

VALLEY CLEAN ENERGY ALLIANCE

Staff Report – Item 9

To: Board of Directors

From: Keyes & Fox, Regulatory Consultant

Subject: Regulatory Monitoring Report – Keyes & Fox

Date: July 14, 2022

Please find attached Keyes & Fox's June 2022 Regulatory Memorandum dated July 6, 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 July 6, 2022.

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: July 6, 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:

- **Ensuring Summer 2021 Reliability:** On June 3, the CPUC issued D.22-06-005 which partially granted VCE, TeMix Inc., and Polaris Energy Services' (collectively, the Pilot Partners) Petition for Modification, approving an increase to the budget for VCE's agricultural irrigation pumping dynamic rates pilot (AgFIT Pilot) by an additional \$690,000 to cover VCE's expenses in carrying out the pilot program.
- **IRP Rulemaking:** On June 15, the ALJ issued a Ruling finalizing the load forecasts and greenhouse gas emission benchmarks for use in 2022 IRP filings.
- **RPS Rulemaking:** On June 24, the Commission issued D.22-06-034 establishing rules for the PCC classification of resources obtained through the VAMO process. On July 1, VCE filed its draft RPS Procurement Plan.
- **PCIA Rulemaking:** On June 10, the ALJ issued a Proposed Decision that would, if adopted, resolve Phase 2 issues related to data access and voluntary allocations in market price benchmark (MPB) calculations. The PD may be heard by the Commission as early as July 14. A June 24 Ruling defined the scope for the next part of the proceeding.
- **PG&E Phase 1 GRC:** On June 13, intervenors submitted direct testimony in the proceeding. 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.

- **RA Rulemaking (2023-2024):** 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.
- **PG&E Regionalization Plan:** On June 24, the CPUC issued D.22-06-028 approving and modifying settlement agreements relating to PG&E's updated regionalization plan and closing the proceeding. In response to comments by VCE and other parties, the Decision incorporated revisions to the proposed decision that require PG&E's regional leadership to hold quarterly "town hall" meetings with stakeholders in each region through at least the end of 2024, allow non-parties to participate in a stakeholder working group and clarified that recovery of regionalization costs from ratepayers is not guaranteed.
- **PG&E Phase 2 GRC:** On June 22, the CPUC issued a Proposed Decision that, if approved, would direct PG&E to implement the settlement agreement provisions for a real-time pricing pilot, adopt the methodology outlined in the marginal generation capacity cost study for use in real-time pricing rate designs, and close this proceeding. The PD may be heard as soon as the August 4 Commission meeting.
- **Provider of Last Resort Rulemaking:** No updates this month.
- **PG&E 2023 ERRR Forecast:** On May 31, PG&E filed its 2023 ERRR Forecast application and supporting testimony. PG&E filed supplemental testimony to its application on June 22.
- **PG&E 2021 ERRR Compliance:** A prehearing conference was held on June 8. A scoping ruling establishing a procedural schedule has not been issued.
- **PG&E 2019 ERRR Compliance:** No updates this month.
- **Utility Safety Culture Assessments:** No updates this month.
- **2022-2023 Wildfire Fund Nonbypassable Charge Rulemaking:** No updates this month.

Ensuring Summer 2021 Reliability

On June 3, the CPUC issued D.22-06-005 which partially granted VCE, TeMix Inc., and Polaris Energy Services' (collectively, the Pilot Partners) Petition for Modification, approving an increase to the budget for VCE's agricultural irrigation pumping dynamic rates pilot (AgFIT Pilot or Pilot) by an additional \$690,000 to cover VCE's expenses in carrying out the Pilot.

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

D.21-03-056 instituted modifications to the planning reserve margin (PRM), effectively increasing the PRM beginning summer 2021 from 15% to 17.5%. For 2021, this results in a minimum target of incremental procurement of 450 MW for PG&E, 450 MW for SCE, and 100 MW for SDG&E. The net costs associated with this incremental procurement would be shared by all customers (including CCA customers) in each IOU's service territory. It also authorized the IOUs to implement a Flex Alert paid media campaign program to encourage ratepayers to voluntarily reduce demand during moments of a stressed grid, adopts modifications and expansions to the Critical Peak Pricing (CPP) program, and established an emergency load reduction program.

[D.21-12-015](#) approved VCE's AgFIT Pilot for three years (2022-2024) and directed that it start no later than May 1. VCE's Pilot will test whether agricultural irrigation pumping customers, which consume on average 18% of VCE's total annual load, can shift load to more optimal times of the day, thereby saving money, reducing the burden to the grid and reducing GHG impacts. Customers participating in VCE's Pilot will receive a "shadow bill." PG&E will continue to bill participating customers based on existing tariffs, but the shadow bill will show the customer savings under the Pilot dynamic rate, and VCE will pay customers for the difference between the shadow bill and the customer's usage under the otherwise applicable tariff. The Pilot scale will be limited to 5 MW of peak load. PG&E will provide funds to or reimburse VCE for crediting any savings realized by the customers with respect to the delivery component of the VCE dynamic rate Pilot in the customers' shadow bills. D.21-12-015 authorized new funding of \$3.25 million for the pumping automation technology, pricing platform and vendor fees and PG&E's administration of the three-year Pilot.

On January 5, VCE submitted Advice Letter 11-E in accordance with D.21-12-015. Advice Letter 11-E was approved by the Energy Division via nonstandard disposition mailed April 11.

On January 31, the Pilot Partners filed a Petition for Modification (PFM) of D.21-12-015 to increase the budget for this Pilot to cover VCE's administrative costs.

On February 4, PG&E submitted Advice Letter 6495-E, which the Pilot Partners Protested on February 24. PG&E filed Supplemental Advice Letter 6495-E-A on April 7, 2022. The Energy Division approved PG&E's advice letters via nonstandard disposition letter issued April 26.

[D.21-12-015](#) also created an additional procurement mandate of 2,000 MW-3,000 MW for 2023, allocated exclusively to the three large IOUs (900 MW-1,350 MW each for PG&E and SCE, and 200 MW-300 MW for SDG&E). It required all incremental resources procured as a result of this proceeding to be available during the net peak. It adopted numerous additional demand-side and supply-side changes aimed at ensuring sufficient resource availability to meet the summer net peak load.

