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: October 8, 2020

Please find attached Keyes & Fox's September 2020 Regulatory Memorandum dated September 30, 2020, 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 September 30, 2020

KEYES&FOX LLP

Valley Clean Energy Alliance

Regulatory Monitoring Report

To:	Valley Clean Energy Alliance ("VCE") Board of Directors
From:	Sheridan Pauker, Partner, Keyes & Fox, LLP Tim Lindl, Partner, Keyes & Fox LLP Ben Inskeep, Principal Analyst, EQ Research, LLC
Subject:	Regulatory Update
Date:	September 30, 2020

Summary

Keyes & Fox LLP and EQ Research, LLC, are pleased to provide VCE's Board of Directors with this monthly informational memo describing key California regulatory and compliance-related updates from the California Public Utilities Commission (CPUC). A Glossary of Acronyms used is provided at the end of this memo.

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

- **PG&E 2021 ERRA Forecast:** The Assigned Commissioner issued a Scoping Memo and Ruling. Joint CCAs (including VCE) filed testimony on PG&E's 2021 ERRA Forecast application. In the related PG&E's ERRA Trigger Application proceeding, a prehearing conference was held.
- **PG&E 2021 PUBA Trigger:** In PG&E's August 2020 monthly balancing account report, PG&E demonstrated that it hit the PCIA Undercollection Balancing Account (PUBA) trigger. The PUBA tracks the differential between capped and uncapped PCIA rates. Once the total revenue differential in the PUBA reaches a trigger threshold, PG&E must file an expedited application to recover part of the amount in the PUBA. Such recovery will take place via a temporary increase to PCIA or PCIA-related rates for VCE's customers. On September 28, 2020, PG&E filed an expedited trigger application addressing the undercollection of its PUBA and proposing to increase in the system average rate for CCA/DA customers in 2021 by $0.0055/kWh, and by $0.0068/kWh for residential customers specifically, or 4.0% over present rates.
- **PG&E's 2019 ERRA Compliance:** PG&E submitted a status update on settlement discussions. A status conference was held September 22, 2020, and the evidentiary hearing planned for September 25, 2020, was canceled. The parties agreed to stipulate the entry of exhibits into the record in lieu of holding evidentiary hearings. The Joint CCAs and PG&E's testimony to date has agreed upon approximately $140 million in adjustments to reduce the Portfolio Allocation Balancing Account (PABA) balances. The PABA underlies the PCIA rates, and the adjustments will be reflected in reduced PCIA rates in 2021 and (possibly) 2022. Approximately $60 million in adjustments remain at issue in the case.
- **PCIA Rulemaking:** CalCCA filed a response to the Joint IOUs' Petition for Modification of D.18-10-019 to make changes to the PCIA calculation regarding line losses. The Joint IOUs filed a reply. CalCCA and the Direct Access Customer Coalition (DACC) filed a response to a Joint IOU advice letter implementing D.20-03-019 on departing load forecast and presentation of the PCIA.

- **Investigation into PG&E's Organization, Culture and Governance:** The ALJ issued a Ruling providing an update on the case status and deciding to only monitor PG&E progress on safety culture for the time being.
- **Direct Access Rulemaking:** The ALJ issued a Ruling seeking comments on a Staff report and recommendation to the Legislature regarding a potential additional expansion of direct access for nonresidential customers.
- **RA Rulemaking (2019-2020):** The CPUC issued D.20-09-003 denying as moot three petitions for modification regarding three previous RA decisions, including a CalCCA PFM that requested extending the RA waiver process from local RA only to system RA and flexible RA as well.
- **RA Rulemaking (2021-2022):** Parties filed comments and reply comments on Track 3.A proposals, utility proposed neutrality rules, and Track 3.A working group reports. The ALJ issued a Ruling modifying the Track 3.B schedule. Finally, CPUC, CAISO and CEC scheduled an October 6, 2020, joint public workshop to consider the potential to provide RA credit to hybrid storage/solar behind-the-meter resources.
- **2020 IRP Rulemaking:** The Assigned Commissioner issued a Scoping Memo and Ruling establishing the issues and schedule for the proceeding going forward, which includes an anticipated May 2021 CPUC decision on a Diablo Canyon analysis that could direct LSEs like VCE to procure additional resources to ensure reliability.
- **2016 IRP Rulemaking:** Parties filed comments and replies, respectively, on the Proposed Decision granting CalCCA's Petition for Modification of D.19-11-016 and closing this proceeding, which the CPUC approved as D.20-09-026 at its September 24, 2020, meeting.
- **RPS Rulemaking:** The ALJ issued a Ruling requesting comments on the Energy Division *Staff Proposal for Alignment and Integration of RPS Procurement Planning and Integrated Resource Planning*. Parties find comments and replies on the ReMAT Proposed Decision, which was held for consideration until the CPUC's October 8, 2020, meeting. Finally, parties submitted comments and replies on the Proposed Decision on new (i.e., not yet serving load) CCAs' RPS Procurement Plans, which the CPUC approved as D.20-09-022 at the CPUC's September 24, 2020, meeting.
- **Wildfire Fund Non-Bypassable Charge (AB 1054):** The CPUC approved D.20-09-023, adopting the Wildfire Non-Bypassable Charge (NBC) of $0.00580/kWh for October 1, 2020, through December 31, 2020, at its September 24, 2020 meeting.
- **PG&E's Phase 1 GRC:** No updates this month; parties are awaiting the issuance of a Proposed Decision.
- **PG&E's Phase 2 GRC:** Parties filed comments and replies on the Proposed Decision approving ratepayer funding for the Essential Usage Study capped at approximately $845,000. The CPUC approved D.20-09-021 at its September 24, 2020, meeting.
- **PG&E Regionalization Plan**: No updates this month; parties are awaiting the issuance of a Scoping Memo and Ruling.
- **Investigation of PG&E Bankruptcy Plan**: The ALJ issued a Proposed Decision that would close this proceeding.
- **Investigation into PG&E Violations Related to Wildfires:** No updates this month. On June 8, 2020, Thomas Del Monte and the Wild Tree Foundation filed applications for rehearing of D.20-05-019, which approved penalties on PG&E for its role in igniting the 2017-2018 wildfires.
- **Wildfire Cost Recovery Methodology Rulemaking:** No updates this month. (An August PG&E Application for Rehearing remains pending regarding D.19-06-027, establishing 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.)

PG&E 2021 ERRA Forecast

On September 10, 2020, the Assigned Commissioner issued a Scoping Memo and Ruling. Also on September 10, 2020, in the related PG&E's ERRA Trigger Application proceeding, a prehearing conference was held. On September 24, 2020, Joint CCAs (including VCE) submitted testimony on PG&E's 2021 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, as well as fuel and purchased power costs associated with serving bundled customers that utilities may recover in rates. PG&E's 2021 ERRA Forecast application proposed capped PCIA rates of $0.03115/kWh (system-average 2021 vintage) and $0.03670/kWh (system-average for 2017 PCIA vintage, which is the system-wide average applicable to most VCE customers). The PCIA rate for most VCE residential customers (*i.e.,* 2017 vintage) would be $0.03846/kWh, although PG&E will update this figure in November. PG&E's application proposes a total 2021 revenue requirement of $2.774 billion, comprised of the following components: (1) CAM, $283 million; (2) PCIA, $2.803 billion; (3) Ongoing Competitive Transition Charge, $20 million; (4) Tree Mortality Non-Bypassable Charge, $73 million; (5) ERRA, $1.841 billion; (6) PUBA, $277 million; and *less* (7) Utility-owned generation costs of $2.522 billion.

  PG&E has filed an expedited PUBA (*i.e.,* an interest-bearing balancing account that is used in the event that the 0.5-cent PCIA cap is reached that tracks obligations that accrue for departing load customers) trigger application (see below), which has the potential to significantly increase the PCIA. PG&E is requesting that any year-end PUBA balance not disposed of via such an expedited application process be included in the PCIA revenue requirement for recovery as part of its November Update via a separate rate adder. However, that rate adder would still be subject to the $0.005/kWh cap, meaning it would not be amortized via 2021 rates but would count towards a possible PUBA trigger application in early 2022.

  PG&E's ERRA Trigger is different than the PUBA trigger mentioned in the previous paragraph (and discussed in more detail below) and will affect bundled customers' rates but not VCE's customers' rates. PG&E's ERRA Trigger application states that its ERRA was more than 5% overcollected as of April 30, 2020, and PG&E forecasts that its incremental ERRA overcollection will be 15.7%, or $793 million, overcollected by December 31, 2020. The Joint CCAs filed a response to PG&E's trigger. Both parties agree a rate change to refund the overcollection is not warranted since the ERRA balance associated with overcollection can be resolved in the utility's 2021 ERRA Forecast Application. A scoping ruling with an abbreviated schedule is anticipated any day.

- **Details**: The Scoping Memo and Ruling identified the issues that are within scope in this proceeding and established a procedural schedule.

