REGULATORY UPDATE FOR MAY 24, 2021 (WEEK OF MAY 17)

CALIFORNIA PUBLIC UTILITIES COMMISSION

New Proposed Decisions and Draft Resolutions[1]

R.20-11-003 (Summer 2021 Reliability). This decision modifies Decision 21-03-056 to clarify that the adopted Emergency Load Reduction Program shall have both day-of and day-ahead triggers for Group A participants (select non-residential customers and aggregators not participating in demand response programs). It additionally clarifies that following an Alert, Warning, Emergency declaration by the California Independent System Operator (CAISO or ISO), Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas and Electric Company (SDG&E) will exercise discretion to activate the day-of trigger for Group A participants, either selectively staggered over time or all participants at the same time.

R.18-12-005 (PSPS). This decision adopts and revises the California Public Utilities Commission's (CPUC or Commission) guidelines and rules for these utilities regarding proactive de-energizations to mitigate the risk of catastrophic wildfire caused by utility infrastructure, also known as Public Safety Power Shut Offs or PSPS events. These new and revised guidelines and rules build upon prior Commission decisions, including Resolution ESRB-8 (July 12, 2018), Decision (D.)19-05-042, and D.20-05-051, and include guidelines on community resource centers and critical facilities and infrastructure, as well as directing the utilities to conduct PSPS simulation exercises.

R.19-11-009 (Resource Adequacy). This decision adopts local capacity requirements for 2022-2024 and flexible capacity requirements for 2022 applicable to Commission-jurisdictional load-serving entities. This decision also adopts refinements to the Resource Adequacy program and addresses issues scoped as Track 3B.1 and Track 4. Issues scoped as part of Track 3B.2 will be addressed in a separate decision forthcoming in this proceeding. Among the refinements this decision makes to the Resource Adequacy program are: (1) revising the maximum cumulative capacity buckets; (2) stating that investor-owned utilities will be directed to move their demand response (DR) portfolios onto their CAISO Supply Plans, but only once the Commission confirms that CAISO permits DR resources to bid variably in its markets and implements a Federal Energy Regulatory Commission (FERC)-approved RAAIM penalty exemption for DR resources; (3) requesting that the California Energy Commission develop recommendations for a comprehensive and consistent measurement and verification strategy, including a new capacity counting methodology for DR addressing ex post and ex ante load impacts for implementation as early as practicable; (4) directing Energy Division to develop regional ELCC values for wind

[1] Per California Public Regulatory Commission (CPUC or Commission) Rules of Practice and Procedure Rule 14.3, comments on proposed decisions are due 20 days after issuance of the proposed decision, and reply comments are due five days thereafter. Comments on draft resolutions are due 20 days after the draft resolution appears in the CPUC's daily calendar, per Rule 14.5.

resources for the upcoming ELCC update for consideration in a successor RA proceeding; and (5) adopting PG&E's proposed point and tier penalty structure for system RA deficiencies.

Draft Resolution ESRB-9. The Commission's General Order (GO) 167 sets forth standards for the maintenance and operation of electric generating facilities. Under the existing language of GO-167, Commission staff may issue citations only for certain specified violations of GO-167. This Resolution modifies the scope of the violations for which Commission staff may issue citations to include any violation of GO-167, and modifies the GO-167 citation process to more closely align with the Commission's other existing electric citation processes.

R.20-05-003 (IRP proceeding). This decision requires at least 11,500 megawatts (MW) of additional net qualifying capacity (NQC) to be procured by all of the load-serving entities (LSEs) subject to the Commission's integrated resource planning (IRP) authority. The capacity requirements are adopted annually, beginning with 3,000 MW by 2023, an additional 4,500 MW by 2024, an additional 2,000 MW by 2025, and an additional 2,000 MW by 2026. The decision specifically orders that the resources from Diablo Canyon be replaced with at least 2,500 MW of firm, zero-emitting resources, and states that the Commission expects that almost all of the resources procured pursuant to this order will be zero-emitting. The 2026 resources are required to be long-lead-time resources, with half coming from long-duration storage and the other half from either firm (at least 85% capacity factor) or dispatchable (between hours 17 and 22) zero-emitting resources, designed to replace the firm and/or dispatchable output of Diablo Canyon and the retiring once-through-cooling facilities. Contracted imported power may be used to count toward the capacity requirements if the imports otherwise meet the requirements for firm imports in the resource adequacy program, are available during the duration of 2024-2026, and are contracted with new resources that have commercial online dates after the date of this decision. Incremental capacity from fossil-fueled resources that represent efficiency improvements, upgrades, or repowering at existing sites may be used to satisfy between 1,000 MW and 1,500 MW of the total 11,500 MW requirements in this decision, to be procured by the investor-owned utilities only by 2025. These resources are determined to be needed for system reliability overall and are best procured by the investor-owned utilities (IOUs), and will therefore have their costs allocated to all customers via the cost allocation mechanism (CAM). LSEs will be required to submit procurement information twice yearly, consistent with Decision (D.) 20-12-044 requirements, to show progress toward the capacity procurement requirements in this decision. Backstop procurement to be conducted by the IOUs may be ordered by the Commission once yearly, with the costs allocated to the deficient LSEs and/or their customers. For the IOUs that must submit their contracts to the Commission for advance approval, Tier 3 advice letters must be submitted for all procurement, except, as mentioned above, for contracts with fossil-fueled resources, which will require full applications.

