accrued Expenses	<u>25,213.88</u>
Total Other Current Liabilities	<u>9,316,585.69</u>
Total Current Liabilities	<u>13,505,449.98</u>
Total Long Term Liabilities	<u>5,585,364.54</u>
Total Liabilities	19,090,814.52
Equity	
3900 · Fund Balance	44,282,440.55
Net Income	-1,628,477.36
Total Equity	<u>42,653,963.19</u>
TOTAL LIABILITIES & EQUITY	<u><u>61,744,777.71</u></u>



Staff Report

Agenda Item # 7.3

Information

Agenda Date	October 22, 2026
To	Board of Directors
Prepared by	Faith Carlson, Regulatory and Legislative Policy Manager Giovanna Signorelli, Regulatory and Legislative Policy Intern
Subject	RCEA Regulatory and Legislative Engagement Report

Summary

The RCEA Board of Directors adopted the RCEA 2026 Policy Platform in January 2026 to serve as a guide for RCEA's staff regulatory and legislative engagement based on the principles set forth in RCEA's RePower Humboldt strategic plan. In accordance with the procedures described in the Platform, staff keeps the Board apprised of legislative stances taken by RCEA through periodic reports summarizing RCEA's legislative engagement. This update covers staff actions since June 2026.

Federal activity is reported monthly in the Executive Director's report.

Staff Regulatory and Legislative Engagement

By law, RCEA abides by the mandates and regulations of several governing institutions within the state of California, including the California Energy Commission, California Public Utilities Commission (CPUC), California Independent System Operator (CAISO), California Air Resources Board, and others.

RCEA engages with governing bodies through a few advocacy groups, both for regulatory and legislative issues. The key advocacy groups RCEA participates in are California Community Choice Association (CalCCA), Joint Community Choice Aggregators (CCAs), and the federal CCA trade association Community Choice Energy Alliance (CCEA). These groups track, draft and submit comments on, and engage in stakeholder groups on issues brought to their attention by their membership.

A summary of tracked legislation and CalCCA positions on various bills from this session is attached, as well as a list of key regulatory topics in which CalCCA or Joint CCAs engage.

RCEA has recently attended both the CalCCA Board retreat and Legislative Planning session to develop strategy and focus areas for the next session. A Regulatory Planning session will occur in November.

In addition to advocacy through CalCCA, RCEA staff have conducted the following advocacy in alignment with the Policy Platform:



- RCEA met with Assemblymember Rogers to discuss AB 1761, his bill to improve transparency into the data and methodology used to calculate the Power Charge Indifference Adjustment (PCIA). Staff described how PCIA volatility and limited access to underlying data complicate forecasting and financial planning and discussed RCEA's need to increase generation rates to maintain financial stability amid rising PCIA-related costs. RCEA emphasized that greater transparency would support more accurate forecasts, reduce unexpected cost fluctuations, and help protect customers from paying more than their fair share.
- RCEA staff have been engaging the CPUC and CEC around load forecasting and its relationship to procurement share. Despite RCEA's year-over-year load decrease, the CEC has forecasted RCEA at a similar rate of increase to regions in the North Bay. The CPUC has ordered RCEA conduct procurement based on this forecasted load increase, which is unlikely to be realized load based on RCEA's own forecasts.
 - In recent conversations with RCEA, the CEC has indicated that they are working to increase the granularity of the forecasting model and are searching for new data sources to better align their forecast with observed trends for RCEA's service territory.
 - RCEA filed reply comments and held ex parte meetings with CPUC Commissioner offices regarding the proposed Reliable and Clean Power Procurement Program (RCPPP), largely focused on RCEA's status as a small load serving entity (LSE) with declining load.
 - RCEA's comments stated that the CPUC should:
 - Adopt a new and existing resource framework, to not penalize early actors towards clean and renewable procurement.
 - Assign procurement need based on forecasted incremental load share in the year the resources are due to be online, to not penalize LSEs who's load growth is lower than the average rate of load growth.
 - Refrain from adopting a prescriptive approach to the Preferred System Plan (PSP) resource allocation to retain CCA procurement autonomy and not introduce new challenges for small LSEs.
 - Retain the current Integrated Resource Plan (IRP) program's obligation transactability mechanism.
 - A Proposed Decision is expected as the next procedural step.
- RCEA filed joint comments and reply comments with the County of Humboldt outlining support for retention of offshore wind in the Base Case for the 2027-2028 Transmission Planning Process, which the CPUC proposes to remove.
 - The comments state that the Commission should:
 - Address RCEA and County of Humboldt's process concerns, as related to conflicts between California and federal policy as well as host community engagement, retain offshore wind in the Base Case, and order a study to assess what transmission upgrades are necessary to support California's and the region's energy goals.
 - Reply comments include the previous points as well as discussion of project cost to ratepayers.
 - RCEA and the County conducted ex partes with all CPUC Commissioners' offices. The County has been taking the lead on engagement with the legislative delegation. The procedural next step is a Proposed Decision.