  Joint CCA testimony argues that PG&E's PCIA increase request is unreasonable and would result in a single-year PCIA rate increase of between 16% and 21% for vintages 2009 through 2018. Joint CCA recommendations would result in a PCIA revenue requirement of $2,537.6 million compared to PG&E's proposal of $2,802.6 million, a 9.5% reduction. The following rates would apply under the Joint CCA' proposed recommendations, including the 2017 rate for VCE's customers:

Vintage	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
2020 Capped	$0.0243	$0.0273	$0.0297	$0.0296	$0.0316	$0.0321	$0.0319	$0.0318	$0.0317	$0.0317	$0.0338	$0.0406	
2020 Uncapped	$0.0326	$0.0394	$0.0414	$0.0431	$0.0437	$0.0438	$0.0439	$0.0434	$0.0427	$0.0420	$0.0406	$0.0406	
2021 Capped	$0.0293	$0.0323	$0.0347	$0.0346	$0.0366	$0.0371	$0.0369	$0.0368	$0.0367	$0.0367	$0.0388	$0.0456	
2021 Uncapped	$0.0321	$0.0383	$0.0400	$0.0417	$0.0421	$0.0423	$0.0425	$0.0424	$0.0433	$0.0436	$0.0434	$0.0270	$0.0270
2019 ERRA Refund											-$0.0082		
Proposed Rates	$0.0293	$0.0323	$0.0347	$0.0346	$0.0366	$0.0371	$0.0369	$0.0368	$0.0367	$0.0367	$0.0306	$0.0270	$0.0270
Capped?	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	
Proposed % Rate Change	21%	18%	17%	17%	16%	16%	16%	16%	16%	16%	-9%	-34%	

- **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. PG&E is proposing another increase to its PCIA to $0.0367/kWh for the 2017 vintage. In comparison, the last ERRA Forecast proceeding established a capped rate of $0.0317/kWh for the 2017 vintage, an increases from the previous rate of $0.0267/kWh.
- **Next Steps**: PG&E will host a remote workshop to discuss COVID-19 load forecast data and preview its impact on the 2021 forecast on October 1, 2020. A Joint Case Management Statement and deadline to confirm a request for evidentiary hearings is due October 2, 2020. Rebuttal testimony is due October 8, 2020, and evidentiary hearings, if needed, will be held October 21, 2020. PG&E's supplemental testimony concerning 2021 load forecast is due October 26, 2020. Opening and reply briefs, respectively, are due October 30, 2020, and November 9, 2020. PG&E's November Update, due November 9, 2020, will include updates to the PCIA benchmarks for forecasting and true-up purposes; comments on the update are due November 20, 2020. PG&E will file its 2020 Annual Electric True-Up advice letter on November 16, 2020.
- **Additional Information**: Scoping Memo and Ruling (September 12, 2020); PG&E August Update (August 14, 2020); PG&E ERRA Trigger Application (July 31, 2020); PG&E Supplemental Testimony correcting errors in Application (July 17, 2020); Application (July 1, 2020); Docket Nos. A.20-07-002 (2021 ERRA Forecast); A.20-07-022 (ERRA Trigger).

PG&E 2021 PUBA Trigger

On September 28, 2020, PG&E filed an expedited trigger application addressing the undercollection of its PCIA Undercollection Balancing Account (PUBA) and proposing to increase in the system average rate for CCA/DA customers in 2021 by $0.0055/kWh, and by $0.0068/kWh for residential customers specifically, or 4.0% over present rates.

- **Background**: The PUBA tracks the differential between capped and uncapped PCIA rates. Once the total revenue differential in the PUBA reaches a trigger threshold, PG&E must file an expedited application to recover part of the amount in the PUBA. Such recovery will take place via a temporary increase to PCIA or PCIA-related rates for VCE's customers.
- **Details**: PG&E's PUBA balance as of the end of August 2020 is undercollected by $113.0 million, which exceeds the 7% trigger, and PG&E expects the PUBA balance to exceed the 10% threshold by the end of October 2020. PG&E proposes to increase rates for its Departing Load customers, including VCE customers, by developing a vintage-specific rate adder designed to collect the forecasted 2020 year-end PUBA balance of $252.8 million over 12 months, beginning January 1, 2021. This rate adder would be applied in addition to the authorized PCIA rates. PG&E would decrease bundled customer rates by reducing the bundled generation revenue requirement by the same amount. PG&E's proposal would increase the system average rate for CCA/DA customers by $0.0055/kWh, and by $0.0068/kWh for residential customers specifically, or 4.0% over present rates.

- **Analysis**: If approved, VCE customers would pay a surcharge in 2021 to recover the forecasted PUBA shortfall in addition to the PCIA rate. PG&E notes that it declined to propose to amortize the undercollection over a one-month period, as authorized under D.18-10-109, because it would result in a 222% increase in the PCIA, increasing the system average rate for CCA/DA customers by 48.9%.
- **Next Steps**: A procedural schedule has not been established yet, but the expedited application is subject to PG&E approval within 60 days of filing. PG&E proposes a schedule that includes an October 13, 2020 protest deadline, followed by a reply on October 19, 2020, a prehearing conference on October 22, 2020, a proposed decision on October 28, 2020, and a final decision approximately 30 days thereafter.
- **Additional Information**: Application (September 28, 2020); Docket No. A.20-09-014.

PG&E's 2019 ERRA Compliance

On September 14, 2020, PG&E submitted a status update on settlement discussions. A status conference was held September 22, 2020, and the evidentiary hearing planned for September 25, 2020, was canceled. The parties agreed to stipulate the entry of exhibits into the record in lieu of holding evidentiary hearings.

- **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 PABA balancing account (which determines the true up values for the PCIA each year). In its 2019 ERRA compliance application, PG&E requested that the CPUC find that its PABA entries for 2019 were accurate, it complied with its Bundled Procurement Plan in 2019 in the areas of fuel procurement, administration of power purchase contracts, greenhouse gas compliance instrument procurement, RA sales, and least-cost dispatch of electric generation resources. PG&E also requests that the CPUC find that during the record period PG&E managed its utility-owned generation facilities reasonably. Finally, PG&E requests cost recovery of revenue requirements totaling about $4.0 million for Diablo Canyon seismic study costs.

  PG&E's supplemental testimony (1) described PG&E's PSPS Program and when it was used in 2019; (2) provided an accounting of the 2019 PSPS events, including a description of how balancing accounts forecast in PG&E's annual ERRA Forecast proceeding and reviewed in the 2019 ERRA Compliance Review proceeding may have been impacted and; (3) described the difference between load forecasting for ratemaking purposes and load forecasting for PSPS events.

  The Joint CCAs' testimony identifies $175.4 million in net reductions to the 2019 PABA balance that should be made, excluding interest. The Joint CCAs argue this amount should be credited back to customers. PG&E's rebuttal testimony states it will make all but $33.6 million of those adjustments as part of its August 2020 accounting close, with the remaining amount still in contention in the proceeding.
- **Details**: PG&E's status update identified that the Joint CCAs requested evidentiary hearings for further record development on two issues: (1) whether Resource Adequacy sales in 2019 complied with PG&E's Bundled Procurement Plan and (2) whether the entries recorded in the ERRA and the PABA with regard to 2019 retail sales volumes and revenues are reasonable, appropriate, accurate, and in compliance with Commission decisions. However, parties subsequently agreed to enter exhibits into the record in lieu of holding evidentiary hearings. PG&E and the Joint CCAs have two other disputed issues that the parties agreed to be resolved through briefs: (1) whether the appropriate entries have been made to the PABA related to retained RPS and (2) whether four power purchase agreements amended in 2019 should be re-vintaged. PG&E and the Joint CCAs identified the following issues as likely to be resolved via settlement: (1) mis-vintaging of a subset of CCA customers; (2) data transparency; (3) whether

PG&E has made proper adjustments reflecting issues resolved either prior to or through PG&E's rebuttal testimony.

The Joint CCAs and PG&E's testimony to date has agreed upon approximately $140 million in adjustments to reduce the PABA balances. The PABA underlies the PCIA rates, and the adjustments will be reflected in reduced PCIA rates in 2021 and (possibly) 2022. Approximately $60 million in adjustments remain at issue in the case.

- **Analysis**: This proceeding addresses PG&E's balancing accounts, including the PABA, providing a venue for a detailed review of the billed revenues and net CAISO revenues PG&E recorded during 2019. It also determines whether PG&E managed its portfolio of contracts and UOG in a reasonable manner. Efforts from the Joint CCAs to date will reduce the level of the PCIA for VCE's customers in 2021 and/or 2022.
- **Next Steps**: Opening and reply briefs, respectively, are due October 19, 2020, and November 9, 2020. The schedule for Phase II of this proceeding has not been issued yet.
- **Additional Information**: Amended Scoping Memo and Ruling (August 14, 2020); Scoping Memo and Ruling (June 19, 2020); PG&E's Application and Testimony (February 28, 2020); Docket No. A.20-02-009.

PCIA Rulemaking

On September 8, 2020, CalCCA filed a response to the Joint IOUs' Petition for Modification of D.18-10-019 to make changes to the PCIA calculation regarding line losses. The Joint IOUs filed a reply on September 18, 2020. On September 21, 2020, CalCCA and the Direct Access Customer Coalition (DACC) filed a response to a Joint IOU advice letter implementing D.20-03-019 on departing load forecast and presentation of the PCIA.

Background: D.18-10-019 was issued on October 19, 2018, in Phase 1 of this proceeding and left the current PCIA in place, maintained the current brown power index, and adopted revised inputs to the benchmarks used to calculate the PCIA for energy RPS-eligible resources and resource adequacy capacity. In the Joint IOUs' PFM of D.18-10-019 in this proceeding, filed concurrently with a PFM of D.17-08-026 in R.02-01-011, the Joint Utilities requested changes to the calculations for applying line losses in the PCIA calculations. First, the Joint IOUs argued that the current formula incorrectly applies line loss adjustments to the RA component of the PCIA calculation. Second, the Joint IOUs argued that the PCIA Template is inconsistent it its application of line losses with respect to the calculation of energy market value. The net impact of these two issues, according to the Joint Utilities, is an overstated forecast of portfolio market value with all customers initially underpaying the PCIA.

Phase 2 relied primarily on a working group process to further develop a number of PCIA-related proposals. Three workgroups examined three issues: (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.

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

The CPUC has not yet issued a Proposed Decision regarding Working Group 3.

