VALLEY CLEAN ENERGY ALLIANCE

Staff Report – Item 8

To: Board of Directors

From: Keyes & Fox, Regulatory Consultant

Subject: Regulatory Monitoring Report – Keyes & Fox

Date: September 8, 2022

Please find attached Keyes & Fox's August 2022 Regulatory Memorandum dated August 31, 2022, 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 August 31, 2022.

KEYES&FOX LLP

EQ Research

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 Jason Hoyle, Principal Analyst, EQ Research, LLC
Subject:	Regulatory Update
Date:	August 31, 2022

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 August 1, VCE submitted its 2022 Incremental Procurement Compliance Filing. During July, PG&E submitted Advice Letters updating its system reliability contracts and providing its Rate Implementation Plan, and a Notice providing a progress update on its efforts to fulfill its reliability obligations.

- **RPS Rulemaking:** On August 29, the Commission issued Resolution E-5220 approving PG&E's Renewable Market Adjusting Tariff (ReMAT) Program tariff and PPA with modifications. On August 15, VCE filed its Motion to Update the draft RPS Procurement Plan.

- **RA Rulemaking (2023-2024):** On August 29, D.22-08-039 adopted the monthly regional wind effective load carrying capability (ELCC) values from the Energy Division's Regional Wind ELCC Study for the 2023 resource adequacy (RA) year and directed the Parties to develop further proposals for quantifying demand response qualifying capacity.

- NEW**Microgrid:** On July 6, the ALJ issued a Ruling requesting comments on a Staff Proposal for the Microgrid Incentive Program (MIP). On August 8, the CPUC issued D.22-08-025 denying an SDG&E request for rehearing of D.21-07-011.

- NEW**Building Decarbonization:** On August 8, the CPUC issued a Proposed Decision that would adopt a Staff Proposal to eliminate gas line extension allowances, the 10-year refundable payment option, and the 50% discount payment option provided under the current gas line extension rules. The elimination would apply to all customers in all customer classes for new applications for gas line extensions submitted on or after July 1, 2023.

- NEW**Transportation Electrification:** On August 9, the CPUC issued D.22-08-024 adopting the plug-in electric vehicle (PEV) submetering protocol and adopting electric vehicle supply equipment (EVSE) communication protocols. Under this Decision, large investor-owned utilities (including PG&E) and small multi-jurisdictional utilities are required to implement the submetering protocol for all customers with PEVs and customer-owned submeters

- NEW**Commercial EV Real-Time Pricing Pilot:** On August 9, the CPUC issued D.22-08-002 approving the Marginal Generation Capacity Cost Study for use by PG&E when calculating Real-Time Pricing rates, adopting the Real-Time Pricing settlement, and closing A.19-11-019. Opt-in enrollment for the Real-Time Pricing Pilot for commercial electric vehicles begins October 1, 2023.

- NEW**Demand Flexibility:** The OIR was issued by the Commission on July 22. Opening comments were filed by VCE and 47 other parties, and a pre-hearing conference is scheduled for September 16.

- NEW**Demand Response Programs (2023-2027):** On July 5, the Assigned Commissioner issued a Scoping Memo and Ruling defining the scope of issues and providing a procedural schedule for Phase 1.

- **PCIA Rulemaking:** On July 19, the CPUC issued D.22-07-008 on PCIA Data Access, resolving Phase 2 issues related to data access and voluntary allocations in market price benchmark calculations. On August 4, the ALJ issued a Ruling requesting comment on long-term fixed-price RPS transactions and providing a Staff Proposal for Incorporating Long-Term RPS Transactions into the RPS MPB.

- **Provider of Last Resort Rulemaking:** On July 15, the CPUC issued a Disposition Letter accepting PG&E AL 6589-E_E-A_E-B on financial security requirements for CCAs which became effective as of August 6.

- **PG&E 2023 Phase 1 GRC:** On July 22, PG&E filed its Track 2 request for a reasonableness review of recorded costs and recovery of $241 million in costs over two years. On August 9, PG&E filed a Case Management Statement reporting no settled issues among the Parties and withdrawing its revenue requirement request for two disputed projects. Track 1 Evidentiary Hearings were held August 15-26, and Keyes & Fox LLP cross examined a panel of PG&E witnesses on their rebuttal to the Joint CCAs' re-vintaging testimony during the hearings.

- **PG&E ERRA Forecast (2023):** On August 4, the Assigned Commissioner issued a Scoping Memo and Ruling setting forth the issues and a schedule intended to meet the deadline for the final 2022 Commission meeting allow for new rates to be effective January 1, 2023.

- **PG&E 2019 ERRA Compliance:** On July 14, the CPUC issued D.22-07-009 extending the statutory deadline for the proceeding by an additional six months until March 1, 2023 in order to resolve the Phase 2 issues related to Public Safety Power Shutoff events.

- **PG&E 2020 ERRA Compliance:** On August 11, the CPUC issued D.22-08-009 extending the statutory deadline in this proceeding through 2023 to provide an opportunity to address the Phase 2 issues related to unrealized sales and revenues resulting from PG&E's Public Safety Power Shutoff events in 2020.

- **PG&E 2021 ERRA Compliance:** On August 9, the Assigned Commissioner issued a Scoping Memo and Ruling defining the issues for consideration, finding that evidentiary hearings are needed, and providing a procedural schedule intended to conclude the proceeding within 18 months.

- **PG&E Regionalization Plan:** On July 25, PG&E met with the Regionalization Stakeholder Group and presented an activity schedule for future meetings and reporting.

- **Utility Safety Culture Assessments:** On July 22, the ALJ issued a Ruling seeking comments on policy questions for safety culture assessments and distributing the Staff Safety Culture Concept Paper 1.

- **Other Dockets:** Provides a summary and status update of other tracked dockets that are either closed or inactive.

IRP Rulemaking

On August 1, VCE submitted its 2022 Incremental Procurement Compliance Filing. During July, PG&E submitted Advice Letters updating its system reliability contracts and providing its Rate Implementation Plan, and a Notice providing a progress update on its efforts to fulfill its reliability obligations.

Background: 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.

D.21-06-035 established a new Mid-Term Reliability (MTR) 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. **VCE's incremental obligations, identified in Table 6, are 8 MW by 2023, 23 MW by 2024, 6 MW by 2025, 4 MW of long-duration storage and 4 MW of zero-emitting resources by 2026**. In addition, 10 MW out of its 2023-2025 procurement requirements must be met through zero-emitting generating capacity that is available from 5-10pm daily.

While each LSE is responsible for meeting procurement obligations to serve its own customers, D.19-11-016 directed IOU procurement on behalf of LSEs that either a) opt out of self-procurement or b) failed to acquire their share of required capacity after electing to do so. Similarly, D.21-06-035, while not allowing for LSEs to opt out of self-procurement, directed the IOUs to procure capacity on behalf of LSEs that failed to deliver their share of required energy or capacity, called backstop procurement.

D.22-02-004 adopted a 2021 Preferred System Plan (PSP) and certified VCE's 2020 IRP. VCE's next IRP is due November 1.

D.22-05-015 adopted Modified Cost Allocation Mechanism (MCAM) principles and methodologies that only apply to any future backstop and opt-out procurement authorized in the IRP process, but not other cost allocation situations such as those related to a central procurement entity. IOUs were required to file Tier 2 advice letters on MCAM implementation by July 18, 2022. The MCAM is based on the original Cost Allocation Mechanism (CAM) adopted in D.06-07-029. It provides a mechanism for recovery of the net costs of electric resource procurement obligations mandated in D.19-11-016 (3,300 MW) and D.21-06-035 (11,500 MW) through nonbypassable charges (NBCs) levied against customers of non-utility LSEs.

Backstop procurement costs are charged directly to customers of the deficient LSE, as a separate line item on the bill. Administrative costs are charged over a 10-year period and contract costs are charged over the life of the contract (generally 10 or more years), and Commission staff will allocate the resource adequacy (RA) value of backstop procurement annually to the LSE over the life of the contract(s), but backstop procurement does not convey any RPS attributes associated with the procured resources, although LSEs may obtain those RPS attributes through voluntary allocation.

2022 IRP Planning Targets

A June 15 Ruling adopted planning targets for 2035, namely 30 MMT and 25 MMT. These targets are in addition to the requirements in D.22-02-004, which requires LSEs to meet their proportional share of the 2030 target of 38 MMT, and plan for a 2030 target of 30 MMT. Each LSE will have four benchmarks and must show how it intends to reach each of the benchmarks. The four benchmarks are as follows:

- For 2030: VCE's proportional share of 38 MMT = 0.112 MMT
- For 2035: VCE's proportional share of 30 MMT = 0.088 MMT
- For 2030: VCE's proportional share of 30 MMT = 0.085 MMT
- For 2035: VCE's proportional share of 25 MMT = 0.070 MMT

VCE's final energy forecast is provided in the Load Forecasts and GHG Benchmarks spreadsheet and its confidential final load forecast was provided by the Commission on July 1.

Details: On July 20, PG&E submitted AL 6658-E with amendments to system reliability contracts approved in AL 6033-E (Procurement Toward Procurement Requirements Under D.19-11-016 – Nexus Renewables and NextEra North Central Valley).

On July 25, the CPUC posted the 2022 Procurement Summary (2021 Procurement Summary) for D.19-11-006 procurement requirements based on LSE filings from February 1. All LSEs had met their August 1, 2021 Tranche 1 obligations as of February 2022 except for PG&E and SDG&E which had shortfalls of 69.6 MW and 16.6 MW, respectively. On July 25, PG&E issued Notice that not all project contracts approved by Resolution E-5140 will be online in time to meet the August 1 Tranche 2 deadline.

On July 29, PG&E submitted AL 6654-E-A (replacing AL 6654-E in its entirety) providing its Rate Implementation Plan pursuant to D.22-05-015 to implement cost recovery associated with reliability contracts procured to meet the MCAM targets established in D.19-11-016 and Mid-Term Reliability targets established in D.21-06-035.

On August 1, VCE submitted its 2022 Incremental Procurement Compliance Filing.

Analysis: The 2022 IRP emphasizes the increasingly integrated nature of planning and procurement activities and requires LSEs to present connections among its procurement obligations for RA, reliability, energy and capacity, and the RPS. LSEs are also required to plan for multiple GHG targets in future benchmark years in their IRPs. Under the MCAM Decision (D.22-05-015), a deficiency in fulfilling RA and reliability procurement obligations results in additional, likely higher, costs to the deficient LSE's customers for at least the next decade, and the lengthy duration of both backstop procurement costs and allocation of backstop procurement resources could easily result in unnecessary and inefficient over-procurement of resources if triggered. In July, the CPUC released its Procurement Summary findings that no LSEs were deficient in meeting reliability procurement obligations under D.19-11-016 as of the February 2022 compliance filings.

Next Steps: VCE's next IRP is due November 1, 2022.

Additional Information: PG&E AL 6686-E (August 19, 2022); VCE 2022 Incremental Procurement Compliance Filing (August 1, 2022); PG&E AL 6654-E-A (July 29, 2022); CPUC 2022 Procurement Summary (July 25, 2022); PG&E AL 6658-E (July 20, 2022); Ruling on final load forecasts and GHG benchmarks (June 15, 2022); D.22-05-015 on Modified Cost Allocation Mechanism (May 23, 2022); Ruling establishing process for load forecasts and GHG benchmarks for 2022 IRP (April 20, 2022);

D.22-02-004 adopting 2021 Preferred System Plan (December 22, 2021); D.21-06-035 establishing a 11,500 MW by 2026 procurement mandate (June 24, 2021); Resolution E-5140 (April 19, 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); PG&E AL 6033-E (December 22, 2020); Scoping Memo and Ruling (September 24, 2020); Resolution E-5080 (August 7, 2020); Order Instituting Rulemaking (May 14, 2020); Docket No. R.20-05-003.

RPS Rulemaking

On August 29, the Commission issued Resolution E-5220 approving PG&E's Renewable Market Adjusting Tariff (ReMAT) Program tariff and PPA. On August 15, VCE filed its Motion to Update the draft RPS Procurement Plan.

