VALLEY CLEAN ENERGY ALLIANCE

Staff Report – Item 7

To: Board of Directors

From: Mitch Sears, Interim General Manager

Subject: Regulatory Monitoring Report – Keyes & Fox

Date: March 11, 2021

Please find attached Keyes & Fox's January 2021 Regulatory Memorandum dated March 3, 2021, 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 March 3, 2021

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:	March 3, 2021

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:

- **New: PG&E's 2020 ERRA Compliance:** PG&E filed its 2020 ERRA Compliance application and testimony.
- **IRP Rulemaking:** On February 22, 2021, the ALJ issued a Ruling providing the results of staff's analysis on mid-term reliability and proposing a new procurement mandate that would be allocated across LSEs of 7,500 MW by 2025. The CPUC also issued D.21-02-028, recommending electricity resource portfolios to CAISO to study in its 2021-2022 Transmission Planning Process (TPP).
- **Ensuring Summer 2021 Reliability:** Parties filed opening and reply briefs on February 5, 2021, and February 12, 2021, respectively. The IOUs submitted advice letters providing contracts for their additional procurement on February 16, 2021. D.21-02-028, which formalized the requirement for IOUs to conduct the additional procurement to address summer 2021 reliability was issued on February 17, 2021. A proposed decision on the remaining issues in this proceeding is anticipated to be issued soon.
- **RPS Rulemaking:** VCE and other retail sellers submitted their Final 2020 RPS Procurement Plans.
- **RA Rulemaking (2021-2022):** The ALJ issued a Ruling providing Energy Division's Track 4 proposal. The Energy Division held workshops on Track 3B.1, Track 3B.2, and Track 4 proposals. CalCCA filed a Protest of PG&E's Advice Letter 6078-E, which proposes that Energy Division approve the Central Procurement Entity Procurement Plan (PP).
- **PG&E's Phase 2 GRC:** The Assigned Commissioner issued a Scoping Memo and Ruling that modifies the scope and procedural schedule to accommodate real-time pricing (RTP) issues being separated into a separate proceeding track. Rebuttal testimony was due February 23, 2021.

- **PCIA Rulemaking:** Parties filed reply comments in response to the questions provided by the Commission with regard to whether the PCIA rate cap should be eliminated (no party opposed doing so) and process changes that should be made to the ERRA Forecast cases.
- **PG&E Regionalization Plan**: PG&E filed its updated regionalization proposal on February 26, 2021. The updated regionalization plan moves Yolo country from Region 1 to Region 2, where it would be grouped with other northern counties, but would no longer be grouped with coastal counties.
- **Direct Access Rulemaking**: No updates this month. On October 16, 2020, and October 26, 2020, respectively, parties filed comments and replies in response to the ALJ Ruling providing a Staff Report and recommendation to the Legislature regarding a potential additional expansion of direct access for nonresidential customers.
- **RA Rulemaking (2019-2020):** No updates this month. Two applications for rehearing remain the only outstanding items to be addressed in this proceeding, which is now closed.
- **Investigation into PG&E's Organization, Culture and Governance:** No updates this month. On November 24, 2020, CPUC President sent a letter to PG&E indicating that she has directed CPUC staff to conduct fact-finding to determine whether to recommend that PG&E be placed into the enhanced oversight and enforcement process.
- **PG&E's 2019 ERRA Compliance:** No updates this month. On November 16, 2020, Joint CCAs and PG&E filed reply briefs on remaining issues not addressed in the pending Settlement Agreement.
- **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.
- **Other Notable Regulatory Updates**:
    - **CPUC Holds Electric Rates En Banc, Issues White Paper:** The CPUC published a white paper and held an En Banc to discuss electric and gas cost and rate trends over the next decade. The white paper finds that since 2013, PG&E's rates have increased by 37%. The paper's 10-year baseline forecast shows steady growth in customer rates (nominal $/kWh) between 2020 and 2030 for the three IOUs, with PG&E's rates forecasted to increase from $0.240/kWh to $0.329/kWh, or about an annual average increase of 3.7%.
    - **PG&E Advice Letter 6090-E and 6090-E-A on Rate Changes:** PG&E filed its advice letter to update its electric rates and tariffs effective March 1, 2021 to implement various revenue requirement and rate design changes approved in PG&E's 2020 General Rate Case Phase 1 Decision D.20-12-005. PG&E will be transitioning Commercial and Industrial and Agricultural customers to the new mandatory Time-of-Use electric rate schedules with later peak hours. PG&E is also modifying the legacy C&I and Agricultural rate schedules to implement revised TOU period rate differentials and rate design changes, which the utility says were approved by D.18-08-013 in PG&E's 2017 GRC Phase II and D.19-05-010 in PG&E's 2019 Rate Design Window.
    - **PG&E Application to Issue $1.2 Billion in Recovery Bonds and Nonbypassable Charge:** On February 24, 2021, PG&E filed an Application requesting authority to issue Wildfire Hardening Recovery Bonds up to a total principal amount of approximately $1.2 billion, to recover fire risk mitigation capital expenditures that have been or will be incurred by PG&E in 2020 and 2021. PG&E would recover these costs by creating a nonbypassable Wildfire Hardening Fixed Recovery Charge.
    - **2022 and 2023 Wildfire Fund Nonbypassable Charge Rulemaking:** The CPUC is expected to vote at its March 4 meeting to open a new rulemaking that will determine the Wildfire Fund Nonbypassable Charge for 2022 and 2023. A prehearing conference is

expected in April. More details on this new rulemaking will be included in next month's regulatory memo.

