VALLEY CLEAN ENERGY ALLIANCE

Staff Report – Item 8

To: Board of Directors

From: Mitch Sears, Interim General Manager

Subject: Regulatory Monitoring Report – Keyes & Fox

Date: July 8, 2021

Please find attached Keyes & Fox's June 2021 Regulatory Memorandum dated June 30, 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 June 30, 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:	June 30, 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:

- **IRP Rulemaking:** On June 24, 2021, the CPUC approved D.21-06-035, imposing an 11,500 MW by 2026 procurement mandate for new or incremental net qualifying capacity on LSEs to be met through long-term (10 year or longer) contracts. VCE's share of the overall incremental new procurement obligation is 44 MW by 2026.
- **Direct Access Rulemaking**: On June 24, 2021, the CPUC approved D.21-06-033, recommending against any re-opening of Direct Access at this time. This proceeding is now closed.
- **RA Rulemaking (2021-2022):** The CPUC issued a Proposed Decision on Track 3B.2 issues, which, if approved, would restructure RA to ensure load will be met in all hours of the day, and change RA to a seasonal, rather than a monthly, obligation. On June 24, 2021, the CPUC approved D.21-06-029, significantly increasing greater Bay Area local capacity requirements for 2022-2024, setting flexible capacity requirements for 2022, making changes to Maximum Cumulative Capacity (MCC) buckets, including resource availability on Saturdays and changes to the valuation of DR, adopting a new points-based penalty structure, and making other significant refinements to the RA program addressing issues scoped as Track 3B.1 and Track 4.
- **PG&E 2022 ERRA Forecast:** On June 1, 2021, PG&E filed its 2022 ERRA Forecast application, preliminarily forecasting that in 2022 the system average bundled service customer rate will increase by 2.4%, the system average Direct Access 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.
- **RPS Rulemaking:** Parties filed comments and replies in response to the April 22, 2021 Ruling on the ReMAT program. On June 24, 2021, the CPUC approved Resolution E-5143, modifying the RPS citation rules and penalty amounts for non-compliance. VCE's Draft 2021 RPS Plan is to be filed on July 1, 2021.

- **PG&E's 2019 ERRA Compliance:** The ALJ issued a Proposed Decision on Track 1 issues, and parties filed opening comments.
- **PCIA Rulemaking:** Parties filed comments on a Ruling providing Energy Division's proposal regarding the timeline for issuing Market Price Benchmark calculations used in the annual ERRA Forecast proceedings to calculate the PCIA. On June 23, 2021, CalCCA and several CCAs jointly filed an Application for Rehearing of the Phase 2 Decision, D.21-05-030.
- **Ensuring Summer 2021 Reliability:** The ALJ issued a Ruling directing PG&E and the California Environmental Justice Alliance to update their respective demand response program proposals for further consideration. On June 24, 2021, the CPUC approved D.21-06-027, modifying D.21-03-056 with respect to the day-of trigger in the emergency load reduction program (ELRP) by resolving an inconsistency in the decision.
- **PG&E's Phase 2 GRC:** Parties filed reply briefs on issues except for real-time pricing. The ALJ issued a Ruling directing PG&E to provide an exhibit containing illustrative rates and bill impacts resulting from several specified marginal cost scenarios.
- **Provider of Last Resort Rulemaking:** A prehearing conference was held June 11, 2021.
- **2022-2023 Wildfire Fund Nonbypassable Charge Rulemaking:** The Assigned Commissioner issued a Scoping Memo and Ruling.
- **PG&E's 2020 ERRA Compliance:** The Assigned Commissioner issued a Scoping Memo and Ruling.
- **PG&E Regionalization Plan**: No updates this month. The ALJ held a status conference on May 18, 2021.
- **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.
- **Investigation into PG&E's Organization, Culture and Governance:** No updates this month. On April 15, 2021, the CPUC issued Resolution M-4852, placing PG&E into Step 1 of the Enhanced Oversight and Enforcement process it established when approving PG&E's bankruptcy plan of reorganization.
- **Wildfire Cost Recovery Methodology Rulemaking:** No updates this month. An August PG&E Application for Rehearing remains pending regarding D.19-06-027, establishing criteria and a methodology for wildfire cost recovery, which has been referred to as a "Stress Test" for determining how much of wildfire liability costs that utilities can afford to pay.

IRP Rulemaking

On June 24, 2021, the CPUC approved D.21-06-035, imposing an 11,500 MW by 2026 procurement mandate for new or incremental net qualifying capacity on LSEs to be met through long-term (10 year or longer) contracts. VCE's share of the overall new procurement obligation is 44 MW.

- **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 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 will aggregate LSE portfolios, analyze the aggregate portfolio, and adopt 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).