Details: CalCCA's response to the Joint IOUs' PFM states that it does not oppose the request to modify the treatment of line losses in calculating the PCIA, but requests that the CPUC clarify that the shift away from forecasted retail sales volumes to generation volumes, as the IOUs propose, will not replace the use of load forecasts in other components of the PCIA methodology.

The Joint IOUs' response to CalCCA clarified that the PFM does not seek the broad revisions that CalCCA opposes.

CalCCA's response to the Joint IOUs' ALs implementing D.20-03-019 on departing load forecast and presentation of the PCIA urged the CPUC to quickly adopt the proposed changes, while noting concern that PG&E and SCE foreshadowed a possible dely in implementing the changes due to planned changes to their billing system. CalCCA urged Energy Division to hold workshops as authorized in D.20-03-019 to develop a set of further bill and tariff changes during 2021 once the CPUC has approved the ALs.

- **Analysis**: The Decision on prepayment is expected to make successful prepayments very difficult because it gave utilities significant control over the process and required the prepayment to include a risk premium. The Joint IOUs' PFM of D.18-10-019, if adopted, would increase the PCIA for VCE's customers.
- **Next Steps**: A proposed decision regarding Working Group 3 is expected in Q3 2020. IOUs must file a Tier 2 advice letter by October 6, 2020 (*i.e.,* 60 days after D.20-08-004 was issued) to establish protocols to administer prepayment requests and negotiations.
- **Additional Information**: CalCCA/DACC Response to Joint IOU AL on D.20-03-019 (September 21, 2020); Joint IOUs PFM of D.18-10-019 (August 7, 2020); D.20-08-004 on Working Group 2 PCIA Prepayment (August 6, 2020); D.20-06-032 denying PFM of D.18-07-009 (July 3, 2020); D.20-03-019 on departing load forecast and presentation of the PCIA (April 6, 2020); Ruling modifying procedural schedule for working group 3 (January 22, 2020); D.20-01-030 denying rehearing of D.18-10-019 as modified (January 21, 2020); D.19-10-001 (October 17, 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.

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

On September 4, 2020, the ALJ issued a Ruling providing an update on the case status and deciding to only monitor PG&E progress on safety culture for the time being.

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

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

- **Details**: The September 4 Ruling filed in the PG&E Safety Culture proceeding (I.15-08-019) and PG&E Bankruptcy proceeding (I.19-09-016) determines that I.15-08-019 will remain open as a vehicle to monitor the progress of PG&E in improving its safety culture, and to address any relevant issues that arise, with the consultant NorthStar continuing in its monitoring role of PG&E. The Ruling declined to close the proceeding (e.g., as requested by PG&E) but also declined to move forward with CCAs' consideration of whether PG&E's holding company structure should be revoked and whether PG&E should be a "wires-only company," as well as developing a plan for service if PG&E's CPCN is revoked in the future.
- **Analysis**: While the docket remains open to monitor PG&E progress on its safety culture, this proceeding is dormant for the time being. Depending on the issues addressed in the future, 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. Numerous issues proposed in the PG&E Bankruptcy OII, including municipalization and sale of PG&E assets, were deferred and stated to be more properly within the scope of this proceeding. However, under the September 4 Ruling, the focus is now on monitoring PG&E's progress on safety culture.
- **Next Steps**: The proceeding remains open, but the judge declined to issue a Scoping Memo and Ruling, choosing instead to monitor PG&E safety culture progress for now.
- **Additional Information**: Ruling updating case status (September 4, 2020); Ruling on case status (July 15, 2020); Ruling on proposals to improve PG&E safety culture (June 18, 2019); D.19-06-008 directing PG&E to report on safety experience and qualifications of board members (June 18, 2019); Scoping Memo (December 21, 2018); Docket No. I.15-08-019.

Direct Access Rulemaking

On September 28, 2020, the ALJ issued a Ruling seeking comments on a Staff report and recommendation to the Legislature regarding a potential additional expansion of direct access (DA) for nonresidential customers (Staff Report).

- **Background**: Phase 1 issues were resolved on May 30, 2019. For Phase 2 of this proceeding, the CPUC will address the SB 237 mandate requiring the CPUC to, by June 1, 2020, provide recommendations to the Legislature on "implementing a further direct transactions reopening schedule, including, but not limited to, the phase-in period over which further direct transactions shall occur for all remaining nonresidential customer accounts in each electrical corporation's service territory." The Commission is required to make certain findings regarding the consistency of its recommendation with state climate, air pollution, reliability and cost-shifting policies.
- **Details**: The Staff Report recommends that the Legislature:
    - Not make a determination as to whether to further expand DA until at least 2024.
    - Condition any further DA expansion on the performance of Energy Service Providers (ESPs) with respect to IRP, RPS and RA requirements through 2024.
    - Make any further DA expansion in increments of 10% of nonresidential load per year, conditioned on ESP compliance with IRP, RPS and RA.
    - "[C]onsider the CPUC's authority in allowing CCAs to recover the costs of investments that are stranded because of unforeseen load departure to address these potential impacts."
    - "Amend P.U. Code Section 949.25 to provide the CPUC with the authority to revoke ESP licenses **and CCA registration** for repeated non-compliance with [RA], RPS or IRP requirements."
- **Analysis**: This proceeding will impact the CPUC's recommendations to the Legislature regarding the potential future expansion of DA in California, including a potential lifting of the existing cap on

nonresidential DA transactions altogether. Further expansion of DA in California could result in non-residential customer departures from VCE and make it more difficult for VCE to forecast load and conduct resource planning. CalCCA has argued that further expansion of nonresidential DA is likely to adversely impact attainment of the state's environmental and reliability goals and will result in cost-shifting to both bundled and CCA customers. The Staff report recognizes this concern and recommends that if DA is further expanded, the Legislature consider permitting CCAs to recover stranded costs from departing DA customers. The Staff report also recommends the Legislature amend the statute to allow the CPUC to revoke both ESP licenses and CCA registration for repeated non-compliance of RA, RPS, or IRP requirements.

- **Next Steps**: Comments on the Staff Report are due October 16, with replies due October 26. A proposed decision attaching the final staff report would follow.
- **Additional Information**: Ruling and Staff Report (September 28, 2020); Amended Scoping Memo and Ruling adding issues and a schedule for Phase 2 (December 19, 2019); Docket No. R.19-03-009; *see also* SB 237.

RA Rulemaking (2019-2020)

On September 16, 2020, the CPUC issued D.20-09-003 denying as moot three petitions for modification regarding three previous RA decisions, including a CalCCA PFM that requested extending the RA waiver process from local RA only to system RA and flexible RA as well.

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

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

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

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

On October 30, 2019, CalCCA filed a PFM of D.19-06-026, seeking the creation of an RA waiver process in 2020 for system and flexible RA obligations.

On July 17, 2020, Western Power Trading Forum (WPTF) filed an Application for Rehearing of D.20-06-002, the Track 2 Decision creating a multi-year central procurement regime for local RA capacity. It requested rehearing and reconsideration of the rejected settlement agreement between WPTF, CalCCA, and other parties, arguing that D.20-06-002 will discourage the procurement of local resources by individual LSEs, discriminates against natural gas resources while increasing the need for CAISO backstop procurement, may undermine reliability by making it more difficult to integrate renewables with the larger western grid, and creates a "sale for resale" procurement construct that could place it under FERC's jurisdiction as a wholesale, rather than a retail, transaction.

On August 5, 2020, WPTF filed an Application for Rehearing of D.20-06-028 with respect to the self-scheduling requirements for non-resource specific RA imports.

- **Details**: CalCCA's PFM had recommended a system and flexible waiver process, with specific requirements for an LSE to demonstrate. D.20-09-003 found CalCCA's proposal for system and flexible RA waivers was addressed in D.20-06-031, where the CPUC declined to adopt the proposal. Accordingly, it found CalCCA's petition was moot and denied the petition. D.20-09-003 also made similar determinations for issues raised by PG&E and renewable energy and storage parties in their respective PFMs of two other previous decisions in this proceeding.
- **Analysis**: D.20-06-002 established a central procurement entity and mostly resolved the central buyer issues, although several details are being refined through a Working Group. Moving to a central procurement entity beginning for the 2023 RA compliance year will impact VCE's local RA procurement and compliance, including affecting VCE's three-year local RA requirements as part of the transition to the central procurement framework. Eventually, it will eliminate the need for monthly local RA showings and associated penalties and/or waiver requests from individual LSEs, but it also eliminates VCE's autonomy with regard to local RA procurement and places it in the hands of PG&E.

  The Track 1 Decision on RA imports will primarily impact LSEs relying on RA imports to meet their RA obligations by increasing the difficulty of procuring such RA in the future.
- **Next Steps**: The only issues remaining to be addressed in this proceeding are WPTF's Applications for Rehearing. Remaining RA issues will be addressed in the successor RA rulemaking, R.19-11-009.
- **Additional Information**: D.20-09-003 denying PFMs filed by PG&E, CalCCA, and Joint Parties (September 16, 2020); WPTF's Application for Rehearing of D.20-06-028 (August 5, 2020); WPTF's Application for Rehearing of D.20-06-002 (July 17, 2020); D.20-06-028 on Track 1 RA Imports (approved June 25, 2020); D.20-06-002 establishing a central procurement mechanisms for local RA (June 17, 2020); D.20-03-016 granting limited rehearing of D.19-10-021 (March 12, 2020); PFM of D.20-01-004 (February 11, 2020); D.20-01-004 on qualifying capacity value of hybrid resources (January 17, 2020); D.19-12-064 granting motion for stay of D.19-10-021 (December 23, 2019); D.19-10-021 affirming RA import rules (October 17, 2019); D.19-06-026 adopting local and flexible capacity requirements (July 5, 2019); Docket No. R.17-09-020.

