VALLEY CLEAN ENERGY ALLIANCE

Staff Report – Item 9

To: Board of Directors

From: Mitch Sears, Interim General Manager

Subject: Regulatory Monitoring Report – Keyes & Fox

Date: October 14, 2021

Please find attached Keyes & Fox's September 2021 Regulatory Memorandum dated October 7, 2021, an informational summary of the key California regulatory and compliance-related updates from the California Public Utilities Commission (CPUC).

Attachment: Keyes & Fox Regulatory Memorandum dated October 7, 2021.

KEYES&FOX LLP

Valley Clean Energy Alliance

Regulatory Monitoring Report

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

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

Subject: Regulatory Update

Date: October 7, 2021

Summary

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

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

- **Ensuring Summer 2021 Reliability:** Parties including VCE filed testimony and rebuttal testimony, followed by briefs and reply briefs on September 20, 2021, and September 27, 2021, respectively. VCE's testimony focused on its Agricultural Demand Response pilot proposal. On September 23, 2021, the CPUC issued D.21-09-045, denying several applications for rehearing of D.21-03-056, the decision from the first phase of this proceeding. On September 30, 2021, the ALJ issued a Ruling taking official notice of the "Revised 2022 Summer Stack Analysis" prepared by CEC and adopted at its September 8, 2021 business meeting.

- **PG&E Regionalization Plan**: Settling parties filed a motion to request Commission approval of two settlement agreements on August 31, 2021. Parties filed comments and reply comments on the settlement agreements in September.

- **RPS Rulemaking:** The ALJ issued a Proposed Decision and Commissioner Rechtschaffen issued an Alternate Proposed Decision modifying the RPS program confidentiality rules. The modifications would significantly affect how long VCE's contract information is kept confidential. Separately, the ALJ issued a Ruling allowing parties of R.05-06-040, a rulemaking relating to confidentiality of information, to file comments on the pending PD and alternate PD.

- **IRP Rulemaking:** The ALJ issued a Ruling granting the motions to file under seal filed by VCE and 40 other LSEs regarding IRPs filed over a year ago on September 1, 2020, as well as biennial procurement compliance filings. Parties also filed opening comments in response to an August ALJ Ruling seeking comments on a proposed Preferred System Plan.

- **RA Rulemaking (2021-2022):** OhmConnect filed a Petition for Modification of D.20-06-031, seeking changes that would allow LSEs to use more demand response resources to meet their RA requirements. The first workshop to develop PG&E's Slice-of-Day proposal was held on the topic of Structural Elements.

- **PG&E 2022 ERRA Forecast:** Intervenor testimony was filed September 22, 2021.
- **PG&E's 2019 ERRA Compliance:** The Assigned Commissioner issued a Ruling consolidating this proceeding with SCE's and SDG&E's ERRA Compliance proceedings (A.20-04-002 and A.20-06-001, respectively).
- **PCIA Rulemaking:** Parties filed comments in response to an August Ruling on the Energy Division staff proposal to change the issue date of the Market Price Benchmark calculations. The ALJ also issued a Ruling requesting comments on ERRA and PCIA issues, to which parties filed comments on October 1, 2021.
- **PG&E's 2020 ERRA Compliance:** The ALJ issued a Ruling cancelling the evidentiary hearing after parties resolved disputed facts. A settlement conference between parties was also held.
- **Provider of Last Resort Rulemaking:** The Assigned Commissioner issued a Scoping Memo and Ruling on September 16, 2021.
- **2022-2023 Wildfire Fund Nonbypassable Charge Rulemaking:** The ALJ issued a Ruling requesting comments on a proposed 2022 Wildfire Fund Nonbypassable Charge. No party filed comments by the October 1, 2021 deadline.
- **PG&E's Phase 1 GRC:** No updates this month. In August, numerous parties, including a coalition of eight CCAs in PG&E's service territory, filed protests or responses to PG&E's 2023 Phase 1 general rate case (GRC) application. The prehearing conference was held August 30, 2021.
- **PG&E's Phase 2 GRC:** No updates this month. On August 25, 2021, the Assigned Commissioner issued an Amended Scoping Memo and Ruling, extending the deadlines and schedule in this proceeding.
- **Investigation into PG&E's Organization, Culture and Governance:** No updates this month. On August 18, CPUC President Batjer sent a letter to PG&E stating that she has directed CPUC staff to investigate whether to advance PG&E further within the Enhanced Oversight and Enforcement process.
- **Direct Access Rulemaking**: No updates this month. In August, CalCCA filed a response to a July application for rehearing filed by a coalition of parties supporting expansion of Direct Access, who challenged a June CPUC decision that recommended against any re-opening of Direct Access. This proceeding is otherwise closed.
- **RA Rulemaking (2019-2020):** No updates this month. Two applications for rehearing remain the only outstanding items to be addressed in this proceeding, which is now closed.
- **Miscellaneous Updates:**
    - A new Order Instituting Rulemaking adopting safety culture assessments under SB 901 is on the CPUC's October 7, 2021, meeting Agenda.
    - The CPUC fined PG&E $106 million for its botched October 2019 PSPS events, during which time its website didn't work and customers were not properly notified in advance of PSPS events. The penalty will be offset by $86 million based on the bill credits PG&E has already provided to some electric customers in 2019, resulting in a net penalty assessed on PG&E of approximately $20 million.
    - PG&E filed Advice Letter 6348-E, stating its intent to sell Carbon Free Energy generated in delivery year 2022 with the standards and criteria in Appendix P of PG&E's Conformed 2014 Bundled Procurement Plan.
    - In R.18-07-006, the CPUC issued a revised Scoping Ruling, opening a third phase of the proceeding to consider strategies to mitigate future energy rate increases. Comments on the Ruling are due October 15, 2021.

