REGULATORY UPDATE FOR DECEMBER 13, 2021 (WEEK OF DECEMBER 6)

CALIFORNIA PUBLIC UTILITIES COMMISSION (CPUC or COMMISSION)

President Biden Nominates Commissioner Guzman Aceves to Lead U.S. EPA Region 9

On November 9, 2021, President Biden announced that current CPUC Commissioner Martha Guzman Aceves has been nominated to lead the U.S. Environmental Protection Agency's Region 9, which covers the southwestern United States and the Pacific Islands.

New Proposed Decisions and Draft Resolutions[1]

Draft Resolution E-5180. This resolution certifies CleanPowerSF's request to elect to administer its energy efficiency program administration plan, and directs Pacific Gas and Electric Company (PG&E) to transfer $4,579,056 to CleanPowerSF for its three-year energy efficiency plan.

Draft Resolution E-5186. This resolution finds that San Diego Gas & Electric Company (SDG&E) complied with Ordering Paragraph (OP) 53 of Decision (D.) 17-12-003 in that SDG&E Advice Letter 3562-E contains all the reporting elements on Demand Response (DR) program cost-effectiveness that were required by the D.17-12-003. This resolution orders SDG&E to propose significant improvements to its DR portfolio to address its DR programs' failing cost-effectiveness and include the proposals in its 2023-2027 DR Portfolio Application. OP 61 of D.17-12-003 directed SDG&E to file its 2023-2027 DR Portfolio Application on November 1, 2021, which has been extended to May 2, 2022.

A.21-06-003 (SDG&E ERRA Forecast). This decision approves Southern California Edison Company's (SCE) total 2022 Energy Resource Recovery Account (ERRA) electric procurement cost revenue requirement forecast of $4.768 billion, modifying SCE's requested revenue requirement of $4.751 billion by $16.200 million to account for a $17.954 million increase to the Solar on Multifamily Affordable Housing (SOMAH) program allocation and $1.754 million decrease from deferred recovery of litigation costs related to SCE's efforts to recover refunds from generators who overcharged SCE during the 2000-2001 California Energy Crisis. SCE is directed to form a working group within 60 days and to file a petition for modification of either D.17-12-022 or D.20-04-012 within 120 days of the issuance date of this decision. The petition for modification will address whether the current rules for SOMAH require the investor-owned utilities to wait for recorded revenues from the previous four quarters before applying the $100 million amount to the SOMAH allocation in an ERRA forecast or Energy Cost Adjustment Clause proceeding. This decision approves SCE's forecast greenhouse gas (GHG) costs, including $152.852 million in direct GHG Cap-and-Trade costs and -$732.458

[1] Per CPUC 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.

million in net 2022 GHG forecast auction proceeds. SCE is directed to return $647.824 million in GHG auction proceeds to SCE's customers, after setting aside $90.592 million in funding for clean energy and energy efficiency projects and $404,474 for outreach and administrative expenses. This decision also authorizes SCE to return $33.029 million to emissions-intensive and trade exposed customers and $614.365 million through the California Climate Credit. In addition, this decision approves SCE's ERRA Trigger Mechanism application and adopts Cost Responsibility Surcharge rates.

R.18-07-003 (RPS Implementation). This decision adopts, with modifications, the 2021 Renewable Portfolio Standard (RPS) plans for the load-serving entities under Commission jurisdiction, including investor-owned utilities and community choice aggregators. Final plans are due no later than 30 days after issuance of this decision.

Voting Meetings

The Commission's next voting meeting will be held December 16, 2021. The agenda includes the following energy related items:

Item 4. R.18-10-007 (Wildfire Mitigation Plans). This decision closes this proceeding. Pursuant to Assembly Bill (AB) 111 (2019), all duties, powers, and responsibilities of the Commission's Wildfire Safety Division were transferred on July 1, 2021, to the Office of Energy Infrastructure, established within the California Natural Resources Agency under the same bill.