  - **Draft Resolution Invoking Step 1 of Enhanced Oversight and Enforcement Process on PG&E:** The CPUC issued draft Resolution M-4852 that, if approved, would invoke Step 1 of the Enhanced Oversight and Enforcement Process for PG&E, which requires "enhanced reporting." It finds that PG&E has made insufficient progress with risk-driven wildfire mitigation efforts and would require PG&E to submit a Corrective Action Plan within 20 days of the Resolution effective date. Comments on the draft resolution are due March 17, and it will be on the agenda at the April 15 Commission meeting.

    More specifically, the draft resolution would find that PG&E is not sufficiently prioritizing its Enhanced Vegetation Management (EVM) based on risk. PG&E ranks its power line circuits by wildfire risk, but the work performed in 2020 demonstrates that PG&E is not making risk-driven investments, according to the draft resolution. It finds that PG&E is not doing the majority of EVM work – or even a significant portion of work – on the highest risk lines. The draft resolution would also require that every 90 days following service of the Corrective Action Plan described above, PG&E would be required to serve a report updating the information required in the Corrective Action Plan until the Commission issues a Resolution or other communication providing otherwise.

New: PG&E 2020 ERRA Compliance

On March 1, 2021, PG&E filed its 2020 ERRA Compliance application.

- **Background**: The annual ERRA Compliance proceeding reviews the utility's compliance with CPUC-approved standards for generation-procurement and cost recovery activity occurring in the preceding year, such as energy resource contract administration, least-cost dispatch, fuel procurement, and balancing account entries.
- **Details**: PG&E is requesting that the CPUC find it complied with its Bundled Procurement Plan (BPP) in the areas of fuel procurement, administration of power purchase contracts, greenhouse gas compliance instrument procurement, resource adequacy sales, and least-cost dispatch of electric generation resources for the 2020 calendar year. It also seeks a CPUC finding that it managed its utility-owned generation (UOG) facilities reasonably, although it recommends that CPUC review of outages at Diablo Canyon Power Plant related to the Unit 2 main generator be delayed to the 2021 ERRA Compliance review. Of significance to the PCIA, PG&E is requesting the CPUC find that entries in its Portfolio Allocation Balancing Account (PABA), which trues up the above-market forecast of generation resources recovered through the PCIA with actual recorded costs and revenues, are accurate.

  PG&E's procurement costs recorded across the portfolio were $158.8 million higher than forecasted, primarily due to higher-than-forecast RPS-eligible contracts, as offset by higher than forecast retained RPS and retained RA, as well as lower than forecast fuel costs for UOG facilities. Activity recorded in the PABA includes the following categories: Revenues from Customers, RPS Activity, RA Activity, Adopted UOG Revenue Requirements, CAISO Related Charges and Revenues, Fuel Costs, Contract Costs, GHG Costs, and Miscellaneous Costs. PG&E has redacted as confidential its 2020 actual and forecast costs for these categories, so it is unclear from the public filing what the magnitude is regarding the difference between actual and forecast costs for each category.
- **Analysis**: This proceeding addresses PG&E's balancing accounts, including the PABA, providing a venue for a detailed review of the billed revenues and net CAISO revenues PG&E recorded during 2020. It also determines whether PG&E managed its portfolio of contracts and UOG in a reasonable manner. Both issues could impact the level of the PCIA in 2022.
- **Next Steps**: Protests and responses will be due 30 days after this application is noticed in the CPUC's daily calendar. (As of March 3, 2021, it had not been.) PG&E has proposed a schedule

that incudes a prehearing conference on May 6, 2021, CalAdvocates/intervenor testimony on July 12, 2021, and proposed and final decisions issued in Q1 2022.

- **Additional Information**: Application (March 1, 2021); Docket No. A.21-03-___(TBD).

IRP Rulemaking

On February 17, 2021, the CPUC issued D.21-02-028, recommending electricity resource portfolios to CAISO to study in its 2021-2022 Transmission Planning Process (TPP). On February 22, 2021, the ALJ issued a Ruling providing the results of staff's analysis on mid-term reliability and proposing a new procurement mandate that would be allocated across LSEs of 7,500 MW by 2025.