Ensuring Summer 2021 Reliability

On September 1, 2021, and September 10, 2021, parties including VCE filed testimony and reply testimony, respectively, on the Staff Concepts Proposal. On September 17, 2021, an Assigned Commissioner's Ruling responded to SCE testimony by clarifying that a separate resolution or decision is not necessary for the IOUs to pursue utility-owned storage projects that can be online by summer 2022. Parties including VCE filed briefs and reply briefs on September 20, 2021, and September 27, 2021, respectively. On September 23, 2021, the CPUC issued D.21-09-045, denying applications for rehearing of D.21-03-056 filed separately by The Protect Our Community Foundation (PCF), and CAlifornians for Renewable Energy (CARE) and filed jointly by Sierra Club, Union of Concerned Scientists, and the California Environmental Justice Alliance (CEJA). On September 30, 2021, the ALJ issued a Ruling taking official notice of the "Revised 2022 Summer Stack Analysis" prepared by CEC and adopted at its September 8, 2021 business meeting.

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

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

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

  - **Increase peak and net peak resources in 2022 and 2023**, including: (1) expedited resource procurement, (2) updates to RA requirements (3) support for CAISO's Capacity Procurement Mechanism authority, (4) analysis of need – particularly at net peak – and resources available to meet this need, in light of recent trends in weather and resource availability, (5) expedited IRP procurement, (6) Planning Reserve Margin adjustment for 2023, (7) interconnection, and (8) other opportunities to increase supply.
  - **Reduce peak and net-peak demand in 2022 and 2023**, including: (1) Flex Alert, (2) Critical Peak Pricing, (3) Emergency Load Reduction Program Pilot, (4) modifications to existing demand response programs (including base interruptible program, agricultural and pumping interruptible, air condition cycling), (5) new demand response programs or pilots, (6) EV participation in DR or load management, (7) measures to minimize loss of demand response enrollment, (8) rate structures, including pilot rates introduced for a limited period or limited to certain customer classes or subsets of such classes (9) other opportunities to reduce demand or net demand including virtual power plants, DER export, distributed generation.

  The Staff Concepts Paper offered a number of ideas to increase peak resources and reduce peak demand, including a modified version of VCE's proposal to tap into the load reduction/ shift potential available in the pumping sector. A CPUC Ruling requested parties comment on and expand on the modified version of VCE's proposal. Staff's concept proposal included a provision to hold PG&E harmless for any difference in cost recovery that would occur under such a pilot. It also proposed to design the experimental rate to incorporate the ideas in the 6-step Distributed Energy Resource & Demand Flexibility roadmap described by Energy Division Staff at the May 25, 2021, workshop on Advance DER and Demand Flexibility Management. VCE and other parties were encouraged to submit a more fleshed out proposal on this topic. Among the other concepts identified by Staff are allowing residential customers to participate in the ELRP program and get paid $1/kWh for demand reduction, implementing penalties on LSEs for failure to comply with D.19-11-016 procurement mandates, providing incentives to LSEs to accelerate procurement ordered under D.21-06-035, increasing RA non-compliance penalties, and establishing a new non-bypassable charge for cost recovery of costs associated with emergency procurement that adds additional reserve margin and does not already fit into an existing cost recovery mechanism.

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

The CEC's Summer 2022 Stack Analysis identifies the risk of potential energy shortfalls under both average and extreme weather planning reserve margins next summer. This analysis projects an additional 200 MW to 4,350 MW of resources may be required to ensure electric system reliability for peak and net-peak hours during summer 2022 without the use of contingency resources.

- **Analysis**: A June 10, 2021, Ruling initially limited additional testimony and consideration in this proceeding going forward to a discussion of proposals made by PG&E and CEJA. In response to the Governor's emergency proclamation, however, the Amended Scoping Memo and Ruling significantly expanded the scope to include other topics and issues that could result in additional resources to maintain grid reliability in 2022 and 2023. This could include additional or accelerated procurement mandates for LSEs, or other changes that could be implemented through LSEs to increase supply and decrease demand during peak summer times in 2022 and 2023.

  VCE's proposal to implement an Agricultural AutoDR Demand Flexibility pilot for customers on irrigation pumping tariffs could result in up to 5 MW of connected irrigation load being served, reducing those customers' bills as well as VCE's cost to serve its customers. PG&E and the California Large Energy Consumers Association filed reply testimony critiquing VCE's pilot proposal.

- **Next Steps**: A proposed decision is expected to be issued October 29, 2021, with a final decision expected November 18, 2021.

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

PG&E Regionalization Plan

On September 10, 2021, Parties, including VCE, filed comments on the August 31, 2021, motion for approval of settlement agreements, followed by reply comments on September 17, 2021.

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

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

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

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

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

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

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

RPS Rulemaking

On September 16, 2021, the ALJ issued a Proposed Decision (PD) and Commissioner Rechtschaffen issued an Alternate Proposed Decision (APD), both of which would significantly modify the RPS program confidentiality rules. On September 30, 2021, the ALJ issued a Ruling allowing parties of R.05-06-040, a rulemaking relating to confidentiality of information, to file comments on the pending PD and alternate PD.

