VALLEY CLEAN ENERGY ALLIANCE

Staff Report – Item 8

To: Board of Directors

From: Keyes & Fox, Regulatory Consultant

Subject: Regulatory Monitoring Report – Keyes & Fox

Date: May 12, 2022

Please find attached Keyes & Fox's April 2022 Regulatory Memorandum dated May 5, 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 May 5, 2022.

KEYES&FOX LLP

EQ Research

Valley Clean Energy Alliance

Regulatory Monitoring Report

To:	Valley Clean Energy Alliance (VCE) Board of Directors
From:	Sheridan Pauker, Partner, Keyes & Fox LLP Tim Lindl, Partner, Keyes & Fox LLP Jason Hoyle, Principal Analyst, EQ Research, LLC
Subject:	Regulatory Update
Date:	May 5, 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:** PG&E submitted supplemental AL 6495-E-A on April 7. The CPUC Energy Division issued nonstandard disposition letters approving VCE's & PG&E's Advice Letters regarding VCE's agricultural irrigation pumping dynamic rates pilot (Pilot), which clarified the rate design and customer billing mechanisms, provided options for VCE's recovery of administrative costs within the existing Pilot budget, established a process for review and payment of VCE invoices, and determined reporting requirements of VCE and PG&E. The Commission issued a Proposed Decision approving VCE and its vendors' Petition for Modification (PFM) requesting an increase to the Pilot budget to cover VCE's administrative expenses.

- **IRP Rulemaking:** The process for LSEs to develop final load forecasts was issued in an April 20 Ruling. The final load forecasts will serve as the basis for 2022 IRPs, resource procurement requirements, RPS Plans, and GHG emission reduction targets.

- **RPS Rulemaking:** On April 6, Assigned Commissioner Rechtschaffen issued a Ruling amending the scope of the proceeding to consider REC classification and the timing and approval process for Voluntary Allocation contracts. Rulings issued on April 11 and April 21 provided requirements for 2022 RPS Plans and updated the procedural schedule. An April 18 Ruling requested comments from the parties on questions related to Voluntary Allocation, REC classification, and scheduling. The Joint IOUs filed their proposed Market Offer process on May 2.

- **PCIA Rulemaking:** An April 18 Ruling requested comments on the impact of voluntarily allocating renewable energy credits to CCAs on the calculation of Market Price Benchmarks (MPB) for the Power Charge Indifference Adjustment (PCIA). In addition, the Ruling directed the joint IOUs and other parties to file a proposal to revise the inputs to the Energy Index MPB

calculation by May 27 and set forth a related procedural schedule. The MPBs are a key input to the PCIA. CalCCA submitted comments in support of Staff's proposal on April 29.

- **PG&E 2021 ERRA Compliance:** CalCCA and two other parties filed Protests in response to PG&E's 2021 ERRA Compliance application (filed February 28), and the parties proposed a new schedule on April 18. This case will audit the actual costs and revenues recorded during 2021 that make up the Power Charge Indifference Adjustment.

- **PG&E Phase 2 GRC:** PG&E filed a Motion for Evidentiary Hearing on April 22 to address issues raised by the one party responding to its non-NEM export compensation proposal for BEV (filed March 24), and a prehearing status conference is set for May 10.

- **PG&E Phase 1 GRC:** The ALJ issued an email Ruling on April 12 that 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. PG&E filed an Application on April 20 to modify its 2023 cost of capital that requests an overall rate of return of 7.78% and a $69.3 million increase in its revenue requirement.

- **RA Rulemaking (2023-2024):** On April 29, the CAISO filed its Final Local Capacity Requirements Report, and the Final Flexible Capacity Requirements Report is delayed until mid-May 2022.

- **PG&E Regionalization Plan:** On April 18, the ALJ filed a Proposed Decision approving the multi-party settlement agreement, which generally approves PG&E's regionalization plan with only a few changes.

- **Provider of Last Resort Rulemaking:** Comments on the March 7 workshop to discuss the proposed framework for considering the issues and recommendations resulting from the previous Phase 1 workshop were filed April 15.

- **PG&E 2020 ERRA Compliance:** On April 27, the CPUC issued a Final Decision approving the Settlement Agreement, approving all uncontested requests in PG&E's Application, and concluding Phase 1. Phase 2 of the proceeding, which remains open, will address issues related to unrealized sales and revenues resulting from PG&E's Public Safety Power Shutoff events in 2020.

- **PG&E 2019 ERRA Compliance:** On April 6, the ALJ issued a Ruling requesting supplemental testimony from the IOUs and amending the procedural schedule. The Joint CCAs filed rebuttal testimony contradicting a calculation in the IOUs' testimony. This case addresses the degree to which the IOUs should be able to recover lost revenues due to Public Safety Power Shutoff events.

- **Utility Safety Culture Assessments:** On April 28, the ALJ issued a Scoping Ruling that indicated the proceeding will be divided into more than one phase and determined the scope and schedule for Phase 1. Phase 1 will focus on developing safety culture assessments for the large investor-owned electric and natural gas corporations. Phase 2 will focus on developing safety culture assessments for the small multi-jurisdiction utilities and the gas storage operators.

- **RA Rulemaking (2021-2022):** The CPUC issued D.22-04-043 on April 27 denying OhmConnect's September 2021 PFM and closing the rulemaking.

- **PG&E 2022 ERRA Forecast:** On April 27, PG&E's request for an extension from May 15 to May 31 to file its 2023 ERRA Forecast was granted.

- **RA Rulemaking (2019-2020):** No updates this month.

- **2022-2023 Wildfire Fund Nonbypassable Charge Rulemaking:** No updates this month.

- **Investigation into PG&E's Organization, Culture and Governance:** No updates this month.

- **Direct Access Rulemaking:** No updates this month.

Ensuring Summer 2021 Reliability

PG&E submitted supplemental AL 6495-E-A on April 7. The Energy Division approved VCE's & PG&E's Advice Letters for the Pilot on April 11 and April 26, respectively, clarifying the rate design and customer billing mechanisms and options for VCE's recovery of administrative costs within the existing budget, establishing a process for review and payment of VCE invoices, and determining reporting requirements of VCE and PG&E. The CPUC issued a Proposed Decision increasing the Pilot budget to cover VCE's administrative expenses.

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 dynamic rate 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. On January 25, PG&E protested VCE's Advice Letter, to which VCE replied on January 31.

On January 31, VCE, TeMix Inc., and Polaris Energy Services (collectively, 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, and the Pilot Partners also filed a Motion to Shorten Time for comments on the PFM as well as on the Commission's proposed decision resolving the PFM. PAO filed a Response to the Pilot Partners' Motion to Shorten Time, on February 9, to which the Pilot Partners replied on February 18.

On February 4, PG&E submitted Advice Letter 6495-E, which the Pilot Partners Protested on February 24. The Pilot Partners objected to PG&E's proposed pricing methodology, PG&E's attempt to establish various participation rules for the Pilot, and other issues. PG&E replied to the Pilot Partners' Protest on March 3.