RA Rulemaking (2021-2022)

On September 11, 2020, and September 18, 2020, respectively, parties filed comments and reply comments on Track 3.A proposals, utility proposed neutrality rules, and Track 3.A working group reports. On September 23, 2020, the ALJ issued a Ruling modifying the Track 3.B schedule. Finally, CPUC, CAISO and CEC scheduled an October 6, 2020, joint public workshop to consider the potential to provide RA credit to hybrid storage/solar behind-the-meter resources.

- **Background**: Per the Scoping Memo, this proceeding is divided into 4 tracks. The first two tracks have concluded, and the proceeding focused on Track 3 issues. Track 3 is divided into Track 3.A and Track 3.B, which are proceeding in parallel. Track 3.A issues include the following topics: (1) evaluation of CAISO's updated LCR reliability criteria; (2) evaluation of an LCR reduction compensation mechanism; (3) consideration of the CPE's Competitive Neutrality Rules; (4) NQC for BTM hybrid resources; and (4) other time-sensitive issues.

  Track 3.B focuses on an examination of the broader RA capacity structure to address energy attributes and hourly capacity requirements, given the increasing penetration of use-limited resources, greater reliance on preferred resources, rolling off of a significant amount of long-term tolling contracts held by utilities, and material increases in energy and capacity prices experienced in California over the past years. Other refinements to the RA program identified during Track 1 or Track 2 will also be considered, including refinements to the MCC buckets adopted in D.20-06-031.

  A future Track 4 will consider the 2022 program year requirements for System and Flexible RA, and the 2022-2024 Local RA requirements.

  Energy Division's initial Track 3.B proposal identified three options for addressing its various concerns about the RA construct that would involve significantly modifying or replacing the existing peak capacity RA construct:
  1. Option 1: Making several fundamental modifications to the existing capacity construct including revising the MCC buckets to make them binding in order to address issues associated with use-limited resources and revising the RA product to include a least-cost dispatch requirement or a bid cap;
  2. Option 2: Enhancing or replacing the current RA capacity / CAISO must-offer obligation construct with a forward energy based system hourly load shape framework that requires load serving entities to demonstrate procurement of sufficient energy from specified physical resources that are contractually obligated to flow (or, in the case of DR, curtail) to meet their energy needs on a forward basis; or
  3. Option 3: Replacing the current RA capacity / CAISO must-offer obligation construct with a fixed price forward energy requirement similar to Option 2, but including a financial hedging component that allows for risk arbitrage and price discovery on the part of generators, which can result in lower forward prices for customers.

- **Details**: In Track 3.A, CPUC, CAISO and CEC rescheduled a joint public workshop, originally scheduled for September 3, 2020, for October 6, 2020, to consider the potential to provide RA credit to hybrid storage/solar behind-the-meter resources.

  In Track 3.B, the Ruling established a revised schedule that reflects modifications to allow additional time to address the scoped issues with workshops and revised proposals. It also adds two opportunities for revisions to Track 3.B proposals. The modified schedule also adds an opportunity to comment on the process, in conjunction with the submission of the second revised proposals, in order to allow parties to comment on whether additional process is warranted.

- **Analysis**: Regulatory developments under consideration in this proceeding could have a significant impact on VCE's capacity procurement obligations and RA compliance filing requirements. A broad array of changes to the RA construct are under consideration, including the consideration of hourly capacity requirements in light of the increasing deployment of use-limited resources; modifications to maximum cumulative capacity buckets and whether the RA program should *cap* use-limited and preferred resources such as wind and solar; the potential expansion of multi-year local forward RA to system or flexible resources; RA penalties and waivers; and Marginal ELCC counting conventions for solar, wind and hybrid resources. The resolution of these issues could impact the extent to which VCE is permitted to rely on use-limited resources such as solar and wind to meet its RA obligations, the amount of RA that is credited to these types of resources, and what penalties (and waivers) would apply should there be a deficiency in meeting an RA requirement.

- **Next Steps**: In Track 3.A, a workshop to discuss bi-annual Load Impact Protocols qualifying capacity updates per D.20-06-031 is scheduled for October 7, 2020. A Proposed Decision on Track 3.A issues is anticipated in Q4 2020.

  In Track 3.B, a workshop on Energy Division and party proposals is anticipated for November 2020, revised Track 3.B proposals due December 18, 2020; comments on revised Track 3.B proposals are due January 15, 2020; a workshop on revised Track 3.B proposals is anticipated for February 2020; second revised Track 3.B proposals and comments on additional process are due March 9, 2020, a Proposed Decision is expected May 2021, and a final Decision on Track 3.B and Track 4 is expected June 2021.

  The schedule and scope of issues for Track 4 will be established in a later Scoping Memo.

- **Additional Information**: Ruling (September 23, 2020); Ruling providing Energy Division's Track 3.B proposal (August 7, 2020); Amended Scoping Memo on Track 3 (July 7, 2020); D.20-06-031 on local and flexible RA requirements and RA program refinements (June 30, 2020); Ruling suspending Track 3 schedule (June 23, 2020); 2021 Final Flexible Capacity Needs Assessment (May 15, 2020); 2021 Final Local Capacity Technical Study (May 1, 2020); Scoping Memo and Ruling (January 22, 2020); Order Instituting Rulemaking (November 13, 2019); Docket No. R.19-11-009.

2020 IRP Rulemaking

On September 24, 2020, the Assigned Commissioner issued a Scoping Memo and Ruling establishing the issues and schedule for the proceeding going forward, which includes an anticipated May 2021 CPUC decision on Diablo Canyon analysis that could direct LSEs like VCE to procure additional resources to ensure reliability.

- **Background**: In the CPUC's IRP process, the Reference System Portfolio (RSP) is essentially a proposed statewide IRP portfolio that sets a statewide benchmark for later IRPs filed by individual LSEs. The CPUC ultimately adopts a Preferred System Portfolio (PSP) after LSEs submit individual IRPs to be used in statewide planning and future procurement. On September 1, 2020, LSEs including VCE filed their 2020 IRPs, which included updates on each LSE's progress towards completing additional system RA procurement ordered for the 2021-2023 years under D.19-11-016.

  A June 5 ALJ Ruling on backstop procurement and cost allocation proposed "trigger points" and associated milestones to arrive at a determination of whether backstop procurement will be conducted for the procurement required by D.19-11-016. An LSE would need to meet each of these milestones in order to avoid backstop procurement taking place on its behalf. Compliance would be determined on a resource-specific basis, allowing for instances of partial compliance (*e.g.,* some projects meet the targets but others do not). The CPUC has not yet adopted this proposal.

  The ALJ's June 15 Ruling proposed a three-year cycle for the IRP process, instead of the current structure of conducting each cycle every two years. The proposed schedule provided for activities on four parallel work streams related to the development of the Reference System Portfolio, the Preferred System Portfolio, the Procurement Track, and the Transmission Planning Process. There would be opportunities for new procurement requirements at least twice during every three-year cycle, beginning with a Q1 2021 Ruling proposing resource procurement, followed by the issuance of a PD/Decision in Q2 2021 ordering additional procurement. Q1 2021 would also include the issuance of a PD finalizing a procurement framework. If the need determination is triggered in Q2 2021 via a Ruling, the CPUC would issue a PD ordering resource procurement, either stand-alone or combined with PSP PD, in Q3 2021.

On August 7, 2020, the CPUC issued Resolution E-5080, which implements an IRP Citation Program for non-compliance with IRP requirements.

- **Details**: The September 24 Scoping Memo and Ruling clarifies that the issues planned to be resolved into this proceeding are organized into the following tracks: (1); (2); (3) adoption of a PSP; (4) recommendations to CAISO's Transmission Planning Process; and (5) development of the next RSP, as follows:
    1. General IRP oversight issues: The Assigned Commissioner indicates that a Proposed Decision is forthcoming on the issues identified in the June 15 Ruling regarding the possibility of moving from a two-year to a three-year IRP cycle. Other issues to be determined in this track include IRP filing requirements and interagency work implementing SB 100.
    2. Procurement track: First, the proceeding will resolve capacity procurement issues with respect to D.19-11-016, as discussed in the June 5 Ruling. The CPUC will then focus on examining LSE plans to replace Diablo Canyon capacity and conduct an overall assessment and gap analysis to inform a procurement order that could direct LSEs to procure additional capacity. Other issues to be addressed in this track include (1) evaluation of development needs for long-duration storage, out-of-state wind, offshore wind, geothermal, and other resources with long development lead times; (2) local reliability needs; and (3) analysis of the need for specific natural gas plants in local areas. Additional procurement requirements may also be considered.
    3. Preferred System Portfolio Development: The CPUC will aggregate LSE portfolios, analyze the aggregate portfolio, and adopt a PSP.
    4. Transmission Planning Process (TPP): The PSP analysis will likely lead to a portfolio to be transmitted by the CPUC to the CAISO for use in its TPP analysis, although this will not be in time for the upcoming TPP process for 2021-2022. In addition, a methodology will be developed to map battery storage resources in the IRP resource portfolios transmitted to the CAISO.
    5. Reference System Portfolio Development: To the extent that a new round of RSP analysis is conducted for the next IRP cycle, this proceeding will be the venue for developing and vetting the resource assumptions associated with that analysis in preparation for the next IRP cycle.
- **Analysis**: This proceeding impacts VCE's compliance requirements, including its IRP filing, as well as issues that could impact VCE's autonomy over its procurement decisions and cost recovery of related procurement directives. The September 24 Scoping Memo and Order indicates that the CPUC could issue a decision on Diablo Canyon replacement capacity in May 2021; this decision could direct VCE and other LSEs to procure additional capacity if it finds LSE IRPs contained insufficient resources to ensure reliability with the retirement of Diablo Canyon. In addition, the June 15, 2020 Ruling proposes changes to the IRP cycle that could change the frequency of IRP filings to once every three years and provide the CPUC two opportunities per three-year cycle to order additional procurement. Under the newly created IRP Citation Program, if the CPUC identifies any deficiencies in VCE's IRP filings, it will have 10 days to cure the identified deficiencies, after which time it would be subject to a financial penalty.
- **Next Steps**: Refer to the September 24 Scoping Memo and Ruling for the full timelines for the above IRP tracks. Through January 2021, the schedule is as follows:
    1. General IRP oversight issues: A Proposed Decision on moving from two-year to three-year IRP cycle is anticipated to be issued soon.
    2. Procurement track: Fall 2020: Commission staff conducts analysis of LSE commitments to address Diablo Canyon replacement power, as included in individual IRPs. October 2020: Proposed decision addressing backstop procurement and cost allocation (emanating from D.19-11-016). November 2020: Commission decision on backstop

procurement and cost allocation. January 2021: Ruling circulating Diablo Canyon replacement power analysis, gap analysis, and proposing procurement strategy for any additional needed power, along with proposed broader framework for IRP procurement.