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

  On September 18, 2020, the ALJ issued a Ruling attaching Staff's Proposed Framework for integrating RPS Procurement Plan requirements into the IRP proceeding uses a two-phased approach that makes a relatively minor change to RPS reporting in the current IRP cycle, while fully integrating all elements of RPS Procurement Plans into the next IRP cycle, proposed to commence in the 2023 calendar year (instead of 2022, under the current two-year cycle, although the issue of a two-year versus three-year cycle is not discussed). It is currently unclear when the CPUC will address this proposal.
- **Details**: Current rules allow LSEs to keep procurement prices confidential for the earlier of 3 years *after* the commercial operation date (COD) or 1 year following the expiration of a contract. Both the PD and APD find that this current window, which typically results in data being held confidential for 5-10 years from the date of contract execution, should be modified.
  - **Contracts Not Requiring CPUC Approval (e.g., VCE's contracts):** The PD would order that contract prices and terms become public **30 days** after *the earlier of* the COD or start of delivery date or 3 years after the contract execution date. The APD makes this information public *6 months after contract execution*.
  - **REC-Only Contracts**. The PD would require contract prices and terms for REC-only contracts to be made public 30 days after contract execution for existing facilities, and 30

days after the COD for new facilities. The APD makes this information public for both new and existing facilities 6 months after CPUC approval, or 6 months after the contract execution date where CPUC approval is not required.

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

- **Analysis**: The PD and APD would significantly reduce the period of time for which VCE and other LSEs could keep RPS data confidential, as detailed above.

- **Next Steps**: Comments on the PDs are due October 6, and replies are due October 11. Parties to R.05-06-040, who are not parties to R.18-07-003, may file comments on the PD and Alternate PD by October 20, 2021, and reply comments by October 25, 2021. Parties to R.18-07-003 may also file additional reply comments by October 25, 2021 limited to responding to the October 20, 2021 comments.

- **Additional Information**: Ruling allowing R.05-06-040 parties to file comments (September 30, 2021); Proposed Decision and Alternate Proposed Decision on RPS confidentiality (September 16, 2021); Ruling aligning IOU RPS Procurement Plan requirements with PCIA decision (May 26, 2021); Ruling extending deadline for draft 2021 RPS Procurement Plan (May 7, 2021); Ruling establishing issues and schedule for 2021 RPS Procurement Plans (March 30, 2021); D.21-01-005 directing retail sellers to file final 2020 RPS Procurement Plans (January 20, 2021); Ruling on Staff proposal aligning RPS/IRP filings (September 18, 2020); Scoping Ruling (November 9, 2018); Docket No. R.18-07-003.

IRP Rulemaking

On September 23, 2021, the ALJ issued a Ruling granting the motions to file under seal filed by VCE and 40 other LSEs regarding IRPs filed over a year ago on September 1, 2020, as well as biennial procurement compliance filings. On September 27, 2021, parties filed opening comments in response to an August ALJ Ruling seeking comments on a proposed Preferred System Plan.

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

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

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

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

  D.21-06-035 established a new procurement mandate of 11,500 MW of additional zero-emitting or RPS-eligible net qualifying capacity to be procured by 2026 by LSEs through long-term (10 or more years) contracts. It ordered that the resources from Diablo Canyon be replaced with at least 2,500 MW of zero-emitting resources. In addition, it specifies that 2,000 MW of the procurement mandate required for 2026 must be "long-lead-time" (LLT) resources, with half coming from long-duration storage and the other half from zero-emitting resources with an 80% or greater capacity factor, with the Decision pointing to geothermal and biomass as the resources best-suited to meet this category. VCE is permitted to use resources that were not online or in-development and contracted and approved by its Board as of June 30, 2020 to count towards its procurement requirements (i.e., contracts approved by the VCE Board and executed after June 30, 2020, can count towards VCE's procurement mandates). LSEs will ***not*** be given the option to opt out up front from providing their proportional share of the capacity required by D.21-06-035. The February 1, 2023 compliance filing will be the first check on the status of LLT resource procurement. VCE's new obligations and a description of the specific resource requirements for each subcategory of procurement are detailed in the following table.

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

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

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

- **Details**: The September 23, 2021 Ruling approving LSE motions to keep certain IRP procurement data confidential also directed LSEs to re-file certain updated information that has been informally provided to Energy Division staff through a formal filing by October 15, 2021.
- **Analysis**: The August 17, 2021 Ruling would accelerate the build-out of clean energy resources by adopting a more aggressive GHG reduction target for the electricity sector over the coming decade. It also poses numerous questions that suggest the CPUC is considering other major changes to procurement mandates that could either result in additional or accelerated procurement requirements for VCE or the imposition of a non-bypassable charge, including on VCE customers, to recover the costs of additional procurement needed for reliability or policy reasons. Compliance filings submitted in August and early September demonstrate VCE's progress towards meeting milestones and requirements with various CPUC procurement mandates.
- **Next Steps**: The schedule is as follows:
    - Procurement track: Reply comments on the August 17, 2021 Ruling are due October 11, 2021. A compliance filing providing updated IRP information must be filed by October 15, 2021.
    - General IRP oversight issues: A Proposed Decision on the IRP cycle (e.g., possibly moving from every 2 years to a 3-year cycle) is anticipated to be issued soon.
    - Preferred System Portfolio Development: A proposed decision and a final decision will be issued after reply comments are filed in response to the August Ruling.