R.20-05-003 (IRP proceeding). Alternate proposed decision of Commissioner Rechtschaffen. This alternate differs from the proposed decision only in the area of eligibility and authorization for resources utilizing fossil fuels. This decision directs procurement of 500 MW of conventional fossil-fueled generation by the IOUs with the following conditions: a. Projects cannot be located in a disadvantaged community; b. Projects at mothballed or retired plants cannot qualify; c. The project must demonstrate greenhouse gas (GHG) emission benefits and incremental NQC; and d. Contracts are limited to five years. The decision also authorizes procurement by the IOUs of an additional 300 MW of eligible fossil-fueled resources that commit to using specified portions of green hydrogen fuel throughout the contract term, and specifies that this procurement will have its costs allocated via the CAM.

Voting Meetings

The CPUC's next voting meeting is scheduled for June 3, 2021. The agenda is scheduled to be published May 24, 2021. The CPUC held a voting meeting on May 20, 2021. The following items were on the agenda:

Item 5. R.17-07-007 (Rule 21). The primary objective in this proceeding is to streamline the interconnection application process; this decision adopts a series of proposals to achieve this goal. Adopted proposals include a modified, notification-only approach for certain projects, a study on cost shifts resulting from a prior distribution upgrade exemption, installation of protective equipment on large machine generators, an option for independent unintentional islanding studies, establishment of a working group to look at distribution-level solutions to anti-islanding, new anti-islanding screens in the interconnection application process for PG&E, development of an interconnection guidebook on anti-islanding, improved efficiencies in the application process that allow for applications based on street address, choice of single batch applications, a future pilot to test operational alternatives to address operational flexibility constraints, and the development and finalization of a template aggregator agreement. **Held to June 3, 2021 voting meeting**.

Item 23. R.17-06-026 (PCIA). This Phase 2 decision (a) removes the cap and trigger for PCIA rate increases; (b) authorizes new Voluntary Allocation, Market Offer, and Request for Information processes for Renewables Portfolio Standard contracts subject to the PCIA; (c) approves a process for increasing transparency of investor-owned utilities' RA resources; and (d) authorizes SCE to continue to apply the approach to GHG-free resources approved in Resolution E-5095 through December 31, 2023. This proceeding remains open to consider (i) Phase 2 issues relating to Energy Resource Recovery Account proceedings and (ii) whether GHG-free resources are undervalued in the PCIA methodology, and if so, the appropriate way to address this problem. **Signed, D.21-05-030.**

Item 25. R.13-11-005 (energy efficiency policies). This decision addresses policy issues surrounding the identification of energy efficiency potential and the setting of goals for program administrators to achieve in the design and implementation of energy efficiency programs. First, the decision adopts a new metric, called Total System Benefit, which combines and optimizes the energy and peak demand savings goals, along with GHG benefits of energy efficiency, into one metric that can be forecasted and tracked. Program administrators will continue to track individual electricity and natural gas savings as well. Next, the decision adopts a new approach to segmenting the energy efficiency program portfolios into programs whose primary purposes are resource acquisition, market support, or equity. A cost-effectiveness threshold will be applied to the resource acquisition programs, since those have readily identifiable costs and benefits that can be quantified. Program administrators will also continue to track the cost-effectiveness of the overall portfolio. The budget amount devoted to the market support and equity programs will be limited to 30% of the total budgets, except in the case of the regional energy network program administrators, who will not be subject to these limits because of the different nature of their portfolios. The evaluation, measurement, and verification budget will remain unchanged at four percent of the total portfolio. Further, this decision addresses changes to the rolling portfolio framework and regulatory processes as proposed by stakeholders in the context of the California Energy Efficiency Coordinating Committee and submitted to the Commission. The current rolling portfolio process originally adopted in D. 15-10-028 is modified to require an eight-year business plan filing and four-year program portfolio filing, with updates to the potential and goals, as well as technical inputs and avoided costs, every two years. **Signed, D.21-05-031.**

