

VALLEY CLEAN ENERGY ALLIANCE

Staff Report – Item 8

To: Valley Clean Energy Alliance Board of Directors

From: Mitch Sears, Interim General Manager

Subject: Regulatory Monitoring Report – Keyes & Fox

Date: July 11, 2019

Please find attached Keyes & Fox's June 2019 Regulatory Memorandum dated July 2, 2019, an informational summary of the key California regulatory and compliance-related updates from the California Public Utilities Commission (CPUC).

Attachment: Keyes & Fox Regulatory Memorandum dated June 7, 2019

Valley Clean Energy Alliance

Regulatory Monitoring Report

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

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

Subject: Regulatory Update

Date: July 2, 2019

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).

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

- **Integrated Resource Planning Rulemaking:** Commissioner Randolph and the judge issued a Ruling establishing the procurement track. The Ruling seeks comments on a proposal to require LSEs including VCE to procure their proportionate shares of 2,000 MW of new peak capacity statewide from resources on-line by August 1, 2021. It would also require SCE to procure 500 MW from existing resources that do not have a contract beyond 2021 for contract terms of 2-5 years, with costs spread across all LSEs, including VCE, via the Cost Allocation Mechanism non-bypassable charge.
- **Renewables Portfolio Standard Rulemaking:** Retail sellers like VCE filed their RPS Procurement Plans. Comments on the plans are due July 19. The CPUC also issued D.19-06-023, which continues the previously established “straight line” methodology to determine RPS requirements for years in between the statutory target years.
- **Resource Adequacy Rulemaking:** The CPUC adopted a revised Proposed Decision establishing local capacity requirements for 2020-2022 and flexible capacity requirements for 2020, while making other refinements to the Resource Adequacy program.
- **Wildfire Cost Recovery Methodology Rulemaking:** At its June 27, 2019, meeting, the CPUC adopted a Decision establishing the criteria and methodology for wildfire cost recovery, which has been referred to as a “Stress Test” for determining how much of wildfire liability costs that utilities can afford to pay, but provided that the Stress Test cannot be applied to a utility such as PG&E that has filed for Chapter 11 bankruptcy protection.
- **Utility Wildfire Mitigation Plans Rulemaking:** Commissioner Picker and the judge issued a Ruling launching Phase 2 of this proceeding, which will examine evaluating Wildfire Mitigation Plan effectiveness, among other issues.
- **Investigation into PG&E’s Organization, Culture and Governance:** The CPUC issued D.19-06-008, requiring safety-related experience information on PG&E board members. On the same

day, Commissioner Picker and the judge issued a Ruling requesting comments on a series of proposals for improving PG&E's safety culture.

- **Power Charge Indifference Adjustment Rulemaking:** Working Group One (Benchmark True-Up and Other Benchmarking Issues) held a meeting, and on July 1, 2019, Working Group One co-leads submitted a second Final Report. The Protect Our Communities Foundation filed a motion requesting an evidentiary hearing on Working Group One's first Final Report. Working Group Three (Portfolio Optimization) filed a progress report.
- **PG&E's 2019 Energy Resource Recovery Account Forecast:** Energy Division partially approved PG&E's Advice Letter implementing the 2019 ERA Forecast revenue requirement, but rejected PG&E's true-up calculation of the 2018 PCIA rates to reflect 2018 brown power costs and revenues. The approved amount of the PCIA refund related to the brown power true-up is approximately \$79.1 million, which exceeds the \$36.3 million originally calculated by PG&E.
- **2018 Rate Design Window:** The judges issued a Proposed Decision (PD) in Phase IIB pertaining to SCE's and PG&E's respective proposals for the implementation of default TOU rates for residential customers, as well as some other related rate proposals.
- **PG&E's 2020 Energy Resource Recovery Account Forecast:** There are no updates this month.
- **PG&E's 2018 Energy Resource Recovery Account Compliance:** There are no updates this month.
- **PG&E's Phase 1 General Rate Case:** There are no updates this month.
- **Other Regulatory Developments:**
 - **SB 237 Direct Access Rulemaking:** The CPUC issued a Proposed Decision (PD) granting a Petition for Modification (PFM) of D.19-05-043, which specified the implementation details for a 4,000 GWh increase in the direct access enrollment cap as required by SB 237 of 2018.

Integrated Resource Planning (IRP) Rulemaking

On June 14, 2019, VCE and most other CCAs filed Advice Letters updating their 2018 IRP with best available estimates of emissions of particulate matter associated with all emitting resources used to serve load, including system power. On June 20, 2019, Commissioner Randolph and the judge issued a Ruling establishing the procurement track of the IRP docket, as anticipated in D.19-04-040 and requesting comments on the framing and structure of this track, as well as potential reliability issues and associated proposals.

- **Background:** In the CPUC's IRP process, it adopts a Preferred System Portfolio (PSP) to be used in statewide planning and future procurement. VCE submitted its IRP on August 1, 2018, and its next IRP filing is due May 1, 2020.

In May 2019, the CPUC issued D.19-04-040, which rejected an aggregation of each of the LSEs' IRPs (the Hybrid Conforming Portfolio) as the statewide PSP, adopting instead a modified version of the Reference System Plan adopted in D.18-02-018 as its PSP. D.19-04-040 opened a new "procurement track" of the proceeding to determine how LSEs are to procure resources to satisfy the PSP by 2030. Specifically, the decision clarifies that the priorities for this track will be to (1) develop mechanisms for a "backstop" procurement in the event an LSE or LSEs fail to procure resources identified in their IRPs, and (2) address procurement that may require collective action. The Decision said some CCAs' "attitude[s]" regarding the IRP process was "[v]ery concerning."