- **Additional Information**: Ruling granting IRP confidentiality motions (September 23, 2021); Ruling proposing a PSP (August 17, 2021); Ruling extending procurement compliance filing deadline (July 10, 2021); D.21-06-035 establishing a 11,500 MW by 2026 procurement mandate (June 24, 2021); Ruling Setting August 1, 2021 Procurement Compliance Deadline (April 9, 2021); D.21-02-028 recommending portfolios for CAISO's 2021-2022 TPP (February 17, 2021); D.20-12-044 establishing a backstop procurement process (December 22, 2020); Scoping Memo and Ruling (September 24, 2020); Resolution E-5080 (August 7, 2020); Ruling on IRP cycle and schedule (June 15, 2020); Order Instituting Rulemaking (May 14, 2020); Docket No. R.20-05-003.

RA Rulemaking (2021-2022)

On September 9, 2021, OhmConnect filed a Petition for Modification of D.20-06-031. On September 22, 2021, the first workshop to develop PG&E's Slice-of-Day proposal was held on the topic of Structural Elements.

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

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

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

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

- **Details**: OhmConnect's Petition for Modification of D.20-06-031 requested that the CPUC raise the demand response Maximum Cumulative Capacity limit of 8.3% to 11.3%. OhmConnect says that the change is needed to create the room for growth envisioned in D.20-06-031 and meet the requirements of the Governor's Emergency Proclamation ordering state energy agencies to expedite and expand DR programs to reduce the likelihood of future rotating power outages.
- **Analysis**: The workshop process on PG&E's Slice of Day proposal could result in major changes to the RA program structure beginning in the 2024 RA compliance year. The new structure would seek to ensure load (including energy storage charging) will be met in all hours of the day, not just during gross peak demand hours and would move RA from a monthly compliance obligation to a seasonal obligation. The details of the framework would be further fleshed out through the specified workshop process and need to be approved by the CPUC in 2022. If OhmConnect's Petition for Modification is granted, it would allow LSEs like VCE to procure a higher percentage of demand response resources to meet its RA obligations than it is currently allowed under the RA compliance rules.
- **Next Steps**: The dates of the PG&E Slice of Day workshops, all to run from 10 a.m. to 3 p.m., are October 6, 2021, October 20, 2021 November 3, 2021, November 17, 2021, December 1, 2021, December 15, 2021, January 5, 2022, and January 19, 2022.
- **Additional Information**: OhmConnect's Petition for Modification (September 9, 2021); D.21-07-014 on restructuring the RA program with PG&E Slice of Day proposal (July 16, 2021); D.21-06-029 adopting local capacity obligations for 2022-2024, flexible capacity obligations for 2022, and refinements to the RA program (approved June 24, 2021); 2019 Resource Adequacy Report (March 19, 2021); Scoping Memo and Ruling for Track 3B and Track 4 (December 11, 2020); D.20-12-006 on Track 3.A issues (December 4, 2020); D.20-06-031 on local and flexible RA requirements and RA program refinements (June 30, 2020); Order Instituting Rulemaking (November 13, 2019); Docket No. R.19-11-009.

PG&E 2022 ERRA Forecast

Intervenor testimony was filed September 22, 2021.

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

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

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

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

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

The Joint CCAs protested the Application on the grounds PG&E has not demonstrated the relief it requests is just and reasonable, is in compliance with all applicable decisions, and prevents illegal cost shifts between bundled and unbundled ratepayers. Among the issues flagged in the Joint CCAs' protest are:

- The appropriateness of certain wildfire and catastrophic event costs included in PG&E's application that have yet to be approved.
- Changes to the utility's Green Tariff Shared Renewables (GTSR) program requested in a separate proceeding may have an impact on this proceeding.
- While the Joint CCAs support the intent of PG&E's proposal, this is not the appropriate proceeding to modify PG&E's non-vintage PCIA sub-account.
- PG&E's proposal to update its Application late in the proceeding to reflect a GRC Phase II decision must not circumvent the procedural rights of parties.
- The Joint CCAs will review the funds PG&E set aside for CCA Disadvantaged Community Green Tariff (DAC-GT) program and the Community Solar – Green Tariff (CS-GT) programs.
- PG&E's emergency summer 2021-2022 peak procurement costs must be consistent with the controlling commission decisions.

- **Details**: Testimony of the Joint CCAs recommends, among other provisions:
  - PG&E should correct the allocation of the gain on sale of its San Francisco headquarters across the ERRA and PCIA vintages to be consistent with the allocation of other common costs included in the PCIA.
  - The 2022 Indifference Amount and 2021 year-end PABA balance should be reduced to remove the above-market cost of solar resources used to supply PG&E's GTSR and DAC-GT programs.
  - PG&E should be required to provide Reviewing Representatives access to confidential data used in prior ERRA Forecasts as part of the existing Master Data Request.
  - PG&E's proposed transfer of the 2021 year-end ERRA balancing account balance to the latest PABA vintage should again be approved as an interim measure until this issue is resolved in the PCIA rulemaking proceeding.
  - PG&E should correct a miscalculation of the RA Charge included in its GTSR and Enhanced Community Renewables rates.
  - PG&E should be required to identify in future ERRA proceedings transactions executed by PG&E as the Central Procurement Entity 22 for Local RA and the effect of CPE procurement on the Cost Allocation Mechanism and PCIA.
- **Analysis**: This proceeding will establish the amount of the PCIA for VCE's 2022 rates and the level of PG&E's generation rates for bundled customers. The illustrative PCIA rates filed by

PG&E suggest a significant decrease in the PCIA for 2022, but these rates will change based on PG&E's November Update filing. For comparison, VCE residential customers' current (2021) PCIA charge is $0.04760/kWh and the proposed residential PCIA rate for 2022 is $0.02817/kWh.