Background: This proceeding addresses ongoing RPS issues. VCE submitted its Final 2021 RPS Procurement Plan on February 17, 2022, its Draft 2022 RPS Procurement Plan on July 1, and its 2020 RPS Compliance Report on August 2, 2021.

Renewable Market Adjusting Tariff (ReMAT) Program

The Renewable Market Adjusting Tariff (ReMAT) program is a feed-in tariff program for small renewable energy generators less than 3 MW in size and was established by AB 1969 and amended by SB 380, SB 32, and SB 2 (1X). The program began in 2008 and offers a fixed-price standard contract to eligible renewable resources (i.e., Qualifying Facilities under the federal Public Utilities Regulatory Policies Act) for exporting electricity to California's three large IOUs. Electricity generated under the ReMAT program counts towards the IOUs' RPS targets. D.21-12-032 directed the three large IOUs to each file a Tier 2 advice letter modifying their ReMAT tariffs and standard PPAs to accommodate the eligibility of facilities enhanced with storage, establish a de minimis threshold for each product category, and provide a process for the IOUs to aggregate remaining capacity to meet their individual share of the statewide ReMAT capacity target.

Voluntary Allocation and Market Offer (VAMO)

In addition, ongoing implementation issues of the Voluntary Allocation and Market Offer process (VAMO) ordered in the PCIA proceeding are considered in the RPS proceeding. Under VAMO, LSEs are first offered an election to take up to their load share percentage of the IOUs' PCIA-eligible RPS portfolio as a direct allocation from the IOU. In the second part of the process, called the Market Offer (MO), the IOUs will offer for sale the remaining portions of their RPS portfolios that were not claimed by LSEs in the Voluntary Allocations.

An April 11 Ruling identified requirements for 2022 RPS Procurement Plans and established two parallel tracks in the proceeding. Track 1 addresses the IOU's proposed Market Offer process and Track 2 addresses retail electricity sellers' 2022 RPS Plans.

An April 21 Ruling established revised dates for the submission of the Market Offer Process document. Pursuant thereto, the Joint IOUs submitted the Market Offer Process document on May 2, and each IOU filed a confidential sales strategy on May 16 to complete the Market Offer Process documentation.

Track 1: Voluntary Allocation / Market Offer Process

The Joint IOUs filed their proposed Market Offer process on May 2. The IOUs proposed that in the first step, the Joint IOUs offer Voluntary Allocations at the Market Price Benchmark (MPB) in 10% increments of each LSE's forecasted annual load share. The Joint IOUs proposed to have LSEs indicate the amounts they are taking under the Voluntary Allocation and sign pro forma Voluntary Allocation Contracts in July 2022. Then, in the second step, the Joint IOUs proposed that remaining

RPS energy not claimed by LSEs in the Voluntary Allocation will be offered to all market participants through the Market Offer process.

On May 23, PG&E submitted modifications (AL 6551-E-A) to its pro forma Market Offer Contract (AL 6551-E) in response to Protests filed by the Alliance for Retail Energy Markets and CalCCA. PG&E modified the Market Offer contract to differentiate the offered products based on whether the resource is eligible for RPS compliance.

On June 24, the Commission issued D.22-06-034 establishing rules for the PCC classification of resources obtained through the VAMO process. The Decision draws a clear distinction between RPS resources procured through Voluntary Allocation versus those procured through the Market Offer mechanism. Even though an LSE procures a "slice" of the IOU's RPS resource portfolio through each mechanism, the PCC classification of RPS resources procured through Voluntary Allocation does not change, while RPS resources procured through the Market Offer mechanism, particularly those with PCC-0 classification, will be treated as if they were a newly contracted resource and will not necessarily retain their original PCC classification. In response to comments filed by CalCCA, the Decision clarified that LSEs who choose not to claim Voluntary Allocations must provide an explanation for that decision in their RPS Plans. On June 29, the CPUC issued Resolution E-5216 approving the Joint IOUs' Voluntary Allocation Pro Forma Contracts (PG&E AL 6517-E and AL 6517-E-A).

Track 2: RPS Plans

Under the April 11 Assigned Commissioner's Ruling, 2022 RPS Plans must be forward looking through 2032 and should inform the Commission of the Retail Seller's activities and plans to procure 65% of RPS resources from long-term contracts of 10 or more years for all compliance periods beginning with the current compliance period that started on January 1, 2021, among other requirements.

VCE filed its Draft 2022 RPS Procurement Plan on July 1. VCE's Draft Plan demonstrates that VCE is well positioned to meet or exceed all RPS requirements in the current RPS Compliance Period 4 (2021-2024), as well as in RPS Compliance Period 5 (2025-2027) and beyond. VCE indicated in its Draft 2022 RPS Procurement Plan that it does not plan to participate in VAMO.

Details: On August 1, PG&E filed AL 6666-E describing proposed modifications to its ReMat program and PPA to comply with the requirement in D.20-08-046 (Attachments A & B) that with contracts for procurement of power, capacity, or reliability with a term of 15 years or more, PG&E obtain both an acknowledgement that the operator has considered long-term climate risk and the operator's climate risk safety plan, if available.

On August 16, the Commission issued a Disposition Letter accepting PG&E's AL 6662-E on ReMAT pursuant to Resolution E-5209, effective July 25. On July 25, PG&E submitted AL 6662-E Modifications to PG&E's ReMAT Program Tariff Pursuant to Resolution E-5209. New tariff prices by resource classification are:

- As-Available Non-Peaking $49.02/MWh
- As-Available Peaking $50.72/MWh
- Baseload $73.50/MWh

On August 29, the CPUC issued Resolution E-5220 approving PG&E ALs 6528-E / 6528 E-A ReMAT Program tariff and PPA with modifications. The modifications required by the Commission include removal of PG&E's proposed negotiation process, modifying the definition of "baseload facility" to include an 80% capacity factor, and a finding that energy storage is an enhancement to a ReMAT-eligible resource and does not count towards the capacity cap.

Analysis: Recent changes to the ReMAT program require PG&E to obtain climate risk information from projects, establish standard-offer PPA prices, remove PG&E's proposed negotiation process, and clarify that energy storage is a project enhancement that does not count towards the capacity cap. Overall, these changes provide more favorable conditions for the small-scale renewable energy projects that are eligible for the ReMAT program and enable these projects to incorporate storage without affecting their eligibility. These changes will encourage development of more small-scale renewable energy projects with storage.

Next Steps:

Track 1: VAMO

- **September 16, 2022:** IOUs Issue Market Offer Solicitation
- **Week of September 19-23, 2022:** Participants' Webinar
- **September 30, 2022:** Bids Due
- **October 14, 2022:** IOUs Notify Qualified Participants
- **October-November 2022:** Agreements Executed
- **November 2022:** IOU Submits Agreement for CPUC Approval
- **3Q 2022:** Proposed Decision on Market Offer process
- **3Q 2022:** Disposition on Tier 2 Market Offer Pro Forma Contract Advice Letters

Track 2: 2022 RPS Plans

- **4Q 2022:** Proposed Decision on LSEs' draft RPS Procurement Plans
- **1Q 2023:** LSEs file final 2022 RPS Plans

Additional Information: CPUC Resolution E-5220 (August 29, 2022); VCE Motion to Update Draft 2022 RPS Procurement Plan (August 15, 2022); PGE AL 6605-E-A (August 3, 2022); VCE 2021 RPS Compliance Report (August 1, 2022); PG&E AL 6666-E (August 1, 2022); PG&E AL 6662-E (July 25, 2022); VCE 2022 Draft RPS Procurement Plan (July 1, 2022); CPUC Resolution E-5209 (June 29, 2022); D.22-06-034 establishing rules for PCC classification (June 24, 2022); Resolution E-5216 approving Joint IOUs' Voluntary Allocation Pro Forma Contracts (June 29, 2022); PG&E AL 6605-E (May 24, 2022); PG&E AL 6551-E-A (May 23, 2022); Ruling on Procedural Schedule (May 20, 2022); Market Offer Process proposal by Joint IOUs (May 2, 2022); PG&E AL 6528-E-A (April 25, 2022); Ruling on RPS Track 1 schedule (April 21, 2022); Ruling seeking comments on Voluntary Allocations and PCC issues (April 18, 2022); PG&E AL 6517-E-A (April 11, 2022); Ruling identifying RPS Plan requirements (April 11, 2022); Amended Scoping Ruling expanding scope (April 6, 2022); PG&E AL 6551-E (April 4, 2022); PG&E AL 6528-E (March 15, 2022); Joint Motion by IOUs Concerning Review of Market Offer Process (March 10, 2022); PG&E AL 6517-E (February 28, 2022); VCE's Final 2021 RPS Procurement Plan (February 17, 2022); D.22-01-004 on draft 2021 RPS Procurement Plans (January 18, 2022); D.21-12-032 (December 17, 2021); Docket No. R.18-07-003.

RA Rulemaking (2023-2024)

On August 29, D.22-08-039 adopted the monthly regional wind effective load carrying capability (ELCC) values from the Energy Division's Regional Wind ELCC Study for the 2023 resource adequacy (RA) year and directed the Parties to develop further proposals for quantifying demand response qualifying capacity.

Background: In Track 3B.2 of the 2021-2022 RA Rulemaking (R.19-11-009), D.21-07-014 rejected proposals for restructuring the Resource Adequacy (RA) program and directed the Parties to hold additional workshops.

The December 2, 2021, Scoping Memo and Ruling divided the proceeding into an Implementation Track and Reform Track. The Reform Track encompasses consideration of a final proposed framework and the slice-of-day workshop report.

The Implementation Track is sub-divided into Phases 1, 2, and 3:

- Phase 1 of the Implementation Track considered critical modifications to the Central Procurement Entity (CPE) structure and concluded in March 2022 with issuance of D.22-03-034.
- Phase 2 consists of the Commission's consideration of flexible capacity requirements (FCR) for the following year, local capacity requirements (LCR) for the next three years, and the highest-priority refinements to the RA program including modifications to the Planning Reserve Margin (PRM) Qualifying Capacity Counting Conventions, which, along with other proposals, will consider the Energy Division's biennial update to the Effective Load Carrying Capability (ELCC) values for wind and solar resources. Phase 2 proposals were submitted in January 2022. Neither CalCCA nor any CCAs individually filed a Phase 2 proposal.
- Phase 3 will consider the 2024 program year requirements for flexible RA, and the 2024-2026 local RA requirements. Other modifications and refinements to the RA program, as identified in proposals by parties or by the Energy Division may also be considered. Phase 3 is expected to conclude by June 2023.

D.22-03-034: This Decision established that in the event of a non-performing self-shown resource, an LSE may substitute another local resource on a like-for-like basis, and that if the CAISO makes a local Capacity Procurement Mechanism (CPM) designation for an individual deficiency then the CPE will be charged any backstop procurement costs and those costs will be allocated to all LSEs on a load ratio share basis. It also requires LSEs that either decline to self-show a local resource to the CPE or fail to bid a local resource into the CPE's solicitation process to file a justification statement in its year-ahead Resource Adequacy filing explaining why the LSE declined to self-show or bid the local resource to the CPE.

On June 24, the CPUC issued D.22-06-050 adopting 2023-2025 Local Capacity Requirements (LCR), 2023 Flexible Capacity Requirements (FCR), and RA program refinements under the RA Reform Track of this proceeding. Among other things, with respect to RA Reform, it adopts SCE's 24-hour "slice of day" framework, with modifications, pending further development of certain implementation details. Further development of the slice-of-day framework is divided into three workstreams focused on refining counting and measurement approaches for future year requirements.