Item 5. A.18-03-009 (SCE and SDG&E Nuclear Decommissioning). The proceeding addresses the reasonableness of decommissioning costs as claimed by the Utilities for the San Onofre Nuclear Generating Station (SONGS) Units 1, 2, and 3. The proceeding consists of three (3) phases. D.19-09-003 resolved Phase 1, which addressed nuclear fuel cancellation costs and the form of the revised 2016 Palo Verde Nuclear Generating Station decommissioning cost estimate. The instant decision resolves Phase 2 (Reasonableness Review of Recorded 2016-2017 Decommissioning Costs) and Phase 3 (Reasonableness of 2017 Decommissioning Cost Estimates). Regarding the 2017 decommissioning costs, the decision finds the following are reasonable: $209.0 million (100% share, 2014 $) for SONGS 1 and (2) $4,479 million (100% share, 2014 $) for SONGS 2 and 3. This decision also finds reasonable SDG&E's estimate of $45.9 million (SDG&E share, 2014 $) for SDG&E-only decommissioning costs.

Item 9. A.21-08-013, A.21-08-014, A.21-08-015 (IOU Cost of Capital). This decision grants the motions of SCE, SDG&E, and PG&E to establish respective memorandum accounts to record the difference between the rates in effect beginning January 1, 2022 and the rates to be adopted in these proceedings.

Item 11. Resolution E-5173. This resolution approves two resource adequacy (RA) power purchase agreements between SCE and AES Redondo Beach, LLC (AES) for Units 5 and 6 of the AES Redondo Beach Generating Station for April 1, 2022 through December 31, 2022, to meet SCE's system, LA Basin local, and flexible RA requirements.

Item 12. R.20-05-012 (SGIP). This decision allocates all Self-Generation Incentive Program (SGIP) accumulated unallocated funds, approximately $67 million, to SGIP energy storage budgets. The accumulated funds derive primarily from previously unreported accrued interest earned on SGIP ratepayer revenue collections since the program's inception in 2001. This decision allocates the funds first to energy storage budgets with waitlisted applications as of the date of adoption of this decision, with priority given to the waitlisted Equity Resiliency budget, Equity and then General Market applications. It then allocates funds that remain after all waitlisted applications have been served, if any, to Equity Resiliency budgets. This decision requires the SGIP Program Administrators to file a Tier 1 advice letter no later than 30 days from the date of adoption of this decision reporting on the resulting funding allocations. It requires an annual Tier 1 budget advice letter and updates fiscal audit requirements for the SGIP Program Administrators for the next five years.

Item 13. R.18-07-003 (RPS Implementation). This decision directs SDG&E to reopen its Renewable Market Adjusting Tariff (ReMAT) program following the parameters adopted in D.20-10-005, as modified in this decision. This decision further establishes a de minimis threshold for each product category, and a process through which the investor-owned utilities shall aggregate remaining capacity across one or two of the three product categories, if necessary, to meet their individual shares of the statewide ReMAT capacity target. This decision reaffirms the utilities' option to provide information-only time-of-delivery factors, as adopted in D.19-12-042, resolves several petitions for modification of D.12-05-035 and D.13-05-034, and defers consideration of the joint petition for modification of D.13-05-034 filed by PG&E and SCE until more information is available.

Item 14. R.18-12-006 (Vehicle Electrification). In D.11-07-029, the Commission adopted a policy of allocated distribution upgrade costs above the individual customer allowances in Rules 15 and 16 to be considered common costs, and allocated to all residential ratepayers, rather than allocating them to the individual customer who triggered the costs. This decision would make that policy permanent, pursuant to the requirements of AB 841 (2020).

Item 15. A.20-12-018 (PacifiCorp EE Programs). This decision authorizes PacifiCorp to administer its energy efficiency programs with a total budget of approximately $6.1 million for 2022-2026 to achieve the higher energy savings targets of 14,474 megawatt hours.

Item 21. Resolution E-5138. This resolution approves SCE's Emergency Reliability Engineering, Procurement, Construction, and Maintenance Contract for 535.7 Megawatts of Utility-Owned Storage. It also finds that the projects do not require a Certificate of Public Convenience and Necessity or Permit to Construct to be issued from the Commission.

Item 24. A.20-08-023 (PG&E Ruby Pipeline Natural Gas Transportation Contract Amendments). This decision resolves the application and request of PG&E for approval of amendments to long-term natural gas transportation contracts with Ruby Pipeline, LLC (Ruby Contracts) entered into on behalf of PG&E's Electric Fuels Department and Core Gas Supply Department. The contract amendments are approved, as well as the request to discontinue the annual certification requirement that PG&E is receiving the lowest price from Ruby Pipeline. Future amendments may be submitted for approval via a Tier 3 advice letter.