- **Next Steps**: Rebuttal testimony is due October 6, 2021, a Joint Conference Statement (last day to confirm request for evidentiary hearing) is due October 7, 2021, a status conference is scheduled for October 8, 2021, the evidentiary hearing is scheduled for October 11-12, 2021, opening briefs are due October 22, 2021, reply briefs are due November 1, 2021, PG&E update is due November 8, 2021, comments on the PG&E update are due November 18, 2021, a proposed decision will be issued December 1, 2021, and a final decision is anticipated on December 13, 2021.
- **Additional Information**: Scoping Memo and Ruling (August 11, 2021); Notice of Prehearing Conference (July 15, 2021); Application (June 1, 2021); Docket No. A.21-06-001.

PG&E's 2019 ERRA Compliance

On September 7, 2021, the Assigned Commissioner issued a Ruling consolidating this proceeding with SCE's and SDG&E's ERRA Compliance proceedings (A.20-04-002 and A.20-06-001, respectively).

- **Background**: ERRA compliance review proceedings review the utility's compliance in the preceding year regarding energy resource contract administration, least-cost dispatch, fuel procurement, and the PABA balancing account (which determines the true up values for the PCIA each year). In its 2019 ERRA compliance application, PG&E requested that the CPUC find that its PABA entries for 2019 were accurate, it complied with its Bundled Procurement Plan in 2019 in the areas of fuel procurement, administration of power purchase contracts, greenhouse gas compliance instrument procurement, RA sales, and least-cost dispatch of electric generation resources. PG&E also requests that the CPUC find that during the record period PG&E managed its utility-owned generation facilities reasonably. Finally, PG&E requests cost recovery of revenue requirements totaling about $4.0 million for Diablo Canyon seismic study costs.

  D.21-07-013 approved a Settlement Agreement entered by all the parties that actively participated in Phase 1 of the proceeding. The Settlement Agreement resolved all but two contested issues between the parties. For the two contested issues, D.21-07-013 found that PG&E must (1) use the same methodology approved in D.20-02-047 (2020 ERRA decision) to calculate the Retained RPS adjustment and update the RPS adjustment with actual 2019 recorded sales data, and (2) retain the same PCIA vintage years for the power purchase agreements PG&E amended in 2019.

  On August 16, 202, PG&E filed an application for rehearing of the Phase 1 decision, D.21-07-013, with respect to its direction to proceed with evaluating potential disallowances for 2019 PSPS events in a Phase II of this proceeding.
- **Details**: The Ruling consolidates the Phase 2 ERRA compliance proceedings of PG&E, SCE, and SDG&E. The issues scoped for Phase 2 are:
  - What is the appropriate methodology for calculating a utility's unrealized volumetric sales and unrealized revenues resulting from PSPS events in any given record year? Based on this methodology, what are the utilities' (PG&E, SCE, and SDG&E) unrealized volumetric sales and unrealized revenues resulting from 2019 PSPS events?
  - Whether it is appropriate for the utilities to return the revenue requirement equal to the unrealized volumetric sales and unrealized revenue resulting from the PSPS events in 2019.
- **Analysis**: This phase of the proceeding will assess whether PG&E should be required to return its revenue requirement associated with unrealized sales associated with its 2019 PSPS events, and the methodology and inputs for calculating such disallowance. VCE's customers could

benefit from such a CPUC-determined disallowance, e.g., via a bill credit or reduced PG&E charges.

- **Next Steps**: Energy Division will host a workshop on the IOU PSPS methodology on October 26, 2021. IOU Phase 2 testimony is due November 5, 2021, Intervenor Phase 2 testimony is due January 17, 2022, IOU rebuttal testimony is due February 15, 2022, and a Joint Case Management Statement is due February 25, 2021.
- **Additional Information**: Ruling consolidating ERRA compliance proceedings (September 7, 2021); PG&E Application for Rehearing of D.21-07-013 (August 16, 2021); D.21-07-013 resolving Phase 1 (July 16, 2021); Joint Motion to Adopt Settlement Agreement (October 22, 2020); Amended Scoping Memo and Ruling (August 14, 2020); Scoping Memo and Ruling (June 19, 2020); PG&E's Application and Testimony (February 28, 2020); Docket No. A.20-02-009.

PCIA Rulemaking

On September 13, 2021, and September 22, 2021, parties filed comments in response to an August Ruling on the Energy Division staff proposal to change the issue date of the Market Price Benchmark calculations. On September 17, 2021, the ALJ issued a Ruling requesting comments on ERRA and PCIA issues, to which parties filed comments on October 1, 2021.

- **Background**: D.18-10-019 was issued on October 19, 2018, in Phase 1 of this proceeding and left the current PCIA in place, maintained the current brown power index, and adopted revised inputs to the benchmarks used to calculate the PCIA for energy RPS-eligible resources and resource adequacy capacity. Phase 2 relied primarily on a working group process to further develop a number of PCIA-related proposals. Three workgroups examined three issues: (1) issues with the highest priority: Benchmark True-Up and Other Benchmarking Issues; (2) issues to be resolved in early 2020: Prepayment; and (3) issues to be resolved by mid-2020: Portfolio Optimization and Cost Reduction, Allocation and Auction.

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

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

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

Details: The September Ruling requests comments in response to questions on ERRA data access, PCIA forecasting data access, confidential data consistency, year-end balances and crediting customers, and the ERRA trigger.

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

- **Analysis**: The issues on which the CPUC is requesting comments in the September Ruling impact CCAs' ability to gain access to confidential IOU data pertinent to the calculation and implementation of the PCIA, as well as the alignment of ERRA and PCIA proceedings.