- **Details:** The Ruling prioritizes procurement by resource type/attribute, as follows: (1) near to medium-term integration and reliability (high priority, defined later as needed in 2019-2024); (2) renewables (medium priority); and (3) long-term reliability (low priority). Notably, the Ruling proposes to require LSEs to procure their proportionate shares of 2,000 MW of new peak

capacity statewide from resources on-line by August 1, 2021. That determination is based on a Staff analysis of resource availability, which has not been subject to vetting by parties, that found that by 2021 there could be a shortage in System RA whereby bilateral RA market could be relying on up to 8,800 MW of imports to meet system peak (double the historic use of imports for system resources and almost as much as is actually available). The increased need for imports stems from the closure of once-through cooling (OTC) units in 2020, a shift in the peak from August to September, retirements, and proposed reductions in the August effective capacity values for both solar and wind. The Ruling recommends a series of solutions for meeting 2021 RA needs, including additional renewables procurement; additional storage and demand response procurement; extending OTC closure timelines until new procurement is authorized or online; and authorizing procurement of existing mothballed or potentially departing units. The May 2020 IRP filings by LSEs would have to address how an LSE would meet the requirement to procure their share of this additional 2000 MWs, including appropriate documentation (e.g., completed CAISO interconnection study, complete environmental review).

In addition, the Ruling also separately proposes that SCE be required to solicit 500 MW from existing resources that do not have a contract beyond 2021 for contract terms of 2-5 years, with costs spread across all LSEs with RA obligations (not only those in SCE's territory), including VCE, via the Cost Allocation Mechanism non-bypassable charge.

- **Analysis:** The procurement track of this proceeding could potentially diminish VCE's authority and control over its resource procurement decisions, although the scope of centralized procurement is now limited to establishing a procurement backstop mechanism and procurement of resources requiring collective action.

In addition to this procurement track, this proceeding is focused on addressing other issues that will be relevant to VCE's 2020 IRP filing. VCE will be required to disclose additional contractual and development status of its resource choices in its 2020 IRP filing, as well a section describing its plans to address the retirement of the Diablo Canyon Generation Plant and the characteristics of its energy output, including flexible baseload and/or firm low-emission energy.

- **Next Steps:** Comments on the Ruling are due July 15, 2019, and replies are due July 25, 2019. VCE must make a separate filing by August 16, 2019, including the contractual status and the development status of each resource. CPUC staff will develop the exact data request format and template, and will also subsequently produce a public progress chart about the contractual and project status data submitted by LSEs. The CPUC is also expected to issue a new Order Instituting Rulemaking on the 2019-2020 IRP cycle in 2019.
- **Additional Information:** [Ruling](#) (June 20, 2019); [D.19-04-040](#) on 2018 IRPs and 2020 IRP requirements (May 1, 2019); Docket No. [R.16-02-007](#).

Renewables Portfolio Standard (RPS) Rulemaking

On June 21, 2019, retail sellers like VCE filed their 2019 RPS Procurement Plans. Parties also filed comments earlier in June on a Proposed Decision (PD) on the implementation of SB 100, which increased the state's RPS target to 60% of retail sales by 2030, with interim targets of 44% by 2024 and 52% by 2027. On June 28, 2019, the CPUC issued D.19-06-023, approving the PD.

- **Background:** In February 2019, the CPUC issued D.19-02-007, approving RPS Procurement Plans filed in 2018 by retail sellers, including VCE. Remaining issues to be addressed in this proceeding are threefold: (1) implementing existing and new statutory requirements (e.g., SB 100) that are mandated or may be mandated during the course of this proceeding; (2) continuing and completing specific tasks identified in R.15-02-020 (the now-closed previous RPS docket), but not completed prior to the issuance of this new Order Instituting Rulemaking (OIR); and (3) continuing, monitoring, reviewing, and improving elements of the RPS program that have previously been put in place, including identifying additional program elements that could be developed. A Ruling issued in April 2019 identified 2019 RPS Procurement Plan filing requirements for all retail sellers, including VCE.

- **Details:** Retail sellers filed 2019 RPS Procurement Plans, with parties now able to file comments on the Plans. The CPUC required CCAs to provide substantial additional information in their RPS Procurement Plans in 2019 compared to 2018.

D.19-06-023 continues the existing “straight line” method for establishing the specific MWh target quantities (RPS procurement quantity requirements) for years in between the statutory target years. However, as in past years, compliance is only measured for the entire multi-year compliance period (e.g., 2017-2020, 2021-2024, etc.). The PD also elects to continue the 60% target for the 2031-2033 compliance period.

- **Analysis:** The PD’s approach to implementing SB 100 was expected and unlikely to be seen as controversial, as it continues the methods and approach it previously established for compliance related to RPS targets (i.e. the “straight-line” method).

Remaining issues to be addressed in this proceeding could also impact RPS compliance obligations and above-market costs for the PCIA calculation. For instance, the April 2019 Ruling proposed a process that would allow LSEs like VCE to forgo filing a separate RPS Procurement Plan in 2020 by using its 2020 IRP filing instead.

