RTO Insider

Your Eyes and Ears on the Organized Electric Markets

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Multiple Entities, Markets Now Beckon in West

By Tom Kleckner

Black Hills Energy's Dan Kline (far left) updates Colorado PUC Commissioners (left to right) Frances Koncilja, Chair Jeffrey Ackermann and Wendy Moser on Mountain West's integration into SPP. | *© RTO Insider*

DENVER — Out in the wild, wild West, four different entities are offering reliability coordination (RC) or market services, Mountain West Transmission Group members are pursuing RTO membership with SPP, and CAISO is pressing the California legislature to allow it to become an RTO.

That was the backdrop of another Colorado Public Utilities Commission public information session last week, its fifth, on the potential marriage between SPP and Mountain West.

"We here are in control of the dowry. We have to be persuaded before this can go any way you want it," Commissioner Frances Koncilja said, reminding her audience that the PUC has jurisdiction over Mountain West members Black Hills Energy and Public Service Company of Colorado (PSCo).

The March 20 session, "What is Going on with Reliability and Market Services in the West?", brought together SPP, Mountain West, CAISO, PJM and Peak Reliability, all of which are considering offering RC services or setting up markets in the West.

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CAISO Moves Ahead with Market Changes (p.4)

States, Utilities, RTOs Push Back on Storage Order

By Rory D. Sweeney

A wide range of stakeholders filed comments this week requesting clarification or rehearing of FERC's Order 841 requiring RTOs and ISOs to revise their tariffs to allow energy storage resources full access to their markets (RM16-23).

While their concerns included specific cost and billing issues, most comments focused on the high-level interaction between federal and state oversight in energy markets and argued that the order had overstepped FERC's authority. (See *FERC Rules to Boost Storage Role in Markets*.)

Implementation Issue

Subsidiaries of AES, including Indianapolis Power & Light, requested clarification that the order — which doesn't require implementation for nearly two years — doesn't supersede MISO's compliance requirements in response to IPL's 2016 complaint that its 20-MW battery was being denied market participation despite its capability. That implementation is

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FERC OKs MISO Plan to Expand Storage (p.11)

Group Contests 'Supplementals' Ruling as PJM, TOs Advance

By Rory D. Sweeney

The fight between PJM transmission owners and customers over supplemental projects isn't over yet, despite a FERC order approving the RTO's plan.

Both sides made filings at FERC this week in the docket determining how oversight of the local, TO-driven projects is handled (ER17-179).

PJM and its TOs said in a compliance filing last week that they are willing to revise their original proposal to provide stakeholders more time to examine the reasons why a TO decides to pursue a supplemental project, but the RTO said many other deadlines can't be adjusted because they must fit within the timing of its current processes. (See *PJM, TOs Propose FERC*

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Ky. Rejects AEP Supplemental Tx Project (p.18)

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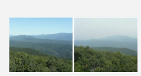

DC Circuit Denies EPA Haze Rule Challenges (p.26)

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IN THIS WEEK'S ISSUE

CAISO NEWS

Berkeley Looks at EVs, Markets, Gas Withholding

By Jason Fordney

| © RTO Insider

Berkeley, Calif. — Electric vehicles are increasing on California highways, but future growth is dependent on solving critical issues around standardization of charging infrastructure, a state regulator said last week.

"The electric vehicle market is transforming on a daily basis," California Public Utilities Commissioner **Carla Peterman** said on Friday at the annual POWER Conference at University of California Berkeley. There are about 376,000 light duty EVs, 43 models and 22,000 public charging stations in the state, she said.

"Our investor-owned utilities have a critical role to play in this market," Peterman said, noting that utilities provide EVs fuel, manage the electric distribution system and help build related infrastructure. The vast majority of charging in California happens at home, she said.

Correctly addressing the standardization of charging infrastructure is extremely important, Peterman said, and there are often worries of stifling innovation because of regulations and cybersecurity, she said. (See *Visibility Key as EVs Seek Growth Beyond Early Adopters*.)