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

  Reply comments on the September Ruling are due October 8, 2021.

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

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

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

PG&E 2020 ERRA Compliance

On September 14, 2021, the ALJ issued a Ruling cancelling the evidentiary hearing after parties resolved disputed facts. A settlement conference between parties was held September 24, 2021.

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

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

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

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

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

  The JCCAs dispute four issues with respect to PG&E's application and testimony: (1) the recovery of CAISO Tariff Section 37 sanctions of $43,500 recorded to the PABA and of $204,000 recorded to the ERRA; (2) the recovery of 2017 and 2018 Diablo Canyon Seismic Studies Balancing Account (DCSSBA) costs and the 2014 DCSSBA correction in the PABA; (3) the venue for review of recorded entries related to Central Procurement Entity procurement costs; and (4) the correct adjustment to the PABA for Green Tariff Shared Renewables entries.

- **Analysis**: This proceeding addresses PG&E's balancing accounts, including the PABA, providing a venue for a detailed review of the billed revenues and net CAISO revenues PG&E recorded during 2020. It also determines whether PG&E managed its portfolio of contracts and UOG in a reasonable manner. Both issues could impact the level of the PCIA in 2022 and 2023.

- **Next Steps**: Opening briefs are due October 19, 2021, reply briefs are due November 9, 2021, and a PD is anticipated for Q1 2022.
- **Additional Information**: Ruling cancelling evidentiary hearing (September 14, 2021); Scoping Memo and Ruling (June 21, 2021); Application (March 1, 2021); Docket No. A.21-03-008.

Provider of Last Resort Rulemaking

The Assigned Commissioner issued a Scoping Memo and Ruling on September 16, 2021.

- **Background**: A POLR is the utility or other entity that has the obligation to serve all customers (e.g., PG&E is currently the POLR in VCE's territory). In 2019 the Legislature passed SB 520, which defined POLR for the first time in statute, confirmed that each IOU is the POLR in its service territory, and directed the Commission to establish a framework to allow other entities to apply and become the POLR for a specific area (a "Designated POLR"). This rulemaking will implement SB 520.
- **Details**: The Scoping Memo and Ruling describes the issues that are within scope in the proceeding and the procedural schedule going forward, although most of the procedural dates currently lack specificity. Phase 1 of this OIR will address POLR service requirements, cost recovery, and options to maintain GHG emission reductions in the event of an unplanned customer migration to the POLR. Phase 2 will build on the Phase 1 decision to set the requirements and application process for other non-IOU entities (i.e., a CCA, Energy Service Provider, or third-party) to be designated as the POLR in place of an existing POLR. Phase 3 will address specific outstanding issues not resolved in Phase 1 and 2 of this proceeding.
- **Analysis**: This proceeding could impact VCE in several ways. First, in establishing rules for existing POLRs, it will address POLR service requirements, cost allocation, and cost recovery issues should a CCA or other LSE discontinue supplying customers resulting in the need for the POLR to step in to serve those customers. Second, in setting the requirements and application process for another entity to be designated as the POLR, it could create a pathway for a CCA or other retail provider to elect to become a POLR for its service area. The preliminary questions (Appendix B to the OIR) suggest these issues will include examining topics such as CCA financial security requirements, portfolio risk and hedging, CCA deregistration, CCA mergers, and CCA insolvency.
- **Next Steps**: A workshop to review the operation and expectation of POLR service, registration, and financial security requirements is scheduled for October 29, 2021. A ruling will be issued in Q4 2021 or Q1 2022 with questions to parties to comment on. Opening and reply comments will be due in Q1 2022.
- **Additional Information**: Scoping Memo and Ruling (September 16, 2021); Ruling scheduling prehearing conference (April 30, 2021); Order Instituting Rulemaking (March 25, 2021); Docket No. R.21-03-011.

2022-2023 Wildfire Fund Nonbypassable Charge Rulemaking

On September 8, 2021, the ALJ issued a Ruling requesting comments on a proposed 2022 Wildfire Fund Nonbypassable Charge. No party filed comments by the October 1, 2021 deadline.

- **Background**: This rulemaking continues to implement AB 1054, which extended a non-bypassable charge on ratepayers to fund the Wildfire Fund. The CPUC issued D.20-12-024 in December 2020 that continues the Wildfire Non-Bypassable Charge (NBC) amount of $0.00580/kWh for January 1, 2021, through December 31, 2021. The NBC amount of 2022 and 2023 will be established in this proceeding.

- **Details**: The proposed 2022 Wildfire Fund Non-Bypassable Charge is $0.0066/kWh, up from $0.0058/kWh in 2021.
- **Analysis**: VCE customers will pay the 2022 and 2023 Wildfire Fund Non-Bypassable Charge amounts established in this proceeding. The proposed charge for 2022 is increasing due to an under-collection of the revenue requirement in 2021 that has been added to the revenue requirement for 2022.
- **Next Steps**: A proposed decision will be issued in November, followed by a Decision in December. The same timeline will also apply in 2022 to establish the 2023 Wildfire Fund NBC amount.
- **Additional Information**: Ruling requesting comments on 2022 Wildfire Fund NBC (September 8, 20210: Scoping Memo and Ruling (June 8, 2021); Order Instituting Rulemaking (March 10, 2021); Docket No. R.21-03-001.

PG&E Phase 1 GRC

No updates this month. In August, numerous parties, including a coalition of eight CCAs in PG&E's service territory, filed protests or responses to PG&E's 2023 Phase 1 general rate case (GRC) application. The prehearing conference was held August 30, 2021.