Details: The Decision granted VCE's request for an incremental \$690,000 in funding to reimburse VCE for its administrative costs in carrying out the Pilot. In light of the Energy Division's subsequent resolution of other issues raised in the PFM, the Decision took no further action.

Analysis: After a conflicted and procedurally complex set of interactions with PG&E regarding the Pilot, most of VCE's concerns have been resolved via the Energy Division's Advice Letter dispositions. The Decision will enable VCE to be reimbursed through distribution funds for its administrative expenses in running the Pilot.

Next Steps: VCE has launched the AgFIT Pilot and is required to submit its expenses to the Energy Division for approval of reimbursement. The first report evaluating the Pilot mid-way through its term is due December 31, 2023 and is to be prepared by an independent evaluator hired by PG&E, in consultation with VCE.

Additional Information: [D.22-06-005](#) granting PFM (June 3, 2022); [Ruling](#) denying Pilot Partners Motion to shorten time (May 3, 2022); [Proposed Decision](#) on PFM (April 29, 2022); Energy Division's [Non-Standard Disposition Letter](#) approving PG&E [AL 6495-E](#) and PG&E [AL 6495-E-A](#) (April 27, 2022); PG&E [AL 6495-E-A](#) (April 7, 2022); Energy Division's [Non-Standard Disposition Letter](#) approving VCE [AL 11-E](#) (April 11, 2022); PG&E [AL 6495-E](#) (February 4, 2022) and [Substitute Sheets](#) for AL 6495-E (March 29, 2022); VCE, TeMix and Polaris [Petition for Modification](#) (January 31, 2022); [Motion](#) to Shorten Time (January 31, 2022); VCE [AL 11-E](#) on Ag Pumping Pilot (January 2, 2022); [D.21-12-069](#) correcting errors in D.21-12-014 (December 27, 2021); [D.21-12-015](#) (December 6, 2021); [D.21-02-028](#) directing IOUs to seek additional capacity for summer 2021 (February 17, 2021); [Scoping Memo and Ruling](#) (December 21, 2020); [Order Instituting Rulemaking](#) (November 20, 2020); Docket No. [R.20-11-003](#).

IRP Rulemaking

On June 15, the ALJ issued a Ruling finalizing the load forecasts and greenhouse gas emission benchmarks for use in 2022 IRP filings.

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, i.e. deficient LSEs. 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 procurement authorized in the IRP process, but not other cost allocation situations such as those related to a central procurement entity. IOUs must file Tier 2 advice letters on MCAM implementation by July 18. The MCAM is based on the original Cost Allocation Mechanism (CAM) adopted in D.06-07-029 but applies specifically to opt-out and backstop procurement conducted by IOUs on behalf of LSEs. 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.

The MCAM adjusts the traditional CAM to account for the fact that procurement costs will only be recovered from customers of LSEs that have opted-out of such procurement and customers of deficient LSEs, rather than all customers in an IOU’s service territory. 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.

One-time Option for LSEs Gaining New Load Since 2019

Because the MCAM development process was extended over several years during which LSEs were making procurement decisions, the CPUC provided a one-time procurement option for LSEs that have gained new load since 2019 as a result of customer migration from IOU service. The one-time option allows LSEs with newly migrated load to enter into bilateral agreements with the relevant IOUs to acquire resource adequacy capacity at the System RA Market Price Benchmark (MPB) as determined in the PCIA context pursuant to D.19-10-001.

Details: On June 15, the ALJ issued a Ruling finalizing the load forecasts and greenhouse gas emission benchmarks for use in 2022 IRP filings. IRP filing requirements, templates and calculators are available on the CPUC's [2022 IRP website](#). 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.

This ruling adopts 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

LSEs that intend to reduce GHG emissions below their proportional share of both the 2030 30 MMT benchmark and the 2035 25 MMT benchmark are only required to submit one preferred portfolio. However, LSEs submitting one preferred portfolio will still be required to submit that portfolio in each of the two sets of Resource Data Templates (RDTs) and Clean System Power (CSP) calculators required for each 2035 GHG target. Otherwise, each LSE must show two conforming portfolios that meet its proportional share of all four benchmarks.

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. Under the MCAM Decision, a deficiency in fulfilling RA and reliability procurement obligations results in additional, likely higher, costs to the LSEs 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 overprocurement of resources if triggered.

Next Steps: IOUs file Tier 2 Advice Letters on MCAM implementation on July 18. VCE's next IRP is due November 1.

Additional Information: [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); [D.21-02-028](#) recommending portfolios for CAISO's 2021-2022 TPP (February 17, 2021); [D.20-12-044](#) establishing a backstop procurement process (December 22, 2020); [Scoping Memo and Ruling](#) (September 24, 2020); [Resolution E-5080](#) (August 7, 2020); [Order Instituting Rulemaking](#) (May 14, 2020); Docket No. [R.20-05-003](#).

RPS Rulemaking

On June 24, the Commission issued D.22-06-034 establishing rules for the PCC classification of resources obtained through the VAMO process. On July 1, VCE filed its draft RPS Procurement Plan.

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

In addition, ongoing implementation issues of the Voluntary Allocation and Market Offer process (VAMO) ordered in the PCIA proceeding are considered here 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: 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.

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. The Plans must describe procurement of RPS resources that achieve the RPS targets while minimizing cost and maximizing customer value; and discuss any plans for building retail seller-owned resources, investing in third party-owned renewable resources, and engaging in the sales of RPS-eligible resources.

Details:

Track 1: 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. The CPUC also adopted the following rules related to RPS resources procured through the Voluntary Allocation process:

- Subsequent transfer/sale of Voluntary Allocation RECs after the Voluntary Allocations will be considered a resale, and the REC PCC classification will change pursuant to D.11-12-052 and other applicable Renewables Portfolio Standard (RPS) law and policy.