Item 26. I.19-11-013 (2019 PSPS Investigation). This proposed decision finds that in 2019, when proactively shutting off electric power to mitigate the risk of catastrophic wildfire caused by their infrastructure, California's three largest investor-owned electric utilities, PG&E, SCE, and SDG&E, failed in certain respects to reasonably comply with the obligation to promote safety in Public Utilities Code Section 451 and with many of the Commission's guidelines in D. 19-05-042, Resolution ESRB-8 (July 12, 2018), and other applicable laws, rules, and regulations. To address the failures of PG&E, SCE, and SDG&E to reasonably protect the public and adhere to state law and the CPUC's rules and regulations pertaining to proactive power shutoffs used as a wildfire mitigation measure, the CPUC directs utilities to, among other things:

(1) forgo collection from customers of the portion of their authorized revenue requirement equal to all future unrealized volumetric sales due to all future proactive power shutoffs;

(2) immediately initiate efforts to engage in the sharing of best practices and lessons learned for initiating, communicating, reporting, and improving all aspects of proactive power shutoffs by regularly holding utility working group meetings;

(3) immediately initiate efforts to assist the CPUC's Safety and Enforcement Division in developing a standardized 10-day post-event reporting template;

(4) file a report on an annual basis in Rulemaking (R.) 18-12-005 or a successor proceeding describing each utility's progress and status on improving compliance with the PSPS guidelines, especially the progress and status of implementing those guidelines not addressed in 10-day post-event reports;

(5) undertake specific corrective actions, set forth below, to improve the utilities' future compliance with the PSPS Guidelines and Public Utilities Code Section 451;

(6) provide Standard Emergency Management System training for all personnel involved

in PSPS planning;

(7) immediately initiate efforts to improve, among other things, communications with those customers dependent on electricity for medical reasons, especially life support, before, during, and after a proactive power shutoff; and

(8) improve transparency in all aspects of utility decision-making related to initiating proactive power shutoffs.

In addition, the CPUC's Safety and Enforcement Division will increase the transparency of its review process of the 10-day post-event reports by, as a first step, preparing a standard template for 10-day post-event reports, which will be issued for comments by parties in R.18-12-005; and, as a second step, establishing a single webpage on the CPUC's website to function as a central repository for all the CPUC's undertakings regarding the proactive power shutoffs that stakeholders, including the general public, can use to easily access the different aspects of the CPUC's review process of proactive power shutoffs, such as identifying the division within the CPUC undertaking a particular aspect of the review process and the subject matter of the review; and, as a third step, posting on this webpage the final documents related to the Safety and Enforcement Division's review of the 10-day post-event reports. **Held to June 3, 2021 voting meeting.**

CALIFORNIA ISO

Stakeholder Initiatives: Upcoming Meetings and Deadlines

Potential Reliability Must-Run Designation: Agnews Power Plant. Comments are due June 1, 2021.

2022 Draft Policy Initiatives Catalog Posted. The California ISO has posted its 2022 Draft Policy Initiatives Catalog to its website. Stakeholder written comments on the draft catalog are due May 21, 2021.

Maximum Import Capability Enhancements: Straw Proposal. Comments on the straw proposal for the California ISO's Maximum Import Capability Enhancements initiative are due May 27, 2021.

20-Year Transmission Outlook. The California ISO has launched a new effort called the 20-Year Transmission Outlook, which will be in parallel to the 2021-2022 transmission planning process. Written comments are due May 28, 2021.

Generator Interconnection: Cluster 14 Revised Study Process and Timeline, Issue Paper and Draft Final Proposal Posted. The California ISO will hold a public stakeholder call on May 21, 2021 to discuss an issue paper and draft final proposal for a revised study process and timeline for Cluster 14. Comments are due May 28, 2021.

2021 Summer Readiness Update. The California ISO has scheduled the next public call on May 26, 2021, to provide an update on the 2021 summer readiness efforts.

New Initiative: External Load Forward Scheduling Rights Process. The California ISO has launched a new initiative called External Load Forward Scheduling Rights Process and scheduled a public stakeholder workshop webinar on July 13, 2021. The purpose of this first workshop is to solicit input and provide stakeholders an opportunity to present the issues that need to be addressed and guiding principles for this stakeholder initiative. Requests to present and topics for the workshop are due July 7, 2021.