Item 25. A.12-01-008, A.12-04-020, A.14-01-007 (Green Tariff Shared Renewables). This decision resolves three petitions for modification of D.15-01-051 and D.16-05-006. It conditionally grants a petition by PG&E, grants in part a second petition by a number of community choice aggregators (Joint CCAs), and denies without prejudice a petition by the Coalition for Community Solar Access. The decision allows PG&E to count some of its current RPS resources towards its Green Tariff Shared Renewables (GTSR) obligation, to address program oversubscription. The decision also grants the Joint CCAs' request to change the methodology for calculating a rate adder for the charge the utility incurs for RA capacity to serve its bundled customers. It also denies a petition from the Coalition that requested changes to the Enhanced Community Renewables program within the GTSR, without prejudice to those issues being raised in a subsequent proceeding.

Item 26. Resolution E-5178. This resolution grants certain amendments to the energy storage agreement for the 75 MW Hummingbird energy storage project in Morgan Hill, California. The amendment delays the online date for the project due to delays associated with Covid-19 impacts, and extends the term, at no additional cost, from 15 to 16 years.

Item 30. A.21-04-010 (SDG&E 2022 Electric Procurement Revenue Requirement Forecasts and GHG-Related Forecasts). This decision adopts the 2022 Electric Procurement Revenue Requirement and Greenhouse Gas-Related Forecasts for inclusion in the retail rates of SDG&E effective January 1, 2022. It also includes the rate impacts from SDG&E's Application (A.) 21-05-006, the 2021 Energy Resource Recovery Account Trigger Proceeding (ERRA Trigger). There will be a separate subsequent decision in A.21-05-006 on the merits of that application; therefore, SDG&E is not requesting approval of the 2021 ERRA Trigger in this application.

Item 45. Draft Resolution SED-5. In this resolution, the CPUC approves an Administrative Consent Order and Agreement between the Commission's Safety and Enforcement Division and SCE to resolve all issues involving the 2017 Liberty, Rye, Meyers, and Thomas Fires and the 2018 Woolsey Fire, whereby SCE agrees to fines, safety measures, and disallowances totaling $550 million as follows: $110 million fine to the General Fund of the State of California; $65 million in shareholder-funded safety measures; and $375 million in permanent disallowances of cost recovery.

CALIFORNIA ISO (CAISO)

Board of Governors Meeting

The CAISO's next Board of Governors general session meeting is scheduled for December 17. The draft agenda may be found here.

Stakeholder Initiatives: Upcoming Meetings and Deadlines

Extended Day-Ahead Market: Working Group Logistics and Schedule. The CAISO will hold a stakeholder meeting on December 16, 2021, to discuss the logistics and schedule for a series of working group meetings for the Extended Day-Ahead Market initiative that will commence the week of January 3, 2022.

EIM Resource Sufficiency Evaluation Enhancements. The CAISO has scheduled a stakeholder call on December 14, 2021, to discuss the revised draft final proposal for Phase 1 of the EIM Resource Sufficiency Evaluation Enhancements initiative. Comments on the revised proposal and meeting are due December 22, 2021.

Interconnection Process Enhancements 2021 Initiative. The CAISO will hold a public stakeholder call on December 13, 2021, to discuss the issue paper/straw proposal for the Interconnection Process Enhancements 2021 initiative. Comments are due January 3, 2022.

Energy Storage Enhancements Straw Proposal. The CAISO will hold a stakeholder call on December 14, 2021, to discuss the straw proposal for the Energy Storage Enhancements initiative. Comments are due January 12, 2022.

CALIFORNIA ENERGY COMMISSION (CEC)

Electric Program Investment Charge (EPIC)

The CEC has announced a two-day EPIC Symposium scheduled for December 14-15, 2021. The Symposium will focus on how California's investments in public interest research will transform the state's energy system. Over the two-day event, panel sessions will focus on:

- Grid resiliency and reliability;
- Equity and affordability;
- Decarbonization of the built environment; and
- Innovation and entrepreneurship in California.