- The Voluntary Allocation price based on the Market Price Benchmark methodology adopted in D.21-05-030 is retained without modification.
- The IOUs are not required to submit advice letter filings for Commission approval of executed pro forma Voluntary Allocation contracts. However, the IOUs must obtain Commission approval of executed pro forma Voluntary Allocation contracts if the contract deviates from the pro forma contract via a Tier 1 advice letter filing.

This Decision also clarifies that LSEs are only expected to include Voluntary Allocation information in the July 1 Draft RPS Plan filings to the extent an LSE has information available and may include the Voluntary Allocation information in the RPS Plan Motion to Update due on August 15. 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: VCE filed its Draft 2022 RPS Procurement Plan on July 1, 2022. 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.

Analysis: 2022 RPS Procurement Plan requirements have a greater focus on long-term planning, not only maintaining the target of procuring 65% of RPS resources from long-term contracts of 10 or more years, but also aligning the RPS plan with IRP requirements in D.21-03-010. The new Voluntary Allocation mechanism has an outsized role in 2022 RPS Plans, providing LSEs an opportunity to claim a slice of an IOU's portfolio of RPS resources prior to entering a competitive bidding process, potentially with the added incentive of obtaining PCC-0 RECs that would otherwise be unavailable. Voluntary Allocation essentially provides LSEs a right of first refusal, accelerates and streamlines the procurement process, and enables RPS procurement at the MPB without competitive bidding while providing all LSEs with equal access to a representative share of an IOU's portfolio of RPS resources. The PCIA will be reduced to the extent allocations and purchases are elected under VAMO.

Next Steps:

Track 1: VAMO

- **July 29, 2022:** LSEs complete the process of determining interest in Voluntary Allocation elections and sign contracts (previous deadline was May 2022)
- **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

- **August 1, 2022:** Opening Comments on LSEs' draft RPS Procurement Plans due

- **August 1, 2022:** Motions requesting evidentiary hearing due
- **August 15, 2022:** LSEs' motion to update draft RPS Procurement Plans due
- **August 15, 2022:** Reply Comments on LSEs' draft RPS Procurement Plans due
- **4Q 2022:** Proposed Decision on LSEs' draft RPS Procurement Plans
- **1Q 2023:** LSEs file final 2022 RPS Plans

Additional Information: VCE's [2022 Draft RPS Procurement Plan](#) (July 1, 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 6551-E-A](#) (May 23, 2022); [Ruling](#) on Procedural Schedule (May 20, 2022); [Market Offer Process](#) proposal by Joint IOUs (May 2, 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); [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); Docket No. [R.18-07-003](#).

PCIA Rulemaking

On June 10, the ALJ issued a Proposed Decision that would, if adopted, resolve Phase 2 issues related to data access and voluntary allocations in market price benchmark (MPB) calculations. The PD may be heard by the Commission as early as July 14. A June 24 Ruling defined the scope for the next part of the proceeding.

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 following the work of Working Group 2, the Commission adopted a framework for PCIA prepayment agreements.

D.21-05-030, the Phase 2 Decision 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.

The most recent step in the PCIA proceeding is D.22-01-023, which modified the PCIA market price benchmark release date to October 1 and the deadline for ERRA forecast applications to May 15 to enable the Commission to timely issue decisions on ERRA forecast applications.

Details: On June 10, the ALJ issued a Proposed Decision that would, if adopted, resolve Phase 2 issues related to data access and voluntary allocations in market price benchmark (MPB) calculations. The PD may be heard by the Commission as early as July 14. The PD includes the following Orders:

- CalCCA may organize a meeting by October 3 to discuss the proposed format and content of the non-confidential analyses of PCIA forecasts that reviewing representatives may disclose to CCAs under this Decision, and the meeting must include the three large IOUs and representatives of any interested CCA.
- One member of CalCCA may file a joint Tier 2 Advice Letter by December 1 on behalf of all CCAs that seek PCIA forecasting data access. The AL must include a standard template for conveying PCIA information reviewed by CCA representatives to their clients, a public appendix with example analysis using dummy data, a proposed non-disclosure agreement (NDA) based on ERRA forecast NDA, and a list of all CCAs that seek forecasting data access and their reviewing representatives.
- CCAs' reviewing representatives must simultaneously serve the Commission and the relevant IOU all information disclosed to their clients.

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.

Analysis: The MPB calculation is used as the basis for the pricing RPS resources under the Voluntary Allocation process, and the MPB benchmark price is used in Energy Resource and Recovery Account (ERRA) forecasts to determine PG&E's PCIA-related revenue requirement. The April 18 ALJ ruling seeks a response to a series of questions regarding approaches to modifying the manner in which 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:

- **July 22, 2022:** Parties may file reply comments on Energy Index MPB Proposals
- **July/August 2022:** Ruling regarding method to include long-term fixed-price transactions in RPS MPB and the value of GHG-free resources
- **August/September 2022:** Workshop on long-term fixed-price transactions in RPS MPB
- **November 2022:** Workshop on value of GHG-free resources

Additional Information: [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](#).

PG&E Phase 1 GRC

On June 13, intervenors submitted direct testimony in the proceeding. 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.

Background: Phase 1 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. PG&E proposes to have a second and third track of this Phase 1 GRC to request reasonableness review of certain memorandum and balancing account costs to be recorded in 2021 and 2022.

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

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

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

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.

PG&E's November 5, 2021 Motion requested extending the turn-around time for filing rebuttal testimony from 30 days to 45 days; delaying the start of evidentiary hearings by three weeks to accommodate the proposed rebuttal testimony timeline; and requested an earlier resolution than Q4 2022 as indicated in the Scoping Memo and Ruling on PG&E's July 16, 2021 Motion for a January 1, 2023 effective date for its 2023 revenue requirement.

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. Also on March 10, the ALJ issued a Ruling on the February 25 Motion filed by TURN, PG&E, and PAO denying their request to shorten time for responses to PG&E's Amended Application and supplementary testimony on wildfire mitigation programs and suspending the March 30 submission date for intervenor testimony pending a ruling on the February 16 Motion to Modify the Schedule filed by TURN, PG&E, and the PAO.

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%.