3. Preferred System Portfolio Development: Fall 2020: (1) Modeling Advisory Group meeting examining GHG emissions benchmarking and modeling differences; and (2) Ruling on resubmittals of information for deficient LSE IRPs, if needed.
4. TPP: October 2020: Ruling seeking comments on proposed portfolio(s) and busbar mapping methodologies for 2021-2022 TPP. November 2020: Party comments and reply comments on proposed portfolio(s) for 2021-2022 TPP. January 2021: Proposed Decision recommending portfolio(s) for 2021-22 TPP.
5. Reference System Portfolio Development: N/A.

- **Additional Information**: Scoping Memo and Ruling (September 24, 2020); Resolution E-5080 (August 7, 2020); Ruling on IRP cycle and schedule (June 15, 2020); Ruling on backstop procurement and cost allocation mechanisms (June 5, 2020); Order Instituting Rulemaking (May 14, 2020); Docket No. R.20-05-003.

2016 IRP Rulemaking

Parties filed comments and replies, respectively, on the Proposed Decision on September 14, 2020, and September 21, 2020. At its September 24, 2020 meeting, the CPUC approved D.20-09-026, granting CalCCA's Petition for Modification of D.19-11-016 and closing this proceeding.

- **Background**: In the CPUC's IRP process, the RSP is essentially a proposed statewide IRP portfolio that sets a statewide benchmark for later IRPs filed by individual LSEs. The CPUC ultimately adopts a Preferred System Portfolio (PSP) to be used in statewide planning and future procurement.

  D.19-11-016 directed VCE to procure 6.3 MW, 9.4 MW, and 12.6 MW of additional resources, to be online by line by August 1, 2021, August 1, 2022, and August 1, 2023, respectively. In addition, D.20-03-028 established a 2019-2020 RSP based on a GHG target for the electric sector for 2030 of 46 million metric tons (MMT), while also requiring LSEs to file an IRP scenario based on a more aggressive 38 MMT target in their IRPs due September 1, 2020.
- **Details**: D.20-09-026 grants CalCCA's Petition for Modification of D.19-11-016, which required LSEs to procure additional system RA to come online in 2021-2023. First, it grants CalCCA's request and determine that the methodology included in D.20-06-031 will be used to determine Qualifying Capacity for hybrid resources used to comply with the requirements of D.19-11-016 (unless or until the methodology is modified again). Second, D.20-09-026 effectively punts on deciding the issue of cost recovery to the new IRP proceeding, R.20-05-003. CalCCA's PFM had argued that the Commission should modify the cost recovery mechanism adopted in D.19-11-016 by requiring an IOU that provides system resource adequacy backstop procurement to an LSE to bill that entity directly for all costs associated with the procurement. However, the Decision grants CalCCA's request to modify D.19-11-016 by eliminating the language that would have limited the mechanism to a customer-billed non-bypassable charge. Finally, Decision closes this docket.
- **Analysis**: D.20-09-026 adopts the permanent hybrid counting methodology from R.19-11-019, which CalCCA suggested is likely to be "less conservative and more accurate," instead of an interim methodology recently adopted, which Energy Division has interpreted as applying for compliance with D.19-11-016. It also opens the door to the possibility that CCAs could recover backstop costs through their generation rates rather than having the IOU directly recover such costs through a non-bypassable charge on CCA customers in cases where the LSE has opted out of self-providing the capacity required by D.19-11-016, although this issue will be determined in the new IRP rulemaking (R.20-05-003).

- **Next Steps**: The proceeding is now closed. All other IRP issues will be addressed through R.20-05-003.
- **Additional Information**: D.20-09-026 (approved at CPUC's September 24, 2020 meeting); D.20-07-009 denying CESA PFM of D.19-11-016 (July 21, 2020); D.20-06-025 dismissing GenOn Holdings Application for Rehearing (June 22, 2020); Ruling correcting LSE load forecasts (May 20, 2020); PG&E's Advice 5826-E (May 18, 2020); D.20-03-028 on RSP and 2020 IRP filing requirements (April 6, 2020); List of Baseline Resources (December 2, 2019); D.19-11-016 (November 13, 2019); Ruling initiating procurement track (June 20, 2019); D.19-04-040 on 2018 IRPs and 2020 IRP requirements (May 1, 2019); Docket No. R.16-02-007.

RPS Rulemaking

On September 18, 2020, the ALJ issued a Ruling requesting comments on the Energy Division *Staff Proposal for Alignment and Integration of RPS Procurement Planning and Integrated Resource Planning*. Parties find comments and replies, respectively, on the ReMAT Proposed Decision on September 10, 2020, and September 15, 2020; the PD was held for consideration until the CPUC's October 8, 2020, meeting. Finally, parties submitted comments and replies on the Proposed Decision on new (i.e., not yet serving load) CCAs' RPS Procurement Plans on September 8, 2020, and September 14, 2020, respectively; D.20-09-022 was subsequently approved at the CPUC's September 24, 2020, meeting.

- **Background**: This proceeding addresses ongoing RPS issues. VCE submitted its 2020 RPS Procurement Plan on July 6, 2020 and its 2019 RPS Compliance Report on August 3, 2020. On August 12, 2020, VCE filed a Motion requesting to update its 2020 RPS Procurement Plan to make several minor clerical corrections to its Plan and noting to the CPUC that VCE anticipated terminating its PPA with Rugged Solar in August 2020.

  On February 27, 2020, the ALJ issued a Ruling requesting comments on a Staff Proposal making changes to confidentiality rules regarding the RPS program. Among other proposals, the Energy Division has proposed to make CCAs' RPS procurement contract terms (e.g., price, quantity, resource type, location, etc.) publicly available 30 days after deliveries begin. The contract price would also be publicly available six months after a contract is signed (if that occurs sooner than 30 days after deliveries begin).

  The Renewable Market Adjusting Tariff (ReMAT) program PD would adopt a June 2020 Staff Proposal for revising the ReMAT program and direct the filing of Tier 2 advice letters by SCE and PG&E within 21 days of the issuance of a decision to implement the revisions. The ReMAT program is a feed-in tariff program for renewable facilities of 3 MW or less. The PD would adopt a pricing methodology for base ReMAT pricing based on recent, non-state mandated long-term RPS contracts (2013-2019), categorized by product category and averaged on a capacity-weighted basis. The calculation produced the following prices in the Staff Proposal: (1) As Available Non-Peaking: $57.54/MWh; (2) As-Available Peaking: $50.23/MWh; (3) Baseload: $79.72/MWh. The ReMAT standard contract is also to be updated to reflect the most recent utility time-of-day periods and factors. The resulting effective prices after these adjustments must be specified in the utility Advice Letters filed for program updates. Base pricing would be updated once annually under a CPUC Resolution process starting in May 2021, retaining a 7-year rolling time horizon.

- **Details**: Staff's Proposed Framework for integrating RPS Procurement Plan requirements into the IRP proceeding uses a two-phased approach that makes a relatively minor change to RPS reporting in the current IRP cycle, while fully integrating all elements of RPS Procurement Plans into the next IRP cycle, proposed to commence in the 2023 calendar year (instead of 2022, under the current two-year cycle, although the issue of a two-year versus three-year cycle is not discussed):

  1. Phase I: 2021-2022: Staff proposes to maintain the status quo in Phase I, where LSEs would continue to prepare and submit annual RPS Procurement Plans, subject to subsequent rulings issued by the Assigned Commissioner and Assigned ALJ. The single

deviation from the current RPS Plans procedure, as proposed by staff, is to transition the Cost Quantification reporting requirement away from the RPS Plans and establish an annual data response for Cost Quantification reporting due February 15 of each calendar year, continuing through Phase II and beyond.

2. Phase II: 2023 and Beyond:

   - *IRP Filing Years ("On-Years," e.g., 2023, 2026, etc. if the CPUC adopts a three-year IRP cycle, as has been separately proposed): Full Integration of RPS Requirements.* In Phase II, the CPUC intends to fully combine RPS Procurement Plans filings with the IRP process. With the exception of the proposed February 15 Cost Quantification filing, retail sellers would only be required to file IRPs in the IRP filing years, and the modified IRP would satisfy that year's RPS Procurement Plan requirements. The IRP Narrative Template will be modified to include the necessary RPS reporting items in two of the current IRP chapters and will also add a chapter specifically devoted to capturing any RPS-required information that does not align into an existing IRP section. If an LSE modifies its planned RPS procurement outside of an IRP year, it would be required to file a Motion to Update.
   - *IRP "Off-Years" (e.g., 2024, 2025; 2027, 2028, etc.): Statutorily Mandated RPS Reporting.* LSEs would be required to file Tier 3 advice letters that contain the statutorily-required RPS information. The information required will not vary from year to year. All RPS Plan requirements in IRP off-years would be due July 15 of each calendar year. If an LSE's procurement (or sales) needs change or if further procurement authorizations are required in IRP off-years, LSEs would be required to file a Motion to Amend their IRP as part of the RPS off-year filing.

