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: June 17, 2019

Please find attached Keyes & Fox's May 2019 Regulatory Memorandum dated June 7, 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

KEYES&FOX LLP

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:	June 7, 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:

- **Renewables Portfolio Standard Rulemaking:** The judge issued a Ruling extending the procedural schedule, establishing a June 21, 2019, deadline for retail sellers like VCE to file their RPS Procurement Plans. The CPUC also issued a Proposed Decision on the implementation of SB 100, which will affect future RPS compliance requirements.
- **Resource Adequacy Rulemaking:** The judge issued a Proposed Decision that would adopt local capacity requirements for 2020-2022 and flexible capacity requirements for 2020, while making a number of changes to the RA program, including relating to load forecasting, accounting for load migration, and adjusting the RA penalty structure and waiver process.
- **Utility Wildfire Mitigation Plans Rulemaking:** The CPUC issued Decisions approving the wildfire mitigation plans filed by PG&E and other entities, as well as a Guidance Decision applicable to all entities filing wildfire mitigation plans. PG&E filed an Advice Letter establishing a Wildfire Plan Memorandum Account to track its costs for implementing its Wildfire Safety Plan.
- **Wildfire Cost Recovery Methodology Rulemaking:** The judge issued a Proposed Decision for adopting criteria and a methodology for wildfire cost recovery, referred to as a "Stress Test" for determining how much of wildfire liability costs that utilities can afford to pay – but it would not apply to utilities like PG&E that have filed for Chapter 11 bankruptcy.
- **Investigation into PG&E's Organization, Culture and Governance:** The judge issued a Proposed Decision that would order PG&E to report on the safety experience and qualifications of the PG&E Board of Directors and establish an advisory panel on corporate governance.
- **Power Charge Indifference Adjustment Rulemaking:** Working Groups One (Benchmark True-Up and Other Benchmarking Issues) and Two (Prepayment) held meetings in May. As directed by the CPUC, PG&E and CalCCA submitted their final report on Brown Power, RPS and RA True-Up issues, identifying areas of consensus and non-consensus.

- **PG&E's 2020 Energy Resource Recovery Account Forecast:** PG&E filed its 2020 Energy Resource and Recovery Account forecast application, which will determine VCE customers' 2020 PCIA. Protests are due July 5, 2019.
- **PG&E's 2019 Energy Resource Recovery Account Forecast:** A group of CCAs jointly protested PG&E's Advice Letters related to the implementation of the 2019 ERRA Forecast revenue requirement, including a true-up of the 2018 PCIA rates to reflect 2018 brown power costs and revenues. PG&E also filed an Advice Letter notifying the CPUC that its ERRA balance has surpassed the four percent Trigger Amount, but it did not request rate changes.
- **PG&E's 2018 Energy Resource Recovery Account Compliance:** The judge held a prehearing conference, and the Assigned Commissioner issued a Scoping Memo and Ruling.
- **PG&E's Phase 1 General Rate Case:** The judges issued a Ruling establishing a series of public participation hearings to be held throughout the summer across PG&E's service territory.
- **2018 Rate Design Window:** Parties filed testimony in Phase III of this proceeding, which considers the IOUs' proposals for fixed charges and/or minimum bills.
- **2019 Rate Design Window:** The CPUC issued a Decision approving the filed settlement agreement relating to agricultural rates and closing the proceeding.
- **Integrated Resource Planning Rulemaking:** No updates this month.
- **Other Regulatory Developments**:
  - **CPUC President Announces Retirement**. CPUC President Michael Picker announced he would retire from the CPUC as early as July, but likely later to allow Governor Newsom time to appoint a successor to fill his seat.
  - **SB 237 Direct Access Rulemaking**. The CPUC issued a Decision in Phase 1 of this proceeding, increasing the annual cap on non-residential direct access enrollment by 4,000 GWh (1,873 GWh in PG&E's service territory). The adopted Decision includes a revision to the original Proposed Decision, responsive to CCA comments, that pushes the beginning of direct access service for the new load allocation from January 1, 2020 to January 1, 2021. CCAs will receive a first notification of the amount of departing load by September 10, 2019 and a final notice by February 10, 2020.

Renewables Portfolio Standard (RPS) Rulemaking

On May 7, 2019, the judge issued a Ruling extending the procedural schedule, establishing a June 21, 2019, deadline for retail sellers like VCE to file their RPS Procurement Plans. On May 22, 2019, the CPUC issued 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 May 29, 2019, PG&E, SCE, and SDG&E jointly filed an informational-only Time-of-Delivery (TOD) proposal.