Details: D.22-08-039 adopted the monthly regional wind effective load carrying capability (ELCC) values from the Energy Division's Regional Wind ELCC Study for the 2023 resource adequacy (RA) year. This Decision also addressed demand response qualifying capacity methodology for the 2023 and 2024 RA years and found insufficient support for adopting the loss-of-load-weighted Load Impact Protocol, and instead directed the Parties to develop proposals on how to use the Load Impact Protocol outputs under the 24-hour slice framework for the 2024 test year in Workstream 2 of this proceeding,

Analysis: Changes to RA methodologies could impact the RA value of a variety of capacity resources which VCE makes use of, including energy storage and demand-side management programs. D.22-

08-039 did not adopt the proposed demand response qualifying capacity methodology for the 2023 and 2024 RA years and ordered development to continue. Methodology proposals have been under development for several years, and the limited progress creates uncertainty as to how resources will be measured and presents challenges for planning and procurement efforts since future operational requirements are unknown.

Next Steps: The procedural schedule for the ongoing tracks and working groups are as follows:

Reform Track Phase 2

- **July – October 2022:** Workstreams 1-3 to resolve remaining implementation details and methodologies as part of the RA Reform Workshops
- **November 15, 2022:** Final proposals from Workstreams 1- 3 filed and served
- **December 1, 2022:** Opening comments on final proposals due
- **December 12, 2022:** Reply comments on final proposals due
- Q1 2023: Proposed decision on Reform Track Phase 2 issued

CPE Procurement Timeline

- **End of August 2022:** LSEs in the SCE and PG&E TAC areas receive updated CAM credits for multi-year system/flexible capacity that was procured by the CPE as a result of the CPE's multi-year local RA showing to the Commission in mid-August.
- **September 2022:** LSEs are allocated final year-ahead system and flexible RA allocations, including CAM credits from CPE-procured system and flexible RA capacity based on revised year-ahead load forecast load ratios.
- **End of October:** LSEs make year-ahead system and flexible showings, and provide justification statements, if applicable, for local resources not self-shown or bid to the CPE.

Additional Information: D.22-08-039 on Regional Wind ELCC (August 29, 2022); PG&E Substitute Sheets for AL 6438-E (August 10, 2022); PG&E Substitute Sheets for AL 6436-E (August 10, 2022); D.22-06-050 on LCR and FCR Requirements and Modifications to the RA Framework (June 24, 2022); White Paper: Advanced Strategies for Demand Flexibility Management and Customer DER Compensation (June 22, 2022); Ruling on availability of MTR analysis supporting data (June 8, 2022); Ruling on Regional Wind ELCC study (June 1, 2022); Final 2023 FCR Report (May 17, 2022); Notice of Final 2023 LCR Report (April 29, 2022); Ruling modifying schedule (April 29, 2022); CAISO Local Capacity Technical Analysis (April 7, 2022); D.22-03-034 on Phase 1 of Implementation Track Modifications (March 18, 2022); Ruling modifying Phase 2 schedule and providing LOLE study and CEC Working Group Report (February 18, 2022); Proposed Decision on CPE revisions (February 10, 2022); Scoping Memo and Ruling (December 2, 2021); Order Instituting Rulemaking (October 11, 2021); Docket No. R.21-10-002.

NEW Microgrid

On July 6, the ALJ issued a Ruling requesting comments on a Staff Proposal for the Microgrid Incentive Program (MIP). On August 8, the CPUC issued D.22-08-025 denying an SDG&E request for rehearing of D.21-07-011.

Background: R.19-09-09 was opened in September 2019 to implement the requirements of SB 1339 (Stern, 2018), which requires the CPUC, in consultation with the CAISO and CEC, to take several actions to facilitate the commercialization of microgrids for distribution customers of the large IOUs. The initial December 2019 Scoping Memo and Ruling broke the proceeding into three tracks. Fourth and fifth tracks were subsequently added to address the establishment of a Microgrid Incentive Program, potential contributions that microgrids can make to mitigating capacity shortages in the near-term, and the development of a multi-property microgrid framework.

Track 1: Addressed the Commission's goal of deploying resiliency planning in areas that are prone to outage events and wildfires, with the goal of putting some microgrid and other resiliency strategies in place by Spring or Summer 2020. Track 1 concluded with the issuance of D.20-06-017. Among other things, the Decision (1) approved PG&E's Community Microgrid Enablement Program, which provides technical and financial support on a prioritized basis for community-requested microgrids for PSPS mitigation purposes; (2) approved PG&E's Make-Ready Program for the period of 2020 through 2022, which includes enabling prioritized substations to operate in islanded mode; and (3) approved PG&E's Temporary Generation Program, which involved leasing mobile generators for temporary use during the 2020 wildfire season.

Track 2: Resulted in the issuance of D.21-01-018 adopted several policy measures including:

- Directing the major IOUs to revise their service rules (Rules 18/19 depending on the utility) to allow microgrids to serve critical facilities on adjacent parcels.
- Adopting the broad design of a microgrid tariff, which includes provisions: (a) limiting it to NEM-eligible resources and storage (with fossil resources permitted using the NEM-MT as a companion), (b) permission for exports and NEM, (c) no aggregate enrollment or project size caps except those applicable to NEM, and (d) no exemption from cost responsibility surcharges (CRS).
- The establishment of a new Microgrids and Resiliency Working Group to consider issues related to the use of non-renewable resources (e.g., export compensation), and the contours of microgrid costs and benefits as a foundation for preventing cost-shifting, which involves the contours of CRS, NBCs, departing load charges, standby charges, and stranded costs.
- Directing the establishment of a Microgrid Incentive Program (budget of $200 million), subject to further development of an implementation plan which is now being considered as part of newly designated Track 4.

On April 16, 2021 the CPUC issued D.21-04-021 modifying D.21-01-018 and denying the rehearing request filed by the City of Long Beach. The Decision slightly refined two conclusions of law contained in D.21-01-018 and clarified that (1) municipal corporations are not subject to the CPUC's regulatory authority as public utilities even if they otherwise meet the applicable definition (i.e., sell electricity to more than two other entities); and (2) maritime transportation is included in the definition of "critical facilities."

Track 3: Resulted in the issuance of D.21-07-011, which suspended the capacity reservation component of standby charges for: (a) technologies that meet CARB's DG air pollution standards, (b) technologies that operate using cleaner renewable fuels such as renewable natural gas, biogas, or green hydrogen; and (c) customers that form a commitment to convert the microgrid to use only renewable fuels (as reasonably practicable) by December 31, 2030. D.21-07-011 required those customers to pay a "demand assurance amount" should a customer's microgrid generation be insufficient to meet the customer's demand. An evaluation of the suspension will be conducted in 2026 to determine whether the suspension is fair and provides value to the public.

Track 4: An expedited Phase 1 of Track 4 responded to the Governor's July 30, 2021 emergency proclamation seeking an acceleration of clean energy development by the Summers of 2022 and 2023 given concerns about resource availability during extreme heat events. D.21-12-004 in Phase 1 adopted programs proposed by PG&E (Temporary Generation expansion) and SDG&E (4 circuit-level microgrid projects).

Phase 2 of Track 4 is a non-expedited effort to develop a microgrid multi-property tariff to further facilitate microgrid commercialization.

Track 5: This track was added in the December 2021 Ruling to scope the value of resiliency, and it will assess the value of resiliency to inform investments in resiliency strategies. The analysis and measurement of resiliency's value has potential to advance the goal of net zero emissions, expand investment in adaptive infrastructure and resiliency measures, while incorporating equity in grid planning.

Details: On July 6, the ALJ issued a Ruling requesting comments on a Staff Proposal for the Microgrid Incentive Program (MIP). The MIP is targeted to develop microgrid technology to bolster climate response resiliency, equitably provide system benefits to disadvantaged vulnerable populations, and reduce the potential that climate change impacts will exacerbate existing inequities among vulnerable populations.

On August 8, the CPUC issued D.22-08-025 denying an SDG&E request for rehearing of D.21-07-011. SDG&E's request for rehearing argued, among other things, that the reservation charge suspension was adopted without proper notice, would unlawfully shift costs to other customers, the demand assurance amount is insufficiently supported by the record, and that the Commission should pursue other methods to compensate microgrid customers that does not involve reducing standby charges.

Analysis: By facilitating the commercialization of microgrids, this proceeding is opening pathways for VCE and its customers to deploy microgrids to enhance the reliability of distributed generation and provide electricity to customers even amidst system outages.

Next Steps:

Track 4 Schedule (December 2021 Ruling)

- **September 2022** - Public Workshop: Stakeholder Presentation on Microgrid Multi-Property Tariff Proposals
- **September 2022** - Opening Comments to Stakeholder Microgrid Multi-Property Tariff Proposals, filed and served
- **October 2022** - Reply Comments to Stakeholder Microgrid Multi-Property Tariff Proposals, filed and served
- **Late October 2022** - ALJ Ruling with Energy Division Staff Proposal for Microgrid Multi-Property Tariff
- November 2022 - Energy Division Public Workshop on Multi-Property Tariff
- November 2022 - Opening Comments to Energy Division Staff Proposal for Microgrid Multi-Property Tariff, filed and served

Track 5 Schedule

- **Q3 2022** – public workshops to be held on Definitions, Metrics, Tools, and Methods
- **Q4 2022** – public workshops to be held on Informing Grid Planning
- **Q1 2023** - Staff Proposal on [*topic*] to be issued
- **Q1 2023** - ALJ Ruling Establishing 2023 Scheduling & Activities to be issued

Additional Information: D.22-08-025 (August 8, 2022); ALJ Ruling Requesting Comments on attached Staff Proposal (July 6, 2022); Amended Scoping Memo and Ruling (December 17, 2021); D.21-12-

004 (December 6, 2021); Amended Scoping Ruling (August 17, 2021); D.21-07-011 (July 16, 2021); D.21-04-021 modifying D.21-01-018 (April 16, 2021); D.21-01-018 (January 21, 2021); Amended Scoping Ruling (July 3, 2020); D.20-06-017 (June 17, 2020); Scoping Memo and Ruling (December 20, 2019); OIR (September 19, 2019); Docket No. R.19-09-09.

NEW Building Decarbonization

On August 8, the CPUC issued a Proposed Decision that would adopt a Staff Proposal to eliminate gas line extension allowances, the 10-year refundable payment option, and the 50% discount payment option provided under the current gas line extension rules. The elimination would apply to all customers in all customer classes for new applications for gas line extensions submitted on or after July 1, 2023.

Background: The initial scope of this proceeding includes alternatives that could lead to the reduction of greenhouse gas (GHG) emissions associated with energy use in buildings, particularly issues related to the State's goals of reducing economy-wide GHG emissions 40% below 1990 levels by 2030 and achieving carbon neutrality by 2045 or sooner.

D.20-03-027 established the framework for Commission oversight of two building decarbonization pilot programs – the Building Initiative for Low-Emissions Development (BUILD Program) and the Technology and Equipment for Clean Heating (TECH Initiative). The decision appropriated 40% of a $200 million budget for the BUILD Program and 60% for the TECH Initiative required under SB 1477.

D.21-11-002 adopted a set of guiding principles for the layering of incentives from various building decarbonization programs and a statewide Wildfire and Natural Disaster Resiliency Rebuild Program (WNDRR Program) to provide incentives to help homeowners impacted by a natural disaster rebuild all-electric homes, and provided guidance on data sharing of customer and other information among the Commission, the California Energy Commission, the participating electric utilities, and the implementers and evaluators of building decarbonization programs. Additionally, it directed the IOUs to study net energy (electric and gas) bill impacts that result when a residential customer switches from a natural gas water heater to an electric heat pump water heater. If an IOU's study reflects a net increase in energy bills, to the IOU must propose a rate adjustment in a new Rate Design Window application in order to eliminate any financial disincentive for fuel switching.

Details: On August 8, the CPUC issued a Proposed Decision that would adopt a Staff Proposal to eliminate (with very limited exceptions) certain gas line extension rules, including allowances, a 10-year refundable payment option, and a 50% discount payment option. The elimination would apply to all customers in all customer classes for new applications for gas line extensions submitted on or after July 1, 2023. Opening comments on the Proposed Decision were filed on August 29. The Proposed Decision may be approved by the Commission as early as the September 15 Commission meeting.