- **Details**: The D.21-06-035 establishes 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. In contrast to the initial proposed decision, the adopted Decision did not include a procurement mandate on IOUs for additional fossil fuel resources. It specifically orders 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. Capacity factor measures how often a generating facility runs and is calculated by dividing the actual electricity output by the maximum possible output over a period of time. 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)		Diablo Replacement	Total
				Long-Duration Storage	**Zero-Emitting Generation Resources**	**Minimum zero-emitting capacity by 2025** ***(subset of 2023, 2024, and 2025 columns)***	
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.	

To calculate individual resource contributions to the required capacity, marginal ELCC values will be used and all capacity values will be based on September Net Qualifying Capacity. Commission staff will finalize the marginal ELCC values that will be used to count the procurement required to be online in 2023 and 2024 by no later than August 31, 2021. Commission staff will also provide guidance on what resource counting LSEs should assume for geothermal, long duration storage, out-of-state wind, and offshore wind for online years through 2028.

IRP 2030 GHG Target: The PD states (p.19) that the CPUC "strongly anticipate[s] the adoption of those [LSE IRP] plans that achieve the 38 MMT GHG limit by 2030, assuming that the aggregated portfolio of all LSEs achieves the necessary reliability levels." LSEs were required to provide IRP scenarios under both a 38 MMT and 46 MMT GHG limit by 2030 in their IRPs filed in September 2020. Note that the 38 MMT a significant decrease from the 46 MMT scenario that had previously been assumed to be the base case for 2030 GHG planning in IRPs.

Allocation of the Procurement Mandate Across LSEs: To allocate LSE procurement requirements, for IOUs and CCAs, D.21-06-035 used updated LSE load forecasts. **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).

Compliance: 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. LSEs will be required to submit procurement information twice annually to show progress toward the capacity procurement requirements in this decision. Backstop procurement to be conducted by the IOUs may be ordered by the CPUC once annually, with the costs allocated to the deficient LSEs and/or their customers. Deficient LSEs will be subject to penalties for failing to deliver the capacity required in 2023-2025 at the level of the net cost of new entry. Penalties will not be assessed on any LSE failing to procure the LLT resources required in 2026; LSEs showing a good faith effort to procure these resources may be granted an extension until 2028 before facing potential penalties. The February 1, 2023 compliance filing will be the first check on the status of LLT resource procurement.

- **Analysis**: D.21-06-035 substantially increased the total amount of procurement required compared to the 7,500 MW proposed in a February 2021 Ruling. It creates new and additional procurement obligations and associated compliance obligations on VCE, including procurement of long-duration storage and zero-emitting resources with high capacity factors. A portion of VCE's overall obligations under D.21-06-035 may have already been achieved through contracts VCE has executed since June 30, 2020, although the carve-outs for specific resource types (e.g., long-duration storage) would require additional procurement.
- **Next Steps**: The schedule is as follows:
    - Procurement track: No next steps at this time.
    - General IRP oversight issues: A Proposed Decision on moving from two-year to three-year IRP cycle is anticipated to be issued soon.
    - Preferred System Portfolio Development: A ruling proposing PSP is anticipated in the coming months, followed by a proposed decision in Q3 2021 and a final decision by the end of 2021.
- **Additional Information**: 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); Ruling on staff reliability analysis and 7,500 MW by 2025 procurement mandate (February 22, 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); Ruling requesting comments on IRP evaluation (December 8, 2020); Ruling providing Staff Proposal on resource procurement framework (November 19, 2020); Scoping Memo and Ruling (September 24, 2020); Resolution E-5080 (August 7, 2020); Ruling on IRP cycle and schedule (June 15, 2020); Ruling on backstop procurement and cost allocation mechanisms (June 5, 2020); Order Instituting Rulemaking (May 14, 2020); Docket No. R.20-05-003.

Direct Access Rulemaking

On June 24, 2021, the CPUC approved D.21-06-033, recommending against any re-opening of Direct Access. This proceeding is now 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 addressed the SB 237 mandate requiring the CPUC to provide recommendations to the Legislature on "implementing a further direct transactions reopening schedule, including, but not limited to, the phase-in period over which further direct transactions shall occur for all remaining nonresidential customer accounts in each electrical corporation's service territory." The Commission was required to make certain findings regarding the consistency of its recommendation with state climate, air pollution, reliability and cost-shifting policies as follows:
    - Be consistent with the state's GHG emission reduction goals, specifically the RPS and IRP process.
    - Not increase criteria air pollution or toxic air contaminants.

- Ensure electric system reliability and specifically be consistent with the RA and IRP programs.
- Not cause undue cost shifting to bundled service customers or direct transaction customers, specifically the PCIA and other mechanisms used to prevent cost shifting.

Details: D.21-06-033 recommends 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." The PD observes 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:

- Observe 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.
- Note 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.
- State 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.