- **Next Steps:** Comments and reply comments, respectively, on RPS Procurement Plans are due July 19, 2019 and August 2, 2019. Motions requesting an evidentiary hearing are due August 2, 2019. Motions to update RPS Procurement Plans are due August 23, 2019.

Comments on the Joint Utilities’ information-only TOD proposal are due June 18, 2019, and reply comments are due June 28, 2019.

- **Additional Information:** [D.19-06-023](#) on implementing SB 100 (May 22, 2019); [Ruling](#) extending procedural schedule (May 7, 2019); [Ruling](#) identifying issues, schedule and 2019 RPS Procurement Plan requirements (April 19, 2019); [PG&E Final, Conforming 2018 RPS Procurement Plan](#) (March 15, 2019); [D.19-02-007](#) (February 28, 2019); [Ruling](#) requesting comments on SB 100 implementation (February 11, 2019); [Scoping Ruling](#) (November 9, 2018); [R.18-07-003](#).

Resource Adequacy (RA) Rulemaking

On June 10, 2019, parties filed informal comments in response to questions posed at the Track 2 Central Buyer workshops held in May. On June 13, 2019, and June 18, 2019, respectively, parties filed comments and reply comments on a Track 3 Proposed Decision (PD). On June 24, 2019, parties filed responses to a Petition for Modification of the Track 2 Decision, D.19-02-022, filed by the Alliance for Retail Energy Markets (AReM) in May. At its June 27, 2019 meeting, the CPUC approved a revised Track 3 PD, which will be D.19-06-026 (the final written decision was not available at the time of this writing).

- **Background:** This proceeding has three tracks, and is currently focused on remaining central buyer issues in Track 2 and on Track 3. [Track 1](#) addressed 2019 local and flexible RA capacity obligations and several near-term refinements to the RA program and is closed. In [Track 2](#), the CPUC adopted multi-year Local RA requirements and declined to adopt a central buyer mechanism (D.19-02-022 issued March 4, 2019). As ordered by D.19-02-022, parties are holding workshops and filing informal comments in 2019 to further address the development of a Local RA central buyer mechanism, with the CPUC indicating it would act by late 2019 if parties did not come to a consensus. It is our understanding that settlement negotiations are underway with respect to these issues. In addition, two Petitions for Modification (PFM) of D.19-02-022 are currently pending:
 - In March 2019, Shell Energy filed a PFM, requesting changes to two components of the decision: (1) the establishment of the multi-year RA requirements even though the CPUC did not designate a central procurement entity, and (2) RA reporting by the Energy Division of LSE-specific resources. The PFM is currently pending.

- In May 2019, AReM filed a PFM, taking issue with that Decision’s direction to disaggregate the local RA areas collectively called “PG&E Other,” which are six separate local capacity areas in Northern California that have been previously aggregated for procurement and compliance purposes. AReM requests that the CPUC modify the D.19-02-022 to ensure that LSEs holding local RA contracts for resources in PG&E Other for years 2020 and beyond executed prior to the effective date of the Decision can fully utilize them for RA compliance for the duration of the original contract term.
- Track 3 of the proceeding addresses further refinements to the RA program.
- **Details:** D.19-06-026 adopts CAISO’s recommended 2020-2022 Local Capacity Requirements and CAISO’s 2020 Flexible Capacity Requirements and makes no changes to the System capacity requirements. It establishes an IOU load data sharing requirement, whereby each non-IOU LSE would annually request data by January 15 and the IOU would be required to provide it by March 1. It also adopts the Energy Division’s “binding notice of intent” proposal 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) becomes a binding obligation of that LSE, regardless of additional changes in an LSE’s implementation to new customers. However, the CPUC has renamed this the “Binding Load Forecast” process to avoid confusion. In addition, the Decision makes a number of changes to the RA penalty structure and waiver process. It also allows load migration to be the only reason for differences between initial and final year ahead load forecasts. Finally, the Decision eliminates the Path 26 constraint and directs the Energy Division to convene a working group on counting methodologies for hydro and use-limited fossil resources with the expectation that the group will submit a proposal into the RA proceeding in early 2020.
- **Analysis:** The D.19-06-026 declines to adopt numerous changes to the RA process requested by CCAs to increase transparency, accountability and market efficiency. Instead, it adopts several modest reforms that generally keep in place the current RA framework and process.

D.19-02-022 affected VCE’s Local RA compliance obligations beginning in 2020 by requiring procurement over a three-year period instead of an annual period. The design, scope, and implementation timeline of a RA central procurement entity remains uncertain. Moving to a central procurement entity would impact VCE’s ability to procure some or all Local RA on its own behalf. If pending petitions for reconsideration by Shell or AReM are granted, VCE’s Local RA compliance obligations could be further impacted.
- **Next Steps:** In Track 2, a final decision regarding the central buyer is anticipated for Q4 2019. The Energy Division will convene a working group in 2019 to develop a proposal to file in this proceeding by early 2020.
- **Additional Information:** [D.19-06-026](#) adopting local and flexible capacity requirements (adopted June 27, 2019); [AReM Petition for Modification](#) (May 24, 2019); [Final Flexible Capacity Needs Assessment](#) (May 15, 2019); [Final Local Capacity Technical Analysis](#) (May 1, 2019); [Shell Energy Petition for Modification](#) of D.19-02-022 (March 18, 2019); [D.19-02-022](#) (March 4, 2019); Docket No. [R.17-09-020](#).