On March 14, the Pilot Partners filed a Reply to the March 2 Responses of PG&E and the PAO to the PFM, requesting the Commission to direct PG&E to release at least $1,197,118 in previously authorized funding to enable the Pilot to launch by May 1 and authorization of VCE's administrative costs, including DRET reporting, if required, and asserting a narrower role for PG&E in the Pilot administration.

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: VCE's AL 11-E was approved by the Energy Division on April 11.[1] The disposition approved the required elements of the Advice Letter, including the Pilot generation rate design and shadow bill process. The Energy Division also clarified that certain VCE administrative expenses may be recovered from existing Pilot budget categories, provided mechanisms for reviewing and funding VCE's administrative expenses related to the Pilot, stated that PG&E need not hold a competitive solicitation for the Pilot independent evaluator, and established limited reporting requirements.

PG&E submitted supplemental AL 6495-E-A on April 7, revising the distribution rate design to conform to the UNIDE framework. The Energy Division's disposition, issued on April 26, approved AL 6495-E, as supplemented by AL 6495-E-A with respect to the delivery component of the Pilot rate and pricing design and PG&E's administrative budget for the Pilot. The Energy Division disapproved the elements of PG&E's Advice Letter regarding customer eligibility, the application of Rule 12 and load cap tracking as well as the Public Advocates Office's request for additional details as outside the scope of D.21-12-015.

The Proposed Decision (issued April 29) would grant the Pilot Partners' request for an increase to the Pilot budget to cover VCE's administrative expenses for the Pilot in the amount of $690,000. The Proposed Decision denies the other requests in the Pilot Partners' PFM as these have been addressed via the Advice Letter dispositions. On May 3, the CPUC denied the Pilot Partners' January 31 Motion to Shorten Time for opening comments on the Proposed Decision.

Analysis: After a conflicted and procedurally complex set of interactions with PG&E regarding the Pilot, VCE's concerns have been resolved via the Energy Division's Advice Letter dispositions and the Pilot launched in May 2022. If approved, the Proposed Decision will enable VCE to be reimbursed for its administrative expenses in running the Pilot.

Next Steps: Opening comments on the Proposed Decision are due May 19 and reply comments are due May 24. The Proposed Decision may be heard by the Commission no earlier than June 2.

Additional Information: Ruling on 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, 2002); PG&E AL 6495-E-A (April 7, 2022);

[1] Please note that although the letter is dated March 23, 2022, it was not issued by the Energy Division until April 11, 2022.

Energy Division's Non-Standard Disposition Letter approving VCE AL 11-E (April 11, 2022); VCE, Polaris, and TeMix Reply to PAO & PG&E Responses (March 14, 2022); PAO Response to VCE, Polaris, and TeMix Reply (March 2, 2022); PG&E Response to VCE, Polaris, and TeMix Reply (March 2, 2022); VCE, Polaris, and TeMix Protest of PG&E AL 6495-E (February 24, 2022); VCE, Polaris, and TeMix Reply to PAO Response (February 18, 2022); PAO Response to Motion to Shorten Time (February 9, 2022); PG&E AL 6495-E (February 4, 2022) and Substitute Sheets for AL 6495-E (March 29, 2022); VCE Reply to PG&E Protest of VCE AL 11-E (January 31, 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); PG&E Protest of VCE AL 11-E (January 25, 2021); 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

The process for developing final LSE load forecasts was issued in an April 20 ruling. The final load forecasts will serve as the basis for 2022 IRPs, resource procurement requirements, RPS Plans, and GHG emission reduction targets.

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

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 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 obligations** 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 5-10pm daily.

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. The 2021 PSP is a statewide resource portfolio that meets a statewide 38 MMT GHG target for the electric sector in 2030. It is derived from an aggregation of individual LSE IRPs with adjustments to extend the timeframe beyond 2030 to 2032 for transmission planning purposes and to add the resources required in D.21-06-035 for mid-term reliability (MTR) purposes. The decision recommends that CAISO use the 38 MMT PSP portfolio as both the reliability base case and the policy-driven base case for study in its 2022-2023 Transmission Planning Process, which is a more aggressive GHG reduction portfolio than the 46 MMT portfolio used in 2020 IRPs. D.22-02-004 also results in the following new resource build by 2032, by technology: Gas: 0 MW; Biomass: 134 MW; Geothermal: 1,160 MW; Wind: 3,531 MW; Wind (New Transmission): 1,500 MW; Offshore Wind: 1,708 MW; Utility-Scale Solar: 17,506 MW; Battery Storage: 13,571 MW; Long-duration Storage: 1,000 MW; Load Shed DR: 441 MW.

MCAM Proposed Decision: A Proposed Decision (PD) on the Modified Cost Allocation Mechanism (MCAM) was issued on March 29 that addresses allocation and recovery of net costs of electric resource procurement for opt-out LSEs (i.e., those LSEs who elected not to self-procure) and backstop procurement obligations.

The PD addresses the issue raised by CalCCA in its May 14 Petition for Modification of D.19-11-016 of whether the nonbypassable charge should appear on retail customers' bills or be directly billed to the LSE. The PD would not adopt CalCCA's proposal for the direct billing of the full MCAM costs from the IOU to the non-IOU LSE, and instead cites the Public Utilities Code's express direction that these costs be allocated "on a fully nonbypassable basis" to "customers" (Section 365.1(c)(2)(i)-(iii)).

The PD also addresses how the costs of backstop procurement associated with D.19-11-016 and D.21-06-035 will be allocated to customers.

Details: The ALJ issued a ruling on April 20 establishing a process for LSEs to update their load forecasts in preparation for developing final load forecasts and greenhouse gas emissions benchmarks for LSEs' 2022 IRPs. LSEs that choose to update their load forecasts must use the template from the Commission's 2022 IRP Cycle website, while an LSE that does not wish to update its load forecasts may simply state that it does not intend to file a template in its written comments.

The updated forecasts will be filed by LSEs on May 16. The Commission and CEC staff will compile these filings and calculate final load forecasts for use by each LSE in its 2022 IRP. The final forecasts will be issued in a June 15 ruling, with peak demand forecasts confidentially distributed to each LSE on July 1.

There are three load forecasts, and an LSE may update all, some, or none of the following:

- The energy forecast (public information) provides a projection of future retail sales. If an LSE chooses not to update its energy forecast, then the IEPR-based forecast will be used. In the IEPR-based forecast, VCE is estimated to account for between 0.82% and 0.83% of PG&E energy sales.
- The peak demand forecast (non-public) may be updated by an LSE, otherwise the Commission and CEC staff will calculate a peak demand forecast based on the energy forecast, resource adequacy or other pre-existing information.
- The behind-the-meter PV (BTM PV) and other demand modifier (e.g., battery storage, energy efficiency, EVs, etc.) forecast may also be updated by an LSE. These forecasts will be used by the Commission and CEC staff in calculating the final peak load forecast.