- **Analysis**: This proceeding determined the CPUC's recommendations to the Legislature regarding the potential future expansion of DA in California. The Decision recommending against expansion of Direct Access at this time could reduce the risk of load migration from CCAs (or IOUs) to ESPs.
- **Next Steps**: This proceeding is now closed.
- **Additional Information**: 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 (2021-2022)

On June 10, 2021, the CPUC issued a Proposed Decision (PD) on Track 3B.2 issues, which address broader RA capacity structure changes. Parties filed comments on the PD on June 30, 2021. On June 24, 2021, the CPUC approved D.21-06-029, adopting local capacity requirements for 2022-2024, flexible capacity requirements for 2022, and refinements to the RA program addressing issues scoped as Track 3B.1 and Track 4.

- **Background**: This proceeding is divided into 4 tracks. The first two tracks have concluded, and the proceeding is now focused on Track 3B.1, 3B.2, and Track 4 issues, described in more detail below. Track 3B.1 is considering incentives for LSEs that are deficient in year-ahead RA filings, refinements to the MCC buckets adopted in D.20-06-031, and other time-sensitive issues. Track 3B.2 includes examination of the broader RA capacity structure to address energy attributes and hourly capacity requirements. Track 4 is considering the 2022 program year requirements for System and Flexible RA, and the 2022-2024 Local RA requirements.

  D.20-12-006 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.

- **Details**: The **Proposed Decision on Track 3B.2** would reject CalCCA/SCE's proposal for restructuring the RA program, and would instead find 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 would direct parties to collaborate to develop a final restructuring proposal based on PG&E's slice-of-day proposal through a series of workshops.

  PG&E Slice of Day Framework is to 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). To avoid administrative burdens associated with slice-of-day requirements for each month, PG&E recommended moving from a monthly RA obligation to a seasonal obligation.

  The PD would direct parties to develop a final RA restructuring proposal by holding at least five workshops over the next approximately six months to develop implementation details based on PG&E's slice-of-day proposal. The workshops should cover the following implementation details: (1) Structural Elements; (2) Resource Counting; (3) Need Determination and Allocation; (4) Hedging Component; and (5) Unforced Capacity Evaluation (UCAP) and Multi-Year Requirement Proposals. An opportunity to comment will follow the workshops. The Commission would consider the final proposed framework and intend to issue a decision in the third quarter of 2022 with details for implementation in 2023 for the 2024 RA compliance year.

  D.21-06-029 resolved Track 3B.1 and Track 4 issues, establishing the following:

  2022-2024 Local Capacity Requirements: D.21-06-029 adopts the CAISO LCR Study requirements for 2022-2024 for all local areas, but states agreement with CalCCA and PG&E that there is value in continuing the previously established LCR Working Group. The LCR Working Group is directed to submit its report into the successor RA proceeding by February 2022 addressing a series of issues including LCR reliability criteria.

  2022 Flexible Capacity Requirements: D.21-06-029 adopts the amounts from the CAISO's Final FCR report, noting that on brief review (since the final CAISO report was filed on May 14, 2021) the amounts appear to be reasonable.

  2022 System Requirements & Planning Reserve Margin (PRM): This section of D.21-06-029 focuses on the PRM, which the CPUC increased from 15% to 17.5% on an interim basis for 2021 and 2022 in D.21-03-056, pending any further modifications in this proceeding. In D.21-06-029, the CPUC states agreement with parties opposing a further increase in the summer 2022 PRM, noting that the Energy Division has been authorized to facilitate a working group to develop assumptions for use in a loss of load expectation (LOLE) study, and that the study will be issued in the coming months for consideration in a future phase of the proceeding. Accordingly, it retains the 17.5% PRM for summer 2022.

  Maximum Cumulative Capacity (MCC) Buckets: D.21-06-029 adopts a series of changes to the MCC buckets, which function as limits on the amount of RA that may be procured from resources with different characteristics. The revisions and other determinations include the following:

  - All buckets will require availability of a resource on Saturday for the 2022 RA compliance year given the Summer 2020 experience with extreme peak loads occurring on some weekend days. This has 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 specified in the PD.

- Revising 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.
- Declining to adopt the Energy Division's proposal to eliminate Category 2 (available from 8 to 16 hours daily) due to a lack of sufficient justification.
- Retaining the DR Category cap at 8.3% at the LSE level, declining to adopt an expanded or lowered cap or other changes proposed by different parties.

DR QC Methodology: A related issue centers on refinements to how the qualifying capacity of DR resources is determined, related in part to concerns that DR is being overvalued in the current load impact protocol (LIP) system. The Energy Division had proposed an interim 5% derate to DR QC for 2022 pending further analysis. Rather than proceed to the ELCC methodology proposed by the CAISO, or the derate proposed by the Energy Division, D.21-06-029 requests 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. The recommendations are requested by March 18, 2022, to be considered for implementation during the 2023 RA compliance year.