Wildfire Cost Recovery Methodology Rulemaking

On June 13, 2019, and June 18, 2019, respectively, parties filed comments and reply comments on a May 2019 Proposed Decision (PD). At its June 27, 2019, meeting, the CPUC adopted the PD, which establishes criteria and a methodology for wildfire cost recovery, which has been referred to as a "Stress Test" for determining how much of wildfire liability costs that utilities can afford to pay (i.e., borne by shareholders rather than ratepayers). The Decision, which had not yet been issued at the time of this writing, also closes this proceeding.

- **Background:** SB 901 requires the CPUC to determine, when considering cost recovery associated with 2017 California wildfires, that the utility’s rates and charges are “just and

reasonable.” In addition, and notwithstanding this basic rule, the CPUC must “consider the electrical corporation’s financial status and determine the maximum amount the corporation can pay without harming ratepayers or materially impacting its ability to provide adequate and safe service.” Costs that would ordinarily be disallowed as not being “just and reasonable” may not exceed this maximum amount. This proceeding will implement the provisions of SB 901 by adopting criteria and a methodology for use by the CPUC in future applications for cost recovery of wildfire costs. The OIR will not adopt a specific financial outcome for purposes of cost recovery in a future wildfire cost recovery application by a utility. Furthermore, the scope of this proceeding does not include the consideration of cost recovery for any specific wildfire.

- **Details:** D.19-06-027 first notes that the Stress Test cannot be applied to a utility that has filed for Chapter 11 bankruptcy protection (i.e., PG&E) because under those circumstances the CPUC cannot determine essential components of the utility's financial status. In that instance, a reorganization plan will inevitably address all pre-petition debts, include 2017 wildfire costs, as part of the bankruptcy process. The framework proposed for adoption in the PD is based on an April 2019 Staff Proposal, with some modifications. The framework is targeted at requiring a utility to pay the greatest amount of costs while maintaining an investment grade rating. It also requires utilities to propose ratepayer protection measures in Stress Test applications and establishes two options for doing so.
- **Analysis:** This proceeding established the methodology the CPUC will use to determine, in a separate proceeding, the specific costs that the IOUs (other than PG&E) may recover associated with 2017 or future wildfires.
- **Next Steps:** This proceeding is now closed.
- **Additional Information:** [D.19-06-027](#) (adopted June 27, 2019); [Assigned Commissioner’s Ruling](#) releasing Staff Proposal (April 5, 2019); [Scoping Memo and Ruling](#) (March 29, 2019); [Order Instituting Rulemaking](#) (January 18, 2019); [R.19-01-006](#). See also [SB 901](#), enacted September 21, 2018.

Utility Wildfire Mitigation Plans Rulemaking

On June 14, 2019, Commissioner Picker and the judge issued a Ruling launching Phase 2 of this proceeding.

- **Background:** This proceeding implements electric utility Wildfire Mitigation Plans pursuant to SB 901 (2018). PG&E’s Wildfire Mitigation Plan, approved with modifications in June 2019 (D.19-05-037), provided an expanded use by PG&E of its Public Safety Power Shutoff (PSPS) program to prevent wildfires from occurring during extreme weather events and dry vegetation conditions, with the number of electric customer premises potentially impacted by PSPS events increasing year-over-year from 570,000 to 5.4 million. The Plan also included increasing vegetation management (removing 375,000 trees in 2019, up 235% from 2017); more frequent inspections of transmission and distribution system infrastructure; 150 circuit miles of system hardening (e.g., undergrounding power lines); enhanced situational awareness through additional weather stations and cameras; and resilience zones. PG&E planned to use pre-installed interconnection hubs (PIH), to be able to quickly and safely connect temporary mobile generation to energize an isolated Resilience Zone to provide service to central community resources like grocery stores when PG&E de-energizes power lines in the area due to wildfire risk conditions. PG&E suggested that the PIHs could evolve into Resilience Zone Microgrids over time, as preferred resource combinations begin to meet technical requirements, and as PG&E’s capability to operate these systems matures.

The CPUC’s separate June 2019 Guidance Decision (D.19-05-036), addressing issues that are common to all of the Wildfire Mitigation Plans, ordered all IOUs to collect data and file reports on this year’s Wildfire Mitigation Plans, initiated a process to establish metrics to evaluate the Wildfire Mitigation Plans, and established a process for 2020 Wildfire Mitigation Plans. It rejected

as incorrect the IOUs' assertion that substantial compliance with their Wildfire Mitigation Plans ensures cost recovery, finding that cost recovery issues are reserved for consideration in the IOUs' General Rate Cases. D.19-05-036 directed CPUC's Safety and Enforcement Division to initiate a process beginning in Fall 2019 to work with all stakeholders to develop a common template for tracking key metrics.

