REGULATORY UPDATE FOR DECEMBER 6, 2021 (WEEK OF NOVEMBER 29)

CALIFORNIA PUBLIC UTILITIES COMMISSION (CPUC or COMMISSION)

Governor Newsom Appoints Alice Reynolds to CPUC

On November 22, 2021, Governor Newsom announced that he was naming Senior Advisor to the Governor for Energy Alice Reynolds to serve as the next president of the Commission. Current Commission President Marybel Batjer will be retiring effective December 30, 2021.

New Proposed Decisions and Draft Resolutions[1]

Draft Resolution E-5174. This resolution modifies the Energy Division's Advice Letter (AL) submission process to eliminate hard copy submission and delivery of energy advice letters and associated documents and implements electronic-only submission and delivery. It also authorizes Energy Division Staff to make future similar, minor submission procedural changes via letters or notices emailed to utilities and parties and posted on the CPUC's public website.

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 San Diego Gas & Electric Company (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.

Voting Meetings

The Commission held a voting meeting on December 2, 2021. The agenda included the following energy-related items. The Commission's next voting meeting will be held December 16, 2021. The agenda is scheduled to be published December 6, 2021.

Item 5. Draft Resolution L-613. On November 19, 2020, Brandon Rittiman sought the disclosure of certain records of the CPUC pursuant to the California Public Records Act. Rittiman sought all communications between any CPUC employee and any agent or employee of the Governor's office concerning two emails sent by Terrie Prosper, who is the Director of the CPUC's News and Outreach Office, to Rittiman on November 18 and November 29, 2020. This Resolution would deny the appeal of Rittiman for a reconsideration of the Commission Staff

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[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.

determination that the records he sought are exempt from disclosure pursuant to California Government Code section 6254(l), which exempts from public disclosure "[c]orrespondence of and to the Governor or employees of the Governor's office or in the custody of or maintained by the Governor's Legal Affairs Secretary." **Approved.**

Item 7. 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. **Held to December 16, 2021.**

Item 8. Draft Resolution E-5170. This Resolution adopts the Financial Security Requirement (FSR) calculations in Pacific Gas and Electric Company (PG&E) AL 6188-E, Southern California Edison Company (SCE) AL 4494-E-A, and SDG&E AL 3757-E-A for the Community Choice Aggregators (CCAs) operating in the service territories of those three investor-owned utilities (IOUs). The three IOUs are required biannually to make an AL indicating the amount of the FSR that each CCA must provide, as set forth in D.18-05-022. However, due to the timing of this Resolution and the imminent filing deadline of the IOUs' next FSR AL in November 2021, this Resolution does not require the CCAs to post new FSRs until the November 2021 AL filing has been approved. **Approved.**

Item 10. R.19-09-009 (Microgrids and Resiliency). This decision adopts enhanced summer 2022 and summer 2023 requirements for PG&E and SDG&E. First, PG&E shall file a Tier 2 AL, within 45 days of the effective date of this decision, to expand its Temporary Generation Program for filling the system capacity shortfalls anticipated in the summers of 2022 and 2023. Second, SDG&E may procure up to four circuit-level energy storage microgrid projects that may provide a total of 160 MWh of capacity to fill system capacity shortfalls anticipated in the summers of 2022 and 2023. The procurement of these four circuit-level energy storage microgrid projects is conditioned upon these resources providing peak and net peak grid reliability benefits in the summers of 2022 and 2023. SDG&E shall file a Tier 2 AL, within 30 days of the effective date of this decision, seeking implementation authorization for procurement of these four circuit-level energy storage microgrid projects. SDG&E shall comply with the Cost Allocation Mechanism for utility-owned generation previously adopted in Rulemaking 20-11-003. Furthermore, SDG&E shall comply with any subsequent modifications to the Cost Allocation Mechanism adopted in Rulemaking 20-011-003. The decision suggests that Los Angeles County propose its Eastern Avenue Emergency Operations Battery Storage Microgrid Project, a Los Angeles Department of Public Health Solar and Battery Storage Project, and Pitchess Detention Center Solar and Battery Storage Project in the Microgrid Incentive Program for consideration, subject to the overall eligibility, cost, and budget constraints of the Microgrid Incentive Program. **Signed, D.21-12-004.**