The final load forecasts will also be used to determine each LSE's GHG benchmark for both the 30 million metric ton (MMT) and the 25 MMT 2035 target scenarios. LSEs are required to include a plan to achieve their GHG benchmark in their individual IRP filing. GHG benchmark targets for each LSE will be issued in a ruling on June 15. VCE's current benchmarks for 2035 are based on a projected 825 GWh (1.0% of PG&E area) and is 0.086 MMT of GHG emissions under the 30 MMT scenario and 0.069 MMT of GHG emissions under the 25 MMT scenario (Table 1 at 11).

Analysis: The final load forecasts establish not only the energy, peak capacity, and RPS-related procurement basis for the 2022 IRP, but also determine VCE's share of the aggregate electric sector's GHG reductions. The final load forecasts will influence all procurement requirements and given the requirements for larger shares of longer-term procurement, could have a substantial impact on future costs.

MCAM: The Proposed Decision regarding the MCAM would clarify that procurement costs will only be recovered from bundled service customers, Opt-Out LSE customers, and potentially Deficient LSEs rather than all customers in an IOU's service territory. If approved, cost recovery under MCAM will occur through a nonbypassable charge on retail customers' bills. Resource Adequacy benefits would also be allocated on the same basis as costs for purposes of the MCAM. Additionally, if the PD is approved, an LSE may acquire unbundled RECs but the transfer of RECs to LSEs must be accompanied by a forward sale of associated energy.

Next Steps: A Final Decision on the MCAM is expected on or after May 5, after which the IOUs will file a Tier 2 Advice Letter to implement the MCAM no more than 60 days following the Final

Decision. VCE's next IRP is due November 1. The CPUC will issue a Ruling by June 15, providing additional direction and detail on the requirements for LSEs' 2022 IRPs.

Load Forecasts and GHG Benchmarks Schedule

- **May 16, 2022:** Updated load forecasts due (or statement accepting CEC forecast)
- **May 16, 2022:** Comments due on proposed 2035 GHG targets
- **May 23, 2022:** Reply comments on GHG targets and load forecasts
- **June 15, 2022**: Ruling on final load forecasts and GHG targets for each LSE
- **July 1, 2022:** Final peak capacity forecast distributed to each LSE confidentially

Additional Information: Ruling establishing process for load forecasts and GHG benchmarks for 2022 IRP (April 20, 2022); Proposed Decision on the Modified Cost Allocation Mechanism (March 29, 2022); D.22-02-004 adopting 2021 Preferred System Plan (December 22, 2021); CCA Motion for Clarification (December 13, 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 April 6, Assigned Commissioner Rechtschaffen issued a ruling amending the scope of the proceeding to consider REC classification and the timing and approval process for Voluntary Allocation contracts. On April 11, the Assigned Commissioner and the ALJ issued a ruling providing requirements and the procedural schedule for Retail Sellers' 2022 RPS Procurement Plans and denying the Joint IOUs' motion to file the Market Offer Process information through a Tier 3 Advice Letter. An April 18 Ruling requested comments from the parties on questions related to Voluntary Allocation, REC classification, and scheduling. The schedule was modified in an April 21 Ruling to allow the IOUs to individually file their confidential market offer information on May 16. The joint IOUs filed their proposed Market Offer Process on May 2.

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.

RPS procurement is a two-part process for LSEs to obtain RPS energy, or RECs. In the first part, called Voluntary Allocation (VA), an LSE chooses what portion of the IOU's RPS portfolio it will accept to meet its own RPS obligations, and then, in the second part of the process, called Market Offer (MO), the IOUs offer for sale the remaining portions of their RPS portfolios that were not claimed by LSEs in the Voluntary Allocation part, together these two parts are the Voluntary Allocation/Market Offer (VAMO) process.

A Joint Motion by the IOUs (December 8, 2021) requested that the CPUC (1) expand the scope of this proceeding to address whether RECs retain their original Portfolio Content Category (PCC) classification when claimed by LSEs under the Voluntary Allocation process; (2) issue guidance on the issue of the PCC classification of allocated RECs before LSEs are required to decide whether to accept allocations; and (3) clarify that pro forma Allocation Contracts will be reviewed in early 2022 via Tier 2 advice letter and that only Allocation Contracts materially deviating from the pro forma would be subject to further review through a Tier 1 Advice Letter.

The Joint IOUs' March 10 Motion sought authorization for review via Tier 3 Advice Letter submission of their proposed modifications to the Market Offer Process. The proposed modifications would allow delivery of Market Offer RPS resources to coincide with delivery of Voluntary Allocations on January

1, 2023, thereby generating revenue from the sale of RECs and reducing above-market costs “to benefit bundled service and departing load customers by optimizing the IOU’s PCIA portfolios.”

Details: The April 6 Amended Scoping Ruling extended the statutory deadline to October 2, 2023, and expanded the scope of the proceeding to include the following issues (comments on these issues were requested in an April 18 ruling):

- PCC classification of RECs allocated under the VAMO process; and
- Timing and approval process for Voluntary Allocation pro forma contracts.

An April 11 Ruling identified requirements for 2022 RPS 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. A modified schedule for RPS Track 1 allowing the IOUs to individually file confidential Market Offer information on May 16 was issued in an April 21 Ruling.

Track 1: Market Offer Process

The Joint IOUs filed their proposed Market Offer process on May 2. The Market Offer process is part of a two-step process for 2022 RPS Procurement. 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 remaining RPS Energy (RECs) not claimed by LSEs in the Voluntary Allocation will be offered to all market participants through the Market Offer process.

Track 2: RPS Plans

2022 RPS Plans (April 11 Ruling) 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.

Analysis: 2022 RPS 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 years or more, but also aligning the RPS plan with IRP requirements in D.21-03-010. The 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. Voluntary Allocation essentially provides LSEs a right of first refusal and accelerates and streamlines the procurement process while providing all LSEs with equal access to a representative share of an IOU’s portfolio of RPS resources, and by avoiding competitive bidding potentially offers lower-cost procurement.

Next Steps:

Track 1: Market Offer Process

- **May 16, 2022:** IOUs individually file confidential Market Offer information
- **May 22, 2022:** Comments on Market Offer process due
- **May 27, 2022:** Reply Comments on Market Offer process due
- **3Q 2022:** Proposed Decision on Market Offer process

Track 2: 2022 RPS Plans

- **July 1, 2022:** Draft RPS Plans filed
- **August 1, 2022:** Comments on Retail Sellers' Draft Plans due
- **August 1, 2022:** Motions requesting evidentiary hearing due
- **August 15, 2022:** Motion to update draft RPS Plans due
- **August 15, 2022:** Reply Comments on Retail Sellers' Draft Plans due
- **4Q 2022:** Proposed Decision on Retail Sellers' Draft Plans

Market Offer Timeline

- **Ongoing:** Participant registration at IOU websites to receive notices regarding the solicitations
- **September 16, 2022:** IOUs Issue 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

Additional Information: 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); Ruling identifying RPS Plan requirements (April 11, 2022); Amended Scoping Ruling expanding scope (April 6, 2022); Joint Motion by IOUs Concerning Review of Market Offer Process (March 10, 2022); VCE's Final 2021 RPS Procurement Plan (February 17, 2022); D.22-01-025 fining Gexa for RPS non-compliance (February 1, 2022); D.22-01-004 on draft 2021 RPS Procurement Plans (January 18, 2022); D.21-12-032 modifying the ReMAT tariff (December 16, 2021); D.21-11-029 amending RPS confidentiality rules (November 19, 2021); Petition for Modification of D.20-10-005 on ReMAT pricing (October 8, 2021); Ruling aligning IOU RPS Procurement Plan requirements with PCIA decision (May 26, 2021); Docket No. R.18-07-003.