- **Details:** Phase 2 will kick off the process contemplated in SB 901 for evaluation of the effectiveness of the current Wildfire Mitigation Plans. The Ruling requests comments on Phase 2 and provides further detail on topics planned to be addressed, including specifying the goals of the forthcoming workshops to be conducted on the CPUC's Safety and Enforcement Division, which will include establishing metrics, with corresponding templates, to evaluate the effectiveness of Wildfire Mitigation Plans; a process for conducting review of the next WMP filings; and discussing additional languages to use when utilities conduct related outreach to customers.
- **Analysis:** PG&E's Wildfire Mitigation Plan established its management approach to preventing wildfires in the future and included provisions impacting the quality of service experienced by VCE customers (e.g., PG&E's procedures for de-energizing electrical lines) and costs paid by VCE customers (e.g., PG&E's expenditures related to maintaining its transmission and distribution systems are paid by all distribution customers, including VCE customers). While wildfire plans can influence the approach and investments made by utilities like PG&E to mitigate the risk of catastrophic wildfires, cost recovery issues are generally outside the scope and will be separately addressed through utility GRCs.
- **Next Steps:** PG&E is required to file a Tier 1 Advice Letter by July 5, 2019, specific to its Wildfire Mitigation Plan that articulates a plan for communicating the fire and weather data and modeling information from its Wildfire Safety Operations Center in real time during potential or actual emergency events to affected agencies, governments, and first responders. In addition, all entities filing Wildfire Mitigation Plans must file a report by July 30, 2019 on data collection that includes proposed metrics for assessing their results. Phase 2 comments, including comments on the reports filed on July 30, 2019, as well as PG&E's second amended Wildfire Mitigation Plan filed in late April 2019 that the CPUC did not yet act on, are due August 21, 2019. A prehearing conference to consider the scope and schedule of Phase 2 is scheduled for August 28, 2019. The CPUC's Safety and Enforcement Division is authorized to convene workshops, tentatively scheduled for September 17, 18, and 19, 2019, for the purpose of initiating the 2020 Wildfire Mitigation Plan process.
- **Additional Information:** [Ruling](#) launching Phase 2 of proceeding (June 14, 2019); [AL 5555-E](#) establishing Wildfire Plan Memorandum Account (June 5, 2019); [D.19-05-037](#) PG&E-specific decision on 2019 Wildfire Mitigation Plan (June 4, 2019); [D.19-05-036](#) Guidance Decision on 2019 Wildfire Mitigation Plans (June 3, 2019); [PG&E Second Amendment to Wildfire Mitigation Plan](#) (April 25, 2019); [PG&E Wildfire Mitigation Plan](#) (February 6, 2019); [Ruling](#) on independent evaluator (January 30, 2019); [Scoping Memo and Ruling](#) (December 7, 2018); [Order Instituting Rulmaking](#) (October 25, 2018); [R.18-10-007](#).

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

On June 18, 2019, the CPUC issued D.19-06-008. On the same day, Commissioner Picker and the judge issued a Ruling requesting comments on a series of proposals for improving PG&E's safety culture.

- **Background:** On December 21, 2019, 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.

- **Details:** D.19-06-008 orders PG&E to report on the safety experience and qualifications of the PG&E Board of Directors and establishes an advisory panel on corporate governance. The Decision is brief, requiring PG&E to provide a variety of information on each PG&E and PG&E Corporation Board member involving safety training, related work experience, previous positions held, and current professional commitments. The newly established CPUC Advisory Panel is likewise addressed only briefly and no information on how members will be selected is provided. However, an Appendix provides biographies for a number of people who spoke at two April 2019 CPUC forums on governance, management, and safety culture.

The Ruling requests comments on four proposals: (1) separating PG&E into separate gas and electric utilities or selling the gas assets; (2) establishing periodic review of PG&E's Certificate of Convenience and Necessity (CPCN); (3) modification or elimination of PG&E Corp.'s holding company structure; and (4) linking PG&E's rate of return or return on equity to safety performance metrics.

- **Analysis:** This proceeding could have a range of possible impacts on CCAs within PG&E's territory and their customers, given the broad issues under investigation pertaining to PG&E's corporate structure and governance.
- **Next Steps:** PG&E's report to the Commission in response to D.19-06-008 is due July 8, 2019. Comments and reply comments on the questions posed in the Ruling, respectively, are due July 19, 2019, and August 2, 2019.
- **Additional Information:** [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, 2019); [I.15-08-019](#).

PCIA Rulemaking

On June 7, 2019, Working Group One (Benchmark True-Up and Other Benchmarking Issues) held a meeting, and on July 1, 2019, Working Group One co-leads submitted a second Final Report. On June 14, 2019, the Protect Our Communities Foundation filed a motion requesting an evidentiary hearing on Working Group One's first Final Report. On June 24, 2019, Working Group Three (Portfolio Optimization) filed a progress report.

- **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.

A Phase 2 Scoping Memo and Ruling relies primarily on a working group process to further develop a number of PCIA-related proposals. It provides that three types of issues are within the Phase 2 scope: (1) issues with the highest priority: Benchmark True-Up and Other Benchmarking Issues; (2) issues to be resolved in early 2020: Prepayment; and (3) issues to be resolved by mid-2020: Portfolio Optimization and Cost Reduction, Allocation and Auction.

- **Details:** The motion for an evidentiary hearing focuses on issues pertaining to the treatment of quantities and value of unsold RA that should be included in the true-up and forecast.
- **Analysis:** Phase 2 of this proceeding could further affect the PCIA paid by VCE's customers in future (post-2019) years, as well as other important PCIA issues that could impact CCAs such as prepayment.
- **Next Steps:** A Working Group Three workshop is scheduled for July 25, 2019, with the next progress report to be filed September 26, 2019. Working Group Two's next progress report is due July 26, 2019. Parties may request evidentiary hearings by filing a motion within ten working days of a working group report being filed. A Proposed Decision (PD) on the Brown Power, RPS and RA true-ups are anticipated in September 2019, with a separate PD issued later Fall 2019 on other Working Group One issues.