Demand Response Adders: Currently DR resources are credited with capacity adders based on the PRM (15%) and transmission and distribution loss factors to account for avoided reserves and reduced losses relative to transmission-connected supply resources.

RA Penalties: D.21-06-029 adds 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 in which 1 point is accrued for non-summer RA deficiencies and 2 points are accrued for summer RA deficiencies. Penalties would be doubled when the accrued number of points is 6-10 and tripled when the accrued points are 11 or greater. Deficiencies of less than 1% of the LSE's system RA requirement will not result in points being accrued. Points under the new penalty system will only be accrued for month-ahead deficiencies, not year-ahead deficiencies, will expire 24 months after the violation, and the provider of last resort will not accrue points from unexpected load returns for which a system RA waiver is granted. This structure will be effective for the 2022 RA compliance year.

- **Analysis**: The Proposed Decision on Track 3B.2 issues 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 later approved by the Commission.

  D.21-06-029 provides a series of refinements to the RA program that could impact VCE's RA obligations and compliance. The Local capacity requirements for the Greater Bay Area are significantly higher for 2022-2024 than those previously adopted for 2021-2023. The changes to RA penalties go into effect in the 2022 RA compliance year and would result in significant increases for repeated RA non-compliance. In addition, changes to the MCC buckets go into effect for the 2022 RA compliance year and impact the eligibility requirements of DR resources and change resource availability hours, and require availability on Saturdays. A working group will be established to make recommendations regarding DR measurement and verification changes that could take effect in RA compliance year 2023. Finally, the overall local and flexibility capacity requirements that are established will be used to set VCE's specific RA requirements.

- **Next Steps**: Reply comments on the PD are due July 5, 2021, and the PD may be heard, at the earliest, at the Commission's July 15 meeting.

- **Additional Information**: 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); Proposed Decision on Track 3B.2 (June 10, 2021); 2022 Final Flexible Capacity Needs Assessment (May 14, 2021); 2022 Final Local Capacity Technical Study Report (April 30, 2021); Ruling providing Energy Division's demand response proposal (April 19, 2021); 2019 Resource Adequacy Report (March 19, 2021); Ruling providing Energy Division's Track 3B.2 proposal (March 17, 2021); Ruling providing Energy Division's Track 4 proposal (February 1, 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); Amended Scoping Memo on Track 3 (July 7, 2020); D.20-06-031 on local and flexible RA requirements and RA program refinements (June 30, 2020); Scoping Memo and Ruling (January 22, 2020); Order Instituting Rulemaking (November 13, 2019); Docket No. R.19-11-009.

PG&E 2022 ERRA Forecast

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.

- **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.
- **Details**: 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

- **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**: Protests or responses to PG&E's application are due July 3, 2021. PG&E anticipates updating the revenue requirements and its rate proposal on November 8, 2021.
- **Additional Information**: Application (June 1, 2021); Docket No. A.21-06-001.

RPS Rulemaking

On June 9, 2021, and June 23, 2021, respectively, parties filed comments and replies in response to the April 22, 2021 Ruling on the ReMAT program. On June 24, 2021, the CPUC approved Resolution E-5143, modifying the RPS citation rules and penalty amounts for non-compliance.

- **Background**: This proceeding addresses ongoing RPS issues. VCE submitted its Final 2020 RPS Procurement Plan on February 19, 2021, and its 2019 RPS Compliance Report on August 3, 2020. Draft 2021 RPS Plans are due July 1, 2021.

  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).

  D.21-01-005, issued in January 2021, praised VCE's draft 2020 RPS Procurement Plan, pointing to it as a "best example" or "best practice" in seven sections of the Plan for other LSEs to emulate in their updates. D.21-01-005 also identified several areas for VCE and most other LSEs to update or modify in its Final 2020 RPS Procurement Plan, which VCE completed through its February 19, 2021 submission.

- **Details**: Resolution E-5143 authorizes the CPUC to penalize retail sellers for non-compliance with requirements for RPS Procurement Plans, as well as penalties for non-compliance with RPS reporting requirements and non-responsiveness to requests for information by Staff related to the implementation and administration of the RPS program. It was revised prior to approval to clarify that deficient *draft* RPS Plans, such as the one due July 1, 2021, are not subject for referral for citation. Resolution E-5143 also describes the process for challenging a penalty under the RPS Citation Program and details the applicable penalties for specified violations.

  The April 22 Ruling requested responses to a series of questions, including whether other retail sellers, such as CCAs, should be eligible to participate in the ReMAT program. It also requests information as to whether modifications are needed to allow renewable systems paired with storage to be eligible under ReMAT. CalCCA filed comments in response, recommending that retail sellers like CCAs be allowed to participate in the ReMAT program and arguing that costs and benefits of ReMAT should be fairly allocated to prevent cost shifting.