- In 2025, RCEA presented at a workshop related to proposals for Equity Metrics in for investor-owned utility (IOU) Distribution Planning and Execution Process. The IOUs submitted an advice letter ignoring all proposals by presenters. RCEA, along with Ava Community Energy, Marin Clean Energy, and Valley Clean Energy protested the joint IOU advice letter. In September of 2026, the CPUC issued a resolution that largely addresses the Joint CCA concerns and adopts metrics that look at headroom, project initiation, and load growth across circuits layered with data related to customer CARE/FERA and Medical Baseline enrollment, CalEnviroScreen data, disadvantaged community status, and Tribal communities.
- In 2025, RCEA commented on IOU Climate Adaptation and Vulnerability Assessment processes. RCEA's comments requested increased collaboration and data sharing with more parties such as CCAs and local governments in crafting climate action and adaptation plans, increased public input, increased engagement with tribes, and increased efforts to engage rural communities. The final methodology was released in July of 2026 and accepted all of RCEA's feedback except for the rural component.

Equity Impacts

This report reflects legislation that is intended to improve CCAs' abilities to tailor services to meet the needs of their local communities which are often unique in their constituent marginalized populations.

Alignment with RCEA's Strategic Plan

RCEA's Policy Platform is guided by RCEA's Strategic Plan. Whenever making advocacy decisions for a given proceeding or issue, RCEA staff references the Policy Platform, and if the topic is not well defined within the platform, consults the Board.

Financial Impact

Budgeted staff and legal costs.

Staff Recommendation

Receive Regulatory and Legislative Engagement Report.

Attachments

1. Tracked Legislation
2. CalCCA and Joint CCA Regulatory Engagement

Tracked Legislation

Bill	Author	Position	Status	Summary
AB 706	Aguiar-Curry (D)	Support	Signed into law	Sponsored by Pioneer Community Energy, AB 706 would establish the Forest Organic Residue and Safety Transformation (FOREST) and Wildfire Prevention Fund and the fire fuel reduction program. The program will support adequate biomass procurement, transport, and other beneficial uses to manage forest biomass waste generated from wildfire fuel reduction efforts. Unlike BioMAT and BioRAM, the fire fuel reduction program would not be funded with ratepayer funds. This bill would enable the state to sustainably utilize its abundance of forest biomass waste without imposing a financial burden on ratepayers.
AB 1761	Rogers (D)	Sponsor	Vetoed with a veto message that cites concerns that the bill would “result in improper dissemination of market-sensitive data and benefit a limited subset of market participants.”	Supports energy affordability by improving transparency and certainty into how the Power Charge Indifference Adjustment (PCIA), a charge on nearly all energy bills, is calculated.
AB 1787	Schultz (D)	Neutral	No longer active for 2026	Requires the CPUC to require IOUs to offer an optional dynamic rate tariff to customers if the CPUC has approved upgrades to the IOU’s smart meter infrastructure and related information management and billing systems on or after January 1, 2026. Some restrictions are placed on Net Energy Metering and Net Billing Tariff customers from participating in optional dynamic rates.
AB 1975	Schultz (D)	Support if Amended	No longer active	AB 1975 aims to reduce the need for infrastructure upgrades by providing financial incentives to investor-owned utilities to encourage load shifting and more efficient use of existing grid capacity. CalCCA has taken a Support, if Amended position because many CCAs across IOU service territories also offer load-shifting and demand flexibility programs and incentives, and these CCA efforts support more efficient grid utilization in addition to managing CCA procurement obligations. In