- **Additional Information:** [Working Group One Report](#) on Brown Power, RPS and RA True-Up (May 31, 2019); [Phase 2 Scoping Memo and Ruling](#) (February 1, 2019); [D.18-10-019](#) Track 2 Decisions adopting the Alternate Proposed Decision (October 19, 2018); [D.18-09-013](#) Track 1 Decision approving PG&E Settlement Agreement (September 20, 2018); Docket No. [R.17-06-026](#).

PG&E's 2019 Energy Resource and Recovery Account Forecast

On June 10, 2019, Energy Division partially approved PG&E's Advice Letter (AL) 5527-E, which implements the 2019 ERRA Forecast revenue requirement, but rejected PG&E's true-up calculation of the 2018 PCIA rates to reflect 2018 brown power costs and revenues. Energy Division also rejected PG&E's AL 5527-E-A, which a group of CCAs had protested in addition to AL 5527-E. Energy Division approved PG&E's AL 5527-E-B, filed on June 5, 2019.

- **Background:** Energy Resource and Recovery Account (ERRA) forecast proceedings establish the amount of the PCIA and other non-bypassable charges for the following year. More specifically, they determine fuel and purchased power costs associated with serving bundled customers that utilities may recover in rates. The CPUC's March 2019 Decision (D.19-02-023) granted the brown power true-up for target year 2018, resulting in a total 2019 PCIA revenue requirement that decreases further from the \$1.043 billion in the Proposed Decision (PD), which itself was a decrease of \$122 million. It also revised the methodology for calculating the brown power true-up, which will likely reduce the amount of the true up compared to original estimates. The exact further amount of the reduction is determined in Advice Letter 5527-E.
- **Details:** PG&E filed and Energy Division approved supplemental 5527-E-B, removing the pro rata adjustment from the 2018 vintage rate calculation. As a result, the amount of the PCIA refund related to the brown power true-up is approximately \$79.1 million, instead of the \$36.3 million originally calculated in 5527-E or \$55.1 million calculated in AL 5527-E-A. (CCAs had argued that the correct Brown Power True-Up should be \$163.8 million.) PG&E additionally included the actual 2019 generation rate ratios rather than the illustrative forecast ratios it had been using previously. No changes were made to the calculation of the brown power indifference amount as presented in AL 5527-E-A. AL 5527-E-B was not protested.
- **Analysis:** This proceeding implements the October Track 2 Decision from the PCIA docket and establishes the amount of the PCIA for VCE's 2019 rates and the level of PG&E's generation rates for bundled customers. Any under or over-collections between January 1, 2019 and the date of the PG&E's Annual Electric True-Up implementing the ERRA will be recovered in 2020 rates.
- **Next Steps:** This proceeding and its implementation are now complete.
- **Additional Information:** [AL 5527-E-B](#) (approved June 10, 2019); [AL 5549-E](#) (May 28, 2019); [AL 5527-E-A](#) (May 15, 2019); [AL 5528-E-A](#) and [AL 5528-E](#) (April 26, 2019 and April 19, 2019); [AL 5527-E](#) (April 18, 2019); [D.19-02-023](#) (March 4, 2019); [PG&E's Application](#) (June 1, 2018); [PG&E's Testimony](#) (June 1, 2018); Docket No. [A.18-06-001](#).

2018 Rate Design Window (RDW)

On June 7, 2019, the judges issued a Proposed Decision (PD) in Phase IIB pertaining to SCE's and PG&E's respective proposals for the implementation of default TOU rates for residential customers, as well as some other related rate proposals.

- **Background:** The IOUs' RDW applications have been consolidated into one proceeding. This proceeding is divided into three phases, with the second phase further bifurcated. A May 2018 [Phase I](#) Decision granted PG&E approval to begin transitioning eligible residential customers to TOU rates beginning in October 2020. A December 2018 [Phase IIA](#) Decision addressed PG&E

restructuring of the CARE discounts into a single line item percentage discount to the customer's total bill.

The proceeding is currently focused on Phase IIB and Phase III. Phase IIB addresses PG&E's rate design proposals and implementation, including a number of issues impacting CCA customers (e.g., PG&E's CCA rate comparison tool and TOU rate design roll out to CCA customers). Phase III considers the IOUs' proposals for fixed charges and/or minimum bills.

- **Details:** For both PG&E and SCE the start date of customer migration to TOU rate is set to begin October 2020 and continue in batches over a period of up to 18 months (potentially less). The Phase IIB PD provides that a CCA wishing to have its customers defaulted to TOU generation rates are directed to notify the IOU by October 2019 of its intentions in order to facilitate a smooth transition and allow the IOU sufficient time to finalize its own transition plan.

The PD conditionally accepts the E-TOU-C design (a tiered two-period design with a 5 p.m to 8 p.m. peak period, with seasonal differentiation in rates but not peak periods), its designation as the default TOU rate, and the price differentials, but directs that it be modified to provide TOU-based price differentiation for the distribution component. The distribution differentiation must be included in the adopted fixed price differentials. During the Summer the differential must be at least 1 cent/kWh but may be up to roughly 5.1 cents/kWh (based on marginal distribution costs), and must be set at 0.23 cents/kWh during the winter. PG&E must propose a revised E-TOU-C price differential in its next Phase 2 rate case in order to allow other parties and the Commission to consider a higher price differential.