To view the agenda for the Symposium, please visit https://www.energizeinnovation.fund/events/epic-symposium#tab-agenda. To register for this event, visit https://www.energizeinnovation.fund/events/epic-symposium#tab-registration.

2021 Integrated Energy Policy Report (IEPR)

On December 16, 2021, the CEC will hold an IEPR workshop on energy demand analysis for the 2021 IEPR. The workshop will focus on (1) the annual electricity and gas forecasts, (2) the hourly and peak electricity demand forecasts, and (3) results of the energy efficiency analysis. The notice and agenda for the workshop are available here.

On December 7, 2021, the CEC published a Notice of Availability and Request for Comments on the Draft 2021 IEPR. Copies of the Notice and the Draft 2021 IEPR are availablehere. Note that only three of the four 2021 IEPR volumes have been released for public comment. Volume III will be released for public comment at a later date under a separate notice of availability. As set forth in the CEC's March 16, 2021 scoping order, the 2021 IEPR volumes cover the following:

- **Volume I** addresses actions needed to reduce GHGs related to the buildings in which Californians live and work, with an emphasis on energy efficiency. It also addresses reducing GHGs from the industrial and agricultural sectors.
- **Volume II** examines actions needed to increase the reliability and resiliency of California's energy system.
- **Volume III** looks at the evolving role of gas in California's energy system, both the importance in near-term reliability and the need for the system to evolve as California works to achieve carbon neutrality—the point at which the removal of carbon pollution from the atmosphere equals or exceeds emissions—by 2045. This volume is not yet available for comment.
- **Volume IV** reports on California's energy demand outlook, including a forecast to 2035 and long-term energy demand scenarios to 2050. The analysis includes the electricity, gas, and transportation sectors.
- The **Appendix** evaluates the benefits of California's clean transportation system.

The CEC held twenty workshops between February 2021 and December 3, 2021 on the topics identified in the scoping order, with another workshop scheduled for December 16, 2021 (as discussed above). Written comments on the three volumes of the Draft 2021 IEPR are due by 5:00 p.m. on December 21, 2021. Instructions for submitting comments are included in the December 7, 2021 Notice of Availability.

Offshore Wind

On December 10, 2021, CEC Staff posted a public notice regarding a December 17, 2021 workshop to further develop understanding of the role of the CPUC's Integrated Resource Planning (IRP) process in relation to offshore wind development in California. According to the notice, the workshop will focus on the IRP "roadmap" for offshore wind and to facilitate a common understanding between planners and stakeholders regarding interaction between the IRP process and the timeline to bring offshore wind to California. The workshop is scheduled to begin at 10:00 a.m.

CEC Business Meetings

The next CEC Business Meeting is scheduled for January 26, 2022.

CALIFORNIA AIR RESOURCES BOARD (ARB)

ARB is holding virtual public workshops as part of the Assembly Bill (AB) 32 Scoping Plan Update. On December 13, 2021, ARB will hold a public workshop on building decarbonization. Comments on the workshop can be submitted to ARB here on or before January 7, 2021. Comments on the recent technical workshop on modeling land management scenarios for natural and working lands can be submitted here on or before January 5, 2022. Recordings of past AB 32 Scoping Plan Update meetings and workshops are available here.

On December 14, 2021, ARB will hold a public workshop on potential amendments to its regulation governing off-road diesel-fueled vehicles. At the workshop, staff will present its proposal for potential amendments to the existing regulation.

On December 14, 2021, ARB will host a virtual public meeting of the AB 32 Environmental Justice Advisory Committee. The agenda and a link to the meeting are available here.

On December 16, 2021, ARB will hold a workgroup meeting on medium and heavy-duty hydrogen fueling infrastructure, including station location planning and timing, renewable hydrogen production and supply, fuel costs, and codes and standards for hydrogen fueling.

ARB is accepting informal public comments on the proposed Advanced Clean Fleets regulation, which aims to achieve a zero-emissions truck and bus California fleet by 2045. Comments may be submitted here on or before December 31, 2021.

On December 7, 2021, ARB held a workshop on potential future changes to the Low Carbon Fuel Standard program. Information on the workshop is available here. Comments on the workshop can be submitted here on or before January 7, 2022.