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

  The September 24 Scoping Memo and Ruling clarifies that the issues planned to be resolved into this proceeding are organized into the following tracks:

  - General IRP oversight issues: This track will consider moving from a two-year to a three-year IRP cycle, IRP filing requirements, and interagency work implementing SB 100.
  - Procurement track: The CPUC is examining LSE plans to replace Diablo Canyon capacity and has conducted an overall assessment and gap analysis to inform a procurement order that could direct LSEs to procure additional capacity (see February 22 Ruling described below). 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.
  - Preferred System Portfolio Development: The CPUC will aggregate LSE portfolios, analyze the aggregate portfolio, and adopt a PSP.
  - TPP: *Completed*. D.21-02-028 transmitted portfolios to the CAISO for use in its TPP analysis.
  - 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.

  D.20-12-044 established a backstop procurement process that would apply to LSEs that did not opt-out of self-procuring their capacity obligations under D.19-11-016. It requires LSEs to file bi-annual (due February 1 and August 1) updates of their procurement progress relative to the contractual and procurement milestones defined in the decision. After review of the compliance filings, CPUC Staff will bring a Resolution before the Commission specifying the amount of backstop procurement required for a particular IOU on behalf of each LSE for each procurement tranche (2021, 2022, and 2023).

- **Details**: The February 22 Ruling presents the results of analysis by Commission staff of the need for electric system reliability resources out to 2026, taking into consideration both the reliability issues experienced in August 2020 as well as the forthcoming retirement of Diablo Canyon. The Ruling proposes mandating that LSEs procure 7,500 MW of effective capacity additions by 2025. Of that total, at least 1,000 MW would be required to come from geothermal resources and 1,000 MW would be required to come from long-duration storage (defined as providing 8 hours of storage or more). The Ruling would allocate individual LSE procurement requirements by using each LSE's (as reported in the LSE's 2020 IRP). The CPUC would calculate each LSE's load and resource balance (based on an LSE's existing resources and those in development as of June

30, 2020) for each year through 2026 to determine their resource shortfall, if any, and then apportion their responsibility for the overall procurement need based on that shortfall relative to that of the other LSEs. All LSEs would be required to procure their share of additional resources (i.e., there is no option for LSEs to opt-out and have the IOUs procure on their behalf, for example), and there would be a noncompliance penalty set at the cost of new entry (CONE), plus the LSE would be responsible for the costs of backstop procurement. For compliance purposes, eligible resources would be those that are contracted and approved by VCE's board after June 30, 2020. However, a compliant resource may not also be used to satisfy an LSE's procurement obligation under D.19-11-016.

Table 3. Total Recommended Mid-Term Procurement Requirements (in NQC MW)

Type of Resource	2023	2024	2025	Total
Geothermal resources	-	-	1,000	1,000
Long-duration storage resources	-	-	1,000	1,000
Any type of resource	1,800	3,700	-	5,500
Total	1,800	3,700	2,000	7,500

D.21-02-028 recommended the following electricity resource portfolios to CAISO to study in its 2021-2022 TPP:

- <u>Base case portfolio, for both reliability and policy-driven purposes, to be used to determine transmission investments needed:</u> a portfolio that meets a 46 million metric ton (MMT) greenhouse gas (GHG) emissions target in 2031, with additional pumped storage and out-of-state renewables included compared to the portfolio adopted in D.20-03-028, which adopted the Reference System Portfolio used by LSEs in 2020 IRPs. (Numerous parties, including CalCCA, advocated for the Commission to use a lower 38 MMT GHG emissions target case for 2030 as the base case.) This base case portfolio includes approximately 9 GW of new battery storage, 16 GW of new in-state renewables, 1 GW of out-of-state renewables, and geothermal and pumped storage resources.
- <u>Two sensitivity portfolios, for study purposes:</u> (1) A portfolio that meets a 38 MMT GHG emissions target in 2031. This portfolio includes approximately 19 GW of new in-state renewables, over 9 GW of new battery storage, and 3 GW of out-of-state renewables. (2) A portfolio that includes a large segment of offshore wind, to improve the transmission assumptions relevant to offshore wind for the benefit of future planning.
- <u>Resource-to-busbar mapping methodology:</u> Includes improvements to the initial recommended methodology to prioritize siting of preferred resources, especially battery storage, in disadvantaged communities and/or local capacity areas with poor air quality.

- **Analysis**: The Ruling's proposal for a new 7,500 MW by 2025 procurement mandate could impose a new procurement obligation and associated compliance obligations on VCE. To the extent VCE is allocated a share of the obligation, it would have to procure a portion of its requirement from long-duration storage and geothermal resources. D.21-02-028 could impact future transmission development and access to and availability of new resources.
- **Next Steps**: The schedule is as follows:
  - <u>General IRP oversight issues:</u> A Proposed Decision on moving from two-year to three-year IRP cycle is anticipated to be issued soon.
  - <u>Procurement track:</u> Comments on the February 22 Ruling proposing a 7,500 MW by 2025 procurement mandate are due March 19, 2021, and replies are due April 2, 2021.
  - <u>Preferred System Portfolio Development:</u> A workshop on a reconciled portfolio aggregation of all LSE IRPs is anticipated for Q1 2021.