PCIA Rulemaking

An April 18 ruling requested comments on a Staff proposal regarding the impact on the RPS Adder (one Market Price Benchmark (MPB) used to calculate the Power Charge Indifference Adjustment (PCIA)) from the Voluntary Allocation of renewable energy credits to CCAs. In addition, the ruling directed the Joint IOUs and other parties to file an Energy Index MPB calculation proposal by May 27 and set forth a related procedural schedule. CalCCA submitted comments in support of Staff's proposal on April 29.

Background: D.18-10-019 was issued on October 19, 2018, in Phase 1 of this proceeding and left the current PCIA in place, maintained the current brown power index, and adopted revised inputs to the benchmarks used to calculate the PCIA for energy RPS-eligible resources and resource adequacy capacity.

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

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

D.22-01-023 modified the PCIA market price benchmark 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. It adopted party proposals to establish a policy for disposition of the year-end balance in the ERRA account and to modify the calculation of the ERRA trigger point and threshold. It also adopted party proposals to support efficient party access to ERRA forecast proceeding data.

PG&E submitted, in accordance with D.22-01-004, two proposed contracts for PCIA-eligible RPS resources: AL 6517-E (February 28) proposing a Voluntary Allocation Contract and AL 6551-E (April 4) proposing a Market Offer Contract.

AL 6517-E Voluntary Allocation Contract proposal

Since PG&E's Voluntary Allocation Contract is a confirmation to PG&E's Edison Electric Institute (EEI) Master Power Purchase and Sale Agreement (Master Agreement), similar to the existing confirmation used in PG&E's bundled RPS energy sales, Voluntary Allocation participants will need a Master Agreement in place with PG&E prior to execution of the Voluntary Allocation Contract.

CalCCA cited several errors in its March 21 Protest of AL 6517-E, including the misapplication of D.22-01-004's calculation of each LSE's load-share percentage from which the LSE may claim long- or short-term Voluntary Allocations, the contract provision(s) enabling PG&E to remove resource from the allocation pool without notice to LSEs and the resulting harm to planning efforts, and the lack of contract provisions for timely access to forecast and meter data by LSEs.

AL 6551-E Market Offer Contract proposal

PG&E submitted the Tier 2 Advice Letter 6551-E requesting approval of a pro forma Market Offer Contract for Power Charge Indifference Adjustment (PCIA)-eligible Renewables Portfolio Standard (RPS) resources, on April 4, as required by D.22-01-004. The proposed Market Offer Contract remains suspended.

This proposed Market Offer Contract is specific to the requirement of D.21-05-030 that all PCIA-eligible RPS energy remaining after a Voluntary Allocation be offered for sale in the Market Offer. The other two requirements of D.21-05-030 – that the Market Offer process 1) be based upon existing processes, rules, oversight requirements, and reporting requirements for REC solicitations previously approved in the Commission's RPS proceeding; and 2) include rules for utility participation in utility-administered solicitations – were addressed in the IOU's Joint Motion in R.18-07-003 (filed March 10).

Since PG&E's Market Offer Contract is a confirmation to PG&E's Edison Electric Institute (EEI) Master Power Purchase and Sale Agreement (Master Agreement), similar to the existing confirmation used in PG&E's bundled RPS energy sales, Market Offer process participants will need a Master Agreement in place with PG&E prior to execution of the Market Offer Contract.

Details of the proposed pro forma Market Offer Contract include:

- A Market Offer participant may bid for all the PCIA-eligible RPS portfolio that remains following Voluntary Allocation.
- PG&E proposes to deliver the PCIA-eligible RPS energy remaining after Voluntary Allocation over the final two years of the current RPS compliance period (i.e., 2023 & 2024) for reasons that include reducing administrative risk, providing flexibility for all LSEs, and enabling reevaluation for future Market Offers.

The proposed contract differs from PG&E's CPUC-approved bundled RPS energy sale contract in the products offered and their delivery periods. The RPS energy sale contract only includes fixed volumes of bundled RECs available for purchase in calendar year 2022, while the proposed contract includes portions of PG&E's PCIA-eligible RPS portfolio that remain unallocated following Voluntary Allocation that will be delivered over 2023 and 2024, like PG&E's existing carbon-free allocation contract.

In its April 25 Protest, CalCCA recommended that PG&E modify its proposed Market Offer Contract to align its Market Offer product offerings with those of SDG&E and SCE so that bidders have greater certainty regarding the value of the products on which they are bidding, and to provide for timely access by counterparties to generation data from RPS resources obtained via Market Offer since generation volume is variable and information regarding actual generation is crucial.

Details: An April 18 ALJ Ruling requested comments on the impact of voluntarily allocating renewable energy credits to CCAs on the calculation of RPS Adder (one MPB used to calculate the PCIA). In addition, the ruling directed the joint IOUs and other parties to file an Energy Index MPB calculation proposal by May 27 and set forth a related procedural schedule. CalCCA submitted comments in support of Staff's proposal on April 29.

Analysis: The two proposed contracts for procurement of PCIA-eligible RPS resources provide details of the terms for procurement of PCIA-eligible RPS resources under the Voluntary Allocation and Market Offer mechanisms. As proposed and protested by CalCCA, PG&E's contracts do not provide for timely access to meter data by LSEs, and PG&E's contracts contain provisions allowing the company to adjust its RPS resource mix without notice. These protested provisions create sources of uncertainty in the quantity and character of RPS resource procured from PG&E and therefore adversely impact an LSE's ability to plan, update, or make necessary modifications for compliance purposes.

The ALJ ruling addresses the fact that voluntarily allocated RPS attributes are valued at the prior year's MPB (i.e., the RPS Adder), potentially skewing that benchmark's representation of recent market activity. CalCCA agreed but noted a concern about whether excluding those transactions could result in the benchmark being based on an illiquid RPS market.