Among numerous other determinations, the PD also:

- Accepts PG&E's proposal to eliminate the existing E-TOU-A rate, which has a 3 p.m. to 8 p.m. weekday peak period, in June 2020.
- Accepts PG&E's revised E-TOU-B proposal, which allows customers to enroll in the existing E-TOU-B rate through May 2020. All customers, including net metering customers are allowed to remain on the rate until October 2025.
- Rejects PG&E's proposal to increase its minimum bill for at least some rate schedules from \$10 to \$15 per month.
- For CCA customers, allows utilities to provide a proxy rate comparison tool using their generation rates but does not obligate them to provide a tool using CCA rates. Rate comparison tool costs will be recovered from all customers through distribution rates, with the exception that any costs incurred to model CCA-specific rates are to be borne by the CCA.
- **Analysis:** This proceeding will impact the timing, details, and implementation of residential TOU rates for bundled PG&E customers as well as VCE customers via rate design changes to the distribution component of customer bills. It could affect the level of VCE's rates compared to PG&E's, and to the extent VCE mirrors PG&E's residential rate design, lead to changes in the way VCE structures its residential rates. CCAs are not obligated to default their customers to TOU generation rates, but regardless of whether a CCA offers TOU generation rates, CCA customers will be subject to default TOU distribution rates.
- **Next Steps:** In Phase IIB, comments on the PD are due June 27, replies are due July 2, and the PD may be adopted, at earliest, at the CPUC's July 11 meeting. In Phase III, evidentiary hearings are scheduled for August 5-16, 2019. Phase III briefs and reply briefs, respectively, are due September 13, 2019, and October 4, 2019, with a Proposed Decision expected in Q1 2020. CCAs wishing to transition to default TOU generation rates should notify the applicable IOU by October 1, 2019.
- **Additional Information:** [Proposed Decision](#) in Phase IIB (June 7, 2019); PG&E Phase III [Revised Testimony](#) on fixed charges (April 12, 2019, and March 29, 2019); [D.18-12-004](#) on Phase IIA Issues (December 21, 2018); [Ruling](#) requesting supplemental testimony on GHG reduction cost estimates (August 17, 2018); [PG&E Supplemental Testimony](#) (August 17, 2018);

[Ruling](#) clarifying scope (July 31, 2018); [D.18-05-011](#) (Phase I) on the timing of a transition to default TOU rates (May 17, 2018); [Amended Scoping Memo](#) (April 10, 2018); PG&E Rate Design Window Application & Testimony (December 20, 2017); Docket No. [A.17-12-011](#) (consolidated).

PG&E's 2020 Energy Resource and Recovery Account Forecast

There are no updates this month.

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

PG&E is forecasting a 2020 total revenue requirement of \$2.908 billion, comprised of \$2.426 billion related to its ERRA, plus four non-bypassable charges, less the costs of utility-owned generation. The non-bypassable charges and associated forecasted revenue requirements are: (1) the Competition Transition Charge (CTC), \$62.2 million; (2) the PCIA, \$2.549 billion; (3) the Cost Allocation Mechanism, \$147.4 million; and (4) the Tree Mortality Non-Bypassable Charge, \$92.6 million. The utility-owned generation revenue requirement is forecasted at \$2.368 billion. PG&E also requested approval of its 2020 sales forecast, as well as its 2020 GHG-related forecasts, which includes a net GHG revenue return of \$391.5 million. PG&E seeks a January 1, 2020 effective date for its rate proposals associated with its proposed electric procurement-related revenue requirements.

- **Details:** N/A.
- **Analysis:** This proceeding will establish the amount of the PCIA for VCE's 2020 rates and the level of PG&E's generation rates for bundled customers.
- **Next Steps:** Protests are due July 5, 2019. PG&E will serve supplemental testimony on July 29, 2019, (the "July Supplement") to update the ERRA Application revenue requirements to reflect (1) the establishment of the Portfolio Allocation Balancing Account (PABA); (2) forecasts of 2019 year-end balancing account balances; and (3) updated 2020 forecasted rates. In November 2019, PG&E will update its 2020 ERRA Forecast revenue requirements, forecasted end of year balancing account balances, electric sales forecast.
- **Additional Information:** [Application](#) (June 3, 2019); [Testimony](#) available on PG&E's regulatory webpage (June 3, 2019); Docket No. [A.19-06-001](#).

PG&E's 2018 Energy Resource and Recovery Account Compliance

There are no updates this month.

- **Background:** ERRA compliance review proceedings review the utility's compliance in the preceding year regarding energy resource contract administration, least-cost dispatch, fuel procurement, and the ERRA balancing account. In its application, PG&E requested that the CPUC find that it 2018 PG&E 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, and least-cost dispatch of electric generation resources, as well as that it managed its utility-owned generation (UOG) facilities reasonably. PG&E also requested recovery of \$4.7 million for Diablo Canyon seismic study costs.
- **Details:** N/A.
- **Analysis:** This proceeding will address whether PG&E correctly calculated and accounted for the actual costs it incurred in 2018 and whether it managed its portfolio of contracts and UOG in a reasonable manner.