				recognition of CCA contributions, and as a matter of competitive neutrality, CalCCA requested that CCAs have the option to propose grid utilization programs of their own and receive an appropriate value for those programs' contributions.
AB 2111	Papan (D)	Support	Signed into law	Sponsored by the CCAs Sonoma Clean Power and Peninsula Clean Energy, modernizes California's transmission planning framework by requiring planners to evaluate multiple plausible future eventualities, including electrification growth, data center demand, and climate-driven grid stress, instead of relying on a single load forecast to drive long-lived transmission investment decisions that may not reflect the range of conditions the grid will face. The bill also directs planning agencies to assess the full system cost impacts of different transmission and resource strategies over longer time horizons so that grid investments are robust across a range of possible futures. RCEA supported the bill individually prior to CalCCA's support.
AB 2234	Papan (D)	Support	Signed into law	Geothermal exploration projects definition would be modified slightly for the purposes of CEQA.
AB 2266	Schultz (D)	Support if Amended	Signed into law	Requires the PUC to consider a process to consolidate certain plans submitted by load-serving entities into a single procurement plan, and would require the commission, when feasible, to consolidate certain compliance reporting for reliability requirements.
AB 2313	Berman	Support	Signed into law	Known as the "Home Energy Choice Act," would establish a program requiring gas corporations to offer incentives for home electrification to customers as an alternative to gas distribution line replacement, starting January 1, 2028.
AB 2369	Rogers (D)	Support	Vetoed	Sponsored by Sonoma Clean Power, requires the CPUC and CEC, in providing transmission-focused information to CAISO, to identify cost effective opportunities to increase the reliability contribution or mitigate congestion of planned or existing energy-

				only resources through transmission capacity expansions.
AB 2383	Zbur (D)	Neutral	Signed into law	As originally written, would require the CPUC to establish a new class of large load retail customers and identifies specific requirements for the new rate schedule to shield non-participating customers from rate increases. End of session amendments requires a CCA generation tariff to establish a "mechanism approved by the Commission" regarding incremental generation costs. However, that same section also declares that the CPUC is not authorized “to regulate the rates or terms and conditions of service offered by a community choice aggregator, consistent with Section 366.2, or an electric service provider, consistent with Section 394.” This was a drafting error. Assembly leadership and Assemblymember Zbur filed a Letter to the Journal making it clear that the PUC is unable to regulate CCA rates consistent with 945.6 (c). The letter states Zbur’s intent to run clean-up legislation next year.
AB 2396	Irwin (D)	Support	No longer active	AB 2396, sponsored by Clean Power Alliance, grants explicit statutory authority for CCAs to sponsor, develop, finance, construct, operate, lease, purchase, and own eligible transmission projects.
SB 886	Padilla (D)	No official position	Signed into law	As originally written, would require the CPUC to establish an electrical corporation tariff that addresses utility costs for serving data centers that interconnect at the transmission level and have peak electricity demands of at least 25 megawatts. CalCCA worked throughout the session with the author and sponsors to resolve several autonomy and other concerns.
SB 1138	Padilla (D)	Sponsor	No longer active for 2026	Supports energy affordability by lowering the cost to consumers of California’s Resource Adequacy (RA) program by allowing load-serving entities (LSEs) to transact RA load obligations on an hourly basis to align with the new slice-of-day RA program. California’s RA program, which ensures there is enough electricity supply to meet customer demand,

				recently transitioned to a new “Slice-of-Day (SOD)” compliance framework. The new SOD framework requires LSEs, such as CCAs, investor-owned utilities (IOUs), and energy service providers (ESPs), to procure enough RA to meet load obligations each hour, rather than monthly. While this aligns resources more precisely with load, under current rules LSEs can only buy or sell RA products for the whole month, even though obligations are unique to each hour. This mismatch forces LSEs to purchase more RA than they need to meet their obligations, creating artificial market scarcity and unnecessarily driving up RA demand (and prices). It’s akin to having to buy a crate of oranges when you only need a few slices. These unnecessary costs fall directly on California ratepayers, totaling tens of millions of dollars annually.
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CalCCA and Joint CCA Regulatory Engagement

*Items in **bold** have not previously been reported to the Board.