Next Steps: PG&E posted a webpage with updated timelines for 2022 Voluntary Allocations:

- **May 31, 2022:** PG&E files ERRA Forecast Application and informs LSEs of initial forecast allocation shares for 2023 Voluntary Allocation
- **May 16 – June 10, 2022:** Voluntary Allocation contracting with LSEs
- **May 27, 2022:** Joint IOU filing of Energy Index MPB Calculation Proposal
- **June 10, 2022:** Final day for LSEs to submit Voluntary Allocation elections to PG&E
- **June 16, 2022:** Comments on Energy Index MPB Proposal
- **June 2022:** PG&E completes Voluntary Allocation contracting
- **June 30, 2022:** Reply Comments on Energy Index MPB Proposal

- **Summer 2022:** LSEs file Draft 2022 RPS Plans informed by Voluntary Allocation elections
- **October 2022**: Each IOU informs LSEs of updated allocation shares for 2023 Voluntary Allocations

Additional Information: Ruling Regarding Market Price Benchmarks (April 18, 2022); Market Offer Contract (AL 6551-E) for PCIA-eligible RPS Resources remaining after VA (April 4, 2022); Voluntary Allocation Contract (Advice 6517-E) for PCIA-eligible RPS Resources (February 28, 2022); D.22-01-023 on Phase 2 (approved January 27, 2021); Ruling requesting comments on PCIA forecasting data access (November 5, 2021); Voluntary Allocation Methodology Advice Letter 6305-E (October 25, 2021); Ruling requesting comments (September 17, 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); 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 2021 ERRA Compliance

CalCCA and two other parties filed protests in response to PG&E's 2021 ERRA Compliance application (filed February 28), and the parties proposed a new schedule on April 18.

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;
  - 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. A Notice was issued on May 3 rescheduling the prehearing conference for June 8.

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

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

- **June 8, 2022:** Prehearing Conference
- **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 ERRA Compliance Application (February 28, 2022); Docket No. A.22-02-015.

PG&E Phase 2 GRC

PG&E filed a Motion for Evidentiary Hearing on April 22 to address issues raised by the one party responding to its non-NEM export compensation proposal for BEV (filed March 24), and a prehearing status conference is set for May 10. The Commission issued an order reassigning A.19-11-019 and R.19-11-019 from ALJ Sisto to ALJ Patrick Doherty on April 27.

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.

With respect to CCA issues, the adopted EDR settlement noted that PG&E and the Joint CCAs agreed to create a collaborative process "to identify and vet EDR applicants that will make it easier for CCAs to provide a generation rate reduction to CCA customers who qualify for PG&E's EDR." D.21-11-016 also approved the agricultural rate design settlement that proposed that the unbundling of the PCIA from the generation component of bundled rates be designed as a flat PCIA rate, not differentiated by season or TOU period, consistent with the PCIA rate design for DA and CCA customers. The PCIA rate for bundled customers will use the most recent vintage of the PCIA rate. Finally, D.21-11-016 approved the revenue allocation settlement, including its proposal that before allocating generation revenue, instead of including the PCIA revenue in the overall generation revenue requirement, PCIA revenue will be removed from each customer class's revenue at present rates based on the most recent vintage PCIA rates. Then, PG&E will use the adopted allocation for generation to allocate the PCIA revenue requirement to customer classes.

On January 18, parties filed a Settlement Agreement 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 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.

The Final Decision, D.22-03-012, adopting the Joint Stipulation, or otherwise resolving the single carryover issue of material fact about the MGCC Property Tax Adder, was issued March 18. This Decision, in accordance with the PG&E/CLECA Joint Stipulation, adopts 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.

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.

Details: 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 day-ahead real-time pricing (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 DAHRTPCEV Non-NEM as DAHRTPCEV NEM customers; and
- Dual participation in ELRP.

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: Potential evidentiary hearing dates were reserved for May 18 – 20. The proceeding remains open to address RTP issues. PG&E's April 22 Motion for an Evidentiary Hearing remains unaddressed.

Additional Information: PG&E Motion for Evidentiary Hearing (April 22, 2022); PG&E Proposal for non-NEM export compensation (March 24, 2022); PG&E MGCC Report (corrected) (March 17, 2022); Decision 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.

PG&E Phase 1 GRC

The ALJ issued an email Ruling on April 12 that 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. PG&E filed an Application on April 20 to modify its 2023 cost of capital that requests an overall rate of return of 7.78% and a $69.3 million increase in its revenue requirement.

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

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 pending November 5, 2021, Motion requests 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 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.

On March 9, PG&E submitted its recorded expense and capital data testimony for 2021.

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.

Details: 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%.

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

Next Steps:

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

- **June 13, 2022:** Intervenor Opening Testimony
- **July 11, 2022:** Concurrent Rebuttal Testimony
- **July 12 – August 15, 2022:** Meet & Confer (minimum of four times)
- **TBD (prior to Evidentiary Hearings):** 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:

- **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: 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 April 29, the CAISO filed its Final Local Capacity Requirements (LCR) Report, and the Final Flexible Capacity Requirements (FCR) Report is delayed until mid-May 2022.

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. Therefore, 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 (further described below).
- 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 and this phase is expected to conclude in June 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: The Final LCR Report (April 29) was accompanied by the CAISO's List of Physical Resources Accounted for in the 2023 and 2027 Local Capacity Technical Studies. The overall capacity needed for LCR has increased by about 336 MW or about 1.3% from 2022 to 2023. The study aids procurement and resource adequacy planning by providing load profiles and transmission capacity information that shows the effectiveness of local resources in meeting temporal local reliability needs.

Analysis: The Decision provides some additional RA flexibility for LSEs by allowing like-for-like substitution in the event of a non-performing self-shown resource and allowing replacement of year 3 resources with other local resources. There is a tradeoff for LSEs between reserving some backup local RA resources by not self-showing to the CPE and potentially incurring higher RA costs if the CPE fails to procure adequate RA resources through its competitive solicitation and as a result must use broker transactions or bilateral contracts to remedy any deficiency in the three-year forward period.

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

Phase 2

- **May 6, 2022:** Comments due on Final 2023 LCR
- **May 13, 2022:** Reply comments on Final 2023 LCR
- **mid-May 2022:** Final FCR Report published
- **2nd business day following Final FCR Report:** Comments due on Final FCR Report
- **May 20, 2022:** Proposed Decision on Final LCR Report and Final FCR Report (if delayed, a separate PD on Final FCR Report will be issued)

CPE Procurement Timeline

- **No later than mid-May 2022:** LSEs make self-shown commitment of local resources to the CPE for the applicable Resource Adequacy (RA) years.

- **No later than June 2022:** The Commission adopts multi-year local RA requirements for the applicable compliance years as part of its June decision.
- **No later than early July 2022:** CPE receives total jurisdictional share of multi-year local RA requirements for the applicable compliance years.
- **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: 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); Workshop Report (February 28, 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); Ruling modifying procedural schedule (December 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 April 18, the ALJ filed a Proposed Decision that would approve the multi-party settlement agreement (MPSA) with few changes.

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 describes 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). A separate settlement agreement is between the South San Joaquin Irrigation District and PG&E. The Multi-Party Settlement Agreement includes a framework within which PG&E will facilitate a stakeholder engagement process for parties to the Multi-Party Settlement Agreement to provide updates and a non-binding forum for input from stakeholders. The proposed settlement would have restricted participation in the Regionalization Stakeholder Group to parties or others who agree to the scope, procedures and protocols of the Regionalization Stakeholder group as outlined in the settlement. PG&E will host two public workshops in 2022 and for each year until the completion of Phase III or its regionalization implementation to provide updates to the public about its regionalization implementation progress.

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

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.

Details: On April 18, the ALJ filed a Proposed Decision that would approve the MPSA in part, approve the PG&E/SSJID Settlement Agreement in totality, and close the proceeding.