Item 12. This decision adopts a $0.00652/kWh rate amount for the Wildfire Fund Non-Bypassable Charge to collect a $1,000,400,704 revenue requirement for January 1, 2022, through December 31, 2022, pursuant to AB 1054, enacted as an urgency measure and signed by the Governor in July 2019. **Signed, D.21-12-006.**

Item 20. R.13-11-005 (EE Portfolios). This decision approves several initiatives designed to produce emergency peak demand (during 4:00 p.m. - 9:00 p.m.) and/or net peak (during 7:00 p.m. - 9:00 p.m.) demand reductions through energy-efficiency actions by the summers of 2022 and 2023. The decision was developed in response to Governor Newsom's July 30, 2021 Emergency Proclamation. This decision approves $185 million in incremental energy-efficiency budgets for program years 2022 and 2023, while also allowing shifting of energy-efficiency funds previously allocated to address summer reliability objectives. **Signed, D.21-12-011.**

Item 24. R.20-11-003 (Summer Reliability). This decision adopts a number of supply- and demand-side requirements to ensure there is adequate electric power in the event of extreme weather during times of greatest need in summers 2022 and 2023. The decision adopts the following demand-side changes:

- Expansion of the Emergency Load Reduction Program (ELRP) adopted in Phase 1 of this proceeding;
- Allows aggregation of vehicle to grid managed charging and discharge to support the grid at net peak;
- Broadens the Flex Alert media campaign to focus on the new Residential ELRP program and continue existing activities into 2022 and 2023;
- Makes changes to existing demand response programs, both on a statewide basis and to individual programs that pertain to each major electric IOU;
- Approves a large smart thermostat incentive program designed to reduce air conditioning a few degrees during emergencies; and
- Adds pilots to test the effectiveness of dynamic rates that change rapidly in response to grid emergencies.

The decision would also adopt the following supply-side measures:

- Allows energy storage projects that are not fully deliverable as long as they provide peak and net peak grid reliability benefits in summer 2022 or 2023;
- Expands the use of a centralized procurement entity as a means of procuring reliability resources located in local areas; and
- Encourages accelerated online dates for procurement already ordered.

Signed, D.21-12-015.

Item 25. 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. **Held to December 16, 2021.**

Item 26. Draft Resolution SED-6. In this Resolution, the Commission approves an Administrative Consent Order and Agreement between the Commission's Safety and Enforcement Division and PG&E to resolve all issues involving the 2019 Kincade Fire. PG&E agrees to pay a $40 million fine to the General Fund of the State of California and to not seek rate recovery of capital expenditures in the amount of $85 million for the permanent removal of abandoned transmission facilities within its service territory, for a total of $125 million. **Approved 3-2, Commissioners Shiroma and Houck dissenting.**

CALIFORNIA ISO (CAISO)

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.

Maximum Import Capability Enhancements. The CAISO held a public stakeholder call on November 23, 2021, to discuss the draft final tariff language and draft Business Practice Manual language for the Maximum Import Capability Enhancements initiative. Written comments on the draft final proposal and draft tariff language are due December 7, 2021.

CALIFORNIA ENERGY COMMISSION (CEC)

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

- 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.

Recordings of recent 2021 IEPR workshops on the electricity and demand forecast for 2021-2025 and supply-side demand response are now available online.

Power Source Disclosure Program

The CEC plans to institute a formal rulemaking to consider limited modifications to Title 20, California Code of Regulations, section 1390 *et seq.* and will hold a pre-rulemaking remote workshop on December 7, 2021 at 9:00 a.m. to solicit stakeholder comment on proposed changes to the Power Source Disclosure (PSD) Program regulations. The PSD regulations require California retail electricity suppliers to disclose to consumers the electricity sources in their portfolios compared with the mix of electricity sources providing power for California.

According to the workshop Notice, the discussion items for the workshop will include:

- Power Charge Indifference Adjustment Resource Allocations
- Audit Requirements and Alternative for Public Agencies
- Power Content Label (PCL) Due Dates
- New Community Choice Aggregation GHG Reporting Requirements
- Unbundled Renewable Energy Credit Reporting Requirements
- PCL Template Formatting

CEC Business Meetings

The next CEC Business Meeting is scheduled for December 8, 2021. The meeting agenda is available here.