- **Additional Information**: Ruling on staff reliability analysis and 7,500 MW by 2025 procurement mandate (February 22, 2021); D.21-02-028 recommending portfolios for CAISO's 2021-2022 TPP (February 17, 2021); D.20-12-044 establishing a backstop procurement process (December 22, 2020); Ruling requesting comments on IRP evaluation (December 8, 2020); Ruling providing Staff Proposal on resource procurement framework (November 19, 2020); Email Ruling requesting comments on individual LSE IRPs (October 9, 2020); 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.

Ensuring Summer 2021 Reliability

Parties filed opening and reply briefs on February 5, 2021, and February 12, 2021, respectively. The IOUs submitted advice letters providing contracts for their additional procurement on February 16, 2021. D.21-02-028, which formalized the requirement for IOUs to conduct the additional procurement to address summer 2021 reliability was issued on February 17, 2021. A proposed decision on the remaining issues in this proceeding is anticipated to be issued soon.

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

  The Scoping Memo and Ruling identified two primary issues as in scope: (1) how to increase energy supply and (2) decrease demand during the peak demand and net demand peak hours in the event that a heat storm similar to the August 2020 storm occurs in the summer of 2021. This OIR is focused on actions that the Commission can adopt by April 2021 and that the parties can implement before the summer of 2021. With respect to increasing supply during peak and net peak demand hours, this proceeding is considering: (1) expedited procurement that could be online by summer 2021 and 2022, including the expansion of gas-fired generation assets; (2) a potential mechanism to update the RA requirements for summer 2021; (3) potential support for the CAISO's CPM to procure additional capacity for summer 2021; (4) stack analysis of resource availability and needs for summer 2021; (5) expedited LSE IRP procurement; and (6) other opportunities to increase supply for summer 2021. To reduce demand during peak and net peak demand hours, this proceeding will consider: (1) Flex Alert paid media and social media; (2) Critical Peak Pricing; (3) out-of-market and outside of the RA framework emergency load reduction program; (4) modifications to the reliability demand response programs, including Base Interruptible Program, Agriculture Pump Interruptible, and Air Conditioner cycling; (5) modifications to Proxy Demand Resources such as the Capacity Bidding Program; (6) other considerations for Demand Response Resources; (7) electric vehicle load; and (8) other opportunities to reduce peak demand and net peak demand hours in summer 2021.

  VCE's opening testimony provided its proposal for an Agricultural AutoDR Demand Flexibility Pilot, which could made available to customers on irrigation pumping tariffs.

- **Details**: D.21-02-028 did not address approaches for decreasing demand to improve reliability, including VCE's suggestion, which will be separately considered in a proposed decision anticipated to be issued in March. D.21-02-028 directed IOU procurements for capacity that is available to serve peak and net peak demand in the summer of 2021 on behalf of all customers with the costs and benefits allocated to benefitting customers through the existing Cost Allocation Mechanism (CAM).

  Accordingly, PG&E requested approval of its share of the additional procurement through two advice letters. PG&E AL 6088-E included 10 contracts for 135.3 MW, with nine contracts relating to incremental energy through increased exports via one or a combination of (1) the reduction of host load (for Combined Heat and Power resources) or (2) increased output above what would otherwise be scheduled or contractually allowed. The tenth agreement was a contract amendment that secured incremental energy supply in peak and net peak periods. PG&E AL 6089-E requested approval of two contracts for 250 MW for Firm Forward Imported Energy for summer 2021.

- **Analysis**: The forthcoming proposed decision in this proceeding addressing remaining issues could result in CPUC directives that could encourage VCE and others to take additional actions that result in greater resource availability or load reduction during the summer 2021 peak and net peak periods. This PD could address VCE's proposed Agricultural AutoDR Demand Flexibility Pilot. D.21-02-028 will indirectly affect VCE customers, as VCE customers along with other benefitting customers will be allocated costs through CAM from PG&E's procurement. As the focus of this proceeding is on summer 2021 reliability, the final order will be issued by April 2021 and implemented quickly thereafter.
- **Next Steps**: The proposed decision will be issued in early to mid-March, followed by the issuance of a final decision in March or April.
- **Additional Information**: D.21-02-028 directing IOUs to seek additional capacity for summer 2021 (February 17, 2021); PG&E AL 6089-E and AL 6088-E on summer 2021 capacity procurement (February 16, 2021) Assigned Commissioner's Ruling directing IOU contracts for additional capacity (December 28, 2020); Scoping Memo and Ruling (December 21, 2020); ALJ Ruling and Staff Proposal (December 18, 2020); Order Instituting Rulemaking (November 20, 2020); Docket No. R.20-11-003.