CalCCA Managed Cases		
<i>Key Agency</i>	<i>Topic</i>	<i>Summary</i>
CPUC	California Advanced Electric Rate Design	The proceeding aims to modernize electric rate design to better reflect cost causation, improve affordability, and support efficient grid use amid rising costs and changing system conditions. The proceeding will evaluate reforms to residential and non-residential rate structures, including time-of-use periods, fixed and demand charges, and marginal cost methodologies, to ensure rates align with current grid cost drivers and promote equitable cost allocation across customers. It responds to increasing affordability pressures driven by wildfire-related costs and rapid load growth. The rulemaking will further consider rate design solutions for large-load customers such as data centers, and support electrification and GHG-reduction goals. CalCCA is working to ensure that any new rate designs, fixed charges, or program structures do not disadvantage CCA customers relative to bundled utility customers or create barriers to CCA participation in serving load, including for electrification and large commercial customers.
CPUC	Climate Credit	Stemming from the Greenhouse Gas (GHG) Cap and Trade program, the California Climate Credit is distributed to all ratepayer electric and natural gas bills, with an average annual credit of \$120. The CPUC recently moved the residential electric climate credit for large IOU territories from April and October to August and September starting in 2026, and the gas Climate Credit from April to February in 2027. The proceeding considers further changes to the structure and timing of the credit. The California Industry Assistance Credit is an annual credit for eligible industrial facilities that are customers of the investor-owned electric utilities. A future phase of the proceeding will consider implementation of the California Industry Assistance to minimize leakage of emissions.
CPUC	Demand Response (DR)	This rulemaking aims to enhance DR in California. Issues include: (1) updates to demand flexible rate systems and processes; (2) dual participation in DR programs and dynamic

		rates; (3) valuation methodologies and evaluation metrics for demand response; (4) CAISO market integration topics; and (5) the impact of Resource Adequacy (RA) Slice-of-Day (SOD) implementation on DR valuation.
CPUC	Diablo Canyon Extension Operations	With the DCPD operations extension, PG&E continues to file annual applications with its DCPD forecasts of operating expenses and revenues through 2030 when the operating extension fully expires.
CPUC	Disconnections	Relates to rules and programs surrounding customer disconnection. Recent activity includes potential changes to customer disconnection caps and customer disconnection reduction pilot programs.
CPUC	Distribution: Distributed Energy Resources	Relates to rules surrounding distributed energy resources, such as cost effectiveness, data access, and equipment performance standards.
CPUC	Distribution: Energization Timelines	Implementation of SB 410 and AB 50, which focus on the establishment of reasonable average and maximum energization target time periods, and procedures for customers to report energization delays to the CPUC. Targets have been established. The next phase of the proceeding covers compliance reporting and penalties for non-compliance. A recent report found that assessing compliance towards the timelines will be challenging due to inconsistent IOU recordkeeping and data fields.
CPUC	Distribution: High Distributed Energy Resource Future	Streamlining of the distribution planning process to better reflect known loads and resources, equitable grid planning, and allow for data access. Also covers smart inverter use cases and cost recovery for grid modernization. Recent activity relates to the role and responsibilities of a Distribution System Operator, which can be compared to CAISO's role as a transmission Market Operator. Additionally, the IOUs each filed their 2026 Grid Modernization Progress Reports on October 1, 2026, detailing their efforts to modernize the distribution and transmission grid to support the safe and reliable integration of DERs. These reports support the CPUC in preparing the biennial update to the Legislature on the progress of modernizing the electric grid.
CPUC	Distribution: Rule 21 OIR	Rule 21 is a tariff that describes the interconnection, operating and metering requirements for certain generating and storage facilities seeking to connect to the electric distribution system.

CPUC	Energy Resource Recovery Account (ERRA)	Filed annually by each of the Investor-Owned Utilities (IOUs) as both a forecast of expected energy procurement-related revenue requirements and as a retroactive compliance review. Key issues include customer vintaging in the PCIA and calculation of the PCIA.
CPUC	General Rate Case (GRC)	In four-year cycles, IOUs submit GRC applications for authority to adjust rates and charges for electric and gas service. The revenue requirements include electric and gas distribution system costs, administrative expenses, and customer service costs. Key issues include PCIA resource vintaging, costs and CCA service fees, and fair treatment of CCA customers in Real Time Pricing pilots.
CEC	Integrated Energy Policy Report (IEPR)	A biennial holistic report assessing energy issues facing the state. The preparation of this report includes the load forecasting process, which drives energy planning and procurement requirements for Load Serving Entities. Recent issues include the accuracy of load forecasts for data centers.
CPUC	Integrated Resource Planning (IRP)	Focuses on the implementation and reform of California's Integrated Resource Planning program to ensure sufficient resource procurement and development and compliance with California's greenhouse gas reduction and reliability goals. There are two open proceedings at the CPUC on this item. One addressing the implementation and compliance of the IRP. This process feeds into the state's Transmission Planning Process at CAISO and addresses ad hoc procurement need. The second proceeding focuses on reforms to better align the IRP program with the Resource Adequacy (RA) and Renewables Portfolio Standards (RPS) programs through an initiative called the Renewable and Clean Power Procurement Program (RCPPP).
CAISO	Interconnection Process Enhancements (IPE), Congestion Revenue Rights (CRR), and Transmission Planning Process (TPP).	CAISO is responsible for bulk power systems, transmission operation, and California's electricity market participation. Current reforms RCEA engages in are related to the acceleration of the interconnection study process for new resources, transmission capacity/transmission plan deliverability to resources for RA eligibility, congestion of transmission capacity, and transmission planning. CalCCA engages in additional issues at CAISO, however RCEA tracks those less closely at this time.