Details: On June 13, intervenors submitted direct testimony in the proceeding. The Joint CCAs submitted 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. A June 24 Email Ruling noticed an August 9 status conference, directed PG&E to prepare a case management statement, provided instructions for the August 15-26 hearings, requested testimony summaries in table format by July 11, and set forth a proposal for the uniform formatting of briefs.

On June 27, PG&E filed two motions: (1) a motion for modification of the email ruling noticing August 9 status conference (requesting an extension of the July 11 due date for parties to submit their Summary of Requests, as well as modifications to hearing exhibit and briefing requirements), and (2) a motion to shorten time for responses to PG&E's motions. On June 29, the ALJs granted PG&E's motions for shortened time, requiring parties to file responses to PG&E's June 27 motions by July 6.

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:

The Track 1 schedule, as modified in the April 12 Ruling is:

- **July 11, 2022:** Rebuttal Testimony

- **July 12 – August 15, 2022:** Meet & Confer (minimum of four times)
- **August 9, 2022:** Status Conference
- **August 15 – August 26, 2022:** Evidentiary Hearings
- **November 4, 2022:** Opening Briefs
- **December 9, 2022:** Reply Briefs
- **March 24, 2023:** Proceeding Submitted
- **Q3 2022:** Proposed Decision on PG&E
- **Q2 2023:** Proposed Decision on A.21-06-021

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

- **July 22, 2022:** PG&E Testimony
- **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: [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); Docket No. [A.22-04-008](#); Docket No. [A.21-06-021](#).

RA Rulemaking (2023-2024)

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.

Background: In Track 3B.2 of the 2021-2022 RA Rulemaking (R.19-11-009), D.21-07-014 rejected CalCCA/SCE's proposal for restructuring the Resource Adequacy (RA) program, and instead found that PG&E's "slice-of-day" proposal best addresses the identified principles and the concerns with the current RA framework and if further developed, is best positioned to be implemented in 2023 for

the 2024 compliance year. The Decision directed parties to collaborate to develop a final restructuring proposal based on PG&E's slice-of-day proposal through a series of workshops.

The 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 for the following year, local capacity requirements for the next three years, and the highest-priority refinements to the RA program including modifications to the Planning Reserve Margin Qualifying Capacity Counting Conventions, which, along with other proposals, will consider the Energy Division's biennial update to the Effective Load Carrying Capability 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. An LSE's self-shown commitment must be firm for Years 1 and 2, but self-shown local resources for year 3 may be replaced like-for-like with other local resources.

Details: On June 1, an ALJ Ruling provided the Energy Division's Regional Wind Effective Load Carrying Capability (ELCC) study, and a [revised version](#) of the study was released on June 9.

On June 8, an ALJ Ruling provided the Energy Commission's Notice of Availability for Mid-Term Reliability (MTR) Analysis [Supporting Data \(Docket No. 21-ESR-01\)](#).

On June 22, the Energy Division released its [white paper](#) on Advanced Strategies for Demand Flexibility Management and Customer DER Compensation that addresses challenges towards reaching 100% renewables, increased electrification in buildings and of vehicles, and deployment of behind-the-meter resources.

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 would adopt SCE's 24-hour "slice of day" framework, with modifications (see Appendix A), pending further development of certain implementation details. The Decision is summarized below, broken into the broad categories for the Implementation Track Phase 2 and the RA Reform Track, and the various sub-topics within each.

Implementation Track

2023-2025 LCR: The Decision adopts the LCR values from the CAISO's study without modification.

2023 FCR: The Decision adopts the FCR values contained in the CAISO's FCR report as well as CAISO's proposal to change the availability assessment hours (AAH) during which RA resources must be available for dispatch for March and April.

Planning Reserve Margin: For summers 2022 and 2023, an "effective PRM" of 20% to 22.5% was adopted in D.21-12-015 which established supply and demand-side measures to ensure reliability during extreme weather events for Summer 2022 and 2023. This Decision adopts a PRM of 16% for the 2023 RA year and a minimum of 17% for the 2024 RA year, and notes that the PRM for the 2024 RA year may be further revised in a June 2023 decision after additional review of LOLE modeling. Only amounts above the PRM are to be charged to all customers via the CAM.

Reform Track Issues

Slice of Day RA Framework: This Decision adopts a 24-hour slice-of-day framework based on a SCE proposal, which requires each LSE to demonstrate that it has enough capacity to satisfy its specific gross load profile, including PRM, in all 24 hours on CAISO's "worst day" in that month. The "worst day" is defined as the "day of the month that contains the hour with the highest coincident peak load forecast." For an LSE that uses energy storage to meet requirements, the LSE must demonstrate it has excess capacity that offsets the storage usage plus efficiency losses. An LSE could combine the capabilities of its resource mix to cover all 24 hours. The Decision eliminates the flexible RA requirement and the MCC buckets but requires additional development prior to doing so. Additionally, the Commission will maintain a public RA Resource Master Database of resources eligible to sell RA, including available MW of RA capacity, hours available for production, other use limitations, hourly profile (for solar and wind) and other details. The Decision defines three workstreams to further develop aspects of the slice of day framework.

Counting for Dispatchable Resources and Storage: The Decision directs the parties to develop an Unforced Capacity- (UCAP)-"light" mechanism to account for the effect of ambient temperature on dispatchable resources, but the Pmax values will continue to be used in the meantime.

Compliance Penalties: The Decision determines that retaining the existing RA penalty structure, as well as basing RA compliance penalties on the largest hour deficiency, is an appropriate penalty mechanism that does not double-penalize LSEs for multiple hour deficiencies under the 24-hour framework.

Analysis: The CPE framework is one of several new components added as the CPUC works toward integrating reliability, RA, and RPS obligations into the Integrated Resource Planning framework. These shifts placing greater responsibility on LSEs also add additional risk to procurement activities, particularly in the event of a delay or underperformance by a counterparty to a resource procurement contract. The Decision establishes SCE's proposed new 24-hour based RA requirements applied to day of the month with the highest coincident peak load on a monthly basis.

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
- **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

- **July 2022:** LSEs receive initial RA allocations, including Cost Allocation Mechanism (CAM) credits from CPE-procured system and flexible capacity from the prior year and any bilateral contracts.
- **Mid-August 2022:** CPE makes local RA showing to the Commission.
- **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.22-06-050](#) on LCR and FCR Requirements and Modifications to the RA Framework (June 24, 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](#).