RPS Rulemaking

On February 19, 2021, VCE and other retail sellers submitted their Final 2020 RPS Procurement Plans.

- **Background**: This proceeding addresses ongoing RPS issues. VCE submitted its Draft 2020 RPS Procurement Plan on July 6, 2020, and its 2019 RPS Compliance Report on August 3, 2020.

  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).
- **Details**: D.21-01-005, issued in January, praised VCE's draft 2020 RPS Procurement Plan, pointing to it as a "best example" or "best practice" in seven sections of the Plan for other LSEs to emulate in their updates. D.21-01-005 also identified several areas for VCE and most other LSEs to update or modify in its Final 2020 RPS Procurement Plan, which VCE completed through its February 19, 2021 submission. In addition to updating its Plan with the status of its RPS contracting, VCE's Final 2020 RPS Procurement Plan included substantive updates to its discussions of its minimum margin of over-procurement and safety/decommissioning considerations in line with the direction of D.21-01-005.
- **Analysis**: The submission of the Final 2020 RPS Procurement Plan completes the 2020 RPS Plan process. Based on prior years, the ALJ is expected to issue a ruling in spring of 2021 that provides the requirements for the 2021 RPS Procurement Plan, which is expected to be due this summer. The 2020 RPS Compliance Report will be due August 1, 2021.

  Other issues to be addressed in this proceeding could further impact future RPS compliance obligations.
- **Next Steps**: A PD aligning RPS and IRP filings is anticipated to be issued soon, followed by an opportunity for comments and reply comments. Both the 2021 RPS Procurement Plan (TBD) and the 2020 RPS Compliance Report (August 1) are expected to be due this summer.

- **Additional Information**: D.21-01-005 directing retail sellers to file final 2020 RPS Procurement Plans (January 20, 2021); Order Granting Rehearing of D.17-08-021 (November 23, 2020); D.20-10-005 resuming and modifying the ReMAT program (October 16, 2020); 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); VCE Motion to Update its 2020 RPS Procurement Plan (August 12, 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); D.19-02-007 (February 28, 2019); Scoping Ruling (November 9, 2018); Docket No. R.18-07-003.

RA Rulemaking (2021-2022)

On February 1, 2021, the ALJ issued a Ruling providing Energy Division's Track 4 proposal. The Energy Division held workshops on February 8-10, 2021 on Track 3B.2 proposals and on February 25, 2021, on proposals in Tracks 3B.1 and 4. On February 18, 2021, CalCCA filed a Protest of PG&E's Advice Letter 6078-E, which proposes that Energy Division approve the Central Procurement Entity (CPE) Procurement Plan (PP).

- **Background**: This proceeding is divided into 4 tracks. The first two tracks have concluded, and the proceeding is now focused on Track 3B.1, 3B.2, and Track 4 issues, described in more detail below. Track 3B.1 is considering incentives for LSEs that are deficient in year-ahead RA filings, refinements to the MCC buckets adopted in D.20-06-031, and other time-sensitive issues. Track 3B.2 includes examination of the broader RA capacity structure to address energy attributes and hourly capacity requirements. Track 4 is considering the 2022 program year requirements for System and Flexible RA, and the 2022-2024 Local RA requirements.

  D.20-12-006 addressed the issues of the financial credit mechanism and competitive neutrality rules for the CPEs. It approved CalCCA's proposed "Option 2," with modifications, which allows the CPE to evaluate the shown resource alongside bid resources to assess the effectiveness of the portfolio. The financial credit mechanism will apply only to new preferred or energy storage resources (i.e., non-fossil-based resources) with a contract executed on or after June 17, 2020. It also adopted PG&E's competitive neutrality proposal for PG&E's service territory. Finally, D.20-12-006 found that the Local Capacity Requirements Working Group should continue to discuss recommendations and develop solutions for consideration in CAISO's 2022 LCR process.

- **Details**: Energy Division's Track 4 proposals include the following, among others:
    - Maximum Cumulative Capacity (MCC) Buckets: All MCC Buckets would be adjusted to require availability Monday through *Saturday* (currently, only Monday through Friday is required for DR resources). This would require updates to some demand response programs. The minimum availability of MCC Category 1 resources would be increased from 40 to 100 hours per month between 4:00 and 9:00 pm and apply year-round. To reduce complexity, Staff also propose to eliminate MCC Category 2. This bucket is rarely used as there are few resources that are available for eight, but not sixteen, hours per day.
    - Marginal Effective Load Carrying Capability (ELCC) for New Solar Contracts: Staff propose that all solar resources that reach COD after December 31, 2020 receive a QC value of 0, i.e., they would not be able to provide any RA compliance benefits. However, resources that reach COD in 2021 or later that were contracted before the date of the Track 4 decision would receive the average ELCC if they provide evidence of the date the contract was signed to CPUC staff.
    - Demand Response (DR) Adders: Staff posed a series of questions regarding DR adders.