Analysis: Building decarbonization generally involves a combination of increased energy efficiency and electrification. The conversion from fossil fuels to electricity is essential to reducing GHG emissions, particularly in the stock of existing buildings. Efforts to decarbonize buildings will likely increase electricity consumption and electric load in VCE's service area and increase the rate of growth in VCE's procurement requirements over time. Early planning for those increased requirements, supporting efforts to maximize energy efficiency as part of decarbonization efforts, and integrating distributed generation and other resources like electric vehicles will have long-term benefits and enable VCE to maximize decarbonization benefits at minimal cost within its service area.

Next Steps:

September 5, 2022 – Reply Comments on Proposed Decision due

September 15, 2022 – Earliest Commission may vote on the Proposed Decision

Additional Information: Proposed Decision (August 8, 2022); ALJ Ruling on procedural schedule (March 22, 2022); Amended Phase 3 Scoping Ruling (December 17, 2021); Phase 3 Scoping Ruling (November 16, 2021); D.21-11-002 (Appendices A-E) Decision on Building Decarb Phase II (November 9, 2021); Phase 2 Scoping Ruling and Staff Proposal (August 25, 2020); D.20-03-027 Establishing Building Decarbonization Pilot Programs (April 6, 2020); ALJ Ruling Requesting Comment and Staff Proposal on Building Decarbonization Pilots (July 16, 2019); Amended Scoping Ruling (July 16, 2019); Assigned Commissioner's Scoping Memo and Ruling (May 17, 2019); OIR (February 8, 2019); Docket No. R.19-01-011.

NEW Transportation Electrification

On August 9, the CPUC issued D.22-08-024 adopting the plug-in electric vehicle (PEV) submetering protocol and adopting electric vehicle supply equipment (EVSE) communication protocols. Under this Decision, large investor-owned utilities (including PG&E) and small multi-jurisdictional utilities are required to implement the submetering protocol for all customers with PEVs and customer-owned submeters.

Background: This rulemaking implements transportation electrification programs, tariffs, and policies and seeks to develop a comprehensive framework to guide the Commission's role in the electrification of California's transportation sector.

On February 3, 2020, the Administrative Law Judge issued a staff proposal, the Draft Transportation Electrification Framework (Draft TEF), intended to govern IOU transportation electrification investments and programs over the next decade. The Draft TEF posed numerous questions to stakeholders regarding Commission-jurisdictional transportation electrification efforts. Parties filed a series of comments on the Draft TEF in 2020. Peninsula Clean Energy and a group of joint CCAs filed comments arguing that CCAs should be permitted to administer transportation electrification programs funded through distribution funds.

D.21-07-028 adopted guidance and a streamlined advice letter process for the IOUs' near-term priority (through 2025) transportation electrification investments and addressed issues of equity as they relate to transportation electrification.

D.21-12-033 implemented AB 841 by extending Commission policy to treat utility-side infrastructure upgrade costs triggered by the installation of electric vehicle supply equipment (EVSE) as distribution costs.

On February 25, Assigned Commissioner Rechtschaffen issued a Ruling proposing to substantially shift the transportation electrification framework in light of several California legislative developments and additional funding opportunities. Under this new framework, there would be five-year funding cycles with mid-term reviews. Funding Cycle 0 (through 2024) would focus implementation of $1.48 billion in already-authorized, IOU-administered programs, including those approved in D.21-07-028. For Funding Cycle 1 (2025 – 2029), the Ruling proposed a $1 billion statewide rebate program for the installation of behind-the-meter EV chargers, prioritizing deployment in underserved and disadvantaged communities, critical sectors, medium-duty/heavy-duty vehicles and multi-unit dwellings. The Ruling proposed a single, statewide third-party administrator of the rebates and a single, statewide third-party administrator of marketing, education and outreach programs. The Ruling discussed potential roles for CCAs in this rebate framework.

On April 25 and May 16, Parties filed opening and reply comments, respectively, in response to the Ruling. The Joint CCAs argued that a uniform statewide program could leave out underserved customer segments, and that local customization of EV charger incentives by CCAs should be authorized.

Details: On August 9, the CPUC issued D.22-08-024 adopting the plug-in electric vehicle (PEV) submetering protocol and adopting electric vehicle supply equipment (EVSE) communication protocols. Under this Decision, large investor-owned utilities and small multi-jurisdictional utilities are required to implement the submetering protocol for all customers with PEVs and customer-owned submeters. The PEV Submetering Protocol is not available to NEM customers at this time; however, by August 5, 2023, the IOUS are directed to hold a public workshop to explore potential pathways to allow PEV submetering for NEM customers and file and serve a workshop report within 60 days following the workshop.

On August 15, the Commission issued a Disposition Letter accepting PG&E's AL 6638-E on the demonstration of pathways to scale vehicle-grid integration Pilot 3 for microgrids, effective August 11.

Analysis: The protocols approved in D.22-08-024 ensure EVs may be connected to the grid with bi-directional equipment, enabling them to function as both an energy consumer and provider depending on grid needs. These capabilities will reduce the cost of EV charging and spur increased adoption of EVs. The protocols also establish uniform technology standards and prevent excess costs associated with utility requirements for duplicative grid interconnection equipment. With these protocols in place, EVs located in VCE's service area will be able to function as an energy resource and provide grid support, potentially helping reduce curtailment and negative prices by providing demand and also providing capacity and emergency response during times of high power demand.

Next Steps: A Proposed Decision on the Assigned Commissioner's Ruling regarding the revised transportation electrification framework was expected for Q2 2022 but has been delayed. Following the decision, the IOUs would be required to file advice letters and issue an RFP for third-party administrators.

Additional Information: D.22-08-024 (Attachment A – Submetering Protocol) (August 9, 2022); PG&E AL 6638-E (July 1, 2022); Ruling granting VCE Party Status (March 30, 2022); Ruling entering Staff Proposal on Transportation Electrification Framework to record (February 25, 2022); D.21-12-033 (December 22, 2021); D.21-07-028 (July 22, 2021); D.20-12-029 (Appendices) (December 22, 2020); D.20-12-027 (December 21, 2020); D.20-09-025 (September 28, 2020); ALJ Ruling providing Staff Proposal of Draft Transportation Electrification Framework (February 3, 2020); OIR (Appendices) (December 19, 2018); Docket No. R.18-12-006.

NEW Commercial EV Real-Time Pricing Pilot

On August 9, the CPUC issued D.22-08-002 approving the Marginal Generation Capacity Cost Study for use by PG&E when calculating Real-Time Pricing rates, adopting the Real-Time Pricing settlement, and closing A.19-11-019. Opt-in enrollment for the Real-Time Pricing Pilot for commercial electric vehicles begins October 1, 2023.

Background: PG&E proposed a pilot to evaluate customer understanding and supporting technology for a commercial electric vehicle rate featuring day-ahead hourly real-time pricing (DAHRTP-CEV). The proposed pilot differs from the CEV rate approved in D.19-10-055 by providing a dynamic price that can change every day from hour to hour. Some key issues identified for consideration in this proceeding include uncertainty regarding revenue recovery and cost shifts, the nascent nature of the customer support vendor and technology ecosystem, Community Choice Aggregator (CCA) and other Energy Service Provider (ESP) participation, bill impacts, and considerations regarding operational infrastructure and scalability. The initial proposed Pilot would allow for enrollment of 50 customers currently being served on a Business Electric Vehicle (BEV) BEV rate schedule.

The DAHRTP-CEV pilot rate was proposed as a rate rider that would replace the time-of-use (TOU) rates on Scheduled BEV-1 and BEV-2 with a generation rate based on the CAISO's day-ahead hourly wholesale market while maintaining the rate for transmission, distribution, and nonbypassable charges from the original CEV Schedule.

D.21-11-017 approved the optional DAHRTP-CEV rate for and customer already enrolled in or eligible to enroll in a BEV rate, required customer outreach and education, and the development of evaluation metrics and reporting requirements for the opt-in rate. Approved rate components for the Pilot include a marginal energy cost (MEC) based on the CAISO hourly day-ahead market rate, a flat volumetric rate adder ($0.01972/kWh) to recover generation costs of service above marginal costs, and the same subscription charges in the existing CEV rate.

This Decision also required the development of a marginal generation capacity cost (MGCC) factor and established a Phase 2 of the proceeding to evaluate the MGCC study resulting in a proposed decision in Q3 2022.

The MGCC Study was filed on March 15, and a corrected version was filed on March 17. The Study identifies an hourly pricing formula that incorporates a temperature-adjusted net load, a price adder based on alert or notification events from the CAISO, and other adjustments, in part, to ensure a non-zero price during times with a low adjusted net load.

On March 24, PG&E filed a supplemental proposal for an export compensation mechanism for non-net energy metering (non-NEM) customers with behind-the-meter resources. This proposal would provide compensation for energy exports from the CAISO market, including resource adequacy if available and appropriate.

A Joint Motion to submit a stipulation on the MGCC was filed on April 13 by the PAO, the California Large Energy Consumers Association (CLECA), Small Business Utility Advocates (SBUA), Enel X North America, Inc. (Enel X), and PG&E. A Joint Motion for Settlement Agreement 9RTP Settlement) was filed June 24 by the PAO, Vehicle-Grid Integration Council (VGIC), Electrify America, and PG&E that resolved all issues related to the DAHRTP-CEV pilot and non-NEM export compensation. A Proposed Decision was filed on June 22.

Details: On August 15, the CPUC issued D.22-08-002 approving the MGCC Study for use by PG&E when calculating RTP rates, adopting the RTP settlement, and closing A.19-11-019.

This Decision adopts the uncontested RTP Settlement, making bundled customers on PG&E's large commercial (B-20), small commercial (B-6), and E-ELEC residential rates, as well as unbundled customers of participating CCAs eligible to participate in the RTP Pilot (additional customers served on other commercial rates may be made eligible at a later date via a Tier 1 AL filing by PG&E).

RTP Pilot Duration: The Stage 1 pilots have a targeted launch date of October 1, 2023, and have an initial duration of 24 months, with the possibility of extension following the Commission's review of the Interim Evaluation Report of the first 12 months that will be submitted on March 1, 2025 in a Tier 2 advice letter.

RTP Pilot Rate Design: The real-time portion of the pilot rates would only replace the generation component while transmission, distribution, Public Purpose Program, and other charges and taxes would be unchanged. The generation component includes the following:

- Marginal Energy Cost (MEC) price signal;
- Marginal Generation Capacity Cost (MGCC) price signal identical to that used in the commercial EV rate; and
- A Revenue Neutral Adder (RNA) intended to make the pilot rates revenue-neutral to the base rate schedule (also includes the PCIA charge and may be adjusted in response to general rate case cycles to maintain revenue neutrality).

Analysis: This proceeding created a real-time pricing pilot that includes pricing for both imports from and exports to the grid by commercial electric vehicles. This mechanism provides a foundation for the use of EVs as mobile energy storage systems and grid resources, potentially enabling a future where vehicles provide an automated dynamic response to real-time electricity price signals and transportation adopts a central role in balancing electricity supply and demand, mitigating grid emergencies, and further enabling higher penetration of renewables. The RTP methodology approved in D.22-08-002 applies to PG&E real-time pricing rates used in this pilot as well as those in approved in D.21-11-017, and revisions to the methodology will be considered after an initial evaluation of the pilot.

Next Steps: Opt-in enrollment begins October 1, 2023. The MGCC Study working group must be reconvened to consider whether any revisions should be made to the marginal generation capacity cost hourly price signal methodology after the initial evaluation of the Pilot is complete, but no later than October 1, 2025.

Additional Information: D.22-08-002 Adopting Decision Real Time Pricing Pilot (August 15, 2022); Joint Motion for Settlement Agreement (June 24, 2022); Joint Motion to submit Stipulation on MGCC (April 13, 2022); PG&E Proposal for export compensation for non-NEM customers (March 24, 2022); Corrected MGCC Study (March 17, 2022); ALJ Ruling on procedural schedule (January 14, 2022); Scoping Ruling and Memo (December 17, 2021); D.21-11-017 PG&E To Implement an Optional Day-Ahead Real Time Rate (Appendix B - Joint Stipulation on Study for MGCC Rate Design Issue) (November 19, 2021); Assigned Commissioner's Scoping Ruling and Memo (January 25, 2021); Application & Testimony (October 23, 2020); Docket No. A.20-10-011.