ARB's next regular Board meeting will be held January 27-28, 2022. The agenda will be available here 10 days prior to the meeting.

MINNESOTA PUBLIC UTILITIES COMMISSION (MPUC)

1. Northern States Power Co. dba Xcel Energy Multiyear Electric Rate Case, MPUC Docket No. 21-630

The MPUC held its initial hearing on Northern States Power Co. dba Xcel Energy's ("Xcel") electric rate case on December 8 & 9, 2021. By way of background, Xcel filed a multiyear rate plan on October 25, 2021, seeking increases of $395.9 million in 2022, an incremental $150.5 million in 2023, and an incremental $131.2 million in 2024. Xcel also proposed an interim rate increase of $288.3 million or 9.4% in 2022 and an incremental $135.1 million or 4.5% in 2023. The issues before the MPUC included whether Xcel's application was complete, whether to refer the case to the Minnesota Office of Administrative Hearings (OAH) for contested case treatment before an administrative law judge, and how to set interim rates. The last issue received most of the MPUC's attention.

In its interim rate petition, Xcel included an interim rates reduction proposal forcing the MPUC to determine whether it should accept Xcel's proposal to reduce/defer interim rates through the continued use of a sales true-up or utilize exigent circumstances to reduce the amount Xcel would be permitted to collect during the interim rates process. Xcel's proposal reduced the interim rate increase from approximately $288 million to approximately $190 million by shifting the portion of the increase due to lost sales revenue to later years (i.e., only shifting the company's collection of the interim rates to later years). Xcel's alternate proposal was also contingent upon receiving approval of an interim rate increase in 2023, which was inconsistent with the MPUC's action in the previous multiyear rate plan. The Minnesota Department of Commerce and an industrial consumer group, the Xcel Large Industrials, submitted comments on Xcel's proposal, noting the potential detrimental consequences of adopting Xcel's proposal, encouraging the Commission to use its statutory authority under Minn. Stat. Section 216B.16 to reduce the amount Xcel could collect through interim rates via a finding of exigent circumstances. These consumer groups preferred this approach rather than deferring costs to later years through true-ups. After significant discussion, the commissioners determined that a finding of exigent circumstances was appropriate. As such, the MPUC accepted Xcel's case as complete, referred it to the OAH, and set interim rates for 2022, including a finding of exigent circumstances that reduced interim rates from an increase of 9.4% to 6.4% for residential customers only.

The MPUC's decision to reduce the residential interim rate increase is consistent with its interim rates decision in Minnesota Power's pending rate case, and demonstrates the agency's ongoing concern with mitigating residential rate increases. Due to the large volume of cases and other matters before the MPUC this year, Xcel's electric case will be litigated in late 2022 and into 2023. A written order is pending.

2. <u>Northern States Power Co. dba Xcel Energy Natural Gas Rate Case and Affiliated Dockets, MPUC Docket Nos. 21-750, 21-678, 21-679</u>

The MPUC met on December 8 & 9, 2021, to review Xcel's natural gas rate case and accompanying petition to withdraw the case via a stay out petition. After remarks from stakeholders and commissioner questions on December 8, the MPUC spent considerable time weighing Xcel's proposals on December 9. Ultimately, consistent with other pending natural gas cases, the MPUC denied Xcel's request for a stay out, and the natural gas case will proceed as filed. After determining that the case will move forward, the MPUC accepted the rate case as complete, set interim rates, and referred the matter to the OAH. A written order is pending.

3. <u>MPUC Hearing December 16, 2021.</u>

The MPUC will meet on December 16, 2021, at 8:00 a.m. PST, to review two matters: (1) the telephone assistance plan; and (2) Xcel's ongoing performance metrics matter.

<u>**TEXAS**</u>

<u>Texas Railroad Commission</u>

On November 30, 2021, the Texas Railroad Commission adopted rules for critical designation of natural gas infrastructure in response to Senate Bill 3 (S.B. 3). The rules define natural gas facilities that would be designated as critical gas suppliers and critical customers.

Critical gas suppliers include gas wells, oil leases that produce gas, natural gas pipeline facilities, underground natural gas storage facilities, and saltwater disposal facilities. Critical customers, which are a subset of critical gas suppliers, are facilities that require electricity to operate. These operators will submit critical customer information to their electric utilities so that the utilities have correct information for purposes of supplying power to the facilities.