- DR MCC Bucket: Staff recommends that the Commission further consider the cap on the DR bucket and requirements for DR resources and requests feedback on various options, such as lowering the 8.3% cap on DR resources in light of the performance of DR resources identified by the Root Cause Analysis.
- Revise the RA Penalty Structure: Staff wants to raise RA penalties for noncompliance. Staff requests feedback on an appropriate system RA penalty and whether the change should be made immediately for 2022 or gradually phased in.

CalCCA's protest of AL 6078-E was based on four grounds:

- PG&E argues erroneously that AB 57 does not apply to CPE procurement.
- The CPE PP lacks a process for "showing" local RA resource attributes for compensation under the Local Capacity Requirement Reduction Compensation Mechanism, as specified in D.20-12-006.
- The CPE PP provides no insight into the process for comparing shown resources with bid resources.
- The CPE PP does not define tools that will be used to enable the Peer Review Group and Independent Evaluator to ensure PG&E has complied with the competitive neutrality rules adopted in D.20-12-006.

- **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 (including removal of RA value for solar resources for projects with CODs after December 31, 2020 that are not under contract as of the date of the Track 4 decision), 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**: Track 3B.1: Comments on Track 3B.1 proposals are due March 12, 2021; reply comments are due March 26, 2021; and a Proposed Decision is expected May 2021.

  Track 3B.2: Comments on Track 3B.2 proposals are due March 12, 2021; reply comments are due March 23, 2021; and a Proposed Decision is expected May 2021.

  Track 4: Comments on Track 4 proposals are due March 12, 2021; reply comments are due March 26, 2021; and a Proposed Decision is expected May 2021.
- **Additional Information**: Ruling providing Energy Division's Track 4 proposal (February 1, 2021). Ruling and Addendum to Energy Division Issue Paper and Draft Straw Proposal for Consideration in Track 3B.2 of Proceeding R.19-11-009 (December 21, 2020); Scoping Memo and Ruling for Track 3B and Track 4 (December 11, 2020); D.20-12-006 on Track 3.A issues (December 4, 2020); 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); 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.

PG&E's Phase 2 GRC

On February 16, 2021, the Assigned Commissioner issued a Scoping Memo and Ruling that modifies the scope and procedural schedule to accommodate real-time pricing (RTP) issues being separated into a separate proceeding track. Rebuttal testimony was due February 23, 2021.

- **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.

  Joint CCAs' testimony recommended that:

  - PG&E present class- and vintage-specific PCIA rates on individual rate schedules, consistent with other NBCs for both bundled and unbundled customers.
  - The CPUC not allow PG&E to offer Economic Development Rate Generation rates below PG&E's Marginal Generation Cost of Service.
  - PG&E's E-ELEC offering should be analyzed further and refined in a proceeding that allows more detailed consideration in rate making.
  - The Commission adopt PG&E's proposal regarding minimum time-of-use rates such that no proposed retail rate is below the PCIA.
- **Details**: The Scoping Memo and Ruling issued in February targets a decision on non-RTP issues in October 2021, and a decision on RTP issues in March 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, though the JCCAs recommend in testimony that more transparency be reflected in utility tariffs. 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 could increase the cost VCE pays to PG&E for various services, to the extent VCE uses these services.
- **Next Steps**: PG&E supplemental testimony on RTP issues only is due March 29, 2021, with intervenor responsive testimony due May 28, 2021, and rebuttal testimony due July 30, 2021. An evidentiary hearing on non-RTP issues is scheduled for April 8-22, 2021, and the evidentiary hearing on RTP issues will occur in September 2021. Opening and reply briefs, respectively, on non-RTP issues are due May 20, 2021, and June 10, 2021. A CPUC decision on non-RTP issues is anticipated for October 2021, and a decision on RTP issues is anticipated in May 2022.

- **Additional Information**: Scoping Memo and Ruling (February 16, 2021); Ruling bifurcating RTP issues into separate track (February 2, 2021); PG&E Status Report (December 18, 2020); D.20-09-021 on EUS budget (September 28, 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.

PCIA Rulemaking

Parties filed reply comments in response to the questions provided in Attachment A of the Amended Scoping Memo and Ruling on February 5, 2021.

- **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**: The Amended Scoping Memo and Ruling added four issues to the scope of Phase 2 of this proceeding. CalCCA, direct access providers, CalAdvocates, TURN, and the utilities responded, as follows:
  - Should the Commission remove or modify the PCIA cap? No party opposed removing the rate cap.
  - Should the Commission modify deadlines or requirements of ERRA and PCIA related submittals and reports in order to increase time for parties to review PCIA data and to facilitate timely implementation of decisions in the ERRA proceedings? CalCCA and the utilities proposed competing modifications to allow more time for the ERRA forecast proceeding.
  - Should the Commission adopt a methodology for crediting or charging customers who depart from the utility service during an amortization period and who are responsible for a balance in the PCIA Undercollection Balancing Account, the Energy Resource Recovery Account, or any other bundled generation account? Both CalCCA and the utilities agreed such a mechanism should be developed, and both pointed to existing practices providing for such credits or charges.