NEW Demand Flexibility

The OIR was issued by the Commission on July 22. Opening comments were filed by VCE and 47 other parties, and a pre-hearing conference is scheduled for September 16.

Background: This rulemaking will update the Commission's rate design principles and guidance for advancing demand flexibility, and through it the Commission may also modify, consolidate, or eliminate existing rates and authorize additional pilots, rates, programs, studies, or tools. The objectives for the rulemaking are:

- enhance the reliability of California's electric system;
- make electric bills more affordable and equitable;
- reduce the curtailment of renewable energy and GHG emissions associated with meeting the state's future system load;
- enable widespread electrification of buildings and transportation to meet the state's climate goals;
- reduce long-term system costs through more efficient pricing of electricity; and
- enable participation in demand flexibility by both bundled and unbundled customers.

Details: The preliminary issues scoped for this proceeding are focused on how the Commission may enable and encourage adoption of widespread demand flexibility to improve system reliability and advance State climate goals affordably and equitably. The scope covers questions regarding updated guiding principles for rate design and evaluation; the use of additional pilots, tariffs, programs, or studies; reform of demand charges and fixed charges; providing universal access to dynamic electricity pricing, and efforts to inform customers and ease the transition to dynamic rates.

On August 15, VCE and Polaris submitted joint opening comments highlighting their experience with the AgFIT Pilot, encouraging the Commission to reexamine or reform demand-based rates, supporting universal real-time access to dynamic prices for all customers and LSEs, and offering examples of lessons and experiences from the AgFIT Pilot, particularly regarding the importance of customer support and outreach, as well as the use of demand automation technology. TeMix filed comments recommending bi-directional rates be based on scarcity pricing rather than marginal cost, supporting authorization of the CalFUSE tariff as opt-in for all customer classes immediately, replacing demand charges with scarcity pricing, using a subscription component to ensure stability and adequate revenue collection, and supporting customer engagement and education outreach efforts. CalCCA filed comments recommending that the Commission ensure that all LSEs have timely access to usage data; that IOU rate designs for transmission and distribution not adversely impact CCA generation rates to the harm of demand flexibility; that the proceeding emphasize that all customers can address the issues of reliability, affordability, and meeting of policy goals whether served as bundled or unbundled load; and that the use of fixed charges be limited to transmission and distribution rates, which are driven primarily by fixed costs.

Analysis: Although the scope of this proceeding has yet to be determined through issuance of the forthcoming Scoping Memo, the potential for broad impact for VCE's customers is apparent. This proceeding will address issues of importance to VCE, including dynamic rates, demand response and other load shifting efforts.

Next Steps: The Commission intends to conclude this proceeding within 24 months and expects to issue a more detailed procedural schedule in late September.

- **September 16, 2022** – Pre-Hearing Conference
- **Q3 2022** – Scoping Memo and Ruling issued

Additional Information: Notice of Pre-Hearing Conference (August 19, 2022); VCE & Polaris Joint Comments (August 15, 2022); CalCCA Comments (August 15, 2022); OIR (July 22, 2022); Docket No. R.22-07-005.

NEW Demand Response Programs (2023-2027)

On July 5, the Assigned Commissioner issued a Scoping Memo and Ruling defining the scope of issues and providing a procedural schedule for Phase 1.

Background: This proceeding addresses the IOUs' Demand Response (DR) Portfolio Applications required under D.17-12-003 for the years 2023-2027. IOU demand response budgets and activities for the years 2018-2022 were approved in D.17-12-003.

PG&E, SCE, and SDG&E each filed Applications for development of a demand response portfolio on May 2, and a May 25 ALJ Ruling consolidated these Applications. The Applications contain both proposals for Bridge Funding that would be expedited in order to implement 2023 programs and ensure continued operation of ongoing demand response programs, while portfolio proposals for the years 2024 – 2027 will be considered in Phase 2. A prehearing conference (PHC) was held on June 16 to discuss the scope, schedule, and other procedural matters.

Details: The July 5 Scoping Memo and Ruling divided the proceeding into two phases. Phase 1 will address the IOUs' 2023 Bridge Year Funding Requests and consider whether the Auction Mechanism should be used with 2023 solicitations for 2024 deliveries, and Phase 2 will address the IOUs' Applications for the years 2024-2027 and continued use of the Auction Mechanism beyond 2024. The Commission expects a Decision regarding Phase 1 to be issued during 2022 and anticipates that consideration of Phase 2 issues will also begin later in 2022.

Phase 2 issues will be scoped to address the 2024-2027 DR program proposals at a later date and will include consideration of the DR Auction Mechanism's future beyond 2024. As part of the Phase 2 scope, the Commission plans to consider the future of the DR Auction Mechanism (Auction Mechanism), including whether it should be continued for delivery year 2024. A DR Auction Mechanism Evaluation Report (Nexant Report) was attached to the July 5 Scoping Memo and Ruling.

Analysis: This proceeding considers the IOUs' Applications for development of demand response portfolio as well as the future use of the DR Auction Mechanism. The design, effectiveness, cost, and availability of these programs will determine their long-term efficacy in using technology to leverage demand as a grid resource. The success of DR programs has long-term potential to reduce electricity costs to consumers across the State.

Next Steps:

Phase 1 Procedural Schedule

- **September 2, 2022:** Concurrent Reply Briefs on Phase I Bridge Funding Applications
- **October 2022:** Proposed Decision on Phase 1 Bridge Funding Applications
- 30 days after issuance of Proposed Decision: Commission decision on Phase I

Phase 1 Auction Mechanism Schedule

- **September 2, 2022:** Reply Testimony Due on Nexant Report and Auction Mechanism
- **September 9, 2022:** Meet and Confer to Determine Need for Evidentiary Hearings
- **September 16, 2022:** Last Day to Request Evidentiary Hearing and Conduct Discovery
- **Late September 2022:** Evidentiary Hearings
- **October 7, 2022:** Opening Briefs on Nexant Report and Auction Mechanism
- **October 28, 2022:** Concurrent Reply Briefs on Nexant Report and Auction Mechanism
- **December 2022:** Proposed Decision

Additional Information: Assigned Commissioner's Scoping Memo and Ruling and Demand Response Auction Mechanism Evaluation report by Nexant (July 5, 2022); Ruling consolidating Applications (May 25, 2022); PG&E Application (May 2, 2022); Docket No. A.22-05-002.

PCIA Rulemaking

On July 19, the CPUC issued D.22-07-008 on PCIA Data Access, resolving Phase 2 issues related to data access and voluntary allocations in market price benchmark calculations. On August 4, the ALJ issued a Ruling requesting comment on long-term fixed-price RPS transactions and providing a Staff Proposal for Incorporating Long-Term RPS Transactions into the RPS MPB.

Background: D.18-10-019 was issued on October 19, 2018, in Phase 1 of this proceeding and left the current Power Charge Indifference Adjustment (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.

In Phase 2, D.20-08-004 the Commission adopted a framework for PCIA prepayment agreements.

D.21-05-030 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 resource adequacy (RA) resources. However, it did not provide unbundled customers proportional access to system and flexible RA products through the RA voluntary allocation and market offer process proposed by PCIA Working Group 3. Likewise, it declined to provide unbundled customers any access to GHG-free energy on a permanent basis. The CCA Parties' Application for Rehearing of D.21-05-030 was denied.

D.22-01-023 modified the PCIA market price benchmark (MPB) release date to October 1 and the deadline for ERRA forecast applications to May 15 to enable the timely issuance of ERRA forecast decisions by the Commission.

On June 24, Assigned Commissioner Reynolds issued a Revised Scoping Memo and Ruling that extends the statutory deadline to June 30, 2023 to address the following issues:

- Whether greenhouse gas-free resources are under-valued in the Power Charge Indifference Adjustment (PCIA), and if so, whether to adopt an adder or allocation mechanism;
- Whether to adopt a new method to include long-term fixed-price transactions in calculating the Renewables Portfolio Standard adder;
- Whether to modify the calculation of the PCIA energy index market price benchmark; and
- Whether to modify or clarify the calculation of the PCIA for Voluntary Allocation or Market Offer transactions.

Details: D.22-07-008 resolved Phase 2 issues related to PCIA data access and voluntary allocations in MPB calculations. This decision establishes a standard process for a representative of CCAs to review confidential ERRA data for the purpose of developing PCIA forecasts and to disclose non-confidential analyses of PCIA forecasts to CCAs. The decision also confirms that Voluntary Allocations should be excluded from calculations of the RPS's MPB.

The data access provided for under this decision is intended to help protect CCA customers from rate volatility by creating a process for a representative of the CCAs to review of PCIA rate and PABA balance forecasts, and to predict whether current trends are likely to continue or self-correct. The decision ordered that CalCCA or any other CCA may convene a meeting by October 3 to discuss the proposed format and content of the non-confidential analyses of PCIA forecasts that may be disclosed to CCAs under this decision.

A joint Tier 2 Advice Letter should be filed on behalf of CCAs by December 1 containing a proposal for the following:

- A standard template for conveying descriptions of drivers of anticipated PCIA changes (using the public analysis of drivers in PG&E's November Update in A.21-06-001 as a model) and descriptions of single- or multi-year PCIA rate projections developed by reviewing representatives;
- A public appendix with a full example analysis that uses the proposed template and dummy information;
- A proposed non-disclosure agreement based on the ERRA forecast non-disclosure agreement; and
- A list of all CCAs that seek this forecasting data access and their reviewing representatives.

CCAs' reviewing representatives must simultaneously serve the Commission and the relevant IOU all information disclosed to clients. Reviewing representatives are permitted to disclose information only once per calendar quarter and are prohibited from disclosing any information pursuant to this decision that is not explicitly included in the approved standard template for disclosures. Joint CCAs may request modification of the standard template for disclosures no more than once per year by filing a Tier 2 Advice Letter by January 31 of each year.

On August 4, the ALJ issued a Ruling requesting comment on long-term fixed-price RPS transactions and providing a Staff Proposal for Incorporating Long-Term RPS Transactions into the RPS MPB. The Staff Proposal includes the following recommendations:

- Including short-term index-plus (STIP) and long-term fixed-price (LTFP) PCC-1 transactions in the RPS MPB while continuing to exclude long-term index-plus (LTIP) and short-term fixed-price (STFP) transactions;

- Requiring LSEs to provide an RA value for LTFP transactions that include RA capacity for use in calculating the RPS MPB; and

- For the semiannual RPS-PCIA Data Request, adding a required field for LSEs to indicate whether a transaction was mandatory, and making the existing "Deemed Capacity Value," "Deemed Energy Value," and "Net Market Value" fields mandatory.

Analysis: The MPB calculation is used as the basis for pricing RPS resources under the Voluntary Allocation process, and the MPB benchmark price is used in ERRA forecasts to determine PG&E's PCIA-related revenue requirement. This proceeding is examining approaches to modifying the way the MPB is calculated, in part, to address the potential misrepresentation of current market activity resulting from use of the prior year's MPB to value RPS resources in the Voluntary Allocation process. Changes to the MPB calculation will influence resource procurement decisions and potentially customer costs.

Next Steps: The August 4 Ruling modified the schedule such that a staff proposal on GHG-free resources will be provided along with a Ruling requesting comment in late August/early September, and the November workshop will now address both staff proposals.