The rules also narrow a controversial opt-out provision in S.B. 3. S.B. 3 includes language to allow for certain facilities to apply for an exception to a critical designation. The Railroad Commission rules exclude certain highly critical facilities from being able to apply for an exception. Examples include any facility that will be on the state's electricity supply chain map, which is due to be published next year; underground gas storage facilities; pipelines that directly serve a power generation plant or local gas distribution companies, gas wells and oil leases that produce a large amount of gas per day; and gas processing plants.

<u>Public Utility Commission of Texas</u>

On October 21, 2021, the Public Utility Commission of Texas (PUCT) approved a rule that creates requirements for power companies to better prepare for winter weather. The rule stems from the Texas Legislature's passage of S.B. 3 in response to the devastation caused to the energy grid by winter storm Uri.

S.B. 3, effective June 8, 2021, is a multi-pronged law that attempts to make the Texas energy system more resilient to the effects of extreme winter weather events. Key to S.B. 3 is a requirement that the PUCT implement winter weatherization requirements so that each of the entities providing electric generation service must implement measures to prepare its generation assets to provide adequate electric generation service during a weather emergency. The new rule, codified as 16 Texas Administrative Code § 25.55, requires electric generators and transmission service providers (TSPs) (collectively, generation entities) to implement the winter weather readiness recommendations identified in the 2012 Quanta Technology Report on Extreme Weather Preparedness Best Practices and the FERC/NERC 2011 Report on Outages and Curtailments During the Southwest Cold Weather Event on February 1-5, 2011. The rule also requires affected entities to fix any known, acute issues that arose from winter weather conditions during the 2020-2021 winter weather season. The deadline for implementation of many components of the new rule is December 1, 2021.

By December 1, 2021, a generation entity within the Electric Reliability Council of Texas (ERCOT) must:

1. Use best efforts to implement weather emergency preparation measures intended to ensure sustained operation of all cold weather critical components during winter weather conditions;
2. Install adequate wind breaks for resources susceptible to outages or derates caused by wind; inspect thermal insulation for damage or degradation and repair damaged or degraded insulation; confirm the operability of instrument air moisture prevention systems; and conduct maintenance of freeze protection components for all applicable

equipment, including fuel delivery systems controlled by the generation entity, the failure of which could cause an outage or derate;

3. Establish a schedule for testing of such freeze protection components on a monthly basis from November through March, and install monitoring systems for cold weather critical components, including circuitry providing freeze protection or preventing instrument air moisture;
4. Use best efforts to address cold weather critical component failures that occurred due to winter weather conditions during the 2020-2021 winter;
5. Provide training on winter weather preparations and operations to relevant operational personnel; and
6. Determine minimum design and experienced operating temperature and other operating limitations based on temperature, precipitation, humidity, wind speed, and wind direction.

The generation entity must also, by December 1, 2021, submit to both the PUCT and ERCOT, on a form prescribed by ERCOT, a winter weather readiness report that:

1. Provides a description of all activities engaged in by the generation entity to complete the above-listed requirements, including any good-cause-based reason for noncompliance; and
2. Includes a notarized attestation sworn by the generation entity's highest-ranking representative, official, or officer attesting to the accuracy of the information in the report and completion of all of the above-listed requirements, subject to any notice of or request for good-cause exception.

The draft report forms for both generation entities and TSPs are available here: Winter Weather Readiness (ercot.com).

With the extremely tight timeframe to comply with the rule, generation entities are entitled to request an exception to the requirements for good cause. The generation entity must still file a winter weather readiness report; however, that report would include a notice that provides:

1. An explanation and supporting documentation of the generation entity's inability to comply with a specific requirement;
2. A description and supporting documentation of the generation entity's efforts to comply with the requirements; and
3. A plan, including supporting documentation and a proposed deadline for each unfulfilled requirement, to comply with requirements.