- Should the Commission consider any other changes necessary to ensure efficient implementation of PCIA issues within ERRA proceedings? The utilities proposed a netting treatment used by SCE be adopted more broadly to avoid recurring ERRA trigger filings as well as the development of a REC tracking framework to track Retained RPS on a going-forward basis. CalCCA recommended the development of a non-docket specific non-disclosure agreement to increase transparency and, in turn, CCAs' ability to forecast where the PCIA is heading based on utility-specific (and currently confidential) data.

- **Analysis**: The 2021 PCIA rate will be implemented through the 2021 ERRA Forecast proceeding.
- **Next Steps**: A PD is anticipated to be issued in Q2 2021.
- **Additional Information**: Amended Scoping Memo and Ruling (December 16, 2020); CalCCA/DACC/AReM Protest of PG&E AL 5973-E (November 2, 2020); PG&E AL 5973-E (October 12, 2020); 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.

PG&E Regionalization Plan

PG&E submitted its updated regionalization proposal on February 26, 2021.

- **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. 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.

  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).

The October Scoping Memo and Ruling determined the scope of this proceeding will include examining (1) whether PG&E should be authorized to implement its Regionalization Proposal, as modified in this proceeding; (2) whether PG&E's proposed five regional boundaries are reasonable; (3) whether PG&E's proposals for regional leadership and a regional organizational structure are consistent with the Commission's direction; (4) whether PG&E's proposed implementation timeline for regionalization is reasonable; (5) whether PG&E's regionalization proposal is reasonable, including its impact on safety and its cost effectiveness; (6) the adequacy and completeness of PG&E's regionalization plan; (7) the process and timeline for regionalization, the cost of regionalization, the criteria to be used for identifying and delineating regions, and the division of responsibilities and decision-making between PG&E's central office and its regional offices; and (8) issues relating to potential cost recovery and the corresponding ratemaking treatment. The Scoping Memo and Ruling did not discuss how municipalization proposals would be impacted by PG&E's regionalization plan, which had been the subject of a Protest of PG&E's application filed by South San Joaquin Irrigation District.

- **Details**: PG&E's updated regionalization plan includes a number of modifications relative to their initial proposal. In response to feedback, PG&E modified its five regions (renamed North Coast, North Valley & Sierra, Bay Area, South Bay & Central Coast, and Central Valley), including moving Yolo County from Region 1 to Region 2 (North Valley & Sierra), where it would be grouped together with the following counties: Colusa, El Dorado, Glenn, Lassen, Nevada, Placer, Plumas, Sacramento, Shasta, Sierra, Solano, Sutter, Tehama, and Yuba. PG&E also provided more information on the new leadership positions that it is creating and its "Lean Operating System" implementation. Currently, PG&E is in Phase 1 of 3 of its regionalization plan, which is focused on refining regional boundaries, establishing roles and governance for regional leadership, and recruiting and hiring for those positions. In Phase 2 (second half of 2021 through 2022), PG&E will establish and implement the regional boundaries and provide the resources and staffing to support it. In Phase 3 (2023 and after), PG&E will continue to reassess, refine and collaborate with other functional groups to improve efficiencies, safety, reliability and customer service.
- **Analysis**: 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 and updated 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. It could also impact municipalization efforts, although this issue has not been explicitly addressed and remains unclear at this time. As part of Region 2, VCE would be grouped with several northern counties in central and eastern California.
- **Next Steps**: An updated, a workshop will be held March 3, 2021, comments are due April 2, 2021, and reply comments are due April 9, 2021. PG&E must engage its Regional Vice Presidents and Regional Safety Directors by June 1, 2021.
- **Additional Information**: PG&E Updated Regionalization Proposal (February 26, 2021); Ruling modifying procedural schedule (December 23, 2020); Scoping Memo and Ruling (October 2, 2020); Application (June 30, 2020); A.20-06-011.

Direct Access Rulemaking

No updates this month. On October 16, 2020, and October 26, 2020, respectively, parties filed comments and replies in response to the ALJ Ruling providing a Staff Report and recommendation to the Legislature regarding a potential additional expansion of direct access (DA) for nonresidential customers.

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

For Phase 2, 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 September 28, 2020 Ruling attached a Staff Report constituting the draft CPUC recommendations to the Legislature required by SB 237. The Staff Report recommends that the Legislature:

    - Not make a determination as to whether to further expand DA until at least 2024, after the conclusion of the 2021-24 RPS compliance period and the fulfillment of procurement ordered by D.19-11-016.
    - 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 ongoing compliance with IRP, RPS and RA requirements.
    - "[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."