PG&E Regionalization Plan

On June 24, the CPUC issued D.22-06-028 approving and modifying settlement agreements relating to PG&E's updated regionalization plan and closing the proceeding.

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, which described how it plans to reorganize operations into new regions. PG&E 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 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. Other functions will remain centralized, such as electric and gas operations, risk management, enterprise health and safety, the majority of existing Customer Care and regulatory and external affairs, supply, power generation, human resources, finance, and general counsel.

In August 2020, parties filed protests and responses to PG&E's application. Of note, South San Joaquin Irrigation District filed a Protest arguing that PG&E's regionalization effort should not create a moratorium or interfere with municipalization efforts.

In February 2021, PG&E submitted its updated regionalization proposal ("Updated Proposal"). In response to feedback, PG&E modified its five regions (renamed North Coast, North Valley & Sierra, Bay Area, South Bay & Central Coast, and Central Valley), including moving Yolo County from Region 1 to Region 2 (North Valley & Sierra), where it would be grouped with the following counties: Colusa, El Dorado, Glenn, Lassen, Nevada, Placer, Plumas, Sacramento, Shasta, Sierra, Solano, Sutter, Tehama, and Yuba.

On August 31, 2021, PG&E, the California Farm Bureau Federation, the California Large Energy Consumers Association, the Center for Accessible Technology, the Coalition of California Utility Employees, the Public Advocates Office at the California Public Utilities Commission (Cal Advocates), the Small Business Utility Advocates, and William B. Abrams filed a Motion for approval of their settlement agreement (Multi-Party Settlement Agreement, or MPSA). The MPSA provides that PG&E will facilitate a stakeholder engagement process to provide updates on PG&E's regionalization and a non-binding forum for input from stakeholders. The proposed settlement would have restricted participation in the Regionalization Stakeholder Group to Parties to the proceeding.

In the separate PG&E/SSJID Settlement Agreement, PG&E clarified and confirmed that its implementation of regionalization will not include any work to oppose SSJID's municipalization efforts. The settlement provided that PG&E may continue to respond to SSJID's municipalization efforts in other forums and proceedings separate from the regionalization proceeding and/or implementation of the Updated Regionalization Proposal.

VCE filed comments on the Motion for approval of the settlement jointly with Pioneer Community Energy that were critical of PG&E's Updated Proposal and the settlement. VCE and Pioneer recommended that the CPUC reject the settlement and require changes to PG&E's Updated Proposal, including alignment with the boundaries of regional councils of governments (COGs) and requirements to coordinate with COGs, the development of metrics to measure PG&E's progress on key safety and customer relations issues, greater coordination between PG&E and CCAs, and improvements to the Regionalization Stakeholder Group to expand its access and efficacy and not limit it to Parties to the proceeding.

On May 9, VCE and Pioneer filed comments on the Proposed Decision to approve the MPSA, recommending that the MPSA be rejected by the Commission because PG&E's Updated Proposal is highly unlikely to lead to meaningful safety, customer responsiveness or accountability improvements at PG&E. VCE and Pioneer requested that, at a minimum, the Commission keep the proceeding open to address issues arising from the stakeholder group, require PG&E to propose reasonable metrics for measuring the utility's safety performance and responsiveness to local communities, and to remove unreasonable restrictions on the scope and participation requirements in the stakeholder group.

Details: D.22-06-028 approved the MPSA but contained some modifications to the Proposed Decision with clarifications that:

- There is no guarantee of eventual recovery of costs recorded by PG&E in the memorandum account (established October 2, 2020);
- That PG&E must hold quarterly "town hall" meetings in each region until the later of Phase III completion or the end of 2024, as suggested by VCE and Pioneer; and
- In response to comments from VCE and other parties, required PG&E to submit a Tier 1 advice letter within 90 days of the final decision describing regionalization implementation activities already undertaken and planned.
- Expanded participation in the Regionalization Stakeholder Group (RSG) by any interested party rather than just parties to the proceeding, as suggested in comments by VCE and other parties. The Decision did not broaden the scope of the RSGs.

The Decision did not require PG&E to propose metrics by which to measure the success of its regionalization efforts and declined the request of all parties that filed comments, including the settling parties, to keep the proceeding open. The Decision approved the PG&E/SSJID Settlement Agreement.

Analysis: The implications of PG&E's regionalization plan on CCA operations, customers, and costs remain largely unclear. As part of Region 2, VCE would be 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 1 advice letter on regionalization implementation actions is due September 21, 2022. PG&E is required to submit a report on its quarterly town hall meetings in each region within 45 days following the end of each quarter, and the first report is due August 16.

Additional Information: [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](#).

PG&E Phase 2 GRC

On June 22, the CPUC issued a Proposed Decision that, if approved, would direct PG&E to implement the settlement agreement provisions for a real-time pricing pilot, adopt the methodology outlined in the marginal generation capacity cost study for use in real-time pricing rate designs, and close this proceeding. The PD may be heard as soon as the August 4 Commission meeting.

Background: PG&E's 2020 Phase 2 General Rate Case (GRC) addresses marginal cost, revenue allocation and rate design issues covering the next three years. D.21-11-016 largely adopted PG&E's proposed marginal costs and methodologies for deriving them but adopted marginal connection equipment costs proposed by the Agricultural Energy Consumers Association and marginal transmission capacity costs proposed by the Solar Energy Industries Association. It also adopted, without modification, several uncontested settlements on rate design issues (residential rate design settlement; settlement on streetlight rate design issues; Economic Development Rate (EDR) settlement; agricultural rate design; C&I rate design) and revenue allocation.

On January 18, parties filed a Settlement Agreement that includes the following terms of the Stage 1 RTP Pilot:

Eligibility: PG&E's bundled customers who are eligible for the B-20, B-6 and E-ELEC rates may participate on an opt-in basis. CCAs will need to affirmatively decide to participate in the Stage 1 Pilots for their customers to be eligible. PG&E agrees to work with its twelve CCAs to seek agreement from one or two of them to participate in the Stage 1 Pilots, if possible.