The PD, if adopted by the Commission, would:

- Allow participation in the Regionalization Working Group (RWG) by any interested party rather than just parties to the proceeding, as suggested in comments by VCE and other parties.
- Have the RWG serve as an oversight function in PG&E's implementation of regionalization providing PG&E additional perspectives during implementation, but not provide the RWG any decision-making authority.
- Not address metrics, including those related to safety, property damage, reliability, customer needs, etc., on the grounds that such metrics are outside the scope of this proceeding.
- Create five regions defined by county boundaries.
- Add between $24.6 and $32.6 million in incremental costs.

Analysis: The implications of PG&E's regionalization plan on CCA operations, customers, and costs remain largely unclear following the proposed MPSA. PG&E's regionalization plan could impact PG&E's responsiveness and management of local government relations and local and regional issues, such as safety, that directly impact VCE customers. It could also impact municipalization efforts, although the pending SSJID settlement agreement stated that PG&E's regionalization efforts will not be in opposition to SSJID's municipalization. As part of Region 2, VCE would be grouped with several northern counties in central and eastern California. The Proposed Decision did not address most of the comments made by VCE and Pioneer regarding the inefficacy of the Updated Proposal, suggestions for greater transparency and responsiveness, or alignment of regional boundaries with COGs.

Next Steps: Opening Comments on the Proposed Decision are due May 9, and Reply Comments are due May 16. The Proposed Decision may be heard by the Commission, at the earliest, on May 19.

Additional Information: Proposed Decision (April 18, 2022); Joint Motion for approval of Settlement Agreements (August 31, 2021); Ruling granting schedule modification (August 20, 2021); Ruling denying evidentiary hearing (July 28, 2021); PG&E Joint Case Management Statement (July 20, 2021); Amended Scoping Memo and Ruling (June 29, 2021); PG&E Updated Regionalization Proposal (February 26, 2021); Ruling modifying procedural schedule (December 23, 2020); Scoping Memo and Ruling (October 2, 2020); Application (June 30, 2020); A.20-06-011.

Provider of Last Resort Rulemaking

Comments on the March 7 workshop to discuss the proposed framework for considering the issues and recommendations resulting from the previous Phase 1 workshop were filed April 15.

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.

Details: 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.

Analysis: This proceeding could impact VCE in several ways. First, in establishing rules for existing POLRs, it will address POLR service requirements, cost allocation, and cost recovery issues should a CCA or other LSE discontinue supplying customers resulting in the need for the POLR to step in to serve those customers. Second, in setting the requirements and application process for another entity to be designated as the POLR, it could create a pathway for a CCA or other retail provider to elect to become a POLR for its service area. The preliminary questions (Appendix B to the OIR) suggest these issues will include examining topics such as CCA financial security requirements, portfolio risk and hedging, CCA deregistration, CCA mergers, and CCA insolvency.

Next Steps: The CPUC indicated in an April 21 email that a forthcoming ruling will both seek party comment on additional issues, including modifications to the Financial Security Requirements, reentry fees and deregistration process, and include or be accompanied by an update to the Phase 1 proceeding schedule. Some parties have recommended an additional workshop or technical conference.

Additional Information: POLR webpage with workshop presentations and videos; Ruling rescheduling second workshop date (February 24, 2022); Ruling setting second workshop and comment period (December 31, 2021); Ruling requesting comments (November 23, 2021); Golden State Power Cooperative Motion to remove cooperatives as respondents (October 28, 2021); Scoping Memo and Ruling (September 16, 2021); Ruling scheduling prehearing conference (April 30, 2021); Order Instituting Rulemaking (March 25, 2021); Docket No. R.21-03-011.

PG&E 2020 ERRA Compliance

On April 27, the CPUC issued a Final Decision approving the Settlement Agreement, approving all uncontested requests in PG&E's Application, and concluding Phase 1. Phase 2 of the proceeding, which remains open, will address issues related to unrealized sales and revenues resulting from PG&E's Public Safety Power Shutoff events in 2020.

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

The June 2021 Scoping Memo and Ruling specifies the proceeding will be divided into two phases. Phase 1 addressed approval of PG&E's generation procurement and cost recovery activity during 2020. Phase 2 issues may be amended based on the outcome of Phase 2 of PG&E's 2019 ERRA compliance proceeding. The tentative list of Phase 2 issues includes whether sales forecasting methods for adjusting the revenue requirement under current decoupling policy should be modified to account for power not sold or purchased during a Public Safety Power Shutoff (PSPS) event in 2020, whether it is appropriate for PG&E to return the revenue requirement equal to the estimated unrealized volumetric sales and unrealized revenue resulting from the PSPS events in 2020, and the appropriate methodology for calculating PG&E's unrealized volumetric sales and unrealized revenues resulting from 2020 PSPS events.

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

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

PG&E is also required to include further testimony in their 2021 Compliance case describing the actions that PG&E has taken to address the deficiencies reported in its Internal Audit Report on the PABA; an internal audit closure document with details of PG&E's implementation of any action plans to address the deficiencies reported in the Internal Audit Report; testimony from its Chief Regulatory Officer on the actions that PG&E will take or has taken to ensure that there is proper accounting and recording of entries in the various balancing and memorandum accounts review in the ERRA compliance proceedings, including, but not limited to, the PABA.

Details: The CPUC issued D.22-04-041 on April 27 concluding Phase 1. In the Final Decision, the CPUC found that PG&E meets the standard for compliance under the Energy Resources Recovery Account (ERRA) regulatory compliance process for the 2020 record year. The decision approved the Settlement Agreement which resolved all the contested issues and approved all of PG&E's uncontested requests.

Analysis: This proceeding addresses PG&E's balancing accounts, including the PABA, providing a venue for a detailed review of the billed revenues and net CAISO revenues PG&E recorded during

2020. It also determines whether PG&E managed its portfolio of contracts and UOG in a reasonable manner. Both issues could impact the level of the PCIA in 2022 and 2023.

Next Steps: Phase 1 has concluded. The proceeding remains open to consider issues in Phase 2, schedule TBD.

Additional Information: D.22-04-041 on Phase 1 (April 27, 2022); Joint Motion for Adoption of Settlement Agreement (October 15, 2021); Scoping Memo and Ruling (June 21, 2021); Application (March 1, 2021); Docket No. A.21-03-008.

PG&E's 2019 ERRA Compliance

On April 6, the ALJ issued a Ruling requesting additional information from the IOUs and amending the procedural schedule.

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

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

- Whether it is appropriate for the utilities to return the revenue requirement equal to the unrealized volumetric sales and unrealized revenue resulting from the PSPS events in 2019.

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

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

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

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

The CCA Parties recommended 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: Opening Briefs are due May 27; Reply Briefs are due June 17.

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 ERRA compliance proceedings (September 7, 2021); PG&E Application for Rehearing of D.21-07-013 (August 16, 2021); D.21-07-013 resolving Phase 1 (July 16, 2021); Joint Motion to Adopt Settlement Agreement (October 22, 2020); Amended Scoping Memo and Ruling (August 14, 2020); Scoping Memo and Ruling (June 19, 2020); PG&E's Application and Testimony (February 28, 2020); Docket No. A.20-02-009.