- **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**: The PD would continue the past practice of using a straight-line method to establish MWh target quantities (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. The PD elects to continue the 60% target for the 2031-2033 compliance period.

The Ruling only modestly revises the schedule for the filing and review of 2019 RPS Plans, generally extending the schedule by three weeks.

The joint utilities' TOD proposal was filed in response to a directive from the CPUC in its February 2019 Decision (D.19-02-007) requiring the utilities to develop informational-only TOD requirements. Historically, TOD factors have been applied to utility contract prices paid to sellers to reflect the higher value of generation supplied during the on-peak hours and the lower value of generation supplied during the off-peak hours, with each utility setting its own TOD factors. PG&E has inserted these factors into executed RPS contracts, where they impact the payment for each hour of production, and used the proprietary energy price forecasts upon which these TOD factors were based in order to assess the value of RPS bids in PG&E's Least-Cost Best-Fit evaluation. In line with that CPUC decision, the Joint IOUs have proposed multiple sets of informational-only TOD "heat maps" in a month-hour matrix for different years. For example, PG&E's 2020 Informational TOD Heat Map shows the that, on weekdays, the lowest TOD factors (mostly in the 0.03 to 0.50 range) are in the months of March-June during the hours of 9am-4pm, and the highest TOD factors (1.42 to 2.67) are in the months of July-December during the hours of 6pm-10pm. Utilities will update TOD factors with each new Phase 2 GRC filing using the public electricity price forecast provided therein, rather than use the Joint IOUs' confidential proprietary energy price forecast information.

- **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.

  With respect to the judge's Ruling, CCAs had requested a longer extension than was granted. For reference, there are additional requirements applicable to CCAs for this year's filing, making the CCA filing requirements more substantial.

  The joint utilities' TOD proposal will impact the costs of RPS contracts, and could therefore impact the costs paid by new departing load customers in the future through the PCIA.

  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 on the PD are due June 11, replies are due June 17, and the PD may be adopted, at earliest, at the June 27 CPUC meeting.

  Proposed RPS Procurement Plans are due June 21, 2019. 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**: Proposed Decision 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); D.18-11-004 on interconnection rules in the BioMAT program per AB 1923 (November 8, 2018); Ruling on revised RPS Procurement Plans (September 19, 2018); Order Instituting Rulemaking (July 23, 2018); R.18-07-003.

Resource Adequacy (RA) Rulemaking

On May 15, 2019, and May 22, 2019, Track 2 Central Buyer workshops were held. On May 24, 2019, the judge issued a Proposed Decision that would adopt local capacity requirements for 2020-2022 and flexible capacity requirements for 2020, while making a number of changes to the RA program. Also on May 24, 2019, The Alliance for Retail Energy Markets (AReM) filed a Petition for Modification of the Track 2 Decision, D.19-02-022.

- **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 Track 2, on March 18, 2019, Shell Energy filed a Petition for Modification (PFM) of D.19-02-022, which adopted multi-year local RA requirements beginning for the 2020 RA year, as well as a number of corresponding modifications to the RA program. Shell requested 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.

  Track 3 of the proceeding addresses further refinements to the RA program, including the load forecasting methodology, which impacts VCE's RA requirements and associated procurement costs. CalCCA submitted a Track 3 proposal on March 22, 2019 incorporating VCE's suggestions to push back the timeline for load forecasting, provide earlier notice to LSEs of California Energy Commission (CEC) plausibility adjustments and an opportunity for LSEs to contest these, penalize LSEs for under-forecasting and compensate impacted LSEs. The CalCCA proposal would also tailor RA purchases to actual month-to-month forecast load.

- **Details**: The PD would adopt CAISO's recommended 2020-2022 LCR values and CAISO's 2020 flexible capacity requirements and would make no changes to the System capacity requirements. It would establish 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. The data would include hourly load data for each customer in the LSE's territory for the prior year, and corrections to such data for the two years prior to that. The PD would also adopt 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.

  In addition, the PD would make a number of changes to the RA penalty structure and waiver process, including increasing the penalty for local RA deficiencies, clarifying penalty calculations for LSEs incurring both system and flexible RA deficiencies, increasing the local RA waiver trigger price, changing the process for requesting a local RA waiver to a Tier 2 Advice Letter filing, and reiterating that requests for waivers of system or flexible RA will be summarily dismissed. Furthermore, the PD would allow load migration to be the only reason for differences between initial and final year ahead load forecasts. Finally, the PD would require the Energy Division to convene a working group to evaluate improvements and refinements prior to the development of the 2021-2023 local Resource Adequacy requirements.