Gov. Jerry Brown in January issued an executive order to pursue 5 million zero-emission vehicles in the state by 2030, including 250,000 plug-in EV chargers and 10,000 DC fast-chargers. A 2013 executive order encouraged development of dual-compatibility charging infrastructure using the two main types of charger connections.

"We are scaling at the rate that we see some benefits of standardization," Peterman said.

Peterman discussed an issue paper on EV charging standards presented at the conference by Massachusetts Institute of Technology researcher Jing Li. The research showed that under mandatory compatibility standards, companies would reduce duplicative investment in charging infrastructure, but the size of the electric vehicle market would expand.

Peterman, who has been on the CPUC since 2012, holds a doctorate in energy and resources from Berkeley and is also a former member of the California Energy Commission.

The CPUC in January approved 15 utility projects designed to speed EV adoption, including the installation of fast-charging infrastructure and electrification of school buses and delivery vehicles.

Former FERC Chairman **Norman Bay** also spoke Friday, commenting on a paper by researchers at the University of Maryland College Park and Harvard University on the role of energy markets and environmental regulations in reducing coal-fired power plant profits and electricity emissions.

"Energy policy can really drive environmental objectives," Bay said, mentioning FERC rulemakings on transmission planning, energy storage, distributed energy resources, demand response and competitive wholesale markets. Well-functioning markets send the signals needed for investment and retirement, reducing the curtailment of renewables, he said.

Bay also discussed how CAISO's Energy Imbalance Market (EIM) is growing and helping to address the state's "duck curve." Obstacles to expanding markets includes their voluntary nature, getting governance correct, jobs, energy costs and reservations about markets in the West.

"I think there is some residual fear of markets, so thank you Enron and the Western electricity crisis," Bay said, adding that educating people on the benefits of markets is key to their growth.

At the conference, Matthew Zaragoza-Watkins of Vanderbilt University discussed his research into what he said was withholding behavior by natural gas pipeline operators in New England. The research showed that some nodes were disproportionately served by specialized types of contracts that allow firms to call for gas on demand and to make large adjustments without notice in the last few hours of the day.

The behavior strongly affected gas and electricity prices, he said, and transferred $3.6 billion from ratepayers to generators and fuel suppliers over a three-year period, about half of which occurred in the winter of 2013-2014, he alleged.

FERC staff looked into the allegations, after the research was presented by the Environmental Defense Fund in an August 2017 paper. There was no withholding of pipeline capacity, and the EDF study was flawed and led to incorrect conclusions, FERC said on Feb. 27.

CAISO NEWS

CAISO Moves Ahead with Market Changes

By Jason Fordney

FOLSOM, Calif. — The CAISO Board of Governors on Thursday approved a controversial proposal on congestion revenue rights and market power mitigation, changes with major financial implications for its markets.

The changes are a result of the CAISO Department of Market Monitoring's conclusion that the annual CRR auctions are costing retail electricity customers hundreds of millions of dollars by forcing them to be unwilling partners in losing transactions.

CAISO's proposal limits CRR sources and sinks to only the combinations needed to hedge congestion costs associated with delivering supply. Auction participants can currently purchase CRRs at generator locations, load locations, trading hubs, pricing nodes, and import and export scheduling points.

Another change establishes a deadline to report transmission outages prior to the auctions to more accurately estimate transmission capacity available for CRR purchases.

The CRR auctions have been highly profitable for financial interests, leading to heavy debate and questioning of CAISO's logic. That debate continued Thursday, with the broadest consensus being that the board-approved changes, which will be submitted for FERC approval, only partially addressed the situation. The ISO says further alterations to the CRR process are in the pipeline.

"This is a serious issue that has to be fixed," Chairman David Olsen said as the board unanimously approved the proposal.

Governor Ashutosh Bhagwat said that without voluntary sellers, "it's not a real market," and he asked whether CRRs could be handled through bilateral transactions.

"These are not voluntary sellers," he said of CRRs, "and it's not working."

There had been much discussion during development of the proposal over whether it would overly limit legitimate hedging activity. (See *CAISO Urged to Take Slower CRR Approach*.)