CALIFORNIA AIR RESOURCES BOARD (ARB)

ARB's next regular Board meeting will be held December 9, 2021. The agenda is available here.

On December 7, 2021, ARB will hold a virtual workshop on the Community Air Protection Program developed under AB 617, including draft recommendations for the 2021 communities and the community selection process. The agenda and a link to the meeting are available here.

ARB is holding virtual public workshops as part of the AB 32 Scoping Plan Update. On December 13, 2021, ARB will hold a public workshop on building decarbonization. Comments on the recent technical workshop on modeling land management scenarios for natural and working lands can be submitted here on or before December 22, 2021. 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.

MINNESOTA PUBLIC UTILITIES COMMISSION

1. Minnesota Power Rate Case, PUC Docket No. 21-335

On December 1 and 2, 2021, the Minnesota Public Utilities Commission ("Commission") met to consider Minnesota Power's general rate case that was filed on November 1, 2021. The Commission heard oral argument and questioned stakeholders on December 1 and deliberated on December 2. The Commission accepted Minnesota Power's filing, referred that matter to the Office of Administrative Hearings for contested case treatment, suspended Minnesota Power's proposed rate increase, and permitted the utility to collect an interim rate increase.

The hearing largely focused on addressing the interim rates aspect of Minnesota Power's case. Prior to the hearing, Minnesota Power, Citizens Utility Board of Minnesota ("CUB"), and Energy CENTS Coalition ("ECC") filed an alternate interim rate proposal (the "Alternate Proposal") to reduce residential customers' interim rates by 50% with Minnesota Power tracking the difference for potential true-up at a later date. Importantly, the Alternate Proposal did not suggest that the Commission find exigent circumstances as contemplated by Minn. Stat. § 216B.16, subd. 3. Other stakeholders submitted comments noting that the Alternate Proposal could harm non-residential customers who will pay a larger portion of interim rates without any assurance of how an interim rate refund or surcharge would be treated at the end of the case.

Throughout questions and deliberations, the Commission expressed interest in reducing interim rates for the residential class; however, the Commission spent considerable time analyzing whether it needed to find exigent circumstances as well as finding specific record support for the 50% reduction for residential customers. Despite parties pointing to no direct evidence in the record, the Commission ultimately took judicial notice of extrinsic evidence to justify a finding of exigent circumstances and the reduction of residential interim rates by 50%. The Commission declined to address the interim rate refund or surcharge calculation at this stage of the case, preferring to preserve flexibility for how it would address the potential refund/surcharge scenarios upon completion of Minnesota Power's case. A written order is pending.

<u>2. CenterPoint Energy Resources Corporation Gas Rate Case and Stay Out Proposal, PUC Docket Nos. 21-755 and 21-435</u>

The Commission also met on December 1 and 2, 2021, to consider CenterPoint Energy Resources Corporation's ("CenterPoint") natural gas rate case and simultaneous petition to stay out/withdraw its case. Upon review, the Commission denied CenterPoint's request to stay out of a rate case, and the Company's natural gas general rate case will proceed and was referred to the Office of Administrative Hearings for contested case treatment. Written orders are pending.

<u>3. Commission Hearings on December 8 and 9, 2021</u>

The Commission will meet at 8:00 a.m. PT on December 8, 2021, to hear oral arguments and conduct commissioner questions on four Northern States Power Company, dba Xcel Energy ("Xcel") matters: (1) the natural gas rate case; (2) the natural gas rate case stay out/withdrawal proposal; (3) the base cost of gas; and (4) Xcel's electric multiyear rate case. The Commission will then convene at the same time on December 9, 2021, to complete deliberations and issue oral decisions.

<u>TEXAS</u>

Texas Railroad Commission

On November 30, 2021, the Texas Railroad Commission adopted rules for critical designation of natural gas infrastructure in response to Senate Bill 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 a critical customer information to their electric utilities so that their electric utilities have the correct information for purposes of supplying power to the facilities.

The rules also narrow a controversial opt-out provision in Senate Bill 3. Senate Bill 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.