- **Analysis**: VCE plans to submit its draft 2021 RPS Procurement Plan on July 1, 2021 and is well positioned to achieve its RPS compliance obligations, having already procured the majority of its RPS obligations for the both the current 2021-2024 compliance period and for future compliance periods through 2030. Resolution E-5143 expands the RPS citation program to allow the CPUC to issue penalties related to non-compliance with requirements for RPS Plans, among other violations with the RPS program.

- **Next Steps**: Draft 2021 RPS Procurement Plans are due July 1, 2021, and the 2020 RPS Compliance Report is due August 2, 2021. Comments on the draft 2021 RPS Procurement Plans are due July 30, 2021, reply comments are due August 8, 2021, and motions to update draft 2021 RPS Procurement Plans are due August 9, 2021. A PD aligning RPS and IRP filings is anticipated to be issued soon, followed by an opportunity for comments and reply comments

- **Additional Information**: 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); Draft Resolution E-5143 on RPS Citation Program (April 23, 2021); Ruling on ReMAT program (April 22, 2021); Ruling establishing issues and schedule for 2021 RPS Procurement Plans (March 30, 2021); Joint Petition for Modification of D.13-05-034 (February 11, 2021); D.21-01-005 directing retail sellers to file final 2020 RPS Procurement Plans (January 20, 2021); Order Granting Rehearing of D.17-08-021 (November 23, 2020); D.20-10-005 resuming and modifying the ReMAT program (October 16, 2020); Ruling on Staff proposal aligning RPS/IRP filings (September 18, 2020); D.20-08-043 resuming and modifying the BioMAT program (September 1, 2020); D.20-02-040 correcting D.19-12-042 on 2019 RPS Procurement Plans (February 21, 2020); Ruling on RPS confidentiality and transparency issues (February 27, 2020); D.19-12-042 on 2019 RPS Procurement Plans (December 30, 2019); D.19-06-023 on implementing SB 100 (May 22, 2019); D.19-02-007 (February 28, 2019); Scoping Ruling (November 9, 2018); Docket No. R.18-07-003.

PG&E's 2019 ERRA Compliance

On June 10, 2021, the ALJ issued a Proposed Decision on Track 1 issues. Parties filed opening comments on the PD on June 30, 2021.

- **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.

  The Joint CCAs' testimony identified $175.4 million in net reductions to the 2019 PABA balance that should be made, excluding interest. The Joint CCAs argue this amount should be credited back to customers. PG&E's rebuttal testimony stated it will make all but $33.6 million of those adjustments as part of its August 2020 accounting close.

  On October 22, 2020, PG&E, Joint CCAs, and Cal Advocates filed a Joint Motion to Adopt Settlement Agreement. The Settlement Agreement resolves all but two of the disputed issues in Phase I of the proceeding. PG&E agreed with certain accounting errors identified by the Joint CCAs. PG&E also committed to provide additional, specific information requested by the Joint CCAs simultaneous with its ERRA Compliance applications and simplify the presentation of that information, resolving the Joint CCAs concern with transparency of the PG&E data supporting entries to the ERRA, PABA and related balancing accounts. PG&E and the Joint CCAs agreed to engage in discussions about the approach to Resource Adequacy solicitations governed by Appendix S of PG&E's 2014 Bundled Procurement Plan. Finally, PG&E agreed to rebill all commercial and industrial CCA customers assigned an incorrect vintage.

- **Details**: The Phase 1 PD would approve a Settlement Agreement entered by all the parties that actively participated in Phase 1 of the proceeding. The Settlement Agreement resolves all but two contested issues between the parties. As described in more detail below, for the two contested issues, the PD would find 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 the first contested issue, PG&E had argued that the appropriate amount that should be transferred from the PABA to the ERRA should be $69.3 million, and that the $92.9 million figure ordered in the 2020 ERRA Forecast Decision was erroneous. The Joint CCAs argued that the correct adjustment should be $95.3 million, calculated using actual 2019 recorded sales. The PD would agree with the Joint CCAs and order PG&E to transfer $95.3 million, including any associated interest retroactive to January 2019, from the PABA to the ERRA, as a result of updating the Retained RPS adjustment that was ordered in the 2020 ERRA Forecast Decision with actual 2019 recorded sales data.

On the second contested issue, Joint CCAs had argued that that the vintage year certain RPS PPAs, which are PCIA-eligible, should be changed to 2019, the year in which the contracts were renegotiated. PG&E asserted that, in the Resolutions approving the renegotiated PPAs, the CPUC had authorized PG&E to retain the existing vintages for the amended PPAs. The PD finds that the Resolution had addressed the amended PPA vintaging issue and that it was therefore not appropriate to address these issues in the current proceeding.