- **September 9, 2022:** Reply comments due on Ruling requesting comments on long-term RPS transactions

- **August/September 2022:** ALJ Ruling requesting comment on a staff proposal regarding GHG-free resources

- **October 3, 2022:** deadline for CCA meeting to discuss PCIA forecast disclosure

- **November 2022:** Workshop on Staff Proposals for long-term fixed-price RPS resources and GHG-free resources

- **December 1, 2022:** CCAs' Tier 2 AL proposal for PCIA data access due

Additional Information: Ruling Requesting Comments and Staff Proposal for Long-Term RPS Transactions (August 4, 2022); D.22-07-008 (July 19, 2022); Revised Scoping Memo and Ruling (June 24, 2022); Proposed Decision on data access and MPB benchmarks (June 10, 2022); Ruling Regarding Market Price Benchmarks (April 18, 2022); Resolution E-5134 approving PCIA pre-payment framework ALs (March 21, 2022); D.22-01-023 on Phase 2 (approved January 27, 2021); Ruling requesting comments on PCIA forecasting data access (November 5, 2021); Ruling requesting comments (September 17, 2021); PG&E AL 5973-E-A PCIA pre-payment framework (August 13, 2021); CalCCA Application for Rehearing of D.21-05-030 (June 23, 2021); 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); PG&E AL 5973-E PCIA pre-payment framework (October 12, 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); D.20-01-030 denying rehearing of D.18-10-019 as modified (January 21, 2020); D.19-10-001 (October 17, 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.

Provider of Last Resort Rulemaking

On July 15, the CPUC issued a Disposition Letter accepting PG&E AL 6589-E_E-A_E-B on financial security requirements for CCAs which became effective as of August 6.

Background: A Provider of Last Resort (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).

The Scoping Memo and Ruling issued September 16, 2021, provides that Phase 1 of this OIR will address POLR service requirements, cost recovery, and options to maintain GHG emission reductions in the event of an unplanned customer migration to the POLR. Phase 2 will build on the Phase 1 decision to set the requirements and application process for other non-IOU entities (i.e., a CCA, Energy Service Provider, or third-party) to be designated as the POLR in place of an existing POLR. Phase 3 will address specific outstanding issues not resolved in Phase 1 and 2 of this proceeding.

A workshop was held on October 29, 2021, for the purpose of reviewing the operation and expectation of Provider of Last Resort service, registration, and financial security requirements, and a second workshop was held on March 7 for the purpose of developing a framework to consider the issues and recommendations of the previous workshop.

Party comments on the first workshop were filed on March 28. Some of CalCCA's proposals included maintaining the six-month runway to prepare for the return of customers, refining the Financial Service Requirements (FSRs) to reflect the current Market Price Benchmarks (MPBs) for Resource Adequacy (RA) and RPS products, maintaining the existing right to an RA waiver, not requiring resource procurement in advance of customer returns, and implementing a three-tiered reporting rubric calibrated to the operating CCA's circumstances.

On May 10, PG&E submitted AL 6589-E with calculated financial security requirements for CCAs, followed by submission of supplemental AL 6589-E-A on May 17. On May 31, CalCCA filed a protest of PG&E ALs 6589-E and 6589-E-A requesting that the Commission require PG&E to correct the period for determination of "peak load" in applying the applicable resource adequacy (RA) cost based on PG&E's own tariff by updating the proposed FSR amount using a peak demand based on the most recent 12 months of historical peaks. On July 7, PG&E submitted its second supplemental AL 6589-E-B that replaces the previous versions in their entirety and revised the number of months used to calculate each Community Choice Aggregator's (CCA) average peak demand forecast to be consistent with PG&E's electric Rule 23, Community Choice Aggregation Service.

Details: On July 15, the CPUC issued a Disposition Letter accepting PG&E AL 6589-E_E-A_E-B on financial security requirements for CCAs which became effective as of August 6. A confidential version of PG&E AL 6589-E-B showing the financial security requirements calculated for individual CCAs was sent to each CCA.

Analysis: PG&E's AL 6589-E-B describes the method and the inputs for determining the Financial Security Requirement (FSR) to be contributed by each CCA to cover the costs between the time a CCA's customers transition to POLR service and when the POLR begins receiving revenue. The resource adequacy portion of each CCA's FSR amount is determined in part by the trailing six months' average of the CCA's peak load. While the costs of meeting the FSR are unavoidable, the amount of the FSR can be influenced by efforts to reduce monthly peak load.

Next Steps:

- **August 2022:** Energy Division Staff Proposal on Phase 1 Issues
- **September 2022:** Workshop on Energy Division Staff Proposal
- **September 2022:** Workshop on Potential/Example Changes to FSR Calculator

- **October 2022:** Opening Comments Filed and Served on Energy Division Staff Proposal/Potential Changes to FSR Calculator
- **October 2022:** Reply Comments Filed and Served on Energy Division Staff Proposal/Potential Changes to FSR Calculator
- Q1 2023 – Q2 2023: Phase 1 Proposed Decision

Additional Information: PG&E AL 6589-E-B and Disposition Letter (July 7, 2022); CalCCA Protest of AL 6589-E (May 31, 2022); Ruling granting extension of time and modifying procedural schedule (May 24, 2022); PG&E's AL 6589-E-A on FSR Requirements (May 17, 2022); PG&E's AL 6589-E on FSR Requirements (May 10, 2022); Ruling Requesting Comments (May 2, 2022); POLR webpage with workshop presentations and videos; Golden State Power Cooperative Motion to remove cooperatives as respondents (October 28, 2021); Scoping Memo and Ruling (September 16, 2021); Order Instituting Rulemaking (March 25, 2021); Docket No. R.21-03-011.

PG&E 2023 Phase 1 GRC

On July 22, PG&E filed its Track 2 request for a reasonableness review of recorded costs and recovery of $241 million in costs over two years. On August 9, PG&E filed a Case Management Statement reporting no settled issues among the Parties and withdrawing its revenue requirement request for two disputed projects. Track 1 Evidentiary Hearings were held August 15-26, and Keyes & Fox LLP cross examined a panel of PG&E witnesses on their rebuttal to the Joint CCAs' re-vintaging testimony during the hearings.

Background: Phase 1 General Rate Case (GRC) applications cover the revenue requirement, including the functionalization of costs into categories such as electric distribution or generation, and impacts which customers (bundled, unbundled, or both) pay for the costs through rates. Phase 2 GRC applications cover cost allocation (i.e., assigning costs to customer classes, such as Residential) and rate design issues. On August 25, 2021, the CPUC Executive Director granted PG&E's request to delay filing its next Phase 2 GRC application until September 30, 2024.

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

On March 9, PG&E submitted its recorded expense and capital data testimony for 2021. On March 10, PG&E filed an Amended Application and submitted supplemental testimony on wildfire mitigation programs.

PG&E and Caltrain submitted a joint report on the status of the third-party audit of costs that PG&E will incur to upgrade the East Grand and FMC substations in connection with Caltrain's project to electrify its commuter rail system between San Jose and San Francisco. PG&E and Caltrain also requested to move consideration of PG&E's proposal for cost recovery of Caltrain Project costs from Track 1 to Track 2 of PG&E's 2023 GRC and proposed a schedule for the submission of testimony reporting on the Audit.

The April 12 email Ruling denied the February 16 Motion to adopt a final date for discovery regarding the earlier submitted testimony and adopted a revised procedural schedule for both Track 1 and Track 2.

On April 20, PG&E filed an application to modify its cost of capital that requests an overall rate of return of 7.78% and a $69.3 million increase in its revenue requirement. The company proposed a capital structure with 47.5% debt at a cost of 4.27%, 0.5% preferred equity at a cost of 5.52%, and 52% common equity at a cost of 11%.

On June 13, intervenors submitted direct testimony, including Joint CCAs' testimony regarding recovery of PG&E's proposed generation revenue requirement from bundled and unbundled customers, a Utility-Owned Generation vintaging framework to be used in future GRC proceedings to properly track and account for generation revenue requirements, and proper functionalization of costs associated with batteries on PG&E's electric distribution system.

On June 24, the CPUC issued D.22-06-033 establishing the effective date of PG&E's 2023 test year revenue requirement as January 1, 2023.

Details: On July 22, PG&E filed its Track 2 request for a reasonableness review of recorded costs and recovery of $206 million in expenses and $129 million in capital expenditures for a total incremental revenue requirement increase of $241 million over two years.

On August 9, PG&E filed a Case Management Statement reporting no settled issues among the Parties and withdrawing its revenue requirement request for two disputed projects. The revenue requirement request for the Gateway Generating Station of $3 million per year for 2021, 2022, and 2023 was withdrawn because the project will not be completed during the GRC period. The request for the Renz Energy Storage project was forecast at $26.5 million, but PG&E reports that the contract for the purchase was terminated and the project will not be installed. During the 2023 GRC period, PG&E also agreed to spend $26 million on small business outreach, $6.8 million on accessibility improvements for customers with disabilities, and $4 million to support the needs of underserved communities including communities of color.

During the Track 1 Evidentiary Hearings (August 15-26), Keyes & Fox LLP cross examined a panel of PG&E witnesses on their rebuttal to the Joint CCAs' re-vintaging testimony. In particular, the Joint CCAs' cross examination focused on getting admissions from PG&E that:

(1) PG&E's hydroelectric facility extensions constitute new commitments;

(2) These new commitments are made on behalf of bundled customers (e.g., PG&E uses these facilities to fulfill its resource adequacy requirements on behalf of bundled customers; decisions regarding whether to sell/retire/relicense the facilities take into account bundled customers' energy needs; PG&E's claim that the ongoing investments in these facilities could result in a lower PCIA is irrelevant to whether the costs associated with these re-investments *belong* in the PCIA; other benefits that PG&E argues flow to unbundled customers from these resources being extended are unmonetized public benefits (which are also provided by CCA-owned resources)); and

(3) The Joint CCAs' general vintaging framework is designed to allow for a case-by-case consideration of new generation resource commitments made by PG&E.

Analysis: This proceeding will set the revenue requirement, and thereby ultimately impact PG&E's rates for 2023-2026. It will establish how the revenue requirement components will be functionalized, which impacts whether the ultimately approved costs will be borne by PG&E bundled customers, unbundled customers like VCE customers, or both. It will also address numerous other issues raised in PG&E's application that could impact rates, policies, and programs implemented by PG&E.

The resolution of the issues covered in the Joint CCAs' direct testimony will impact how certain generation-related costs in PG&E's current and future applications will be vintaged for purposes of PCIA cost recovery. It will also impact how the costs associated with an energy storage project are functionalized.

Next Steps:

<u>The Track 1 schedule, as modified in the April 12 Ruling is:</u>

- **Q3 2022:** Decision on PG&E Motion for Interim Rates
- **November 4, 2022:** Opening Briefs

- December 9, 2022: Reply Briefs
- March 24, 2023: Proceeding Submitted
- Q2 2023: Proposed Decision on A.21-06-021

The Track 2 schedule, as modified in the April 12 ruling is:

- **TBD:** Amended Scoping Memo issued, if needed
- **November 14, 2022:** Intervenor Opening Testimony
- December 14, 2022: Concurrent Rebuttal Testimony
- December 15, 2022 **–** January 20, 2023 – Meet & Confer (minimum of two times)
- TBD (prior to Evidentiary Hearings): Status Conference
- January 23 – January 27, 2023: Evidentiary Hearings
- February 24, 2023: Opening Briefs
- March 24, 2023: Reply Briefs
- March 24, 2023: Proceeding Submitted
- 2Q 2023: Proposed Decision on A.21-06-021

Additional Information: CPUC Resolution E-5217 (August 11, 2022); Case Management Statement (August 9, 2022); PG&E Track 2 Request (July 22, 2022); PG&E AL 6641-E (July 7, 2022); D.22-06-033 on Effective Date of 2023 Revenue Requirement (June 24, 2022); PG&E Application to establish 2023 Cost of Capital (April 20, 2022); Ruling on Motions and Request to Modify Schedule (April 12, 2022); ALJ Ruling denying Motion to Shorten Time, accepting PG&E's Amended Application, and suspending intervenor testimony deadline (March 10, 2022); PG&E's Amended Application (March 10, 2022); PG&E Affordability Metrics Report (February 23, 2022); ALJ Ruling on Public Participation Hearings (February 2, 2022); PG&E/Caltrain Report (February 1, 2022); Ruling denying PG&E Motion to submit supplemental testimony (November 12, 2021); Motion of PG&E to modify procedural schedule (November 5, 2021); Scoping Memo and Ruling (October 1, 2021); PG&E Application (June 30, 2021); 2023 Cost of Capital Docket No. A.22-04-008; Docket No. A.21-06-021.