D.20-09-022 on new CCA 2019 RPS Procurement Plans approved the Plans, but ordered that these new CCAs file more robust RPS Plans in the future. It does not directly impact VCE, or address any filings made by VCE (such as VCE's 2020 RPS Procurement Plan). However, D.20-09-022 includes language echoing previous Decisions that criticized CCAs for providing "scant information" and questioned whether all CCAs will be able to fulfill their long-term RPS requirements.

- **Analysis**: The Staff proposal on integrating RPS/IRP issues would largely maintain the existing compliance framework through 2022, limiting any benefits that could arise from better coordinating these compliance filings until 2023 and thereafter. Beginning in 2023, the Staff proposal would reduce RPS Procurement Plan filing requirements by integrating them with the IRP filing in IRP filing years, and significantly slimming them down to the statutory requirements in IRP off-years, made via an Advice Letter filing that would be subject to full Commission approval.

  D.20-08-043, which reopened the Bioenergy Market Adjusting Tarrif (BioMAT) program, will impact VCE customer rates, as the program and associated cost recovery is through a non-bypassable charge would be extended through 2025. It does not allow VCE to directly enter into BioMAT contracts.

  The reopening of the ReMAT program, if approved by the CPUC, could impact VCE by reopening a program that could compete with VCE with respect to the procurement of small-scale renewable energy facilities.

  The pending Staff Proposal on RPS confidentiality rules included provisions that, if adopted, would result in VCE being required to provide more transparency on various RPS information, such as RPS PPA pricing and other contract information.

  Other issues to be addressed in this proceeding could further impact future RPS compliance obligations.

  Next Steps: The CPUC is anticipated to consider the PD on the ReMAT program at its October 8, 2020, meeting.

Comments on the ALJ Ruling aligning RPS Procurement Plan and IRP filings are due October 9, 2020, and replies are due October 20, 2020.

A PD/Decision on the 2020 RPS Procurement Plans is anticipated in Q4 2020, after which retail sellers may file "Final" 2020 RPS Procurement Plans, also expected in Q4 2020.

- **Additional Information**: D.20-09-022 on new CCA 2019 RPS Procurement Plans (approved at CPUC's September 24, 2020 meeting); Ruling on Staff proposal aligning RPS/IRP filings (September 18, 2020); D.20-08-043 resuming and modifying the BioMAT program (September 1, 2020); Proposed Decision resuming and modifying ReMAT (August 21, 2020); VCE Motion to Update its 2020 RPS Procurement Plan (August 12, 2020); Ruling extending procedural schedule on RPS Procurement Plan review (July 10, 2020); Assigned Commissioner Ruling (ACR) establishing 2020 RPS Procurement Plan requirements (May 6, 2020); D.20-02-040 correcting D.19-12-042 on 2019 RPS Procurement Plans (February 21, 2020); Ruling on RPS confidentiality and transparency issues (February 27, 2020); D.19-12-042 on 2019 RPS Procurement Plans (December 30, 2019); 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); D.19-02-007 (February 28, 2019); Scoping Ruling (November 9, 2018); Docket No. R.18-07-003.

Wildfire Fund Non-Bypassable Charge (AB 1054)

The CPUC approved D.20-09-023, adopting the Wildfire Non-Bypassable Charge (NBC) of $0.00580/kWh for October 1, 2020, through December 31, 2020, at its September 24, 2020 meeting.

- **Background**: This rulemaking implemented AB 1054 and extended a non-bypassable charge on ratepayers to fund the Wildfire Fund. The scope of this proceeding was limited to consideration of whether the CPUC should authorize ratepayer funding of the Wildfire Fund established by AB 1054, enacted in July 2019, via the continuation of an existing non-bypassable charge (Department of Water Resources bond charge) that would have otherwise expired by the end of 2021. On August 26, 2019, the Bankruptcy Court tentatively granted PG&E's request to participate in the Wildfire Fund.

  D.19-10-056, issued in October 2019, approved the establishment of a non-bypassable charge on IOU customers to provide revenue for the newly established state Wildfire Fund pursuant to 2019 AB 1054. The charge will only be assessed on customers of utilities that participate in the Wildfire Fund (i.e., PG&E, SCE, and SDG&E), and will expire at the end of 2035. The Decision also provides that once a large IOU commits to Wildfire Fund participation, it may not later revoke its participation. The annual revenue requirement for the charge among the large IOUs will total $902.4 million, allocated at $404.6 million for PG&E, $408.2 million for SCE, and $89.6 million for SDG&E. There was a June 30, 2020, deadline for PG&E to satisfactorily complete its insolvency proceeding under AB 1054, and therefore become eligible to participate in the Wildfire Fund. The Wildfire Fund NBC will be collected on a $/kWh basis, with the revenue requirement allocated based on each class's share of energy sales. Residential CARE and medical baseline customers are exempt. The Wildfire Fund NBC cannot take effect until the DWR Bond charge sunsets, which may take place as early as the second half of 2020.

- **Details**: Under D.20-09-023, PG&E will collect the Wildfire NBC of $0.00580/kWh from eligible customers beginning October 1, 2020. DWR estimates that the 2021 Wildfire Fund NBC will be comparable to the 2020 charge, but it will notify the CPUC of the 2021 charge amount by November 1, 2020.

- **Analysis**: This proceeding establishes a new non-bypassable charge of $0.00580/kWh from eligible VCE customers beginning October 1, 2020, to fund the Wildfire Fund under AB 1054. The DWR Bond Charge ended at the end of September 2020.

- **Next Steps**: The Wildfire Fund NBC is set to go into effect on October 1, 2020. DWR will propose the 2021 Wildfire NBC amount, which expected to be similar to the 2020 Wildfire NBC, to the CPUC by November 1, 2020.
- **Additional Information**: D.20-09-023 adopting 2020 Wildfire NBC (approved by the CPU on September 24, 2020); D.20-07-014 approving servicing orders (July 24, 2020); Ruling on Wildfire NBC implementation (July 3, 2020); D.20-02-070 denying Application for Rehearing (March 2, 2020); D.19-10-056 approving a non-bypassable charge (October 24, 2019); Scoping Memo and Ruling (August 14, 2019); Order Instituting Rulemaking (August 2, 2019); Docket No. R.19-07-017. *See also* AB 1054.

PG&E's Phase 1 GRC

No updates this month; parties are awaiting the issuance of a Proposed Decision.

- **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.

  The Settlement Agreement, filed December 30, 2019, would result in an increase in PG&E's 2020 revenue requirement of $575 million (*i.e.*, $483 million lower than PG&E's original request), with additional increases of $318 million, or 3.5% in 2021, and $367 million, or 3.9%, in 2022. The Settlement Agreement would result in PG&E withdrawing its proposal for a non-bypassable charge related to its hydroelectric facilities. It would require PG&E to develop new and enhanced reporting to provide increased visibility into the work it performed. It also provides for PG&E's ability to purchase insurance coverage up to $1.4 billion to protect against wildfire risk and other liabilities, reflected in PG&E's forecast as a cost of $307 million. The consolidated 2020 electric and gas bill impact would be 3.4%.

  Joint CCAs' responded to an August PG&E's Motion to update the Settlement Agreement pointing out that, while PG&E's Motion does not impact the revenue requirements in the Settlement or specific CCA arguments in this proceeding, it is yet another example of PG&E transparency and accuracy issues that have been a repeated issue throughout this proceeding. Joint CCAs urged the CPUC to order PG&E in future general rate cases to (1) exercise greater care to improve the accuracy of its filings, (2) more carefully track the utilization of its various common Customer Care services between bundled and unbundled customers and use those numbers to propose proper functionalization methods, and (3) present its allocations of all shared costs more transparently.
- **Details**: N/A.
- **Analysis**: PG&E's GRC proposals included 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. However, that proposal would be withdrawn if the Settlement Agreement is approved. The remaining CCA-related issues in the case include the Joint CCAs' recommendations that the Commission:

  1. Revise the allocation of certain customer-service costs since unbundled customers use those services far less than bundled customers.

2. Ensure CCAs can connect clean generation to PG&E's temporary microgrids during PSPS events.
3. Revise the settlement's exorbitant decommissioning costs for PG&E's PCIA-eligible facilities.
4. Revise the settlement to ensure grid modernization data is accessible to CCAs to ensure a level playing field in the provision of grid services.

- **Next Steps**: The ALJs will issue a proposed decision.
- **Additional Information**: PG&E Motion to update the Settlement Agreement (August 13, 2020); Ruling adopting confidential modeling procedures (August 13, 2020); E-mail Ruling granting in part PG&E's Motion for Official Notice and Joint CCAs Motion to file sur-reply (June 5, 2020); Joint CCAs' PG&E Motion for Official Notice of Facts (January 27, 2020); Joint Motion for Settlement Agreement (January 14, 2020); E-Mail Ruling modifying procedural schedule (December 2, 2019); E-Mail Ruling suspending briefing deadlines (November 25, 2019); D.19-11-014 (November 14, 2019); 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); Docket No. A.18-12-009.