  AReM' Petition for Modification of D.19-02-022 takes 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.

- **Analysis**: The PD would decline to adopt numerous changes to the RA process requested by CCAs to increase transparency, accountability and market efficiency. Instead, it would adopt 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. In Track 3, comments and reply comments, respectively, on the PD are due June 13, 2019, and June 18, 2019. The earliest date that the CPUC could vote on the PD is June 27, 2019.

- **Additional Information**: Proposed Decision adopting local and flexible capacity requirements (May 24, 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); Amended Scoping Memo and Ruling (January 29, 2019); 2017 Resource Adequacy Report (August 3, 2018); D.18-06-030 setting local capacity requirements and resource adequacy program revisions and D.18-06-031 adopting flexible capacity requirements for 2019 (both on June 22, 2018); Scoping Memo and Ruling (January 1, 2018; modified in part on May 2, 2018); Docket No. R.17-09-020.

Utility Wildfire Mitigation Plans Rulemaking

Comments and reply comments, respectively, were filed by parties on May 20, 2019 and May 28, 2019 on Proposed Decisions regarding wildfire mitigation plans filed by PG&E and other entities. D.19-05-036, a Guidance Decision applicable to all entities filing wildfire mitigation plans, and D.19-05-037, a PG&E-specific Decision, were issued on June 3, 2019, and June 4, 2019, respectively. On June 5, 2019, PG&E filed Advice Letter (AL) 5555-E to create a memorandum account to track wildfire safety plan costs.

- **Background**: This proceeding implements electric utility Wildfire Mitigation Plans pursuant to SB 901 (2018). PG&E's Wildfire Mitigation Plan 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.

- **Details**: The Guidance Decision (D.19-05-036) addressing issues that are common to all of the Wildfire Mitigation Plans, orders all IOUs to collect data and file reports on this year's Wildfire Mitigation Plans, initiates a process to establish metrics to evaluate the Wildfire Mitigation Plans, and establishes a process for 2020 Wildfire Mitigation Plans. D.19-05-036 stresses the importance of IOUs focusing on outcomes, *i.e.*, mitigating the risk of catastrophic wildfires, rather than emphasizing inputs like number of trees removed or miles of conductor installed. It rejects 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 directs 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.

The separate Decision on PG&E's Wildfire Mitigation Plan (D.19-05-037) approved the plan subject to specific reporting, metrics, data and advice letter requirements identified. The CPUC did not act on the second amended Wildfire Mitigation Plan distributed by PG&E on April 25, 2019, deferring consideration to Phase 2 of this proceeding. D.19-05-037 also imposes additional requirements on PG&E for its 2020 Wildfire Mitigation Plan.

PG&E's AL 5555-E proposes to establish a Wildfire Plan Memorandum Account (WPMA) effective May 30, 2019. The WPMA will track costs incurred to implement PG&E's Wildfire Safety Plan. AL 5555-E notes that cost recovery for costs recorded to the WPMA will likely occur either through a general rate case or future application.

- **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**: Protests of AL 5555-E are due June 25, 2019. D.19-05-036 establishes a number of follow-up actions required of entities filing Wildfire Mitigation Plans, including filing Tier 3 advice letters six months and twelve months after the effective date of the decision describing concerns about the effectiveness of any program in their Wildfire Mitigation Plans ("off ramps") and filing a report by July 30, 2019 on data collection for Wildfire Mitigation Plans that includes proposed metrics for assessing their results (party comments on the reports are due August 21, 2019). The CPUC's Safety and Enforcement Division is authorized to convene one or more workshops in 2019 for the purpose of initiating the 2020 Wildfire Mitigation Plan process.

  In addition, PG&E specifically is required to file a Tier 1 Advice Letter within 30 days of issuance of a final decision 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.
- **Additional Information**: 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 Rulemaking (October 25, 2018); R.18-10-007.

Wildfire Cost Recovery Methodology Rulemaking

On May 24, 2019, the judge issued a Proposed Decision (PD) for adopting 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).