PG&E ERRA Forecast (2023)

On August 4, the Assigned Commissioner issued a Scoping Memo and Ruling setting forth the issues and a schedule intended to meet the deadline for the final 2022 Commission meeting allow for new rates to be effective January 1, 2023.

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

On May 31, PG&E filed its 2023 ERRA Forecast application, requesting a 2023 ERRA forecast revenue requirement for ratesetting purposes of $4.486 billion. After accounting for $2.373 billion of Utility Owned Generation (UOG)-Related Costs and other adjustments totaling $2.534 billion, PG&E requested a net revenue requirement of $1.952 billion. These figures are expected to change when PG&E files its Fall Update in October.

Details: After consideration of the issues and discussion during the July 18 Pre-Hearing Conference (PHC), the August 4 Scoping Memo and Ruling identified the following issues to be considered in this proceeding:

1) Whether PG&E's requested 2023 ERRA forecast revenue requirement is reasonable, including but not limited to consideration of the following:

   (a) forecast costs for fuel and purchased power expenses;

   (b) disposition of PG&E's forecast December 31 year-end balancing account balances;

   (c) disposition of recorded Voluntary Allocation Market Offer Memorandum Account (VAMOMA) balances; and

   (d) approval of PG&E's methodology to include 2021 and 2022 renewable energy credits (RECs) toward the 2023 Power Charge Indifference Adjustment (PCIA) revenue requirement calculation and to allocate the value of 2021 and 2022 RECs to benefit bundled and departing load customers responsible for applicable Portfolio Allocation Balancing Account (PABA) vintage costs;

2) Adopt forecasted electric sales for 2023;

3) Adopt a forecast of greenhouse gas (GHG) revenues, revenue return, and administrative, programmatic, and customer outreach costs for 2023;

4) Determine whether PG&E's 2021 GHG administrative and customer outreach costs as reasonable; and

5) Adopt rate design proposals associated with PG&E's total electric procurement revenue requirements to be effective in rates on January 1, 2023, including Green Tariff Shared Renewables (GTSR) rates.

Other issues, raised by CalCCA, that will also be included in the scope are:

6) Whether PG&E has adequately supported its new proposed REC Tracking and Accounting Methodology, and whether the Commission should rule that the consideration of that methodology beyond the 2023 Renewables Portfolio Standard (RPS) Compliance Year is beyond the scope of this proceeding. At the PHC PG&E confirmed that its proposal was strictly limited to 2023 and was PG&E was not seeking, nor relying on any approval, for subsequent years.

7) That PG&E should continue to return the ERRA-PCIA Financing Subaccount (PFS) credit to bundled and unbundled customers by amortizing the final year of that credit through the PABA consistent with Decision 22-02-002.

Analysis: This proceeding will determine PG&E's rates for 2023 based on its revenue requirement forecast. While final forecast figures will not be available until October, PG&E's Application forecasted rates for CCA customers to decline 3.6% from $0.14287/kWh to $0.13779/kWh based on a $250.26 million revenue requirement reduction. Specific procurement costs that are expected to change in the Fall Update include those related to reliability under D.19-11-016 and D.21-06-035, Central Procurement Entity (CPE) administration and procurement, Voluntary Allocation/Market Offer (VAMO) process pending Commission decisions in R.18-07-003,

Next Steps: The following procedural schedule includes some timelines that are more condensed than their normal duration in an attempt to meet the deadline for the final 2022 Commission Meeting and allow for new rates to be effective January 1, 2023.

- **September 7, 2022** - Intervenor Testimony

- **September 28, 2022** - Concurrent Rebuttal Testimony
- **October 3, 2022** - Market Price Benchmark provided by Energy Division
- **October 3, 2022** - Status Conference
- **October 7, 2022** - Evidentiary Hearings
- **October 14, 2022** - Concurrent Opening Briefs
- **October 17, 2022** - October Update from PG&E
- **October 21, 2022** - Concurrent Reply Briefs
- November 1, 2022 - Comments on October Update
- November 8, 2022 - Reply Comments & Submission
- November 29, 2022 - Proposed Decision
- December 6, 2022 - Comments on Proposed Decision due
- December 9, 2022 - Reply Comments on Proposed Decision due
- December 15, 2022 - Commission Meeting Target

Additional Information: Scoping Memo and Ruling (August 4, 2022); Application (May 31, 2022); Docket No. A.22-05-029.

PG&E 2019 ERRA Compliance

On July 14, the CPUC issued D.22-07-009 extending the statutory deadline for the proceeding by an additional six months until March 1, 2023 in order to resolve the Phase 2 issues related to Public Safety Power Shutoff events.

Background: Phase 1 has been resolved. The September 7, 2021, Ruling consolidated the Phase 2 ERRA compliance proceedings of PG&E, SCE, and SDG&E. The issues scoped for Phase 2 are:

- What is the appropriate methodology for calculating a utility's unrealized volumetric sales and unrealized revenues resulting from PSPS events in any given record year? Based on this methodology, what are the utilities' (PG&E, SCE, and SDG&E) unrealized volumetric sales and unrealized revenues resulting from 2019 Public Safety Power Shutoff (PSPS) events?
- Whether it is appropriate for the utilities to return the revenue requirement equal to the unrealized volumetric sales and unrealized revenue resulting from the PSPS events in 2019.

At the October 26, 2021, workshop hosted by Energy Division, the IOUs (PG&E, SCE, and SDG&E) made a joint presentation of their proposal for a methodology to calculate the revenue requirement of the estimated unrealized volumetric sales and unrealized revenue resulting from PSPS events.

The Joint CCAs filed a Motion on November 4, 2021, requesting the CPUC clarify the scope of issues in this proceeding. The November 12, 2021, Ruling clarified the CPUC's intent to consider a range of PSPS methodologies, which may be proposed by both the IOUs and other parties. It provided that parties may conduct additional discovery to support their proposal of a reasonable alternative PSPS methodology. The CPUC will consider a PSPS methodology that includes unrealized generation-related volumetric sales and revenues, along with the joint IOU proposal and potentially other PSPS methodologies

Details: The Joint IOUs' recommendations to adopt their common methodology for calculating unrealized revenue from end-use customers de-energized during PSPS events were determined to be reasonable and approval was recommended in the Joint Case Management Statement.

Previously, the CCA Parties' testimony identified all retail rate components that should be considered to provide a full accounting of the unrealized retail revenue during PSPS events. The testimony also described how, absent a ratemaking remedy, the IOUs will fully recover their authorized revenue requirement from all customers, including those receiving no electricity service during PSPS events, through pre-established balancing account mechanisms. The CCA Parties also explained the potential impact of PSPS events on wholesale generation revenue and the need to account any such reductions if generation resources are forced offline due to PSPS events.

The CCA Parties made recommendations on the following issues which remain in dispute per the Joint Case Management Statement:

- The calculation of unrealized retail revenue during PSPS events should include additional CPUC-jurisdictional rate components tied to balancing accounts that record IOU costs incurred despite lost sales to end use customers.
- Each IOU should make a full accounting of the balancing accounts implicated by the total unrealized retail revenue.
- Unrealized wholesale generation revenue should be quantified if utility-owned generation resources, or contracts with take-or-pay provisions, are forced out of service due to a PSPS event.
- Each IOU should record adjusting entries to affected balancing accounts, equal to the unrealized retail and wholesale generation revenue as applicable, to comply with the Commission's directive to "forgo collection in rates from customers of all authorized revenue requirement equal to estimated unrealized volumetric sales and unrealized revenue resulting from PSPS events."

TURN also filed testimony recommending that ***all*** revenue requirements from retail sales be disallowed.

Analysis: Phase 2 of the proceeding is assessing whether PG&E should be required to return its revenue requirement associated with unrealized sales associated with its 2019 PSPS events, and the methodology and inputs for calculating such a disallowance. VCE's customers could benefit from such a CPUC-determined disallowance, e.g., via a bill credit or reduced PG&E charges. The Phase 2 determination will also impact the 2020 and 2021 ERRA Compliance proceedings.

Next Steps: There is no current procedural schedule.

Additional Information: Order Extending Statutory Deadline (July 18, 2022); ALJ Ruling Admitting Additional Exhibits into Evidence (July 13, 2022); Amended Procedural Schedule (April 6, 2022); Joint Case Management Statement (February 25, 2022); Order Denying Rehearing of D.21-07-018 and PG&E's application for rehearing of D.21-07-013 (December 3, 2021); Ruling consolidating ERRA compliance proceedings (September 7, 2021); PG&E Application for Rehearing of D.21-07-013 (August 16, 2021); D.21-07-013 resolving Phase 1 (July 16, 2021); Joint Motion to Adopt Settlement Agreement (October 22, 2020); Amended Scoping Memo and Ruling (August 14, 2020); Scoping Memo and Ruling (June 19, 2020); PG&E's Application and Testimony (February 28, 2020); Docket No. A.20-02-009.

PG&E 2020 ERRA Compliance

On August 11, the CPUC issued D.22-08-009 extending the statutory deadline in this proceeding through 2023 to provide an opportunity to address the Phase 2 issues related to unrealized sales and revenues resulting from PG&E's Public Safety Power Shutoff events in 2020.

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 prior year, such as energy resource contract administration, least-cost dispatch, fuel procurement, and balancing account entries.

PG&E requested 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 Power Cost Indifference Adjustment (PCIA), PG&E requested the CPUC find that entries in its Portfolio Allocation Balancing Account (PABA), which trues up the above-market forecast of generation resources recovered through the PCIA with actual recorded costs and revenues, are accurate.

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

The Scoping Memo and Ruling specifies the proceeding will be divided into two phases. Phase 1 addressed 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 includes whether sales forecasting methods for adjusting revenue requirement under current decoupling policy should be adjusted to account for power not sold or purchased during a Public Safety Power Shutoff (PSPS) event in 2020, whether it is appropriate for PG&E to return the revenue requirement equal to the estimated unrealized volumetric sales and unrealized revenue resulting from the PSPS events in 2020, and the appropriate methodology for calculating PG&E's unrealized volumetric sales and unrealized revenues resulting from 2020 PSPS events.

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

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

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

PG&E agreed that entries to the PABA for costs associated with the Green Tariff Shared Renewables program should be reduced by $5 million for 2019 and 2020, as Joint CCAs had argued. PG&E also agreed that certain issues should be in the scope of future ERRA proceedings, resolving the Joint CCA concern regarding its ability to review PG&E's accounting with respect to transactions with the CPE in future ERRA Compliance proceedings. Finally, PG&E agreed to transfer from PABA to ERRA 2014 and 2017 Diablo Canyon Seismic Studies Balancing Account recorded costs, whereas the 2018 costs were retained in the PABA, which resolved the Joint CCAs concerns about that cost recovery.

Details: Phase 1 concluded in April 2022 with issuance of D.22-04-041 approving the Settlement Agreement. On August 11, the CPUC issued D.22-08-009 extending the statutory deadline in this proceeding through 2023 to provide an opportunity to address the Phase 2 issues related to unrealized sales and revenues resulting from PG&E's Public Safety Power Shutoff events in 2020.

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 will also determine 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: Phase 1 of the proceeding has concluded. Phase 2 will address issues associated with PSPS events during 2020, but it will not begin until after the Commission resolves issues related to the establishment of a common accounting methodology for PSPS events in Phase 2 of the 2019 ERRA Compliance proceeding, which is expected in Q4 of 2022.

Additional Information: D.22-08-009 (August 11, 2022); PG&E AL 6621-E (June 17, 2022); D.22-04-041 (April 21, 2022); Joint Motion for Adoption of Settlement Agreement (October 15, 2021); Scoping Memo and Ruling (June 21, 2021); Application (March 1, 2021); Docket No. A.21-03-008.

PG&E 2021 ERRA Compliance

On August 9, the Assigned Commissioner issued a Scoping Memo and Ruling defining the issues for consideration, finding that evidentiary hearings are needed, and providing a procedural schedule intended to conclude the proceeding within 18 months.