Utility Safety Culture Assessments

On April 28, the ALJ issued a Scoping Ruling that indicated the proceeding will be divided into more than one phase and determined the scope and schedule for Phase 1. Phase 1 will focus on developing safety culture assessments for the large investor-owned electric and natural gas corporations. Phase 2 will focus on developing safety culture assessments for the small multi-jurisdiction utilities and the gas storage operators.

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. The AB 1054 assessments are specific to wildfire safety efforts and include a workforce survey, organizational self-assessment, supporting documentation, and interviews. SB 901 directs the CPUC to establish a safety culture assessment for each electrical corporation, conducted by an independent third-party evaluator. SB 901 also requires that the CPUC set a schedule for each assessment, including updates to the assessment, at least every five years, and prohibit the electrical corporations from seeking reimbursement for the costs of the safety culture assessments from ratepayers.

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 Prehearing Conference discussed the adoption of a definition of “safety culture” by the Commission, the scope and mechanisms that should be adopted in a safety culture assessment framework, the schedule and process to be applied to safety culture assessments, and metrics and methodologies for measuring safety culture change.

Details: On April 28, the ALJ issued a Scoping Ruling that indicated the proceeding will be divided into more than one phase and determined the scope and schedule for Phase 1. Phase 1 will focus on developing safety culture assessments for the large investor-owned electric and natural gas corporations. 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 that is 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.

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 June and July 2022, followed by a Staff Proposal in August 2022.

- **June 2022:** Safety Policy Division Technical Working Group Meetings #1 and #2
- **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.

RA Rulemaking (2021-2022)

The CPUC issued D.22-04-043 on April 27 denying OhmConnect’s September 2021 Petition for Modification and closing the rulemaking.

Background: This proceeding addressed Resource Adequacy (RA) requirements and structure. D.20-12-006, issued December 2020, addressed the issues of the financial credit mechanism and competitive neutrality rules for the Central Procurement Entities (CPEs). It approved CalCCA’s proposed “Option 2,” with modifications, which allows the CPE to evaluate the shown resource alongside bid resources to assess the effectiveness of the portfolio. D.21-06-029 (issued June 2021) adopted local capacity requirements for 2022-2024, flexible capacity requirements for 2022, and refinements to the RA program. It adopted a series of changes to the Maximum Cumulative Capacity (MCC) buckets, which function as limits on the amount of RA that may be procured from resources with different characteristics.

Details: The CPUC issued D.22-04-043 on April 27 denying OhmConnect's September 2021 Petition for Modification and closing the rulemaking.

Analysis: Increasing the demand response cap, as OhmConnect requested and CCAs and others supported, would allow LSEs like VCE to procure a higher percentage of demand response resources to meet RA obligations than is currently allowed under the RA compliance rules. Any future proposals to broadly increase the demand response cap will require consideration of how doing so will affect grid reliability.

Next Steps: This proceeding is now closed.

Additional Information: D.22-04-043 denying OhmConnect's September 2021 petition (April 27, 2022); OhmConnect's Petition for Modification (September 9, 2021); D.21-07-014 on restructuring the RA program with PG&E Slice of Day proposal (July 16, 2021); D.21-06-029 adopting local capacity obligations for 2022-2024, flexible capacity obligations for 2022, and refinements to the RA program (approved June 24, 2021); 2019 Resource Adequacy Report (March 19, 2021); Scoping Memo and Ruling for Track 3B and Track 4 (December 11, 2020); D.20-12-006 on Track 3.A issues (December 4, 2020); D.20-06-031 on local and flexible RA requirements and RA program refinements (June 30, 2020); Order Instituting Rulemaking (November 13, 2019); Docket No. R.19-11-009.

PG&E 2022 ERRA Forecast

On April 27, PG&E's request for an extension from May 15 to May 31 to file its 2023 ERRA Forecast was granted. On February 11, the CPUC issued D.22-02-002, resolving all issues and closing the proceeding; however, an Application for Rehearing remains pending.

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

PG&E's Fourth Supplemental Testimony included both an "October Update" and a "December Update." A group of CCA parties recommended in comments that the CPUC adopt the proposed forecasted revenue requirements and associated rates from the December Update and requested the rates be implemented by February 1, 2022. The CCA parties said that adopting the December update would reduce likely volatility between 2022 and 2023 rates and that adoption of an October Update would clearly violate State law and Commission precedent. The CCAs noted that PG&E's forecasted costs to serve load in 2022 are 66.5% higher than in 2021.

CalCCA, the Joint CCAs, PG&E, and other parties support a 12-month amortization of the revenue requirements. In contrast, the California Large Energy Consumers Association, Agricultural Energy

Consumers Association, and California Farm Bureau Federation advocate for a 24-month amortization period.

Details: 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.

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: PG&E's 2023 ERRA Forecast will be filed May 31. The proceeding is now closed. However, as described above, an application for rehearing is pending.

Additional Information: Application for Rehearing (March 15, 2022); D.22-02-002 (February 11, 2022); Ruling modifying procedural schedule (January 14, 2022); Ruling directing PG&E to provide amortization scenarios (December 17, 2021); Scoping Memo and Ruling (August 11, 2021); Notice of Prehearing Conference (July 15, 2021); Application (June 1, 2021); Docket No. A.21-06-001.

RA Rulemaking (2019-2020)

No updates this month.

Background: This proceeding had three tracks, which have now concluded. Track 1 addressed 2019 local and flexible Resource Adequacy (RA) capacity obligations and several near-term refinements to the RA program. D.19-10-020 purported to affirm existing RA rules regarding imports but adopted a distinction in the import RA compliance requirements for resource-specific and non-resource specific contracts and required, for the first time, that non-resource-specific resources self-schedule (i.e., bid as a price taker) in the CAISO energy market. D.20-06-028 adopted revisions to the Resource Adequacy import rules based on the Energy Division's proposal, with modifications.

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

The second Track 2 Decision, D.20-06-002, adopted implementation details for the central procurement of multi-year local RA procurement to begin for the 2023 compliance year in the PG&E and SCE (but not SDG&E) distribution service areas, including identifying PG&E and SCE as the central procurement entities for their respective distribution service areas and adopting a hybrid central procurement framework. The Decision rejected a settlement agreement between CalCCA and seven other parties that would have created a residual central buyer structure and a multi-year requirement for system and flexible RA. Under D.20-06-002, if an LSE procures its own local resource, it may (1) sell the capacity to the CPE, (2) utilize the resource for its own system and flexible RA needs (but not for local RA), or (3) voluntarily show the resource to meet its own system and flexible RA needs, and reduce the amount of local RA the CPE will need to procure for the amount of time the LSE has agreed to show the resource. Under option (3), by showing the resource to the CPE, the LSE does not receive one-for-one credit for shown local resources. A competitive solicitation (RFO) process will be used by the CPEs to procure RA products. Costs incurred by the CPE will be allocated ex post based on load share, using the Cost Allocation Mechanism (CAM). D.20-06-002 also established a Working Group (co-led by CalCCA) to address: (a) the development of a local capacity requirements reduction crediting mechanism, (b) existing local capacity resource contracts (including gas), and (c) incorporating qualitative and possible quantitative criteria into the RFO evaluation process to ensure that gas resources are not selected based only on modest cost differences.