- **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**: The PD 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, the PD states that 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, as follows:

  - A utility requests application of the Stress Test to determine if disallowed wildfire costs should be allocated to ratepayers, either via a new application or in a second phase of a proceeding in which costs were disallowed.
  - The CPUC applies a three-factor evaluation to determine the maximum amount a utility can pay (the "customer harm threshold"). The amount allocated to ratepayers equals the total Stress Test Costs minus the customer harm threshold.
  - The CPUC considers potential ratepayer protection measures as conditions of cost recovery, with an intention of mitigating ratepayer impacts because the Stress Test determination will be final and not subject to future revision.

  The PD requires utilities to propose ratepayer protection measures in Stress Test applications and establishes two options for doing so. Under Option #1, the utility must submit a proposal for providing ratepayers with "equity warrants" that provide ratepayers with a portion of the upside of increase share prices. The equity warrants are to be held in a special purpose fund or trust to offset rate impacts of Stress Test costs. The revised Staff Proposal appears to require that ratepayers receive an incremental 1% of the upside for each $500 million in wildfire liability that they are responsible for, up to a maximum of 15%. Option #2 allows a utility to propose its own ratepayer protection measures that offer equivalent or greater protections to ratepayers compared to the equity warrant concept.

- **Analysis**: This proceeding will establish the methodology the CPUC will then use to determine, in a separate proceeding, the specific costs that the IOUs (other than PG&E, if the PD is adopted in its current form) may recover associated with 2017 or future wildfires.
- **Next Steps**: Comments on the PD are due June 13, 2019, replies are due June 18, 2019, and the PD may be considered for adoption by the CPUC, at earliest, at its June 27, 2019, meeting.
- **Additional Information**: Proposed Decision (May 24, 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.

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

On May 7, 2019, the judge issued a Proposed Decision (PD). Parties filed comments on the PD on May 28, 2019, and replies on June 3, 2019.

- **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**: The PD would order PG&E to report on the safety experience and qualifications of the PG&E Board of Directors and establish an advisory panel on corporate governance. The PD is brief. It requires PG&E to, within 20 days after the effective date of a decision, 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 bios for a number of people who spoke at two April 2019 CPUC forums on governance, management, and safety culture.
- **Analysis**: Given the broad initial scope, and limited scope of the PD, this proceeding could have a range of possible impacts on CCAs and their customers. The scoping memo, while focused on PG&E, raised a series of questions regarding the future of the existing models of electricity generation, transmission and distribution in California and the entities participating in providing these services.
- **Next Steps**: The PD may be adopted, at earliest, at the June 13, 2019, CPUC meeting.
- **Additional Information**: Proposed Decision (May 7, 2019); Joint Ruling (March 28, 2019); Joint CCA Comments (February 13, 2019); Scoping Memo (December 21, 2019); I.15-08-019.

PCIA Rulemaking

On May 16, 2019, and May 31, 2019, respectively, Working Group One (Benchmark True-Up and Other Benchmarking Issues) and Working Group Two (Prepayment) held meetings. On May 24, 2019, Working Group Two provided its first progress report. On May 31, 2019, PG&E and CalCCA submitted its report on the Brown Power, RPS and RA True-Up.

- **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**: Working Group One's Report addresses Issues 1-7, which concern methodologies to calculate and true-up the PCIA market price benchmarks (MBPs). The report identifies areas of remaining disagreement between PG&E and CalCCA, as well as presents consideration of a proposal submitted by TURN.
- **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 One meeting regarding a proposal for Load Forecasting, Rate Design, and Tariff Changes is scheduled for June 7, 2019. Working Group One's second report on remaining high priority issues is due July 1, 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; therefore, such a request is due June 10,

2019, for the first Working Group One Report. 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 2020 Energy Resource and Recovery Account Forecast

On June 1, 2019, PG&E filed its 2020 Energy Resource and Recovery Account (ERRA) forecast application.

- **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.
- **Details**: 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.
- **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 2019 Energy Resource and Recovery Account Forecast

On May 8, 2019, a group of CCAs jointly filed a protest of PG&E's Advice Letter (AL) 5527-E, which implements the 2019 ERRA Forecast revenue requirement, including a true-up of the 2018 PCIA rates to reflect 2018 brown power costs and revenues. On May 15, 2019, PG&E submitted AL 5527-E-A in response to an Energy Division staff request for PG&E to provide PCIA calculations in a similar manner to those provided by SCE. On May 20, 2019, the CCAs filed a protest of AL 5527-E-A. On May 28, 2019, PG&E filed AL 5549-E, notifying the CPUC that its ERRA balance has surpassed the four percent Trigger Amount.