Duration: Stage 1 Pilots shall have a duration of 24 months, subject to potential extension.

Enrollment: PG&E will make its best efforts to program and make available for enrollment the three Stage 1 RTP rates by October 1, 2023.

Pricing: The RTP element of the Stage 1 Pilot RTP rates will replace the generation component of the customer's otherwise applicable rate schedule. The remaining transmission, distribution, Public Purpose Program and other charges and taxes remain the same as the otherwise applicable underlying rate. The generation component to be used in the Stage 1 Pilots' RTP rates will include: (1) a Marginal Energy Charge, (2) a Marginal Generation Capacity Cost, and (3) a Revenue Neutral Adder (designed to make the forecasted annual generation revenue collected under the three Stage 1 Pilot RTP rates revenue neutral to the base schedule). Residential customers would have 1 year of bill protection. There would be a limited amount of participation incentives as well.

All development, implementation, and operating costs for the Stage 1 Pilots, as well as for the separate Customer Research Study for residential, agricultural, and small commercial customers, will be recovered in distribution rates from all customers.

D.22-03-012 (March 18) adopted the Joint Stipulation resolving the single carryover issue of material fact about the MGCC Property Tax Adder and established a property tax factor of 1.25% for the 2021-2026 marginal generation capacity cost (MGCC) for new customer rates effective June 1. A corrected version of PG&E's MGCC Report was filed on March 17.

On March 24, PG&E proposed an export compensation mechanism for non-NEM customers enrolled in the Day-Ahead Hourly Real Time Pricing (DAHRTP) rate. The proposed Business Electric Vehicle (BEV) Pilot will include customers on any BEV rate and not only customers on the DAHRTP Commercial Electric Vehicle (CEV) rate. Compensation for energy will come from the CAISO market participation entity, and to the extent available will include compensation for Resource Adequacy. PG&E has not yet proposed a budget for the Pilot but has proposed a cost-effectiveness evaluation and a report on lessons learned to be issued two years after implementation. The proposal includes a market participation option instead of a tariff rate to allow all BEV customers in the PG&E service territory (including customers of CCAs or direct access providers) to participate without requiring each retail LSE to offer its own tariff rate. Some key considerations that PG&E has requested be addressed through a stakeholder process include interconnection jurisdiction, resource adequacy compensation methodology, and managing and monitoring customer revenue generation.

PG&E served the required supplemental testimony (March 24) for its proposed export compensation mechanism for customers enrolled in the day-ahead real-time pricing (DAHRTP-CEV) rate that do not participate in net metering but provide behind-the-meter resources. The Vehicle Grid Integration Council (VGIC) was the only party to file responsive testimony, and rebuttal testimony was scheduled to be served on April 29. PG&E's Motion for Evidentiary Hearing in A.20-10-011 (filed April 22) requested the Commission grant evidentiary hearings on several disputed questions related to the export compensation mechanism for customers enrolled in the DAHRTP-CEV rate that do not participate in net metering but provide behind-the-meter resources. The disputed issues raised by VGIC, as identified in PG&E's Motion, are:

- Whether PG&E's market participation approach belongs in this proceeding;
- PG&E's consideration of resource adequacy valuation and compensation;
- PG&E's proposed use of a "complex and lengthy approach" that includes a cost-benefit analysis for export valuation;
- Potential use of the same compensation mechanism for DAHRTP-CEV Non-NEM as DAHRTPCEV NEM customers; and
- Dual participation in ELRP.

Details: On June 2, the CPUC issued a disposition letter accepting PG&E's AL 6563-E, which replaced fixed-price hourly rates charged for CCA services with charges based on labor costs, pursuant to D.21-11-016.

On June 7, the CPUC issued a disposition letter accepting PG&E's AL 6566-E, which provides electric rate changes pursuant to D.21-11-016. The final system average PCIA rate for 2022 vintage is \$0.02456/kWh.

On June 22, the CPUC issued a Proposed Decision that, if approved, would direct PG&E to implement the provisions of the January 18 settlement on real-time pricing issues, adopt the methodology outlined in the marginal generation capacity cost study for use in real-time pricing rate designs approved in D.21-11-017, order that the marginal generation capacity cost study working group be reconvened after initial evaluation of PG&E's real-time pricing rates is complete but no later than October 1, 2025 to consider whether any revisions should be made to the marginal generation capacity cost hourly price signal methodology, and close A.20-11-019 (A.20-10-011 would remain open).

Analysis: This phase of the proceeding could impact real-time pricing rate design issues for PG&E customers. If the settlement agreement is adopted, VCE could elect to allow its customers to participate in the Stage 1 RTP Pilot. The Settlement Agreement provides that cost recovery of development, implementation, and operating costs for the Stage 1 Pilots, as well as for the separate Customer Research Study, would be recovered in distribution rates that both bundled PG&E and VCE customers pay.

Next Steps: The PD may be heard no earlier than the **August 4** Commission meeting. Comments on the PD are due **July 12**.

Additional Information: [PD](#) on RTP Pilot (June 22, 2022); PG&E [Motion](#) for Evidentiary Hearing (April 22, 2022); PG&E [AL 6566-E](#) on Illustrative Electric Rate Changes (April 18, 2022); PG&E [AL 6563-E](#) for CCA Service Fees (April 15, 2022); PG&E [Proposal](#) for non-NEM export compensation (March 24, 2022); PG&E [MGCC Report](#) (corrected) (March 17, 2022); [D.22-03-012](#) on property tax adder (March 18, 2022); [Ruling](#) on timing to respond to PG&E/CLECA Motion (January 25, 2022); [Motion](#) by PG&E/CLECA to establish a separate expedited schedule (January 21, 2022); PG&E [Motion](#) on MGCC Study (January 18, 2022); PG&E [Motion](#) (January 18, 2022); [Motion](#) to Adopt Settlement Agreement (January 18, 2022); [D.21-11-016](#) on revenue allocation and rate design (November 19, 2021); [Amended Scoping Memo and Ruling](#) (August 25, 2021); [Ruling](#) bifurcating RTP issues into separate track (February 2, 2021); [D.20-09-021](#) on EUS budget (September 28, 2020); [Exhibit \(PG&E-5\)](#) (May 15, 2020); [Scoping Memo and Ruling](#) (February 10, 2020); [Application, Exhibit \(PG&E-1\): Overview and Policy, Exhibit \(PG&E-2\): Cost of Service, Exhibit \(PG&E-3\): Revenue Allocation, Rate Design and Rate Programs, and Exhibit \(PG&E-4\): Appendices](#) (November 22, 2019); RTP Pilot Docket No. [A.20-10-011](#); Phase 2 GRC Docket No. [A.19-11-019](#).