CALIFORNIA ENERGY COMMISSION

On May 21, 2021, the California Energy Commission (CEC) published a notice of a joint agency workshop with the CPUC and the California ISO to initiate a process to explore next steps to plan for the development of resources that will be needed to achieve the goals set forth in Senate Bill 100 (SB 100). The workshop will be held in two sessions on June 2, 2021, the first at 10:00 a.m. and the second at 2:00 p.m. Additional information regarding the workshop sessions is available in the CEC's *SB 100 Implementation Planning for SB100 Resource Build* docket, 21-SIT-01 (Docket). The notice indicates that the CEC will also post a meeting schedule to the Docket prior to the June 2, 2021 workshop.

The next CEC Business Meeting is scheduled for June 9, 2021.

CALIFORNIA AIR RESOURCES BOARD

The California Air Resources Board (CARB) will hold a series of public workshops related to development of the 2022 Scoping Plan Update to achieve carbon neutrality by 2045. Workshops will be held on June 8, June 9, and June 10, with focused discussion on natural and working lands, equity and environmental justice, the transportation sector, and the electricity sector.

On May 20, 2021, CARB adopted the Clean Miles Standard (Standard), which sets electrification and greenhouse gas (GHG) emissions targets for the light-duty fleets of transportation network companies (TNC) like Uber and Lyft. The Standard will be implemented by the CPUC and is aimed at helping achieve the statewide mandate to reduce GHG emissions 40% below 1990 levels by 2030. The electrification target, measured by the percentage of electric vehicle miles traveled (eVMT), will commence in 2023 with a target of 2% eVMT and increase to 90% eVMT in 2030. The GHG emissions target uses a metric of grams of CO_2 per passenger-mile-traveled (g CO_2/PMT), and also encourages a reduction in vehicle miles traveled (VMT) relative to passenger miles traveled. The Standard requires a transportation network company to meet a GHG target of 252 g CO_2/PMT in 2023, decreasing to 0 g CO_2/PMT in 2030. Transportation network companies have various options to reduce company-wide GHG emissions to the annual targets, including improving fleet-wide fuel efficiency, reducing VMT by increasing shared rides, reducing VMT by reducing deadhead miles (i.e., those miles driven without a passenger), and earning CO_2 credits by investing in active transportation infrastructure or by providing integrated fare services to connect riders to mass transit. During discussion at the Board meeting, Board members expressed concern regarding potential impacts of the Standard on TNC drivers, particularly those living in multi-family housing without access to vehicle charging infrastructure and affordable vehicle charging. The Board directed staff to formulate conforming modifications to the proposed regulation, which would be circulated for 15 days of public comment (15-day changes), including related to gathering data related to adverse impacts on drivers and increasing CO_2 credits available for TNCs facilitating connectivity to mass transit.

CARB has issued a notice for public comment on proposed modifications to the Regulation for Reducing Sulfur Hexafluoride Emissions from Gas Insulated Switchgear. Amendments to the Regulation were adopted by CARB on September 24, 2020, subject to additional conforming modifications to the Regulation. Comments on the proposed conforming modifications are due May 26, 2021. The amendments expanded the scope of the Regulation to all insulating gases with a global warming potential greater than one, established a timeline for phasing out acquisition of sulfur hexafluoride gas-insulated equipment, and revised reporting requirements. Comments on the proposed conforming modifications can be submitted here.

CARB's next Board meeting will be held June 24-25, 2021.

MINNESOTA PUBLIC UTILITIES COMMISSION

1. Xcel Energy Multi-Dwelling Unit Electric Vehicle (EV) Pilot Program, PUC Docket No. E002/M-20-711

On May 20, 2021, the Minnesota Public Utilities Commission (Commission) met to consider Xcel's petition for approval of its proposed multi-dwelling unit (MDU) EV Service Pilot program. The goal of Xcel's pilot is to address key barriers to EV charging for the MDU portion of the residential housing sector. Those barriers include: (1) high upfront cost of charging infrastructure; (2) lack of awareness, education, and technical knowledge; (3) parking for EV charging with surface and shared parking; and (4) landlord-tenant issues due to shared electric use in common areas. Xcel's petition proposed placing make-ready EV infrastructure in MDUs, as well as level 2 EV chargers at the option of the MDU owner. After review, the Commission approved Xcel's petition with modifications and a written order is pending.