- **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**: According to the calculations of the CCAs, the correct Brown Power True-Up should be $163.8 million, rather than $36.3 million calculated by PG&E. For reference, in AL 5527-E, PG&E proposed 2019 PCIA rates based in part on its Brown Power True-Up calculation, resulting in an average PCIA of $0.02871/kWh for 2018 vintage customers and $0.02891/kWh for 2019 vintage customers. For residential customers, the PCIA rates calculated by PG&E are $0.02960/kWh for 2018 vintage customers and $0.02993/kWh for 2019 vintage customers.

  In AL 5527-E-A, PG&E performed the alternate calculation requested by the Energy Division, which contains a revenue-only update to the PCIA calculation presented in Advice 5527-E and removes the cost component of the PCIA brown power true up for 2018. PG&E asserts that the alternate revenue calculations requested by staff are contrary to the PCIA Decision (D.18-10-019) and the CPUC's direction in the ERRA Forecast proceeding, and requests approval of AL 5527-E as filed.

  In AL 5549-E, PG&E notified the CPUC that its ERRA balance has surpassed the four percent Trigger Amount based on a $282.5 million balance (overcollection) as of April 30, 2019, or 4.9 percent of PG&E's prior year recorded generation revenues. PG&E does not recommend a change in rates at this time, noting that the number of accounting, rate, and other changes that are expected to occur in the next 60-75 days and proposing to update this advice letter no later than July 29, 2019.

- **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**: We anticipate PG&E will be filing a second supplemental advice letter, AL 5527-B. PG&E requests an effective date of June 1, 2019, for AL 5527-E. Protests of AL 5549-E are due June 17, 2019.

- **Additional Information**: 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.

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

A prehearing conference was held on May 8, 2019, and a Scoping Memo and Ruling was issued on June 3, 2019.

- **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**: The Scoping Memo and Ruling provides that this proceeding will investigate whether PG&E has complied with its CPUC-approved bundled procurement plan (BPP). The Ruling rejected as outside of the scope of this proceeding two issues raised by a group of CCAs: (1) the reasonableness of PG&E's portfolio management strategies, and (2) the impact of PG&E's bidding behavior on market prices. The Ruling also establishes a procedural schedule, as described below.
- **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)

On May 7, 2019, the judges issued a Ruling establishing a series of public participation hearings to be held throughout the summer across PG&E's service territory.

- **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.

2018 Rate Design Window (RDW)

On May 31, 2019, parties filed testimony in Phase III of this proceeding.

- **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**: N/A.
- **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 it residential rates.
- **Next Steps**: In Phase IIB, a Proposed Decision is expected in June 2019. In Phase III, rebuttal testimony due June 28, 2019, with evidentiary hearings 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.
- **Additional Information**: 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).

2019 RDW

In May 20, 2019, the CPUC issued D.19-05-010, approving the filed settlement agreement and closing the proceeding.

- **Background**: This proceeding stems from PG&E's recently completed 2017 Phase 2 general rate case (GRC), where a new set of default rates (AG-A, AG-B, and AG-C) and opt-in rates (AG-RA, AG-RB, and AG-RC) were adopted to replace the legacy set of agricultural rate schedules. The associated settlement required PG&E to file a 2019 RDW proposal seeking bill mitigation measures for "highly impacted" customers, defined as those that would see bill increases over 7% and $100 per year.
- **Details**: The Decision grants a petition for modification filed by PG&E regarding a decision issued in its previous Phase 2 General Rate Case (D.18-08-013 in docket A.16-06-013) with respect to grandfathered rates applicable to agricultural solar customers, and it approves the settlement agreement previously filed in this proceeding. Settling Parties agreed to rate modifications to the 2017 GRC Phase 2 rates proposed in PG&E's 2019 RDW testimony, including the addition of time-of-use differentiation to the distribution component, modification of Schedule AG-C demand charges, and addition of a higher load factor rate for customers under 35 kW. As part of a transition from connected load to metered demand (which can adversely affect some agricultural customers when their metered demand exceeds their connected load used for billing), parties also agreed to transition all AG-A customers who are not highly-impacted to the new 2019 RDW rates in March 2021, and to transition all highly-impacted AG-A customers to the new 2019 RDW rates in March 2022. However, highly impacted customers are not eligible for this delay in transitioning to new rates if they are CCA, direct access, or net metering customers beginning service on or after August 9, 2018.
- **Analysis**: This proceeding resulted in changes, or will result in future changes, to rates for PG&E's agricultural customers, including impacting the distribution rate design applicable to agricultural customers under specific schedules. It also resulted in a beneficial extended transition period for certain customers, but prohibits new CCA customers (since August 9, 2018) from being eligible.
- **Next Steps**: N/A.
- **Additional Information**: D.19-05-010 (May 20, 2019); Ruling canceling procedural schedule (March 13, 2019); Settlement Agreement (March 5, 2019); Scoping Memo and Ruling (January 24, 2019); PG&E Application (November 26, 2018); A.18-11-013.