PG&E's Phase 2 GRC

Parties filed comments and replies, respectively, on the Proposed Decision that would approve ratepayer funding for the Essential Usage Study (EUS) capped at approximately $845,000, on September 7, 2020, and September 14, 2020. The CPUC approved D.20-09-021 at its September 24, 2020, meeting.

- **Background**: PG&E's 2020 Phase 2 General Rate Case (GRC) addresses marginal cost, revenue allocation and rate design issues covering the next three years. PG&E's pending Phase 1 GRC (filed in December 2018 via a separate proceeding) will set the revenue requirement that will carry through to the rates ultimately adopted in this proceeding.

  In this proceeding, PG&E seeks modifications to its rates for distribution, generation, and its public purpose program (PPP) non-bypassable charge. PG&E proposes to implement a plan to move all customer classes to their full cost of service over a six-year period (the first three years of which are covered by this GRC Phase 2) via incremental annual steps. PG&E proposes to use marginal costs for purposes of revenue allocation and to adjust distribution one-sixth of the way to full cost of service each year over a six-year transition period.

  Of note, PG&E is proposing changes to the DA/CCA event-based fees that were not updated in the 2017 Phase 2 GRC proceeding. In addition, PG&E proposes to remove the PCIA revenue from bundled generation revenue and allocate that cost separately to bundled customers, collecting the PCIA from bundled customers on a non-time differentiated, per-kWh basis (i.e., the same way it is collected from DA/CCA customers). PG&E will continue to display the PCIA with other generation charges on customer bills, but will unbundle the PCIA as part of unbundled charges in each rate schedule.

  PG&E's final EUS plan describes how the IOUs' study will identify the essential usage of electricity for the IOUs' residential customers. The EUS will determine what constitutes essential usage for residential customers (*e.g.*, cooking, lighting, space conditioning) in the different IOU service territories and climate zones. The apparent use case is that essential service be reflected in the Tier I baseline quantities.
- **Details**: D.20-09-021 authorizes each large IOU to file a Tier 1 advice letter that will establish an EUS cost recovery balancing account for tracking each IOUs' respective share of the actual costs associated with the EUS, with a cost allocation of: PG&E, 45%; SCE, 43%; and SDG&E, 12%. The IOUs estimate that the final EUS report will be completed in January 2022.

- **Analysis**: This proceeding will not impact the transparency between a bundled and unbundled customer's bills because of the Working Group 1 decision in the PCIA rulemaking. However, it will affect the allocation of PG&E's revenues requirements among VCE's different rate classes. It will also affect distribution and PPP charges paid by VCE customers to PG&E. Further, PG&E includes a cost-of-service study the purpose of which is to establish the groundwork for separating net metering customers into a separate customer class in the utility's next rate case. If PG&E's proposed CCA fee revisions are adopted, it will increase the cost VCE pays to PG&E for various services.
- **Next Steps**: Cal Advocates' testimony is due October 23, 2020. Two public participation hearings are scheduled for November 6, 2020. Intervenor testimony is due November 20, 2020. Rebuttal testimony is due February 15, 2021. An evidentiary hearing is tentatively scheduled for March 1-12, 2021. A CPUC decision is anticipated for September 2021.
- **Additional Information**: D.20-09-021 on EUS budget (approved at CPUC's September 24, 2020 meeting); Ruling scheduling public participation hearings (August 20, 2020); Ruling extending procedural schedule (July 13, 2020); Exhibit (PG&E-5) (May 15, 2020); Scoping Memo and Ruling (February 10, 2020); Application, Exhibit (PG&E-1): Overview and Policy, Exhibit (PG&E-2): Cost of Service, Exhibit (PG&E-3): Revenue Allocation, Rate Design and Rate Programs, and Exhibit (PG&E-4): Appendices (November 22, 2019); Docket No. A.19-11-019.

PG&E Regionalization Plan

No updates this month; parties are awaiting the issuance of a Scoping Memo and Ruling.

- **Background**: PG&E was directed to file a regionalization proposal as a condition of CPUC approval of its Plan of Reorganization in I.19-09-016. On June 30, 2020, PG&E filed its regionalization proposal, which describes how it plans to reorganize operations into new regions. PG&E proposes to divide its service area into five new regions: North Coast, Sierra, Bay Area, Central Coast, and Central Valley. The regional boundaries will align with county boundaries. Yolo County would be part of PG&E Region 1 (North Coast), grouped together with the following counties: Colusa, Glenn, Humboldt, Lake, Mendocino, Napa, Sacramento, Solano, Sonoma, and Trinity. PG&E will appoint a Regional Vice President by June 2021 to lead each region, along with Regional Safety Directors to lead its safety efforts in each region.

  The new regions would include five functional groups that report to the Regional Vice President encompassing various functions including: (1) Customer Field Operations, (2) Local Electric Maintenance and Construction, (3) Local Gas M&C, (4) Regional Planning and Coordination, and (5) Community and Customer Engagement. Other functions will remain centralized, such as electric and gas operations, risk management, enterprise health and safety, the majority of existing Customer Care and regulatory and external affairs, supply, power generation, human resources, finance, and general counsel. PG&E will propose in a separate proceeding the enterprise-level safety and operational metrics it is developing that could also be considered to evaluate the effectiveness of its regionalization implementation. PG&E proposes a phased implementation, with progress establishing all regions in 2021, although some functions would not be fully shifted until 2022. PG&E also proposes to establish a Regional Plan Memorandum Account to record any incremental costs PG&E may incur in connection with development and implementation of regionalization.
- **Details**: In August, parties filed protests and responses to PG&E's application. Of note, South San Joaquin Irrigation District filed a Protest arguing that PG&E's regionalization effort should not create a moratorium or interfere with municipalization efforts. In addition, five CCAs filed responses or protests to PG&E's application, with MCE and EBCE filing protests and City of San Jose, City and County of San Francisco, and Pioneer Community Energy filing responses. CCA responses/protests sought more information on the implications of regionalization on CCA customers, CCA operations, and CCA-PG&E coordination; PG&E's overarching purpose, goals, and metrics to judge success of regionalization; the delineation between centralized and

decentralized functions in PG&E's application; and budgets and cost recovery related to regionalization, among other issues. CCAs also identified various concerns specific to their CCAs (e.g., EBCE's and MCE's service areas would both be split across two PG&E regions; SJCE expressed concern with its service area being assigned to the Central Coast region; Pioneer expressed concern that it would be the only CCA in its region, which would be the only region not to be "anchored" by an urban area). PG&E's reply defended the sufficiency of its application, stated that it will supply more details on the impacts of its regionalization plan through discovery and workshops, agreed with SJCE's proposal on extending the procedural schedule, and noted that its proposal is a starting point and will be modified to reflect feedback.

- **Analysis**: As noted in the responses and protests of CCAs, the implications of PG&E's regionalization plan on CCA operations, customers, and costs is largely unclear based on the information presented in PG&E's application. PG&E's regionalization plan could impact PG&E's responsiveness and management of local government relations and local and regional issues, such as safety, that directly impact VCE customers beginning in 2021. As part of Region 1, VCE would be grouped with several coastal and northern counties.
- **Next Steps**: A scoping memo and ruling is expected to be issued next to establish the scope and schedule of this proceeding. PG&E must engage its Regional Vice Presidents and Regional Safety Directors by June 1, 2021.
- **Additional Information**: Ruling setting prehearing conference (August 5, 2020); Application (June 30, 2020); A.20-06-011.

Investigation of PG&E Bankruptcy Plan

On September 17, 2020, the ALJ issued a Proposed Decision that would close this proceeding.

- **Background**: This case addressed regulatory review and approval of PG&E's bankruptcy plan, in particular whether the plan meets the AB 1054 Wildfire Fund requirements, which imposes a June 30, 2020 deadline. Under AB 1054, in order for PG&E to be eligible to participate in the Wildfire Fund, its plan must be "neutral, on average, to ratepayers." This proceeding considered the ratemaking implications of the proposed plan and settlement agreement, whether the plan satisfactorily resolves claims for monetary fines of penalties for PG&E's pre-petition conduct, whether to approve the governance structure of the utility and the appropriate disposition of potential changes to PG&E's corporate structure and authorization to operate, whether to make any other approvals related to the confirmation and implementation of the plan, and any other findings necessary to approve a proposed settlement, including but not limited to whether doing so is in the public interest.

  D.20-05-053 approved the financial elements of PG&E's reorganization plan, including:

  1. $13.5 billion Fire Victim Trust. The reorganization plan also specifies that the Fire Victim Trust would be funded through $6.75 billion in cash, and $6.75 billion in stock of reorganized PG&E Corp.
  2. $11 billion settlement with insurance claim holders and companies.
  3. Reinstatement of $9.575 billion in existing, prepetition PG&E-funded debt claims.
  4. Refinancing of $11.85 billion in existing, prepetition PG&E debt with newly issued debt.
  5. Payment in full of general unsecured claims and certain other liabilities, with interest at the legal rate.
  6. A $7.5 billion post-emergence 30-year securitization transaction.