2. Xcel Energy Petition for Approval of a Time-of-Use Service Tariff, PUC Docket No. E002/M-20-86

Following comments from stakeholders, the Commission met on May 20, 2021, to consider Xcel's petition for approval of a Time-of-Use (TOU) Service Tariff, which was brought pursuant to the Commission's previous approval of Xcel's EV charging pilot order. Xcel filed its petition on January 17, 2020, and included specific rate design and policy goals. On May 29, 2020, the Clean Energy Organizations (CEOs) filed an alternative TOU proposal in the same docket. Importantly, prior to implementation of the TOU tariff, Xcel must complete installation of its advanced metering infrastructure, which is scheduled to be completed in 2024. As such, the Minnesota Department of Commerce updated its position, recommending that the Commission defer this matter until 2024. Despite the three-year runway, the Commission took the following action:

- It found that it is in the public interest to develop a new General Service TOU rate with implementation as soon as reasonably possible.

- The Commission required Xcel to pilot both the CEOs' proposed rate design and Xcel's proposed rate design starting in 2022 and running until a new default general TOU rate is in place, and within six months of the Commission order make a filing in the existing docket that includes several reporting requirements, including but not limited to: (1) a detailed implementation plan; (2) a customer education and engagement plan for the pilot; (3) details of a customer bill protection mechanism; (4) details of a true-up mechanism for revenue neutrality; (5) a discussion of how pilots will inform the development of a new TOU rate to be proposed as early as 2024; and (6) a detailed enrollment process for both EV-charging and non-EV-charging customers.

- Xcel's report must also include a discussion of possible segregation of commercial and industrial customers for separate TOU tariffs that may result in more effective and equitable rates while accomplishing the goals of a general TOU structure.

- Xcel must consult with parties to get feedback on the pilot design and explain how that feedback is incorporated.

- The Commission will defer a decision on a default TOU rate structure in this matter, and require Xcel to file for a request for a new default TOU rate structure in its next rate case following the substantial completion of the installation of advanced metering infrastructure (AMI) meters in Xcel's Minnesota service territory or in a separate proceeding within one year of substantial completion of the installation of AMI meters in Xcel's service territory, whichever comes first, but no later than November 1, 2025.

- Lastly, Xcel must file a detailed analysis and explanation of forecasted 2025 load data from its most recent IRP, including an analysis and determination of whether there is a systematic bias contained within the 2025 forecasted hourly cost duration model.

A written order is pending, after which parties will learn more about Xcel's pilot TOU programs.

OREGON

Oregon Public Utility Commission (OPUC) Meeting this Week
On Tuesday, May 25, 2021 at 8:30 a.m. PST, the OPUC will hold a public meeting to discuss PG&E's avoided cost updates for Qualifying Facilities 10 MW or Less, under Schedule 201 of its tariff (docket [UM 1728]). PG&E's application can be located [here].

Negotiations Continue in Regard to House Bill (HB) 3375

On Tuesday, May 25, 2021, the Senate Committee on Energy and Environment will hold a working session to discuss HB 3375. This bill, if passed, will establish Oregon's policy on off-shore wind energy research and development. The ultimate goal is to develop up to 3 GW of commercial scale off-shore wind energy by 2030. The current form of the bill is located here.

WASHINGTON

Washington's Clean Energy Transformation Act (CETA) Carbon and Markets Workgroup Summary Report Now Available – UE-210183

The Washington Utilities and Transportation Commission (WUTC) is conducting several rulemakings and workshops to implement Washington's 2019 CETA. CETA requires electric utilities to produce 100% of electricity from renewable or non-carbon-emitting sources by 2045. Last week, WUTC published a master list of energy and carbon market issues related to the implementation of CETA. The summary report can be located here.

FEDERAL ENERGY REGULATORY COMMISSION

FERC issued several notable decisions during its monthly open meeting that was held last week:

- FERC issued orders in long-running 2000/01 California Energy Crisis dockets. In Docket No. EL00-95, FERC accepted a compliance filing by the CAISO and CalPX called the "settlement overlay," which reconciled refund calculations with the amounts already paid and received under settlement agreements by the California Parties and more than 60 market participants. FERC's acceptance cleared the way for accomplishing market-clearing and the wind-down of the CalPX. In Docket No. EL02-71, FERC affirmed the factual findings reached in the most recent Initial Decision in the proceeding, which found that the California Parties' general claims of market dysfunction were insufficient to overcome the *Mobile-Sierra* presumption and that the California Parties failed to tie seller-specific evidence to the transactions at issue.

- FERC issued a show cause order that directed GreenHat Energy, LLC and its principals to demonstrate why they should not be subject to over $200MM in combined civil penalties for apparent manipulation that occurred with Financial Transmission Rights in the PJM market.

- FERC accepted several Facilities Service Agreements from the MISO region that included utility self-funding of network upgrades—a method of funding that has been in dispute for the past six years.