CEC	Load Management Standards (LMS)	Similar to demand flexibility, LMS requires IOUs and CCAs over a certain size to maintain time-varying rates and are accessible to the public.
CPUC	Power Charge Indifference Adjustment (PCIA)	This rulemaking considers changes to the PCIA as well as rules and processes applicable to the Energy Resource Recovery Account annual forecast and compliance proceedings. In Track One, completed last year, there was a change to the methodology related to the calculation of the PCIA. Previously, the PCIA was assessed primarily using a one-year average energy price. Now, the PCIA is assessed primarily via a three-year average. CalCCA has filed a case in the CA Court of Appeal, Third Division, regarding the Track One decision. The Supreme Court granted CalCCA’s petition on September 23, 2026, ordering the Court of Appeal, Third District, to grant CalCCA’s Writ Petition and hear the case. CalCCA awaits further instruction regarding next steps from the Court of Appeal. Track Two addresses the treatment of pre-2019 banked Renewable Energy Credits. September 17, 2026, the CPUC issued a decision that assigns a \$0 valuation to these RECs, which means that CCA customers that paid for them will not receive financial credit for the RECs eventual use. CalCCA will file an Application for Rehearing to the CPUC. Track Three is currently in the early stages, with data transparency and data access are the present issues. Other proposals for reform of PCIA are likely issues in the next phase of Track Three. Tracks can occur in parallel or on a schedule not necessarily tied to numeral order. Phases must occur in order.
CPUC	PG&E Helms Uprate Application	PG&E proposal to increase the capacity of the existing Helms pumped storage facility and allocation of costs and benefits of the expansion to specific PCIA vintages.
CPUC, CAISO, and FERC	Regional Coordination	Regionalization generally means integrating elements of electricity markets across a particular region, such as the West, under the operation and management of a single Federal Energy Regulatory Commission (FERC) regulated regional entity. Energy markets, transmission planning, transmission system operation, reliability, and other elements can be regionalized individually or in combination. The implementing legislation, AB 825 (2025) requires the CPUC to make a determination

		that certain requirements have been satisfied before an electrical corporation can participate in an energy market governed by an independent Regional Organization (RO) RO. The CPUC opened a proceeding to implement AB 825 September 17, 2026. AB 825 authorizes the CAISO, on or after January 1, 2028, to implement tariff modifications accepted by the FERC to operate the energy markets whose rules are governed by the independent RO, if the CAISO governing board has adopted a resolution finding that the specified requirements have been adopted by the RO.
CPUC and CEC	Renewable Portfolio Standard (RPS)	Program that requires load serving entities to reach continuously escalating renewable energy procurement goals.
CPUC and CAISO	Resource Adequacy (RA)	Focuses on the implementation and reform of California's Resource Adequacy program, which was designed in response to California's energy crisis to ensure safe and reliable operation of the grid. The CPUC is currently conducting Loss of Load Expectation (LOLE) Studies and Planning Reserve Margin (PRM) Proposal development. LOLE assesses how likely an outage is to occur due to insufficient generation, rather than outage associated with power line operations such as PSPS events. The PRM assesses what an additional percentage buffer of RA eligible resources are needed beyond the minimum RA requirement to ensure not more than a 1-day-in-10-year LOLE outage standard.
CPUC	Rule 17/18	Rule 17/18 provides customer protections such that, if an IOU billing error persists for more than three months (three years for non-residential), the IOU cannot collect more than three months of back charges. This can lead to CCA undercollections. Historically, each IOU handled these undercollections differently. PG&E voluntarily provides CCAs the amount undercollected through shareholder funds; SCE and SDG&E provide no compensation to CCAs for undercollections. The IOUs filed a Joint Application on June 22, 2026 that CCAs should not be compensated for undercollections because they are a "cost of doing business".
CPUC	Rule 30	PG&E submitted an application for a new interconnection rule for new transmission level customers. This rule would apply to transmission connected customers, such as data centers or