Public Utility Commission of Texas

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 Senate Bill 3 (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 generators 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 generators 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

OPUC Declines to Issue Declaratory Ruling in DR 57 re Small Generator Interconnection

Last Thursday, the OPUC issued Order 21-455, which declined to substantively consider the petition for a declaratory ruling filed by the Renewable Energy Coalition, Community Renewable Energy Association, and Oregon Solar and Storage Industries Associated. In its order OPUC declined to consider a utility's obligations towards small interconnection customers that seek to pursue an independent system impact study under OAR 860-082-0060(7)(h). Among other reasons, OPUC's decision was due to the fact that any declaratory ruling would not have a binding effect on the petitioners because as trade associations the petitioners are not interconnection applicants and would not have cause to provide a public utility with an independent system impact study. Further explanation of the OPUC's decision can be located in the order here.

WASHINGTON

WUTC Meetings this Week

On Thursday, December 9 at 9:30 a.m. PST, the WUTC will host an open meeting in a wide range of dockets including UE-210829 (regarding PacifiCorp's petition for exemption under WAC 480-100-605, which requires the utility to consider the social cost of greenhouse gases in its clean energy implementation plan). The meeting agenda and dial-in details can be located here.

NEW YORK (NYPSC AND NYISO)

New York Public Service Commission

On November 30, 2021, Governor Kathy Hochul announced that the New York State Energy Research and Development Authority has finalized contracts with Clean Path New York LLC for its Clean Path NY project and H.Q. Energy Services (U.S.) Inc. for its Champlain Hudson Power Express project. The projects stem from the New York Public Service Commission's (PSC) Tier 4 energy solicitation process, and will deliver renewable energy to New York City. The projects are vital to fulfill the Climate Leadership and Community Protection Act (CLCPA) requirement that New York be powered by 70 percent renewable energy by 2030.

If approved by the PSC, the selected projects are expected to deliver 18 million megawatt-hours of clean energy per year, or more than a third of New York City's annual electric consumption, from a plethora of clean energy sources including wind, solar, and hydroelectric power, backed by energy storage, from upstate New York and Quebec.

New York Independent System Operator

On December 2, 2021, the New York Independent System Operator (NYISO) provided an update regarding market changes that will be necessary to accommodate the thousands of megawatts of renewable resources coming online in New York over the next decade to meet the clean energy requirements under the CLCPA.

These market charges are components of NYISO's Grid in Transition program, and include carbon pricing and buyer-side mitigation to distributed energy resource participation models, including for storage, hybrid, and co-located resources.

NYISO provided updates regarding the current market improvements that are underway or completed, including (i) implementation of a software design for carbon pricing; (ii) buyer-side mitigation to distributed energy resource participation models; (iii) implementation of software-defined wide area network (SD-WAN) in the Distributed Energy Resource Participation Model; and (iv) implementation of the hybrid storage model, including integration of the rules and software needed to enable large-scale weather dependent and energy storage resources to participate as co-located resources behind a single interconnection point.

NYISO's plan for 2022 includes continued efforts to balance intermittency and improve price formation. Additionally, NYISO has a number of capacity and new resource integration projects for 2022.

The 2021 Master Plan, which provides a multi-year vision for future NYISO enhancements, anticipates reviewing the Real-Time Market Structure project in 2025. However, in this update, NYISO asked for stakeholder input regarding whether the review of the Real-Time Market Structure project should begin in 2022.

FEDERAL ENERGY REGULATORY COMMISSION (FERC)

Willie L. Phillips was sworn in as a FERC Commissioner last week. 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 (DCPSC). He previously served as Assistant General Counsel for the North American Electric Reliability Corporation (NERC) and has served in leadership roles for the National Association of Regulatory Utility Commissioners (NARUC), the Organization of PJM States (OPSI), the Mid-Atlantic Conference of Regulatory Utility Commissioners (MACRUC), and the Electric Power Research Institute (EPRI) Advisory Council. Commissioner Phillips was unanimously confirmed by the Senate and brings the Commission back to its full complement of five commissioners.

Last week on December 1, FERC denied a petition for waiver filed on behalf of several project company subsidiaries of Invenergy, seeking relief from financial posting requirements in the SPP generator interconnection process. The petitioners argued that SPP's interconnection study results contained errors that they were looking to resolve before committing additional non-reimbursable capital to the interconnection process. FERC ultimately denied the waiver, however, distinguishing its decision from an order from just three months ago where it granted a waiver in arguably-similar circumstances. The order is here.

The Commission's next open meeting is December 16, 2021.

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 (AEP) Service Corporation 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:

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; and
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.