Integrated Resource Planning (IRP) Rulemaking

There are no updates this month.

- **Background**: VCE submitted its IRP on August 1, 2018, and its next IRP filing is due May 1, 2020. In the CPUC's IRP process, it adopts a Preferred System Portfolio (PSP) to be used in statewide planning and future procurement. 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 opens 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 procurement track will evaluate the need for the following types of resources: diverse renewable resources in the near term, to reduce reliance on fossil-fueled generation and at levels sufficient to reach the 2030 optimized portfolio, in coordination with the RPS program; near-term resources with load-following and hourly or intra-hour renewable integration capabilities; existing natural gas resources at minimal levels consistent with reliability needs; and long-duration storage resources, approached in a technology-neutral manner. The approved revised PD said some CCAs' "attitude[s]" regarding the IRP process was "[v]ery concerning."

The decision also found that VCE's 2017-18 IRP filed in August 2018 is not yet approved, and required VCE to file a Tier 2 Advice Letter to provide best available estimates of emissions of particulate matter associated with all emitting resources used to serve load for the years of 2018, 2022, 2026, and 2030. (This requirement applies to 16 other CCAs as well.)

- **Details**: N/A.
- **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.

  With the exception of this procurement track, this proceeding is focused on addressing 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**: The procurement track will begin Summer 2019. VCE's Advice Letter updating its 2018 IRP with best available estimates of emissions of particulate matter associated with all emitting resources used to serve load, including system power, is due on June 14, 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**: D.19-04-040 on 2018 IRPs and 2020 IRP requirements (May 1, 2019); Ruling seeking comments on the Reference System Plan scenarios and analysis for 2019-2020 IRPs (February 11, 2019); Ruling and attachments on Proposed Preferred System Portfolio for 2017-2018 and Proposed IRP Portfolios for 2019-2020 CAISO Transmission Planning Process (January 11, 2019); Ruling seeking comments on reliability issues (November 16, 2018); Ruling finalizing production cost modeling approach and schedule (November 15, 2018); VCE's 2018 IRP (August 1, 2018); D.18-02-018 adopting IRP reference plan and load-serving entity requirements (February 13, 2018); Docket No. R.16-02-007.

Other Regulatory Developments

- **CPUC President Announces Retirement**. CPUC President Michael Picker announced he would retire from the CPUC as early as July, but likely later to allow Governor Newsom time to appoint a successor to fill his seat, local media reported. When asked about his tenure at the CPUC, Picker responded, "It's the most frustrating job I've ever had."
- **SB 237 Direct Access Rulemaking**. On June 3, 2019, the CPUC issued D.19-05-043 in Phase 1 of this proceeding (Docket No. R.19-03-009), increasing the annual cap on non-residential direct access enrollment by 4,000 GWh (1,873 GWh in PG&E's service territory). The adopted Decision includes a revision to the original Proposed Decision that pushes the beginning of direct access service for the new load allocation from January 1, 2020 to January 1, 2021. The revision was made in response to party comments arguing that a 2020 start date coupled with the timing of California's resource adequacy (RA) cycle for LSEs could cause cost shifts to CCA and bundled utility customers. This could occur because LSEs were required to submit preliminary 2020 load forecasts on April 19, 2019, which form the basis of the allocation of RA requirements. Since those load forecasts would not capture future customer departures to direct access service, a 2020 start date could result in CCAs and utilities having procured more RA capacity than they actually require for 2020 (i.e., incurring costs for customers that they end up not serving in 2020).

Due to this change, the Decision incorporated corresponding changes that eliminate a two-year phased approach for allowing new direct access enrollment (50% for service beginning in 2020 and 50% in 2021) and revises the schedule for customers to enroll in direct access and for departing load to be reported to the customers' current energy provider. CCAs will receive a first notification of the amount of departing load by September 10, 2019 and a final notice by February 10, 2020 after customers have signed contracts with their respective retail access providers, in time for the CCAs to prepare their April 2020 preliminary load forecast filing for the 2021 RA year.