  D.20-05-053 also approved, with modifications, numerous proposals put forth by CPUC President Batjer for providing more oversight of PG&E along with management and operational changes at PG&E. The Decision did not address the Joint CCAs' recommendation that the CPUC develop a plan to phase out PG&E's retail electric generation service to customers or CCA requests that the CPUC require PG&E to undertake asset sales, instead determining that the PG&E Safety Culture proceeding (I.15-08-019) is the more appropriate forum for these issues. The Decision also rejected the Joint CCAs' request to revoke PG&E's existing holding company structure. Among other determinations, the Decision:

7. Requires that PG&E implement regional restructuring, resulting in local PG&E operating regions led by an officer of the utility that reports directly to the CEO. PG&E is required to file an application for regionalization by June 30, 2020.
8. Requires PG&E to have a separate Chief Risk Officer (CRO) and Chief Safety Officer (CSO). It establishes an Independent Safety Monitor that would functionally act in the same capacity as the federal court monitor after the termination of the federal monitor. The details on implementing the Independent Safety Monitor would be determined in the future.
9. Clarifies and expands the authority of the Safety and Nuclear Oversight (SNO) Committees of PG&E's boards of directors (e.g., the SNO Committees would have oversight over PG&E's Wildfire Mitigation Plan and PSPS program, among others).
10. Provides for the establishment of additional requirements applicable to the boards of directors of PG&E and PG&E Corp., but allows their membership to remain largely the same.
11. Finds that PG&E may not seek cost recovery for 2017/2018 wildfire claims except via the proposed securitization.
12. Declines to adopt a safety-based earnings adjustment mechanism, but it will continue to be considered it in the future, either in the PG&E Safety Culture proceeding (I.15-08-019) or another proceeding.
13. Requires PG&E to reimburse the CPUC for, and bar cost recovery on, various costs the CPUC incurred for outside expertise in relation to the Chapter 11 bankruptcy cases.
14. Adopt an Enhanced Oversight and Enforcement process for PG&E, revised and detailed in Appendix A, designed to provide a clear roadmap for how the CPUC will closely monitor PG&E's performance. The proposal specifies various steps that PG&E could progress through if repeatedly found to be non-compliant, with the last step being a review and possible revocation of its certificate of public convenience and necessity.

- **Details**: Issues that were brought up but not resolved in this proceeding can be addressed in the PG&E Safety Culture proceeding (I.15-08-019), although that proceeding is now only monitoring PG&E's progress in this area.
- **Analysis**: D.20-05-053 provided the CPUC's approval for allowing PG&E to emerge from bankruptcy under PG&E's reorganization plan, with some additional changes required to its operations, management, and oversight, although keys aspects of requirements related to regionalization and the independent monitor remain to be determined in the future. The Decision excluded consideration of municipalization issues and did not address VCE's bid to PG&E to purchase the transmission and distribution assets of PG&E as part of PG&E's restructuring, along with other proposals for more significant reforms of PG&E's structure and operations.
- **Next Steps**: Comments are due October 7, 2020, replies are due October 12, 2020, and the PD may be heard, at the earliest, at the CPUC's October 22, 2020, meeting.
- **Additional Information**: Ruling (July 15, 2020); D.20-05-053 (June 1, 2020); PG&E Motion for official notice and Plan of Reorganization (March 24, 2020); Order Instituting Investigation (October 4, 2019); Docket No. I.19-09-016.

Investigation into PG&E Violations Related to Wildfires

No updates this month. On June 8, 2020, Thomas Del Monte and the Wild Tree Foundation filed applications for rehearing of D.20-05-019, which approved penalties on PG&E for its role in igniting the 2017-2018 wildfires.

- **Background**: The scope of the proceeding included violations of law by PG&E with respect to the 2017 and 2018 wildfires, including the 2017 Tubbs Fire and the 2018 Camp Fire, what penalties should be assessed, what remedies or corrective actions should occur, and what if any systemic issues contributed to the ignition of the wildfires. SED issued a Fire Report on June 13, 2019 that found deficiencies in PG&E's vegetation management practices and procedures and equipment operations in severe conditions. CAL FIRE also found that PG&E's electrical facilities ignited all but one of the fires addressed in this investigation. This investigation ordered PG&E to take immediate corrective actions to come into compliance with CPUC requirements.

  The terms of the Settlement Agreement between PG&E, SED, the CPUC's Office of the Safety Advocate, and CUE would have resulted in $1.675 billion in PG&E penalties. Specifically, PG&E would not have been permitted seek rate recovery of wildfire-related expenses and capital expenditures totaling $1.625 billion. In addition, PG&E would have been required to spend $50 million in shareholder-provided settlement funds on specified System Enhancement Initiatives.

  The Presiding Officer's Decision provided for penalties on PG&E totaling $2.137 billion. The total included an increase of $198 million in the disallowances for wildfire-related expenditures that was provided in the Settlement Agreement. It also increased PG&E's System Enhancement Initiatives and corrective actions by $64 million and added a $200 million fine payable to the General Fund. In total, these changes increased PG&E's penalties by $462 million relative to the Settlement Agreement. The Presiding Officer's Decision also required any tax savings associated with the shareholder payments under the settlement agreement, as modified by this decision, to be returned to the benefit of ratepayers.

  D.20-05-019 approved with modifications the Settlement Agreement, as provided in Commissioner Rechtschaffen's "Decision Different." It approved penalties totaling $2.137 billion, however the $200 million fine payable to the General Fund is permanently suspended, resulting in an effective penalty total of $1.937 billion. In addition, the decision required any tax savings associated with the shareholder obligations for *operating expenses* under the Settlement Agreement (but not tax savings associated with capital expenditures, in order to avoid any potential legal conflict with IRS normalization rules) to be returned to the benefit of ratepayers in PG&E's next GRC. Finally, the decision rejected PG&E's attempt to classify the $200 million fine as a Fire Victim Claim or Fire Claim.

- **Details**: The Wild Tree Foundation and Thomas Del Monte each filed Applications for Rehearing (attached) of D.20-05-019, which approved penalties on PG&E for its role in igniting the 2017-2018 wildfires. The Applications for Rehearing both challenge the permanent suspension of the $200 million fine imposed on PG&E, as well as other aspects of the settlement that was approved with modifications.

- **Analysis**: D.20-05-019 resulted in the largest penalty in CPUC history. It required additional spending by PG&E to mitigate future wildfire risk, potentially positively impacting the quality of service experienced by VCE customers. The decision did not hinder PG&E's reorganization plan from moving forward, whereas PG&E had argued that provisions in the original Presiding Officer's Decision could have imperiled the plan.

- **Next Steps**: The applications for rehearing are the only remaining items in this proceeding.

- **Additional Information**: Thomas Del Monte Application for Rehearing (June 8, 2020); Wild Tree Foundation Application for Rehearing (June 8, 2020); D.20-05-019 (May 8, 2020); Decision Different of Commissioner Rechtschaffen (April 20, 2020); Motion by Commissioner Rechtschaffen (March 27, 2020); Presiding Officer's Decision approving the settlement agreement with modifications (February 27, 2020); Joint Motion for Approval of Settlement Agreement (December 17, 2019); Amended Scoping Memo and Ruling (October 28, 2019); GO

95 Rule 31.1; GO 95 Rule 35; GO 95 Rule 38; Order Instituting Investigation (June 27, 2019); Docket No. I.19-06-015.

Wildfire Cost Recovery Methodology Rulemaking

No updates this month. An August 7, 2019, PG&E Application for Rehearing remains pending regarding the CPUC's recent Decision establishing 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 (D.19-06-027).

- **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."

  D.19-06-027 found 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 requires 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.

  PG&E's application for rehearing challenges the CPUC's prohibition on applying the Stress Test to utilities like itself that have filed for Chapter 11 bankruptcy. PG&E's rationale is that SB 901 requires the CPUC to determine that the stress test methodology to be applied to all IOUs. Several parties filed responses to PG&E's application for rehearing disagreeing with PG&E.
- **Details**: N/A.
- **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**: The only matter remaining to be resolved in this proceeding is PG&E's application for rehearing. This proceeding is otherwise closed.
- **Additional Information**: PG&E Application for Rehearing (August 7, 2019); D.19-06-027 (July 8, 2019); Assigned Commissioner's Ruling releasing Staff Proposal (April 5, 2019); Scoping Memo and Ruling (March 29, 2019); Order Instituting Rulemaking (January 18, 2019); Docket No. R.19-01-006. *See also* SB 901, enacted September 21, 2018.

Glossary of Acronyms

AB	Assembly Bill
AET	Annual Electric True-up
ALJ	Administrative Law Judge
BioMAT	Bioenergy Market Adjusting Tariff
BTM	Behind the Meter

CAISO	California Independent System Operator
CAM	Cost Allocation Mechanism
CARB	California Air Resources Board
CEC	California Energy Commission
CPE	Central Procurement Entity
CPUC	California Public Utilities Commission
CPCN	Certificate of Public Convenience and Necessity
CTC	Competition Transition Charge
DA	Direct Access
DWR	California Department of Water Resources
ELCC	Effective Load Carrying Capacity
ERRA	Energy Resource and Recovery Account
EUS	Essential Usage Study
GRC	General Rate Case
IEPR	Integrated Energy Policy Report
IFOM	In Front of the Meter
IRP	Integrated Resource Plan
IOU	Investor-Owned Utility
ITC	Investment Tax Credit
LSE	Load-Serving Entity
MCC	Maximum Cumulative Capacity
OII	Order Instituting Investigation
OIR	Order Instituting Rulemaking
PABA	Portfolio Allocation Balancing Account
PD	Proposed Decision
PG&E	Pacific Gas & Electric
PFM	Petition for Modification
PCIA	Power Charge Indifference Adjustment
PSPS	Public Safety Power Shutoff
PUBA	PCIA Undercollection Balancing Account
QC	Qualifying Capacity
RA	Resource Adequacy
RDW	Rate Design Window
ReMAT	Renewable Market Adjusting Tariff
RPS	Renewables Portfolio Standard
SCE	Southern California Edison
SED	Safety and Enforcement Division (CPUC)

SDG&E	San Diego Gas & Electric
TCJA	Tax Cuts and Jobs Act of 2017
TOU	Time of Use
TURN	The Utility Reform Network
UOG	Utility-Owned Generation
WMP	Wildfire Mitigation Plan
WSD	Wildfire Safety Division (CPUC)