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

  On August 25, 2021, the CPUC Executive Director granted PG&E's request to delay filing its next Phase 2 GRC application until September 30, 2024.
- **Details**: In their protest of PG&E's application, the Joint CCA parties identified the following list of preliminary issues they plan to examine or address in this proceeding:
  - **Compliance with the Commission's Cost Allocation Directives in D.20-12-005** (PG&E's most recently decided Phase 1 GRC decision), including PG&E's cost functionalization methodology, wildfire costs, and allocation of Customer Care costs.
  - **Reinvestments in and Recovery of Legacy Owned Generation Costs**, including solar contract renewals or the decommissioning of legacy owned assets, which impact Joint CCAs' customers through the PCIA and related vintaging of costs.
  - **Other Issues that May Require Further Investigation and Analysis**, including how costs related to PSPS Events should be tracked and allocated; whether and how any funds that PG&E receives as credits (such as Department of Energy settlement funds) should be allocated to departing load customers; and how PG&E's regionalization proposal impacts its relationship and dealings with CCAs and their customers.

  In August, TURN also filed a Motion (currently pending) requesting a Ruling requiring PG&E to supplement its proposal with an alternative spending plan that limits the growth in proposed spending by the rate of inflation.
- **Analysis**: This proceeding will set the revenue requirement, and thereby ultimately impact PG&E's rates, for 2023-2026. It will establish how the revenue requirement components will be functionalized, which impact whether the ultimately approved costs will be borne by PG&E bundled customers, unbundled customers like VCE customers, or both. It will also address

numerous other issues raised in PG&E's application that could impact rates, policies, and programs implemented by PG&E.

- **Next Steps**: The next step will be the issuance of a scoping memo and ruling that will provide the list of issues within the scope of the proceeding and the procedural schedule.
- **Additional Information**: Scoping Memo and Ruling (September 15, 2021); Ruling scheduling prehearing conference (August 19, 2021); PG&E Application (June 30, 2021); Docket No. A.21-06-021.

PG&E's Phase 2 GRC

No updates this month. On August 25, 2021, the Assigned Commissioner issued an Amended Scoping Memo and Ruling, extending the deadlines and schedule in this proceeding.

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

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

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

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

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

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

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

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

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

- **Details**: The Amended Scoping Memo and Ruling provides the procedural schedule for the remainder of the proceeding, including indicating that the proposed decision on all issues except for real-time pricing issues will be issued in October 2021, rather than September as previously indicated.
- **Analysis**: This proceeding will not impact the transparency between a bundled and unbundled customer's bills because of the Working Group 1 decision in the PCIA rulemaking, though the JCCAs recommend in testimony that more transparency be reflected in utility tariffs. However, it will affect the allocation of PG&E's revenue requirements among VCE's different rate classes. It will also affect distribution and PPP charges paid by VCE customers to PG&E. Further, PG&E includes a cost-of-service study the purpose of which is to establish the groundwork for separating net metering customers into a separate customer class in the utility's next rate case. If PG&E's proposed CCA fee revisions are adopted, it could increase the cost VCE pays to PG&E for various services, to the extent VCE uses these services.
- **Next Steps**: A proposed decision on non-RTP issues is anticipated for October 2021, with a final decision expected in November 2021. An evidentiary hearing on RTP issues is scheduled for January 24-26, 2021, followed by opening briefs in February 2022, reply briefs in March 2022, a proposed decision in June 2022, and a decision in July 2022.

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

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

No updates this month. On August 18, CPUC President Batjer sent a letter to PG&E stating that she has directed CPUC staff to investigate whether to advance PG&E further within the Enhanced Oversight and Enforcement process. Previously, the CPUC issued Resolution M-4852 in April 2021, placing PG&E into Step 1 of the Enhanced Oversight and Enforcement process it established when approving PG&E's bankruptcy plan of reorganization.

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

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

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

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

- **Details**: President Batjer's letter to PG&E identified "a pattern of self-reported missed inspections and other self-reported safety incidents," concluding that "this pattern of deficiencies warrants the fact-finding review." PG&E self-reported missed inspections of hydroelectric substations, distribution poles, and transmission lines. PG&E also reported missing internal targets for enhanced vegetation management and failing to identify dry rot in distribution poles treated with Cellon coating. Many of these issues occurred in High Fire Threat District areas.

- **Analysis**: President Batjer's letter indicates that PG&E could move further along the Enhanced Oversight and Enforcement process due to its pattern of deficiencies. The CPUC would have to issue a draft resolution (with an opportunity for parties to file comments), followed by a final resolution, to move PG&E into another step of the Enhanced Oversight and Enforcement process.
- **Next Steps**: The proceeding remains open, but there is no procedural schedule at this time.
- **Additional Information**: Letter from President Batjer to PG&E (August 18, 2021); Resolution M-4852 (April 15, 2021); Letter from President Batjer to PG&E (November 24, 2020); Ruling updating case status (September 4, 2020); Ruling on case status (July 15, 2020); Ruling on proposals to improve PG&E safety culture (June 18, 2019); D.19-06-008 directing PG&E to report on safety experience and qualifications of board members (June 18, 2019); Scoping Memo (December 21, 2018); Docket No. I.15-08-019.