During Thursday's discussion, CAISO CEO Steve Berberich responded to the criticism by saying that CRRs are a valid market tool. But "this is a watershed moment for this organization to send a message … and that is, we agree the current situation has to change," he said.

By the Monitor's calculations, the CRR auction has had a $750 million deficiency for retail ratepayers, and annual deficiencies will grow in 2018 under the current structure. The Monitor did not support the changes and said the auction should be based on "willing buyers and sellers" and that more fundamental flaws should be addressed.

CAISO Approves Bidding Rule Changes

The board also approved CAISO's Commitment Cost and Default Energy Bid Enhancements (CCDEBE), another contentious proposal that is opposed by some investor-owned utilities.

The proposal replaces a static commitment cost bid cap with a local market power mitigation test, which identifies whether a resource needs to be committed to relieve a transmission overload or other constraints. The ISO will only mitigate bids when a generator fails the test.

The Energy Imbalance Market (EIM) Governing Body earlier this month gave advisory approval of the changes, subject to a condition that staff brief it and the CAISO board at the 12-month point following implementation of the changes. (See *EIM Governing Body Approves CAISO Bidding Flexibility*.) The ISO has been developing the proposal since last year to address what is said to be inadequate cost recovery for generators.

Under the current rules, bids are capped at the generator's reference level, which is determined by multiplying costs — based on published natural gas price indices — by 125%.

CAISO recently adjusted the proposal by lowering the proposed multiplier for the first 18-month period after implementation to 150% from 200%. The ISO plans to phase in commitment cost bidding flexibility, first raising the commitment cost multiplier to 150% for the first 18 months, and then increasing it to 300% if no issues arise.

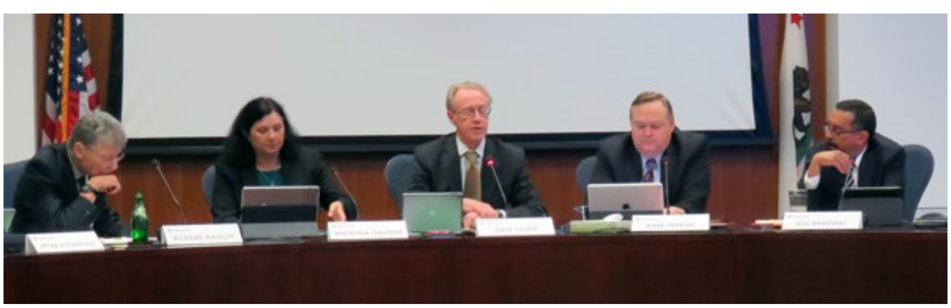
Pacific Gas and Electric wants CAISO to maintain the existing 125% cap, saying CCDEBE will have limited benefits. NRG Energy said the proposed caps are too low.

Board Approves Transmission Plan

The board on Thursday also approved the ISO's 2017-2018 transmission plan, which cuts $2.7 billion from previously approved projects. The plan outlines the proposed design and construction of 17 new projects costing about $271 million. It recommends cancellation of 18 projects and revises 21 others in PG&E's service area, and two in the San Diego Gas & Electric territory.

The main reasons for the reductions were changing load forecasts, energy efficiency improvements and increased residential rooftop solar systems. (See *CAISO Recommends $2.7 Billion Tx Spending Cut*.)

The approval will be used to launch the next planning phase, as it is plugged into the California Public Utilities Commission transmission procurement plan for utilities. The process will determine eligibility for incentive rate cost recovery from FERC by virtue of being part of a state plan.



The CAISO Board of Governors (left to right): Richard Maullin, Angelina Galiteva, Dave Olsen, Mark Ferron and Ashutosh Bhagwat. | © *RTO Insider*

CAISO NEWS

CAISO: New 2019 RMR Contracts Possible

By Jason Fordney

A CAISO official revealed last week that a generation owner has approached the ISO about seeking a 2019 reliability-must-run contract, a development likely to sharpen an ongoing stakeholder debate about the out-of-market payments.