- **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 2019. It also determines whether PG&E managed its portfolio of contracts and UOG in a reasonable manner. Efforts from the Joint CCAs to date will reduce the level of the PCIA for VCE's customers in 2021 and/or 2022. The PD would side with the Joint CCAs on this issue of the appropriate amount that should be transferred from the PABA to the ERRA, further reducing the level of the PCIA for VCE customers. It would side with PG&E on the issue of retaining the existing vintaging for several amended PPAs. Joint CCAs' argue that the vintaging issue has not been previously determined by the CPUC, and that the re-vintaging of these contracts, which could reduce VCE customers' associated PCIA charges, should be addressed in ERRA compliance proceedings by the CPUC, rather than by CPUC Staff through the advice letter process.
- **Next Steps**: Reply comments are due July 5, 2021, and the PD may be heard, at the earliest, at the CPUC's July 15, 2021, meeting. The schedule for Phase II of this proceeding has not been issued yet.
- **Additional Information**: Proposed Decision (June 10, 2021); Joint Motion to Adopt Settlement Agreement (October 22, 2020); Ruling modifying extending deadline for briefs and reply briefs (October 12, 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 June 15, 2021, and June 22, 2021, parties including CalCCA filed comments on a Ruling providing Energy Division's proposal regarding the timeline for issuing Market Price Benchmark calculations used in the annual ERRA Forecast proceedings to calculate the PCIA. On June 23, 2021, CalCCA, Central Coast Community Energy Authority, East Bay Community Energy, Peninsula Clean Energy, Silicon Valley Clean Energy Authority, and City of San José jointly filed an Application for Rehearing of the Phase 2 Decision, D.21-05-030.

- **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.

- **Details**: 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.

  The May 20, 2021 ALJ Ruling requested comments on an attached proposal by the Energy Division regarding the timeline for issuing Market Price Benchmark calculations used in the annual ERRA Forecast proceedings to calculate the PCIA. CalCCA's comments on the Ruling recommended implementation of the Staff Proposal next year (i.e., during the IOUs' 2023 ERRA forecast cases). CalCCA also recommended that SCE and PG&E be required to file their ERRA forecast applications on May 1 each year instead of June 1. Targets Q1 2022 implementation for this year's ERRA forecast proceedings, similar to SCE's request in its 2022 ERRA forecast application.

- **Analysis**: D.21-05-030 eliminated the cap-and-trigger framework for PCIA changes. Further, it denied certain proposals from Working Group 3. Importantly, the current PCIA calculation does not fully value certain of the IOUs' portfolio attributes, but D.21-05-030 rejected the allocation of these valuable PCIA attributes to CCAs as proposed by Working Group 3. D.21-05-030 also largely allowed the IOUs to avoid any consequences for failing to optimize their above-market portfolios, including an IOU decision to simply decline all offers to buy out current above-market contracts. While D.21-05-030 failed to take on meaningful reform to the problematic ERRA forecast proceeding timelines and transparency issues, ALJ Ruling would potentially increase the timelines for parties to litigate that proceeding.

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

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

  - **August 18, 2021**: IOUs each file a Tier 2 advice letter to justify its methodology for determining how much of its PCIA-eligible Resource Adequacy is reserved as part of its Bundled Portfolio Plan.
  - **August 18, 2021**: After meeting and conferring with parties to this proceeding, IOUs jointly file a Tier 2 advice letter to propose (1) a methodology for calculating potential Voluntary Allocation shares based on vintaged, annual load forecasts, and (2) a methodology for dividing their RPS portfolios into shares to be allocated.
  - **September 1, 2021**: PG&E, SDG&E and SCE must host a joint workshop within 14 days of filing the advice letter to discuss the proposed methodologies
  - **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**: 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.

Ensuring Summer 2021 Reliability

On June 15, 2021, the ALJ issued a Ruling directing PG&E and the California Environmental Justice Alliance (CEJA) to update their respective demand response program proposals for further consideration. On June 24, 2021, the CPUC approved D.21-06-027, modifying D.21-03-056 with respect to the day-of trigger in the emergency load reduction program (ELRP) by resolving an inconsistency in the decision.

- **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.

  The Scoping Memo and Ruling identified two primary issues as in scope: how to (1) increase energy supply and (2) decrease demand during the peak demand and net demand peak hours in the event that a heat storm similar to the August 2020 storm occurs in the summer of 2021.

  VCE's opening testimony provided its proposal for an Agricultural AutoDR Demand Flexibility Pilot, which could made available to customers on irrigation pumping tariffs.

  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 establishes 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 would be five years, 2021-2025. After-the-fact pay-for-performance would 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.

The rehearing requests of D.21-03-056 concerned the use of fossil-fueled resources and the limits (or lack thereof) that the Decision placed on them as summer 2021 reliability resources. The CPUC's Order on rehearing found that the evidence it relied on was sufficient for indicating a need for capacity resources, that no intervenor's rights to due process were violated, and that nothing prohibits the CPUC ordering procurement of natural gas resources where it deems them necessary. The Order left certain aspects of the rehearing requests related to the use of fossil fueled back-up generation unaddressed.