Background: PG&E's Application requested the CPUC find that during 2021:

- It complied with its CPUC-approved 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.
- It managed its utility-owned generation (UOG) facilities reasonably.

- Its expenditures in the Green Tariff Shared Renewables Memorandum Account (GTSRMA) were reasonable.
- Its entries in the Portfolio Allocation Balancing Account (PABA), Energy Resource Recovery Account (ERRA), Green Tariff Shared Renewables Balancing Account (GTSRBA), Disadvantaged Community – Single-Family Affordable Solar Homes (DAC SASH) balancing account (DACSASHBA), Disadvantaged Community - Green Tariff Balancing Account (DACGTBA), and Community Solar Green Tariff Balancing Account (CSGTBA) were consistent with applicable tariffs and CPUC directives.

PG&E also presented its Central Procurement Entity's (CPE) administrative costs recorded to the Centralized Local Procurement Sub-Account (CLPSA) in the New System Generation Balancing Account (NSGBA).

PSPS Impacts: This Application does not include any testimony addressing the calculation of unrealized volumetric sales or unrealized revenues resulting from Public Safety Power Shutoff (PSPS) events, and once the Commission has resolved the issue in the Phase II 2019 ERRA Compliance proceeding PG&E plans to request direction from assigned ALJ regarding the presentment of PSPS information in this proceeding.

Protests of PG&E's application were filed on April 6 by three parties including CalCCA and the Cal Advocates office. PG&E filed supplemental testimony on July 15.

Details: The August 9 Scoping Memo and Ruling identified the following issues for consideration in this proceeding:

1) Whether PG&E, during the record period, prudently administered and managed, in compliance with all applicable rules, regulations and Commission decisions, including but not limited to Standard of Conduct No. 4 (SOC 4), the following:

    a) Utility-Owned Generation facilities;

    b) Qualifying Facilities (QF) Contracts; and

    c) Non-QF Contracts.

    If not, what adjustments, if any, should be made to account for imprudently managed or administered resources?

2) Whether PG&E achieved least-cost dispatch of its energy resources and economically triggered demand response programs pursuant to SOC 4.

3) Whether the entries recorded in the ERRA and the Portfolio Allocation Balancing Account are reasonable, appropriate, accurate, and in compliance with Commission decisions.

4) Whether PG&E's greenhouse gas compliance instrument procurement complied with its Bundled Procurement Plan.

5) Whether PG&E administered resource adequacy procurement and sales consistent with its Bundled Procurement Plan.

6) Whether the costs incurred and recorded in the following accounts are reasonable and in compliance with applicable tariffs and Commission directives:

    a) Green Tariff Shared Renewables Memorandum Account;

    b) Green Tariff Shared Renewables Balancing Account;

c) Disadvantaged Communities - Single Family Solar Affordable Homes Balancing Account;

d) Disadvantaged Communities - Green Tariff Balancing Account;

e) Community Solar Green Tariff Balancing Account; and

f) Centralized Local Procurement Sub-Account of the New System Generation Balancing Account.

7) Whether there are any safety considerations raised by this Application.

8) What is the revenue requirement equal to the estimated unrealized volumetric sales and unrealized revenue resulting from the Public Safety Power Shutoff events in 2021 that PG&E must forgo in accordance with D.21-06-014? What is the appropriate methodology for calculating PG&E's unrealized volumetric sales and unrealized revenues resulting from 2021 PSPS events?

Analysis: The proceeding will determine the reasonableness and appropriateness of PG&E expenditures, including some CPE administration costs. Some uncertainty remains regarding the treatment of PSPS events during this time period pending the Commission's determination on the utilities' proposed common methodology for calculating unrealized volumetric sales and unrealized revenues associated with PSPS events in the Phase II 2019 ERRA Compliance proceeding.

Next Steps: The Scoping Memo and Ruling adopted the following schedule:

- **October 31, 2022** – Intervenors' prepared direct testimony served
- **December 9, 2022** – Prepared rebuttal testimony served
- December 2022 to early January 2023 – Settlement Talks held
- January 6, 2023 – Status Conference
- January 11, 2023 – Completion of Settlement Talks
- January 17-19, 2023 – Evidentiary Hearing
- February 17, 2023 – Concurrent Opening Briefs due
- March 7, 2023 – Concurrent Reply Briefs due
- May-June 2023 – Proposed Decision

Additional Information: Assigned Commissioner's Scoping Memo and Ruling (August 9, 2022); PG&E Supplemental testimony (July 15, 2022); PG&E Errata testimony (May 11, 2022); PG&E 2021 ERRA Compliance Application (February 28, 2022); Docket No. A.22-02-015.

PG&E Regionalization Plan

On July 25, PG&E met with the Regionalization Stakeholder Group and presented an activity schedule for future meetings and reporting. The proceeding is otherwise closed.

Background: D.20-05-051 approved PG&E's reorganization following bankruptcy and directed PG&E to file a regionalization proposal (I.19-09-016). On June 30, 2020, PG&E filed its regionalization proposal in which it proposed to divide its service area into five new regions, each led by a Regional

Vice President, and each with a Regional Safety Director to lead its safety efforts. The new proposed 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 Maintenance and Construction, (4) Regional Planning and Coordination, and (5) Community and Customer Engagement, while other functions remain centralized. In February 2021, PG&E submitted an Updated Proposal with renamed regions that also moved 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.

D.22-06-028 approved the MPSA but contained some modifications to the Proposed Decision including clarifications that PG&E must hold quarterly "town hall" meetings in each region and that any interested party may participate in the Regionalization Stakeholder Group (RSG).

Details: On July 25, PG&E held a meet and confer with the RSG and made a presentation providing a recap of the purpose and scope of the RSG and highlighted an activity schedule for future meetings. Townhall meetings in each region will be held during August or September 2022, and the first Town Hall meeting for VCE's region will be held on September 1.

Analysis: The implications of PG&E's regionalization plan on CCA operations, customers, and costs remain largely unclear. As part of Region 2, VCE is grouped with Butte, Colusa, El Dorado, Glenn, Lassen, Nevada, Placer, Plumas, Sacramento, Shasta, Sierra, Solano, Sutter, Tehama, Yolo, and Yuba Counties. The Decision did not address most of the comments made by VCE and Pioneer regarding the inefficacy of the Updated Proposal, the need for the Commission to adopt and utilize metrics to measure the efficacy of PG&E's regionalization, suggestions for greater transparency and responsiveness, or alignment of regional boundaries with existing councils of governments.

Next Steps: PG&E's Tier 3 advice letter on regionalization implementation actions is due September 21. PG&E is required to submit a report on its quarterly townhall meetings in each region within 45 days following the end of each quarter, and it plans to file its first Quarterly Report with the Tier 3 AL in September. The next RSG meeting is planned for late September or early October 2022.

Additional Information: PG&E Presentation to Regionalization Stakeholder Group (August 25, 2022); D.22-06-028 on Regionalization (June 24, 2022); Joint Motion for approval of Settlement Agreements (August 31, 2021); Amended Scoping Memo and Ruling (June 29, 2021); PG&E Updated Regionalization Proposal (February 26, 2021); Application (June 30, 2020); A.20-06-011.

Utility Safety Culture Assessments

On July 22, the ALJ issued a Ruling seeking comments on policy questions for safety culture assessments and distributing the Staff Safety Culture Concept Paper 1.

Background: IOU safety culture assessments are required as part of AB 1054 and SB 901. AB 1054 directed the CPUC's Wildfire Safety Division, now the Office of Energy Infrastructure Safety, to conduct annual safety culture assessments of each electrical corporation that are specific to wildfire safety efforts and include a workforce survey, organizational self-assessment, supporting documentation, and interviews. SB 901 directed the CPUC to establish a safety culture assessment for each electrical corporation that is conducted by an independent third-party evaluator at least every five years. This proceeding will implement these safety culture assessments for regulated utilities.

The April 28 Scoping Ruling divided the proceeding into multiple phases and established the scope for Phase 1 to focus on developing safety culture assessments for the large investor-owned electric and natural gas corporations, while Phase 2 will focus on developing safety culture assessments for the small multi-jurisdiction utilities and the gas storage operators.

Phase 1 issues to be determined or considered include defining “safety culture”, the design of an inclusive and collaborative framework for conducting safety culture assessments focused on actual safety improvement, creating metrics and methodologies to evaluate the efficacy of the safety culture assessment process, and procedural matters related to the Phase 1 process timeframe, management, and coordination with other ongoing safety-related initiatives.

Details: Ideas discussed during the June and July technical working group meetings related to safety culture definitions, frameworks, and collaborations are outlined in the Staff Safety Culture Concept Paper 1. The July 22 ALJ Ruling seeks to further develop the ideas presented in the Staff Concept Paper with formal comments on these Phase 1 policy questions.

Analysis: This rulemaking will define safety culture concepts and determine how the safety culture of PG&E and other IOUs in California will be assessed and evaluated. It could impact VCE and its customers to the extent it succeeds or fails to influence PG&E’s safety culture and hence the safety of VCE customers. It could also impact the rates VCE customers pay to PG&E to mitigate or address safety issues (e.g., wildfires caused by PG&E transmission equipment; explosions from PG&E natural gas infrastructure, etc.).

Next Steps: A workshop will be held on the Staff Proposal in September 2022.

- **September 2022:** Safety Policy Division Workshop on Staff Proposal
- **October 2022:** Opening Comments on Staff Proposal
- **November 2022:** Reply Comments on Staff Proposal

Additional Information: ALJ Ruling seeking comment (Staff Safety Culture Concept Paper 1) (July 22, 2022); CPUC Safety Culture and Governance webpage; Scoping Ruling with procedural schedule (April 28, 2022); Webinar recording of the workshop (March 11, 2022); Order Instituting Rulemaking (October 7, 2021); Docket No. R.21-10-001.

Other Dockets

The following table identifies other tracked dockets that are closed or inactive.

Docket	Name	Status
R.21-03-001	Wildfire Fund NBC (2022-2023) Rulemaking	The Department of Water Resources will issue a notice in September 2022 identifying the amount they calculate will be needed for the 2023 Wildfire Fund NBC.
I.15-08-019	Investigation into PG&E Organization, Culture and Governance	D.21-11-010 extended the statutory deadline until November 8, 2022 to allow for continued monitoring of PG&E’s ongoing safety performance and to provide the Commission time to establish next steps for the proceeding.
R.20-11-003	Ensuring Summer 2021 Reliability	D.22-06-005 closed the proceeding.
A.19-11-019	PG&E 2020 Phase 2 GRC	D.22-08-002 closed the docket; all current activity is now covered under the Commercial EV Real-Time Pricing docket.
A.21-06-001	PG&E 2020 ERRA Forecast	D.22-02-002 closed the proceeding.

R.19-03-009	Direct Access Rulemaking	D.21-06-033 closed the proceeding, but a Petition for Rehearing (July 29, 2021) remains outstanding.

Glossary of Acronyms

AB	Assembly Bill
ALJ	Administrative Law Judge
BEV	Business Electric Vehicle
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
DA	Direct Access
ELCC	Effective Load Carrying Capacity
ERRA	Energy Resource and Recovery Account
GRC	General Rate Case
IEPR	Integrated Energy Policy Report
IFOM	In Front of the Meter
IRP	Integrated Resource Plan
IOU	Investor-Owned Utility
LSE	Load-Serving Entity
MCAM	Modified Cost Allocation Mechanism
MCC	Maximum Cumulative Capacity
OII	Order Instituting Investigation
OIR	Order Instituting Rulemaking
PABA	Portfolio Allocation Balancing Account
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
RSG	Regionalization Stakeholder Group
ReMAT	Renewable Market Adjusting Tariff
RPS	Renewables Portfolio Standard
RTP	Real-Time Pricing
TOU	Time of Use
TURN	The Utility Reform Network
UOG	Utility-Owned Generation
VAMO	Voluntary Allocation/Market Offer
WMP	Wildfire Mitigation Plan
WSD	Wildfire Safety Division (CPUC)