Keith Johnson, CAISO infrastructure and regulatory policy manager, acknowledged the generator's request in response to a series of questions during an hourslong stakeholder meeting that at times became slightly charged as market participants delved deeply into the ISO's energy procurement policies.

Generation owners typically inquire about an RMR when they are considering shutting down a unit and want to know if it might be eligible to receive one of the increasing number of contracts the grid operator has been inking in recent years to keep gas-fired plants available for reliability reasons.

Stakeholders have questioned whether retirement notifications and subsequent discussions between generation owners and CAISO should remain confidential or be announced immediately. In response, the ISO is working on rule changes that would allow it to provide the public early notification of unit retirements under different scenarios.

The notification changes are included in "Phase 1" of a broader set of RMR and capacity procurement mechanism (CPM) changes that CAISO is developing. Another primary component of the program is a must-offer requirement for RMR units that will "look, feel and act more like resource adequacy," Johnson said.

The ISO on March 13 issued its draft final proposal for Phase 1, with the goal of getting approval from the Board of Governors in May, in place for fall contracting for the 2019 operating year. Comments are due April 10 on the proposed rule changes, a topic of a similarly pointed stakeholder session last month. (See *CAISO, Stakeholders Debate RMR Revisions*.)

CAISO has received plenty of feedback about including more RMR/CPM reforms in Phase 1, but Johnson told stakeholders March 20 that "we are avoiding shoehorning stuff in there that can't be adequately vetted with you."

Owner and Facility	Capacity (MW)	Condition 1 or 2
Dynegy Oakland	165	Condition 2
Calpine Feather River	47	Condition 2
Calpine Yuba City	47	Condition 2
Calpine Metcalf Energy Center	593	Condition 2

Current RMR facilities | *CAISO*

More comprehensive RMR/CPM refinements are being considered for a later Phase 2, CAISO said in a presentation during the meeting. Thirteen items are up for discussion for the second phase, including more clarification regarding the differences between RMR and CPM, and whether the two programs can be merged into one procurement tool.

Additionally, CAISO had already developed and submitted a package of RMR changes to FERC, which it said it expects to be approved on April 12.

RMR critics — which include the California Public Utilities Commission — say the growing need for the contracts points to market deficiencies that call for broader reforms across the market. The commission replaced a previous set of CAISO-approved RMRs with energy storage. (*See CPUC Retires Diablo Canyon, Replaces Calpine RMRs*.)

NRG Energy subsidiary GenOn recently notified the commission that it plans to retire three gas-fired plants by early next year, possibly setting them up for RMRs. (See *NRG Set to Retire California Gas Plants*.)

ERCOT NEWS

TAC Briefs


| © RTO Insider

Members Approve Changes Removing RUC Capacity from ORDC

AUSTIN, Texas — ERCOT's Technical Advisory Committee last week approved staff's recommendation to remove reliability unit commitment (RUC) capacity from the grid operator's operating reserve demand curve (ORDC), passing a revision request with minimal discussion.

Staff's other binding document revision request (OBDRR) revises the online and offline capacity reserves for those resources online during a RUC instruction, and meets the Public Utility Commission of Texas' directive to remove RUC capacity from the ORDC as part of its project assessing the Texas market's price formation rules (No. 47199). (See "Commission Directs ERCOT to Revise ORDC," *Marquez to Depart Texas PUC*.)

The OBDRR, which passed unanimously, will go to a vote of the Board of Directors during its April 10 meeting. Kenan Ogelman, ERCOT vice president of commercial operations, said staff will work "expeditiously" to get the change made by July 1.

"We've committed to the PUC that we would implement this as early as possible," Ogelman said during the TAC's March 22 meeting.

The ORDC creates a real-time price adder to reflect the value of available reserves and is meant to incentivize resources to produce more energy and reserves. PUC staff recommended removing both RUC and reliability-must-run capacity from the ORDC, saying it would ensure that scarcity pricing is accurate and reflective of market dynamics.

ERCOT staff said it would take two or three months and $30,000 to $40,000 to make the software changes, an increase from the $15,000 to $25,000 estimate ERCOT gave the PUC earlier this month. The affected systems include Market Management Systems, data and information products, and analytic data.