- **Details**: The Ruling directs PG&E and CEJA to "refresh" their "Residential Rewards Pilot Program" and "Just Flex Rewards" proposals, respectively, through testimony served on July 7. All parties may then serve reply testimony by July 21 that responds to the CEJA Just Flex Rewards and PG&E Residential Rewards Pilot Program proposal refreshes. For reference, CEJA's Just Flex Rewards proposal would target and prioritize low-income and disadvantaged community households by allowing them to affirmatively opt-in when a Flex Alert is issued and receive a fixed $10 payment per event for taking actions to reduce demand. PG&E's "Residential Rewards Pilot Program" would leverage existing and newly installed smart thermostats to provide 30 to 45 MW of load reduction by providing performance incentives without penalty for DR events for residential bundled and CCA participants who enroll.

  D.21-06-027 modifies D.21-03-056 to clarify guidance regarding the ELRP day-of trigger. For reference, the ELRP is intended to provide the ability for the CAISO and IOUs to request load reductions during emergency conditions of high grid stress. . D.21-06-027 clarifies that the ELRP will have both day-of and day-ahead triggers for Group A participants (certain non-residential customers and aggregators that do not participate in DR programs), without an option for participants to opt-out of the day-of trigger. The IOUs are directed to file a joint supplemental Tier 1 AL implementing the change within 15 days of the adoption of a Decision.

- **Analysis**: D.21-06-027 resolves an inconsistency in D.21-03-056 by directing the inclusion of a day-of trigger for Group A participants in the ELRP. D.21-03-056 did not address VCE's proposed Agricultural AutoDR Demand Flexibility Pilot, and the June 10, 2021, Ruling has limited additional testimony and consideration, at least for now, to a discussion of proposals made by PG&E and CEJA.

- **Next Steps**: PG&E and CEJA testimony refreshing their proposals are due July 7, 2021. All parties may then serve reply testimony by July 21 that responds to the CEJA Just Flex Rewards and PG&E Residential Rewards Pilot Program proposal refreshes.

- **Additional Information**: 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's Phase 2 GRC

Parties filed reply briefs on June 10, 2021. The ALJ issued a Ruling on June 16, 2021, directing PG&E to provide an exhibit containing illustrative rates and bill impacts resulting from several specified marginal cost scenarios.

- **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.

- **Details**: 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.

- **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**: PG&E was directed to provide an exhibit containing illustrative rates and bill impacts resulting from several specified marginal cost scenarios by July 16, 2021. A CPUC decision on non-RTP issues is anticipated for October 2021. Rebuttal testimony on RTP issues is due July 30, 2021, followed by an evidentiary hearing September 20-23, 2021, and a decision on RTP issues in May 2022.
- **Additional Information**: 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.

Provider of Last Resort Rulemaking

A prehearing conference was held June 11, 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. It provides for a two-phased rulemaking so that the POLR requirements for the current POLRs can be established prior to addressing a framework for a Designated POLR. Phase 1 will focus on the issues necessary for a comprehensive framework for the existing POLRs (IOUs). It 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 set rules that allow a different entity (i.e., a CCA, ESP, or a third-party) to be designated as POLR, including setting the requirements and application process. Emergent issues and cross-over issues will be considered in both phases depending on the circumstances.

- **Details**: CalCCA's April 2021 comments on the OIR provided the following recommendations:
  - The POLR should provide service for a short duration (three – six months) from short term procurement with costs allocated to those that receive POLR service.
  - Existing structures (e.g., Financial Security Requirements, Transitional Bundled Service, System RA Waiver for the POLR in limited circumstances, etc.) can be used directly while others can be expanded or adjusted for the purpose of addressing POLR needs (e.g., Load Transfer and CCA implementation time frames and processes).
  - CPUC should examine ways in which retail providers could voluntarily take on customer service from defaulting LSEs in a "next to last provider" arrangement which could obviate or reduce the need for a POLR.
  - CPUC should ensure that rules regarding procurement are imposed equitably on all LSEs such that the requirements are stable and transparent in a manner that LSEs can procure as necessary to comply with requirements while providing reliable, affordable, and environmentally sound resources in a manner that minimizes the risk of LSE default.
- **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**: TBD.
- **Additional Information**: 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 June 8, 2021, the Assigned Commissioner issued a Scoping Memo and Ruling.

- **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 Scoping Memo and Ruling identified the only issue in this proceeding as determining the 2022 and 2023 Wildfire Fund Non-Bypassable Charge amounts.
- **Analysis**: VCE customers will pay the 2022 and 2023 Wildfire Fund Non-Bypassable Charge amounts established in this proceeding.