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

Details: The proceeding remains open but is inactive.

Analysis: D.22-02-008 upheld the CPUC's prior decision (D.20-06-002), which established a CPE. Moving to a CPE beginning for the 2023 RA compliance year impacted VCE's local RA procurement and compliance, including affecting VCE's three-year local RA requirements as part of the transition to the central procurement framework. Eventually, it will eliminate the need for monthly local RA showings and associated penalties and/or waiver requests from individual LSEs, but it also eliminates VCE's autonomy with regard to local RA procurement and places it in the hands of PG&E.

Next Steps: The proceeding remains open but is inactive. Remaining RA issues will be addressed in the successor RA rulemakings.

Additional Information: D.22-02-008 denying WPTF's Application for Rehearing (February 11, 2022); D.20-09-003 denying PFMs filed by PG&E, CalCCA, and Joint Parties (September 16, 2020); WPTF's Application for Rehearing of D.20-06-028 (August 5, 2020); WPTF's Application for Rehearing of D.20-06-002 (July 17, 2020); D.20-06-028 on Track 1 RA Imports (approved June 25, 2020); D.20-06-002 establishing a central procurement mechanisms for local RA (June 17, 2020); D.20-03-016 granting limited rehearing of D.19-10-021 (March 12, 2020); D.20-01-004 on qualifying capacity value of hybrid resources (January 17, 2020); D.19-12-064 granting motion for stay of D.19-10-021 (December 23, 2019); D.19-10-021 affirming RA import rules (October 17, 2019); D.19-06-026 adopting local and flexible capacity requirements (July 5, 2019); Docket No. R.17-09-020.

2022-2023 Wildfire Fund Nonbypassable Charge Rulemaking

No updates this month.

Background: This rulemaking continues to implement AB 1054, which extended a nonbypassable charge (NBC) on ratepayers to fund the Wildfire Fund. The CPUC issued D.20-12-024 in December 2020 that continues the Wildfire NBC amount of $0.00580/kWh for January 1, 2021, through December 31, 2021. On December 6, 2021, the CPUC issued D.21-12-006 adopting a Wildfire Fund nonbypassable charge of $0.00652/kWh for January 1 through December 31, 2022.

Details: The 2022 Wildfire Fund NBC is $0.00652/kWh, up from $0.0058/kWh in 2021. The reason for this increase is that the Department of Water Resources (DWR) demonstrated a collection shortfall of $13.0 million for 2021 and $85.0 million for 2020 (due largely to a lag in initiating and remitting IOU collections for the Wildfire Fund NBC to DWR at the outset of the Wildfire Fund NBC's existence). Therefore, because of this total $98.0 million under-collection in 2020 and 2021, the 2022 Wildfire Fund NBC is obliged to collect both this 2020-2021 shortfall and 2022's necessary revenue requirement of $902.4 million.

Analysis: VCE customers will pay the 2022 and 2023 Wildfire Fund NBC amounts established in this proceeding. The charge for 2022 is increasing due to an under-collection of the revenue requirement in 2021 that has been added to the revenue requirement for 2022.

Next Steps: 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.

Additional Information: D.21-12-006 on Wildfire NBC for 2022 (December 6, 2021); Ruling requesting comments on 2022 Wildfire Fund NBC (September 8, 2021): Scoping Memo and Ruling (June 8, 2021); Order Instituting Rulemaking (March 10, 2021); Docket No. R.21-03-001.

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

No updates this month.

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

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

A September 4, 2020, Ruling determined that I.15-08-019 will remain open as a vehicle to monitor the progress of PG&E in improving its safety culture, and to address any relevant issues that arise, with the consultant NorthStar continuing in its monitoring role of PG&E.

In April 2021, the CPUC issued Resolution M-4852, placing PG&E into the first of six steps of the Enhanced Oversight and Enforcement process. On August 18, 2021, CPUC President Batjer sent a letter to PG&E stating that she has directed CPUC staff to investigate whether to advance PG&E further within the Enhanced Oversight and Enforcement process. President Batjer's letter to PG&E

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

On October 25, 2021, President Batjer sent a letter to PG&E asserting that PG&E’s “execution and communication of its wildfire mitigation device setting known as Fast Trip has been extremely concerning and requires immediate action to better support customers in the event of an outage.” It finds that since PG&E initiated the Fast Trip setting practice on 11,500 miles of lines in High Fire Threat Districts in late July, it has caused over 500 unplanned power outages impacting over 560,000 customers. It goes on to say that these Fast Trip-caused outages occur with no notice and can last hours or days. The letter goes on to outline near-term and ongoing transparency and accountability actions, as well as cost tracking.

Details: No updates this month.

Analysis: The August 18, 2021, and October 25, 2021, CPUC letters to PG&E indicate the CPUC has significant concerns with PG&E’s outages related to both Public Safety Power Shutoff (PSPS) events and its implementation of Fast Trip. Unlike a PSPS event, by definition, Fast Trip settings do not allow for advance notice to customers of an outage.

Next Steps: The proceeding remains open, but there is no procedural schedule at this time.

Additional Information: Letter from President Batjer to PG&E on Fast Trip issues (October 25, 2021); Letter from President Batjer to PG&E (August 18, 2021); Resolution M-4852 (April 15, 2021); Letter from President Batjer to PG&E (November 24, 2020); Ruling updating case status (September 4, 2020); Ruling on case status (July 15, 2020); Ruling on proposals to improve PG&E safety culture (June 18, 2019); D.19-06-008 directing PG&E to report on safety experience and qualifications of board members (June 18, 2019); Scoping Memo (December 21, 2018); Docket No. I.15-08-019.

Direct Access Rulemaking

No updates this month.

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

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

Several parties, including the Alliance for Retail Energy Markets and the Direct Access Customer Coalition, filed an Application for Rehearing of D.21-06-033 in July 2021.

Details: The Application for Rehearing remains pending, otherwise the proceeding is inactive.

Analysis: This proceeding determined the CPUC’s recommendations to the Legislature regarding the potential future expansion of Direct Access in California. D.21-06-033 recommendation against expansion of Direct Access at this time could reduce the risk of load migration from CCAs (or IOUs) to ESPs.

Next Steps: The only remaining item to be addressed in this proceeding is the Application for Rehearing filed by direct access advocates.

Additional Information: CalCCA Response to Application for Rehearing (August 13, 2021); Application for Rehearing of D.21-06-033 (July 29, 2021); D.21-06-033 recommending against direct access expansion (approved June 24, 2021); Ruling and Staff Report (September 28, 2020); Amended Scoping Memo and Ruling adding issues and a schedule for Phase 2 (December 19, 2019); Docket No. R.19-03-009; *see also* SB 237.

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)