ERCOT Legal Staff Delays Bylaw Revisions

ERCOT's legal staff said they need a two-month delay to complete changes to the grid operator's bylaws and articles of incorporation to include additional feedback from stakeholders. Staff was to share with the TAC comments and its recommendations for the board's April 10 meeting but will now not make a final recommendation until the June board meeting.

Vickie Leady, ERCOT's assistant general counsel and assistant corporate secretary, said staff have received "extraordinarily helpful" comments from stakeholders on issues such as definitions of affiliates and membership segments. The bylaws were last revised in 2000.

Some of the market's largest players — American Electric Power, CenterPoint Energy, Exelon, Oncor and Luminant Generation — banded together to provide joint comments.

The delay puts a hold on Southern Cross Transmission's (SCT) bid to become ERCOT's first merchant DC tie operator. (See "Members Debate Southern Cross' Bid to be Merchant DC Tie Operator," *ERCOT Technical Advisory Committee Briefs: Feb. 22, 2018*.)

Oncor and Texas Industrial Energy Customers filed comments recommending SCT be placed in the independent power market segment, while SCT reiterated that it should be placed in the investor-owned utility segment. ERCOT continues to believe that those are the two most appropriate segments for SCT.

Market's Weather-Sensitive ERS down in 2017

ERCOT procured 9.17 MW of weather-sensitive emergency response service (ERS) last summer, about half the amount procured in each of the two previous summers, despite the disruptions caused by Hurricane Harvey.

Weather-sensitive ERS was implemented in 2014 to capture the demand response potential of summer residential and commercial air conditioning loads.

Mark Patterson, manager of market operations support, said the decrease resulted because several transmission and distribution service providers recently modified their standard-offer programs to allow more participation from residential loads — reducing the load that bid to serve as weather-sensitive ERS.

Patterson said on Harvey's worst day, Aug. 29, the hurricane only reduced 20 MW of capacity obligated to provide service from the 2,300 ERS sites in the storm's area.

The grid operator projected it will have spent $49.4 million procuring ERS during the year, leaving more than $577,000 unspent.

TAC Unanimously Approves Protocol Changes

Members unanimously endorsed a nodal protocol revision request (NPRR868) that modifies the hub bus and load zone definitions and price calculations to account for the current usage of power flow buses — as opposed to electrical buses — in the day-ahead market and congestion revenue rights auction systems.

Staff sponsored the NPRR, noting there can be differences between power-flow model buses and electrical buses, making it more suit-able to use power flow buses.

However, electrical buses — physical transmission elements that use breakers and switches to connect loads, lines, transformers, generators and related infrastructure —

Continued on page 7

ERCOT NEWS

Texas Commission Names New Executive Director

By Tom Kleckner

The Public Utility Commission of Texas last week approved the choice of John Paul Urban as its executive director during a special open meeting.

PUC Chair DeAnn Walker said Urban will oversee "something of a reorganization" once he comes on board.

Urban brings a strong political background with him. He worked in a number of legislative positions since graduating from the University of Texas in 2000 and was the PUC's director of government relations for three and a half years before joining NRG Energy in a managerial position.

"Based on his past tenure at the PUC, John Paul has an excellent grasp of the agency's mission and a sterling reputation in both the capitol and our regulated industries," Walker said in a statement. "We are confident in his ability to lead the agency as it fulfills its oversight role."

Urban replaces Brian Lloyd, who announced his resignation from the commission in January. (See *Texas PUC Executive Director to Resign*.)

Walker also announced new titles for two longtime staffers as part of the strategic alignment that Urban's hiring will complete. Thomas Gleeson, who has been at the commission for 10 years, will become the PUC's chief operating officer, while Stephen Journeay will become commission counselor in the Office of Policy and Docket Management.

Journeay, who sits in front of the PUC during open meetings and coordinates the work on dockets, will now report directly to the commissioners, instead of the executive director. He is a licensed attorney and professional engineer and has been with the PUC since 1996.