		manufacturing. CalCCA is working to ensure fair treatment of CCAs under the potential new rule and access to load planning data. CalCCA has publicly filed comments supporting the CPUC's approval of a Partial Settlement proposed by CalCCA.
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Joint CCA Managed Cases		
<i>Key Agency</i>	<i>Topic</i>	<i>Summary</i>
CEC, CPUC	Building Decarbonization	A suite of programs that aim to reduce Greenhouse Gas (GHG) emissions from buildings.
CPUC	De-Energization	Rulemaking related to utility power shutoffs, including Public Safety Power Shutoffs (PSPS).
CEC, CPUC	Demand Response and Energy Efficiency	This issue relates to demand response programming or energy efficiency programs.
CPUC	Safety, Reliability, and Resiliency of Electrical Distribution Systems	Responds to aging infrastructure, extreme weather, wildfire-mitigation practices, equity concerns, and growing electrification. A recent decision adopted an updated template for Annual Customer Reliability Reports and quarterly data reporting. The new template requires IOUs to notify public safety partners in addition to customers of outages, expands the definition of outages, and collects data on outage impacts for circuits that are underground vs above ground, and for customers located in disadvantaged communities or tribal lands, and if they have access and functional needs.
CPUC	Net Billing Tariff (NBT)	Rulemaking related to the development and implementation of Net Billing Tariff (NBT) and related rates. A higher court recently ordered the CPUC to readdress the NBT decision. There has been no action since that order.
CPUC	PG&E Billing Modernization	Proposal to increase rates to recover costs from the Billing Modernization Initiative.
CPUC	PG&E Safety Culture	This issue focuses on wildfire management related issues, including PG&E compliance, and proactive measures such as undergrounding.

CPUC and CEC	Renewable Financing	Issues tracked related to On-Bill Financing, Tariff-On-Bill, Go Green Financing, and other funding efforts.
CPUC	Senate Bill 1221 Implementation	Mandates the designation and establishment of neighborhood decarbonization zones. Recently, the CPUC has updated maps for potential decarbonization zones and adopted an application process for candidate locations for the pilot.
CPUC	Self-Generation Incentive Program (SGIP)	SGIP which provides incentives for emerging distributed energy resources.
CPUC	SoCalGas Microgrid Tariff Application	Application to give SoCalGas the authority to administer the Microgrid Optional Tariff program which is applied to non-residential customers. There is a proposed decision awaiting CPUC vote to reject this application.
CEC, CPUC, and CARB	Transportation Electrification	CEC Clean Transportation Program, CPUC proceeding of Transportation Electrification Policy and Infrastructure (TEPI), and updates to CARB Low Carbon Fuel Standard (LCFS) implementation, targets, and compliance. Recently, there have been changes to reporting requirements for Vehicle to Grid Integration, reducing compliance burden to CCAs.



Staff Report

Agenda Item # 10.1

Information

Agenda Date	October 22, 2026
To	Board of Directors
Prepared by	Beth Burks, Executive Director
Subject	Request to Form Energy Risk and Rates Ad Hoc Sub Committee

Summary

RCEA has received the 2027 PG&E rate estimate resulting from final 2026 and forecast 2027 market price benchmark. These results indicate lower generation rates for PG&E and a higher Power Charge Indifference Adjustment (PCIA). These changes have risk and rate implications for RCEA.

Staff is requesting the formation of an Energy Risk and Rates Ad Hoc Sub Committee for the purpose of making recommendations to the RCEA board on managing risk and rate changes moving forward. The expected duration of the ad hoc subcommittee is through the end of fiscal year 2027-28.

Background

In July 2026, the RCEA Board adopted Resolution 2026-9 Adopting a rate strategy to maintain \$26,000,000 in cash reserves for fiscal soundness. The Resolution authorized the following:

1. Adopted electricity retail rates at 6% above PG&E generation rates effective September 1, 2026, to maintain a \$26,000,000 cash reserve.
2. Authorized staff to no more than quarterly reduce or increase retail rates to maintain a \$26,000,000 cash reserve.
3. Directed staff to notify the Board of any necessary rate adjustments at the next scheduled Board meeting.
4. Directed staff to seek Board approval prior to any increase that would result in RCEA retail rates exceeding PG&E generation rates by 9.5%.

Based on the latest forecast it is likely that we will need to consider options beyond what the resolution has authorized and therefore are requesting an ad hoc subcommittee be formed that can receive regular risk updates and make recommendations to the Board.

Staff Recommendation

Approve the formation of an Energy Risk and Rates Ad Hoc Subcommittee through the end of Fiscal Year 2027-28 to receive regular risk updates and make recommendations to the Board, and appoint no more than 5 board members to serve on the committee.



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Attachments

None