  CalCCA's comments argued that the CPUC should add a condition for reopening DA that will foster attainment of state goals and ensure competitive neutrality for all LSEs. CalCCA recommended establishing a Phase 3, Track 1 process for further development of DA reopening conditions, including competitively neutral switching rules, rules governing CCA stranded cost recovery, clear compliance metrics, and ESP transparency measures. Furthermore, CalCCA recommended establishing a Phase 3, Track 2 to be implemented following the issuance of 2021-2024 Renewable Portfolio Standard (RPS) compliance reports to assess readiness for DA reopening.

  ESPs argued against delaying a Legislative determination on further DA reopening, for a faster pace of DA reopening, and that access to additional load should depend on the compliance of each ESP, rather than compliance of all ESPs. Both DA advocates and IOUs opposed stranded asset recovery by CCAs.

- **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**: A proposed decision attaching the final staff report is anticipated to be issued next.

- **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)

No updates this month. Two applications for rehearing remain the only outstanding items to be addressed in this proceeding, which is now closed.

- **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.

  Details: The only two remaining items to be addressed in this proceeding are two applications for rehearing filed by Western Power Trading Forum (WPTF). First, on July 17, 2020, 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.

Second, 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.

- **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 most directly impacted 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); 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.

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

No updates this month. On November 24, 2020, CPUC President sent a letter to PG&E indicating that she has directed CPUC staff to conduct fact-finding to determine whether to recommend that PG&E be placed into the enhanced oversight and enforcement process.

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

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

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

- **Details**: In her November 2020 letter to PG&E, President Batjer pointed to a "pattern of vegetation and asset management deficiencies that implicate PG&E's ability to provide safe, reliable service to customers," and stated the "Wildfire Safety Division Staff has identified a volume and rate of defects in PG&E's vegetation management that is notably higher than those observed for the other utilities."
- **Analysis**: CPUC President Batjer's letter indicates the CPUC is currently investigating whether to move PG&E into its newly created enhanced oversight and enforcement process. This six-step process could ultimately result in a revocation of PG&E's certificate of public convenience and necessity if it fails to take sufficient corrective actions.
- **Next Steps**: The proceeding remains open, but there is no procedural schedule at this time.
- **Additional Information**: Letter from President Batjer to PG&E (November 24, 2020); Ruling updating case status (September 4, 2020); Ruling on case status (July 15, 2020); Ruling on proposals to improve PG&E safety culture (June 18, 2019); D.19-06-008 directing PG&E to report on safety experience and qualifications of board members (June 18, 2019); Scoping Memo (December 21, 2018); Docket No. I.15-08-019.

PG&E's 2019 ERRA Compliance

No updates this month. On November 16, 2020, Joint CCAs and PG&E filed reply briefs on remaining issues not addressed in the pending Settlement Agreement.

- **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 identified $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 stated it will make all but $33.6 million of those adjustments as part of its August 2020 accounting close.

  On October 22, 2020, PG&E, Joint CCAs, and Cal Advocates filed a Joint Motion to Adopt Settlement Agreement. The Settlement Agreement resolves all but two of the disputed issues in Phase I of the proceeding. PG&E agreed with certain accounting errors identified by the Joint CCAs. PG&E also committed to provide additional, specific information requested by the Joint CCAs simultaneous with its ERRA Compliance applications and simplify the presentation of that information, resolving the Joint CCAs concern with transparency of the PG&E data supporting entries to the ERRA, PABA and related balancing accounts. PG&E and the Joint CCAs agreed to engage in discussions about the approach to Resource Adequacy solicitations governed by Appendix S of PG&E's 2014 Bundled Procurement Plan. Finally, PG&E agreed to rebill all commercial and industrial CCA customers assigned an incorrect vintage.

- **Details**: The two remaining issues not covered by the Settlement Agreement are (1) the request in PG&E's rebuttal testimony to reverse the $92.9 million adjustment it made in response to D.20-02-047 to its PABA regarding the amount of RPS energy the utility retained to serve its bundled customers in 2019; and (2) the utility's decision not to re-vintage four RPS contracts renegotiated during 2019.
- **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**: A proposed decision is anticipated to be issued soon. The schedule for Phase II of this proceeding has not been issued yet.
- **Additional Information**: Joint Motion to Adopt Settlement Agreement (October 22, 2020); Ruling modifying extending deadline for briefs and reply briefs (October 12, 2020); Amended Scoping Memo and Ruling (August 14, 2020); Scoping Memo and Ruling (June 19, 2020); PG&E's Application and Testimony (February 28, 2020); Docket No. A.20-02-009.

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
PURPA	Public Utility Regulatory Policies Act of 1978 (federal)
QC	Qualifying Capacity
QF	Qualifying Facility under PURPA
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)