"When I found out he was reporting to the executive director, it didn't make much sense," Walker said. "He really reports to us."

Walker also announced Andrew Barlow has been hired as the PUC's communications director. Barlow previously served in communications roles for former Texas Gov. Rick Perry and former Texas Lt. Gov. David Dewhurst.

TAC Briefs

Continued from page 6

are used for real-time hub and load zone calculations.

The rewritten formulas will clarify the scenario when buses are de-energized in contingency analyses and align the protocols with ERCOT systems. For the day-ahead and CRR calculations, the LMP of the hub bus is the simple average of the LMPs for each energized power flow bus in the hub. If all power flow buses within a hub bus are de-energized, the LMP does not include the de-energized hub bus. If power flow buses are de-energized under a contingency, the disconnected megawatts are redistributed among the remaining energized buses.

Staff designated the NPRR as urgent and said it would be implemented as soon as possible following board approval.

The TAC also unanimously approved three other NPRRs, two system-change requests (SCRs) and a change to the retail market guide (RMGRR):

Cheryl Mele, Bob Helton and Diana Coleman lead the TAC meeting. | © *RTO Insider*

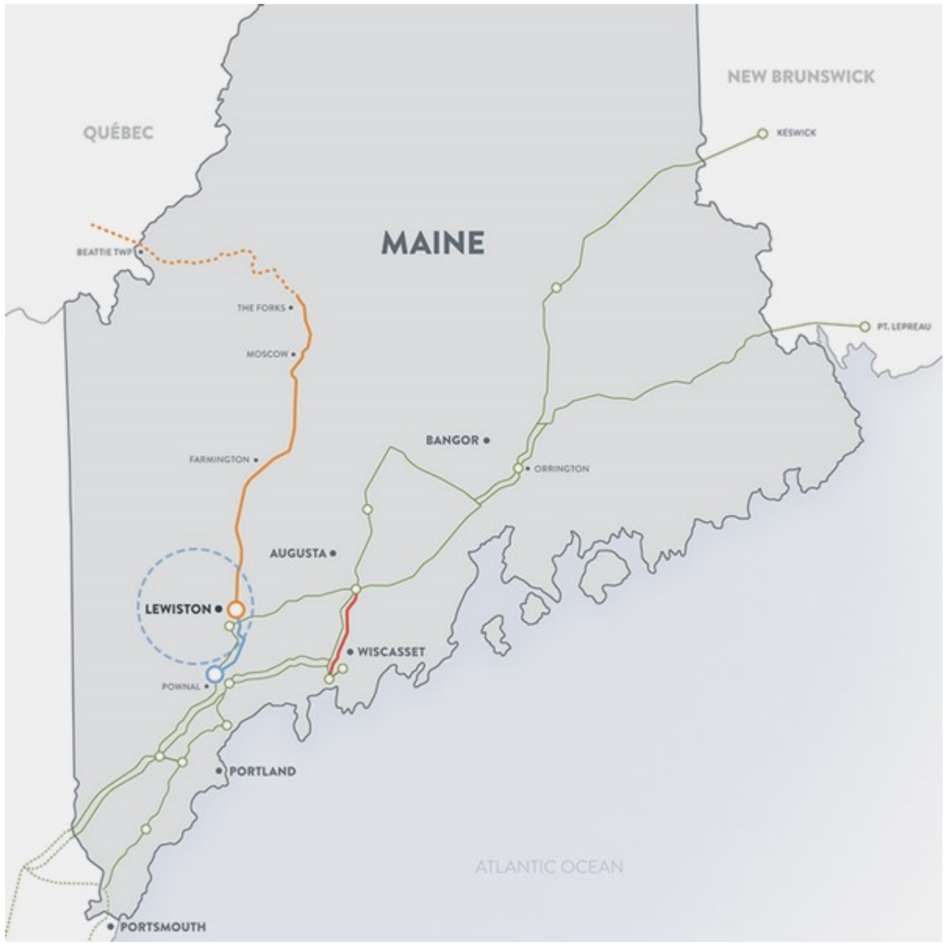
- NPRR858: Requires ERCOT to publish all current operating plans (COPS) data that are submitted by generators, once its confidentiality has expired, a change from the limited subset currently available. The change provides transparency into all intra-hour updates to COPS data, as generators can update them at any time and change aggregate information available to the market.
- NPRR864: Modifies the RUC engine to scale down commitment costs of fast-start resources with less than one-hour starts. Following the change, the RUC engine will recommend slow-start resource commitments only if redispatching online resources and market-based self-commitments of fast-start resources will not resolve the reliability issue. With the change in the generation portfolio, market-based commitment decisions could be made much closer to real time than in the past, allowing more self-commitments to materialize in real time than is reflected in COPS many hours earlier.
- NPRR865: Requires ERCOT to publish shift factors for hubs, load zones and DC ties for the real-time market, mimicking the day-ahead market's current practice and providing more information on the inputs used to calculate pricing aggregations.
- SCR793: Gives transmission service providers access to the same ERCOT-generated status telemetry as the ISO's operators in monitoring line outages with calculated subsynchronous resonance condition monitoring points.
- SCR795: Updates the resource limit calculator's formula for calculating dispatched generation by including the addition of a predicted five-minute wind ramp (PWRR). The PWRR will be calculated from the intra-hour wind forecast and a configurable factor to capture the forecasted five-minute wind ramp, relieving regulation service's burden to cover the five-minute gain or loss of generation from variations in wind, and instead dispatch this energy economically.
- RMGRRR0150: Clarifies the content and format of the competitive retailer safety net spreadsheet within the market guide and removes Section 9, Appendix A1: Competitive Retailer Safety Net Request, which eliminates conflicts between the appendix and language found in Sections 7.4 (Safety Nets) and 7.10 (Emergency Operating Procedures for Extended Unplanned System Outages).