Provider of Last Resort Rulemaking

No updates this month.

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. CalCCA's comments urged a more pragmatic approach based on recent actual experience of customer returns and an evidence-based examination of the actual risks of customer returns to addressing POLR issues. Some of CalCCA's proposals include 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, providing for recovery of financing costs if the POLR must pay for costs prior to receipt of revenues from customer returns, refining the implementation planning process for new CCAs, and implementing a three-tiered reporting rubric calibrated to the operating CCA's circumstances.

PG&E's comments on the first workshop included a proposal for an insurance pool to ensure liquidity equal to about two months incremental energy procurement costs for the POLR with each CCA posting its annual contribution to the insurance pool in the form of either cash or a letter of credit, and a proposed initial set of metrics for monitoring the financial health of CCAs that the company recommended be further developed and refined through a workshop process or with other stakeholder feedback.

The primary issues raised in comments to Workshop 2 were:

- Applicability of POLR to Electric Service Providers (ESPs): Both CalCCA and TURN argue that there is no basis for excluding ESPs from any POLR obligations adopted by the Commission since ESPs are subject to the same market conditions that cause CCA defaults.
- Upfront Liquidity: PG&E expressed the need for upfront liquidity equal to two months of POLR costs and estimated the cost of providing energy-only service for two months to CCA customers in its territory at between \$200 and \$400 million. CalCCA estimated the costs for two months of CAISO service if all CCA customers statewide returned their load to POLR service to be about \$800 million, and recommended that risks be defined not only by their costs but also by their probability of occurrence since it is very unlikely that all or even a majority of CCAs would fail simultaneously and "failing to account for the probability of an event will significantly over-securitize the risk at the expense of customers."
- Right of First Refusal (ROFR) or Novation: There are differences among the parties regarding both the need for the costs and benefits of resources procured by a failing LSE to follow those customers returned to POLR service, and the mechanism by which those resources might follow customers.

Other topics discussed include the mechanism of the FSR, mechanisms for financial monitoring, and the possibility of a statewide not-for-profit central entity to manage POLR.

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.

Details: 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.

Analysis: This proceeding is addressing aspects of financial security requirements that will apply to VCE when finalized. The amount, methods of compliance (i.e., cash deposit, letter of credit, etc.), and organization of FSR management will impose a financial obligation on VCE at some future time of a currently unknown nature and amount. Additionally, this proceeding could impact VCE operations in a couple of ways. First, in establishing rules for existing POLRs, it will address POLR service requirements, cost allocation, and cost recovery issues should a CCA or other LSE discontinue supplying customers resulting in the need for the POLR to step in to serve those customers. Second, in setting the requirements and application process for another entity to be designated as the POLR, it could create a pathway for a CCA or other retail provider to elect to become a POLR for its service area.

Next Steps:

- **July 19, 2022:** Reply Comments on questions presented in May 2 Ruling
- **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: 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 ERRA Forecast

On June 22, PG&E filed supplemental testimony in support of its 2023 ERRA Forecast application.

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 \$4.736 billion. After accounting for \$2.479 billion of Utility Owned Generation (UOG)-Related Costs and amounts related to capped 2020 departing load PCIA rates addressed in D.20-12-038, PG&E requested a revenue requirement in this application of \$2.263 billion.

D.22-02-002 approved a 2022 forecast of electric sales and energy procurement revenue requirements of \$2.4 billion, effective in rates on March 1. It found the December Update, updated again with the actual year-end ERRA main account balance, provided the most accurate forecast for 2022 revenue requirements, and approved the 12-month amortization that was supported by CCAs. Under the December Update adopted in D.22-02-002, **the 2022 total PCIA rate for 2017-vintaged customers (i.e., most VCE customers) will fall 59% relative to 2021 to \$0.01969/kWh for residential customers and to \$0.01897/kWh on a system-average basis.** The Decision also found that all customers who were financially responsible for the ERRA-PCIA Financing Subaccount (ERRA-PFS) balance should be entitled to the appropriate credit and directed PG&E to transfer the \$95 million ERRA-PFS credit for 2022 to the 2020 vintage subaccount. It approved a request by CCAs and directed PG&E to include the confidential workpapers supporting the PCIA rates from the prior year's ERRA Forecast proceeding as part of the Master Data Request it will provide in each subsequent ERRA Forecast proceeding. D.22-02-002 denied without prejudice the CCA's request to direct PG&E to provide data demonstrating its future role as a CPE in future ERRA forecast proceedings.

On March 14, the California Large Energy Consumers Association and Agricultural Energy Consumers Association filed an Application for Rehearing (AFR) of D.22-02-002. The AFR argues that the Commission should have adopted a 24-month amortization period for the undercollected ERRA balance. PG&E filed its response to the AFR on March 29, defending the use of a 12-month amortization period. The Commission has not yet acted on the AFR.

Details: N/A

Analysis: D.22-02-002 results in a 59% reduction to VCE's PCIA rates in 2022 compared to 2021. While the PCIA rate will fall substantially in 2022 for VCE customers, the non-RPS benchmarks that contributed to the reduction in the PCIA in 2022 could result in the opposite effect in 2023. That is, the same high benchmarks that helped reduce the 2022 forecast case may be too high compared to next year's actuals, which would create large Portfolio Allocation Balancing Account (PABA) undercollection balances for 2023 rates. The change in the PCIA rate from the December Update will help mitigate such a swing in rates in 2023. D.22-02-002 also improves transparency by requiring PG&E to provide confidential workpapers supporting the PCIA rates from the prior year's ERRA Forecast proceeding as part of the Master Data Request it will provide in each subsequent ERRA Forecast proceeding.