Direct Access Rulemaking

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

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

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

  - Observed that Direct Access providers do not have a track record of relying on long-term contracts to meet their energy needs, which could impede the development of new, needed resources.
  - Noted that allowing expansion could undermine the long-term contracts that LSEs such as CCAs have already entered (i.e., due to load migration) and make it difficult for them to enter new contracts.
  - Stated that currently, the CPUC is not able to ensure that Direct Access expansion would not increase GHG emissions and other pollutants when compared to retaining the current cap, as Direct Access providers have historically relied primarily on unspecified power and lead to a net decline in clean energy procurement.
- **Details**: In their July Application for Rehearing, parties including the Alliance for Retail Energy Markets and the Direct Access Customer Coalition argued that:
  - The CPUC broke the law and abused its discretion when it disregarded the express duties imposed on it by SB 237.

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

CalCCA's August response argued that:

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

- **Analysis**: This proceeding determined the CPUC's recommendations to the Legislature regarding the potential future expansion of DA in California. D.21-06-033 recommending against expansion of Direct Access at this time could reduce the risk of load migration from CCAs (or IOUs) to ESPs.
- **Next Steps**: The only remaining item to be addressed in this proceeding is the Application for Rehearing.
- **Additional Information**: CalCCA Response to Application for Rehearing (August 13, 2021); Application for Rehearing of D.21-06-033 (July 29, 2021); D.21-06-033 recommending against direct access expansion (approved June 24, 2021); Ruling and Staff Report (September 28, 2020); Amended Scoping Memo and Ruling adding issues and a schedule for Phase 2 (December 19, 2019); Docket No. R.19-03-009; *see also* SB 237.

RA Rulemaking (2019-2020)

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

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

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

  The second Track 2 Decision, D.20-06-002, adopted implementation details for the central procurement of multi-year local RA procurement to begin for the 2023 compliance year in the PG&E and SCE (but not SDG&E) distribution service areas, including identifying PG&E and SCE as the central procurement entities for their respective distribution service areas and adopting a hybrid central procurement framework. The Decision rejected a settlement agreement between

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

In Track 3, D.19-06-026 adopted CAISO's recommended 2020-2022 Local Capacity Requirements and CAISO's 2020 Flexible Capacity Requirements and made no changes to the System capacity requirements. It established an IOU load data sharing requirement, whereby each non-IOU LSE (e.g., CCAs) will annually request data by January 15 and the IOU will be required to provide it by March 1. It also adopted a "Binding Load Forecast" process such that an LSE's initial load forecast (with CEC load migration and plausibility adjustments based on certain threshold amounts and revisions taken into account) becoming a binding obligation of that LSE, regardless of additional changes in an LSE's implementation to new customers.

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

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

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

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

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

- **Next Steps**: The only issues remaining to be addressed in this proceeding are WPTF's Applications for Rehearing. Remaining RA issues will be addressed in the successor RA rulemaking, R.19-11-009.

- **Additional Information**: D.20-09-003 denying PFMs filed by PG&E, CalCCA, and Joint Parties (September 16, 2020); WPTF's Application for Rehearing of D.20-06-028 (August 5, 2020);

WPTF's Application for Rehearing of D.20-06-002 (July 17, 2020); D.20-06-028 on Track 1 RA Imports (approved June 25, 2020); D.20-06-002 establishing a central procurement mechanisms for local RA (June 17, 2020); D.20-03-016 granting limited rehearing of D.19-10-021 (March 12, 2020); D.20-01-004 on qualifying capacity value of hybrid resources (January 17, 2020); D.19-12-064 granting motion for stay of D.19-10-021 (December 23, 2019); D.19-10-021 affirming RA import rules (October 17, 2019); D.19-06-026 adopting local and flexible capacity requirements (July 5, 2019); Docket No. R.17-09-020.

Glossary of Acronyms

AB	Assembly Bill
AET	Annual Electric True-up
ALJ	Administrative Law Judge
BioMAT	Bioenergy Market Adjusting Tariff
BTM	Behind the Meter
CAISO	California Independent System Operator
CAM	Cost Allocation Mechanism
CARB	California Air Resources Board
CEC	California Energy Commission
CPE	Central Procurement Entity
CPUC	California Public Utilities Commission
CPCN	Certificate of Public Convenience and Necessity
CTC	Competition Transition Charge
DA	Direct Access
DWR	California Department of Water Resources
ELCC	Effective Load Carrying Capacity
ERRA	Energy Resource and Recovery Account
EUS	Essential Usage Study
GRC	General Rate Case
IEPR	Integrated Energy Policy Report
IFOM	In Front of the Meter
IRP	Integrated Resource Plan
IOU	Investor-Owned Utility
ITC	Investment Tax Credit
LSE	Load-Serving Entity
MCC	Maximum Cumulative Capacity
OII	Order Instituting Investigation
OIR	Order Instituting Rulemaking
PABA	Portfolio Allocation Balancing Account
PD	Proposed Decision

PG&E	Pacific Gas & Electric
PFM	Petition for Modification
PCIA	Power Charge Indifference Adjustment
POLR	Provider of Last Resort
PSPS	Public Safety Power Shutoff
PUBA	PCIA Undercollection Balancing Account
PURPA	Public Utility Regulatory Policies Act of 1978 (federal)
QC	Qualifying Capacity
QF	Qualifying Facility under PURPA
RA	Resource Adequacy
RDW	Rate Design Window
ReMAT	Renewable Market Adjusting Tariff
RPS	Renewables Portfolio Standard
SCE	Southern California Edison
SED	Safety and Enforcement Division (CPUC)
SDG&E	San Diego Gas & Electric
TCJA	Tax Cuts and Jobs Act of 2017
TOU	Time of Use
TURN	The Utility Reform Network
UOG	Utility-Owned Generation
WMP	Wildfire Mitigation Plan
WSD	Wildfire Safety Division (CPUC)