- **Next Steps:** Intervenor testimony and reply testimony is due July 12, 2019 and July 24, 2019, respectively. PG&E rebuttal testimony is due August 2, 2019. Evidentiary Hearings are scheduled for August 19-23, 2019. Briefs and reply briefs are due October 4, 2019, and October 25, 2019, respectively. A Proposed Decision is anticipated in Q1 2020.
- **Additional Information:** [Scoping Memo and Ruling](#) (June 3, 2019); [Notice of Prehearing Conference](#) (April 17, 2019); [Response](#) of EBCE and PCE (April 5, 2019); [Resolution](#) categorizing proceeding as ratesetting (March 14, 2019); [PG&E Application](#) (February 28, 2019); Docket No. [A.19-02-018](#).

PG&E Phase I General Rate Case (GRC)

There are no updates this month.

- **Background:** PG&E's three-year GRC covers the 2020-2022 period. For 2020, it has requested an additional \$1.058 billion (from \$8.518 billion to \$9.576 billion), or a 12.4% increase over its 2019 authorized revenue requirement, comprised of increases related to its gas distribution (\$2.097 billion total, or a \$134 million increase), electric distribution (\$5.113 billion total, or a \$749 million increase), and generation (\$2.366 billion total, or a \$175 million increase) services. If approved, it would increase a typical monthly residential electric (500 kWh) and natural gas (34 therms) customer bill by \$10.57, or 6.4%, comprised of an electric bill increase of \$8.73 and a gas bill increase of \$1.84. For 2021 and 2022, PG&E requested total increases of \$454 million and \$486 million, respectively. PGE's GRC does not include a request for cost recovery related to 2017 and 2018 wildfire liabilities.

Overall, more than half of PG&E's proposed increase in this GRC is directly related to wildfire prevention, risk reduction, and additional safety enhancements. Specifically, PG&E proposes expanding its integrated wildfire mitigation strategy, the Community Wildfire Safety Program, which PG&E established following the October 2017 North Bay wildfires to mitigate wildfire threats, with plans to spend an incremental \$5 billion between 2018-2022. PG&E is also requesting a two-way balancing account for insurance premiums and other financial-risk transfer instruments, under which it would be permitted to recover up to \$2 billion in insurance costs.

Significantly, PG&E is proposing to shift substantial hydroelectric generation costs into a non-bypassable charge, arguing that its hydro facilities provide benefits beyond electricity generation. PG&E proposes to shift costs associated with these alleged public benefits from its generation rates (applicable only to bundled customers) to a non-bypassable charge (e.g., the Electric Public Purpose Programs charge). Examples of current and future costs that would be recovered through the non-bypassable charge include, but are not limited to: (1) protection of the natural habitat of fish, wildlife, and plants; (2) outdoor public recreation; (3) protection of historic resources; (4) compliance with conservation easements on the watershed lands; (5) post-decommissioning activities that are a result of FERC orders. PG&E estimates that the unrecovered historic costs that it would shift to the non-bypassable electric charge are \$83.1 million for fish and wildlife and recreation values, plus tens of millions in forecasted future costs, with new license compliance (~\$59 million in 2021-2022) expected as the largest subcategory of future expenses.

- **Details:** N/A.
- **Analysis:** PG&E's GRC proposals include shifting substantial costs associated with its hydroelectric generation from its generation rates (applicable only to its bundled customers) into a non-bypassable charge affecting all of its distribution customers, including VCE customers, which would negatively affect the competitiveness of VCE's rates relative to PG&E's.
- **Next Steps:** Nine public participation hearings are scheduled for July and August, beginning with a July 9, 2019, hearing in San Francisco. Public Advocates Office testimony is due June 28, 2019, followed by intervenor testimony on July 26, 2019. Public participation hearings will be held in July/August 2019. An evidentiary hearing is scheduled to begin September 23, 2019. A

proposed GRC Phase 1 decision is targeted for Q1 2020. PG&E will propose its cost allocation and rate design in its 2020 GRC Phase 2 proceeding, which PG&E plans to file by November 22, 2019.

- **Additional Information:** [Ruling](#) setting public participation hearings (May 7, 2019); [Scoping Memo and Ruling](#) (March 8, 2019); [Joint CCAs' Protest](#) (January 17, 2019); [Application](#) and [PG&E GRC Website](#) (December 13, 2018); [A.18-12-009](#).

Other Regulatory Developments

- **SB 237 Direct Access Rulemaking:** On June 28, 2019, the CPUC issued a Proposed Decision (PD) granting a Petition for Modification (PFM) of D.19-05-043, which specified the implementation details for a 4,000 GWh increase in the direct access enrollment cap as required by SB 237 of 2018. Comments on the PD are due July 18, replies are due July 23, and the PD may be adopted, at the earliest, at the CPUC's August 1 meeting. The PD would adopt changes to a provision in D.19-05-043 that specifies that CCAs be notified of departing load by September 10. The PD would modify this to characterize the September 10 notification as a "preliminary" report, and add language providing for the delivery of a final departing load report to CCAs by February 10, 2020. The PFM sponsors contended that a February 3, 2020 deadline for submitting direct access service requests is the important date for setting the April 2020 preliminary load forecast (for RA purposes), which formed the basis for the various deadlines established in D.19-05-043.