Next Steps: No procedural schedule has been issued in this proceeding, however, protests to PG&E's Application are due on July 6, and replies are due on July 16.

Additional Information: [Application](#) (May 31, 2022); Docket No. [A.22-05-029](#).

PG&E 2021 ERRA Compliance

A prehearing conference was held on June 8. At that conference, the Administrative Law Judge indicated that she would establish an eighteen-month schedule for this proceeding, and issue a procedural schedule consistent with that timeline. A scoping ruling has not been issued.

Background: PG&E's application requested that 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 presents its Central Procurement Entity's administrative costs recorded to the Centralized Local Procurement Sub-Account (CLPSA) in the New System Generation Balancing Account (NSGBA).

PSPS Impacts: PG&E states that since the CPUC is currently considering the utilities' proposed common methodology for calculating unrealized volumetric sales and unrealized revenues resulting from Public Safety Power Shutoff (PSPS) events in the consolidated Phase II 2019 ERRA Compliance proceeding, it has not included with this 2021 ERRA Compliance application any testimony addressing the calculation of unrealized volumetric sales or unrealized revenues. PG&E plans to send an email to the assigned ALJ requesting direction regarding whether and in what format PSPS information should be presented as part of this Application once the Commission has resolved the issue in the Phase II 2019 ERRA Compliance proceeding.

Issues: PG&E proposes the following issues be considered in this proceeding:

- Whether PG&E, during the record period, prudently administered and managed the following, in compliance with all applicable rules, regulations, and Commission decisions, including but not limited to Standard of Conduct No. 4 (SOC 4):
 - Utility-Owned Generation Facilities
 - Qualifying Facilities (QF) Contracts and Non-QF Contracts. If not, what adjustments, if any, should be made to account for imprudently managed or administered resources?
- Whether PG&E achieved least-cost dispatch of its energy resources and economically triggered demand response programs pursuant to SOC 4;
- Whether the entries recorded in the Energy Resource Recovery Account and the Portfolio Allocation Balancing Account are reasonable, appropriate, accurate, and in compliance with Commission decisions;
- Whether PG&E's greenhouse gas instrument procurement complied with its Bundled Procurement Plan;
- Whether PG&E administered resource adequacy procurement and sales consistent with its Bundled Procurement Plan;
- Whether the costs incurred and recorded in the following accounts are reasonable and in compliance with the applicable tariffs and Commission directives:
 - Green Tariff Shared Renewables Memorandum Account;
 - Green Tariff Shared Renewables Balancing Account;
 - Disadvantaged Community - Single Family Solar Affordable Homes Balancing Account;
 - Disadvantaged Community - Green Tariff Balancing Account;
 - Community Solar Green Tariff Balancing Account; and
 - Centralized Local Procurement Sub-Account.
- Whether there are any safety considerations raised by this Application.

Details: Protests of PG&E's application were filed by three parties including CalCCA and the Cal Advocates office. At the prehearing conference on June 8, the Administrative Law Judge indicated that she would establish an eighteen-month schedule for this proceeding and issue a procedural schedule consistent with that timeline. A scoping ruling has not been issued.

Analysis: The proceeding has just begun, and its full scope is yet to be determined. A CPUC determination in the Phase II 2019 ERRR Compliance proceeding on the utilities' proposed common methodology for calculating unrealized volumetric sales and unrealized revenues resulting from PPS events could expand the scope of this proceeding.

Next Steps: PG&E, in agreement with parties filing protests, proposed the following timeline:

- **August 24, 2022:** Cal Advocates and Intervenor Testimony
- **October 1, 2022:** PG&E Rebuttal Testimony
- **October - November 2022:** Settlement Discussions
- **November 14-16, 2022:** Evidentiary Hearings
- **December 2, 2022:** Opening Briefs
- **December 19, 2022:** Reply Briefs

Additional Information: [Notice](#) rescheduling prehearing conference (May 3, 2022); PG&E 2021 ERRR Compliance [Application](#) (February 28, 2022); Docket No. [A.22-02-015](#).

PG&E's 2019 ERRR Compliance

No updates this month.

Background: Phase 1 has been resolved. The September 7, 2021, Ruling consolidated the Phase 2 ERRR 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.

Next Steps: There is no current procedural schedule for the proceeding.

Additional Information: [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 ERA 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](#).

Utility Safety Culture Assessments

No updates this month.

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 the statutory requirements of SB 901 relating to the Commission’s assessment of safety culture for regulated utilities, examine what methodologies should be employed in the safety culture assessments to ensure results are comparable across IOUs and can measure changes in IOU safety culture over time, consider requiring that IOUs implement specific safety management practices to improve safety culture through adoption of a Safety Management System standard, consider adopting a maturity model to use in safety culture assessments, and determine accountability metrics.

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: N/A

Analysis: This rulemaking will assess the safety culture of PG&E and other IOUs in California. 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 series of Technical Working Group meetings will be held in July 2022, followed by a Staff Proposal in August 2022.

- **July 2022:** Safety Policy Division Technical Working Group Meetings #3 and #4
- **TBD:** All Party Consensus Workshop on Technical Working Group Topics
- **August 2022:** ALJ Ruling issuing Safety Policy Division Staff Proposal for Conducting Safety Culture Assessments and the Maturity Model for the Large Investor-Owned Electric and Natural Gas Corporations
- **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: 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](#).

2022-2023 Wildfire Fund Nonbypassable Charge Rulemaking

No updates this month.

Next Steps: 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.

Glossary of Acronyms

| | |
|--------------|--|
| AB | Assembly Bill |
| AET | Annual Electric True-up |
| 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 |
| 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 |
| ReMAT | Renewable Market Adjusting Tariff |
| RPS | Renewables Portfolio Standard |
| TOU | Time of Use |
| TURN | The Utility Reform Network |
| UOG | Utility-Owned Generation |
| WMP | Wildfire Mitigation Plan |
| WSD | Wildfire Safety Division (CPUC) |