PUCT Staff will collaborate with ERCOT in reviewing these good-cause exemption notices, and the PUCT reserves the right to notify the generation entity that it disagrees with the assertion of good cause. If PUCT Staff disagrees with the assertion of good cause, the generation entity must preserve the good-cause exemption by submitting, within seven days of receipt of the notice of disagreement, a request for approval of the good-cause exemption to the

PUCT. The request for approval must contain, in addition to all of the requirements of the good-cause exemption notice, (1) proof that notice of the request has been provided to ERCOT, and (2) a notarized attestation sworn to by the generation entity's highest-ranking representative, official, or officer with binding authority over the entity attesting to the accuracy and veracity of the information in the request for approval.

Another component of the new rule provides for ERCOT inspections of generation entities and TSPs to ensure compliance with the requirements in the 2021-2022 winter season. ERCOT has the ability to make determinations on good-cause exemption requests during an inspection. ERCOT will prioritize inspections based on the risk level. The outcome of the ERCOT inspection may subject a generator to a PUCT enforcement investigation or civil penalties.

This rule represents the first of two phases in the PUCT's response to the requirements of S.B. 3. At a future date, the PUCT will implement a second, more comprehensive set of weather emergency preparedness reliability standards.

OREGON

Oregon Public Utility Commission (OPUC) Approves PGE's 2021 All-Source Request for Proposal (RFP)

Last Friday, the OPUC issued Order 21-460 which approved Portland General Electric Company's (PGE) 2021 All-Source RFP. The recent order adopted OPUC Staff's 11 recommendations outlined in its Staff Report located here. On Friday, December 17 at 9:00 a.m. PST, the OPUC will hold a bidder workshop to address changes to the 2021 RFP following Order 21-460. The workshop will also provide an overview of the bidding process for potential resource providers. The dial in details and full agenda can be located here.

OPUC Meetings this Week

On Tuesday, December 14 at 9:30 a.m. PST, the OPUC is hosting a public meeting to discuss a wide range of dockets including UM 1826 (related to electric utility participation in clean fuel programs), AR 622 (related to rulemaking for small scale renewable energy projects), and UM 2193 (related to PacifiCorp's 2022 All-Source RFP).

NEW JERSEY

On December 7, 2021, Consolidated Edison Transmission submitted its Clean Link New Jersey proposal to PJM. The Clean Link New Jersey project would involve construction of 27-miles of undersea cable and 23 miles of onshore cable that would connect up to 2.4 Gigawatts of offshore wind-generated electricity to the PJM grid. The proposal stems from the joint competitive solicitation initiated by the New Jersey Board of Public Utilities and PJM for new transmission upgrades necessary to reliably connect the 7,500 MW of offshore wind energy generation that New Jersey is expected to add to that state's generation portfolio by 2035.

Consolidated Edison Transmission expects the project to cost $2.75 billion and, if approved, commence service by June 2028.

FEDERAL ENERGY REGULATORY COMMISSION (FERC)

Willie L. Phillips was sworn in as the fifth FERC Commissioner earlier this month. Phillips is serving a five-year term that ends June 30, 2026. Commissioner Phillips most recently served as the Chairman of the Public Service Commission of the District of Columbia. He previously served as Assistant General Counsel for the North American Electric Reliability Corporation and has served in leadership roles for the National Association of Regulatory Utility Commissioners, the Organization of PJM States, the Mid-Atlantic Conference of Regulatory Utility Commissioners, and the Electric Power Research Institute Advisory Council. Commissioner Phillips was unanimously confirmed by the Senate and brings the FERC back to its full complement of five commissioners.

Mark your calendars…***carefully***! In an order issued late Friday, December 10, 2021, FERC denied requests for rehearing of its non-order allowing the Southeast Energy Exchange Market (SEEM) to go into effect by operation of law. FERC determined the requests for rehearing were two days late. Here's how: generally, a request for rehearing is due no later than 30 days following FERC final action on a filing. In this case, however, FERC issued no order due to a 2-2 tie among the commissioners and, as a result, SEEM went into effect by operation of law on October 12. FERC issued an order on October 13 confirming the effective date. Petitioners calculated their deadline for requesting rehearing based on the October 12 effective date, which would have put their 30-day deadline at November 11…which was a federal holiday. So they filed November 12. The problem is that FERC says its 60-day clock began on October 11, despite that date also being a holiday, because to act the FERC had *until the later of* sixty days after a completed filing is submitted (October 10—a Sunday) *or* the date before the requested effective date (October 11—a holiday). And that meant requests for rehearing were due by October 11 + 30 days = November 10, 2021. Rest assured that FERC's conclusion here will not be the end of the story, however this saga at least provides strong encouragement to very carefully calculate rehearing deadlines when a filing goes into effect by operation of law.