- **Next Steps**: The procedural schedule shows no activities until September 2021. In September, the Department of Water Resources will transmit a notice to CPUC identifying the proposed NBC amount for 2022, and CPUC will issue a Ruling seeking comments. 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**: Scoping Memo and Ruling (June 8, 2021); Order Instituting Rulemaking (March 10, 2021); Docket No. R.21-03-001.

PG&E 2020 ERRA Compliance

On June 21, 2021, the Assigned Commissioner issued a Scoping Memo and Ruling.

- **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.
- **Details**: 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.
- **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**: Intervenor testimony is due July 12, 2021, rebuttal testimony is due August 13, 2021, evidentiary hearings are scheduled for September 13-17, 2021, opening briefs are due October 19, 2021, reply briefs are due November 9, 2021, and a PD is anticipated for Q1 2022.
- **Additional Information**: Scoping Memo and Ruling (June 21, 2021); Application (March 1, 2021); Docket No. A.21-03-008.

PG&E Regionalization Plan

No updates this month. The ALJ held a status conference on May 18, 2021.

- **Background**: PG&E was directed to file a regionalization proposal as a condition of CPUC approval of its Plan of Reorganization in I.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. CCA responses/protests sought more information on the implications of regionalization on CCA customers, CCA operations, and CCA-PG&E coordination; PG&E's overarching purpose, goals, and metrics to judge success of regionalization; the delineation between centralized and decentralized functions in PG&E's application; and budgets and cost recovery related to regionalization, among other issues. CCAs also identified various concerns specific to their CCAs (e.g., EBCE's and MCE's service areas would both be split across two PG&E regions; SJCE expressed concern with its service area being assigned to the Central Coast region; Pioneer expressed concern that it would be the only CCA in its region, which would be the only region not to be "anchored" by an urban area).
- **Details**: PG&E submitted its updated regionalization proposal on February 26, 2021. 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.
- **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 this issue has not been explicitly addressed and remains unclear at this time. As part of Region 2, VCE would be grouped with several northern counties in central and eastern California.

- **Next Steps**: TBD.
- **Additional Information**: 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.

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.

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

No updates this month. On April 15, 2021, the CPUC issued Resolution M-4852, 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.

The September 4 Ruling filed in the PG&E Safety Culture proceeding (I.15-08-019) and PG&E Bankruptcy proceeding (I.19-09-016) 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.

- **Details**: Resolution M-4852 placed 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.
- **Analysis**: PG&E must adhere to its Corrective Action Plan or the CPUC could move it into an additional 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**: 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.

Wildfire Cost Recovery Methodology Rulemaking

No updates this month. An August 7, 2019, PG&E Application for Rehearing remains pending regarding the CPUC's recent Decision establishing criteria and a methodology for wildfire cost recovery, which has been referred to as a "Stress Test" for determining how much of wildfire liability costs that utilities can afford to pay (D.19-06-027).

- **Background**: SB 901 requires the CPUC to determine, when considering cost recovery associated with 2017 California wildfires, that the utility's rates and charges are "just and reasonable." In addition, and notwithstanding this basic rule, the CPUC must "consider the electrical corporation's financial status and determine the maximum amount the corporation can pay without harming ratepayers or materially impacting its ability to provide adequate and safe service."

  D.19-06-027 found that the Stress Test cannot be applied to a utility that has filed for Chapter 11 bankruptcy protection (i.e., PG&E) because under those circumstances the CPUC cannot determine essential components of the utility's financial status. In that instance, a reorganization plan will inevitably address all pre-petition debts, include 2017 wildfire costs, as part of the bankruptcy process. The framework proposed for adoption in the PD is based on an April 2019 Staff Proposal, with some modifications. The framework requires a utility to pay the greatest amount of costs while maintaining an investment grade rating. It also requires utilities to propose ratepayer protection measures in Stress Test applications and establishes two options for doing so.

PG&E's application for rehearing challenges the CPUC's prohibition on applying the Stress Test to utilities like itself that have filed for Chapter 11 bankruptcy. PG&E's rationale is that SB 901 requires the CPUC to determine that the stress test methodology to be applied to all IOUs. Several parties filed responses to PG&E's application for rehearing disagreeing with PG&E.

- **Details**: N/A.
- **Analysis**: This proceeding established the methodology the CPUC will use to determine, in a separate proceeding, the specific costs that the IOUs (other than PG&E) may recover associated with 2017 or future wildfires.
- **Next Steps**: The only matter remaining to be resolved in this proceeding is PG&E's application for rehearing. This proceeding is otherwise closed.
- **Additional Information**: PG&E Application for Rehearing (August 7, 2019); D.19-06-027 (July 8, 2019); Assigned Commissioner's Ruling releasing Staff Proposal (April 5, 2019); Scoping Memo and Ruling (March 29, 2019); Order Instituting Rulemaking (January 18, 2019); Docket No. R.19-01-006. *See also* SB 901, enacted September 21, 2018.

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)