The FERC has extended the waiver of its requirement that filings be notarized or supported by sworn declarations until March 31, 2022. The FERC also extended the waiver of its requirements to hold in-person meetings or submit notarized documents for open access transmission tariffs.

The FERC's next open meeting is December 16, 2021. The FERC is expected to address the following topics of interest:

1. Action in its rulemaking docket regarding managing transmission line ratings.
2. A new rulemaking proceeding on Rate Recovery, Reporting, and Accounting Treatment of Industry Association Dues and Certain Civic, Political, and Related Expenses.
3. Action on a complaint by a wind generator regarding SPP's affected system studies process for the project.

4. Action on a protest by Northwestern Corporation to a QF certification for a solar plus storage facility. The protest is based both on *Broadview* (exceeding 80 MW) and on the basis that the solar and battery systems are separate power production facilities that must be calculated individually and then aggregated. While the protest recognizes that the former is at issue in the appeal of *Broadview*, the latter was not addressed by FERC in *Broadview*.

Market-Based Rate (MBR) Database: FERC extended the deadline for baseline submissions to the new MBR relational database. Baseline submissions will now be due February 1, 2022. Baseline submissions are required for all entities with MBR authorization.

Reactive Power Capability Compensation: On November 18, 2021, FERC issued a Notice of Inquiry (NOI) seeking comments on reactive power capability compensation and market design. (Link to NOI here.) Reactive power is a critical component of the bulk electric system. Almost all bulk electric power is generated, transported, and consumed in alternating current (AC) networks. These AC systems consume both real and reactive power. Reactive power supports the voltages necessary for system reliability to allow the supply of real power from generation to load. Reactive power is considered an ancillary transmission service, and costs are recovered separately from the cost of standard transmission service.

In 1999, the FERC approved a method proposed by American Electric Power Service Corporation (AEP) for allocating costs for a synchronous generator between real and reactive power capability. *Am. Elec. Power Serv. Corp.*, Opinion No. 440, 88 FERC ¶ 61,141 (1999). This so-called AEP methodology is now recommended by FERC when an entity seeks to recover reactive power capability costs.

Over the last decade, reactive power compensation has become a key component in cost recovery for renewable resources, and the AEP methodology has been applied to non-synchronous generators such as solar and wind facilities. The NOI recognizes this shift in the industry. FERC noted that it has processed approximately 260 reactive power proceedings in PJM and 125 reactive power proceedings in MISO, the two RTO/ISOs where reactive power compensation is greatest. The majority of these proceedings involve renewable resource generators.

In the NOI, FERC is seeking comments on the applicability of the AEP methodology to renewable resources. The AEP methodology was initially developed for synchronous generators, and FERC seeks to examine the appropriateness of its application to non-synchronous generators. Specifically, FERC seeks comments on the following:

1. The failure of the AEP methodology to account for the degradation of a resource's reactive power capability over time.
2. The applicability of the cost-of-service ratemaking principles in the AEP methodology to the categories of equipment unique to non-synchronous generators.
3. The lack of specific accounts in the Uniform System of Accounts for non-hydro non-synchronous resources.

4. The lack of verifiable data underlying the cost-of-service rates. A majority of the reactive power applicants have been granted waivers from FERC's accounting and reporting requirements, so these applicants do not have accounting entries as found in FERC Form No. 1 to support the reactive power rates.
5. Whether the PJM compensation model for reactive power should be revised due to possible overcompensation. The PJM market monitor has argued that reactive power compensation should not be provided via a separate cost-of-service compensation model, and instead should be determined based on capacity markets in PJM. Alternatively, the PJM market monitor argues that the current scheme should be revised to avoid overcompensating resources for reactive power capability.

FERC also seeks comment on (i) alternatives to the AEP methodology, particularly with respect to different resource types; (ii) the various compensation models across the RTO/ISOs; and (iii) whether resources connected to a distribution system should be eligible for reactive power capability compensation through transmission rates.

Initial Comments are due January 31, 2022, and Reply Comments are due February 28, 2022.