— Tom Kleckner

ISO-NE NEWS

Generators Challenge HVDC Line at Maine PUC

By Michael Kuser



New England Clean Energy Connect project map | *Central Maine Power*

Three top generators in Maine have asked the state's Public Utilities Commission to allow them to intervene late as full parties in the proceeding on New England Clean Energy Connect (NECEC), the 1,200-MW HVDC transmission line proposed by Central Maine Power (CMP) and Hydro-Quebec.

The 145-mile project before the PUC (2017-00232) would deliver Canadian hydropower from Quebec to Lewiston, Maine, at an estimated cost of $950 million. CMP is a subsidiary of Avangrid.

Massachusetts last month selected NECEC as the alternative for the state's 9.45-TWh clean energy solicitation after the New Hampshire Site Evaluation Committee (SEC) unanimously rejected Eversource Energy and Hydro-Quebec's Northern Pass, the 1,090-MW transmission project that the Bay State had awarded the contract just a week earlier. (See *Mass. Picks Avangrid Project as Northern Pass Backup*.)

Survival Mode

Generators Calpine, Dynegy and Bucksport Generation, owners of one-third of the installed electric generating capacity in Maine, told the PUC that awarding a certificate of public convenience and necessity to NECEC would threaten their plants' economic survival and harm the region's competitive wholesale power market.

The PUC plans to issue a decision on the proposal by September, a year after CMP filed, which is standard procedure. Maine Gov. Paul LePage and his Energy Office both wrote letters to the PUC urging it to review CMP's petition in an "expeditious manner" and not delay or suspend the proceeding.

CMP on March 23 responded and said they did not object to the late-filed intervention — if the PUC prohibits the intervenors from reopening phases of the case that have already closed.

The generators "seek to entirely reset the clock in this matter and introduce intervenor testimony in utter disregard of the fact that the commission and the parties are six months into a 12-month case schedule, the period for intervenor discovery on CMP's initial petition has closed, and the deadline for intervenor testimony has passed, not once, but two times," CMP said.

The generators argued that the developer presented reduced wholesale energy and capacity prices in the region and in Maine as the primary benefit of the project and made no case for reliability benefits.

However, CMP did just that in its September 2017 filing: "In addition to the electricity price suppression, [greenhouse gas] reductions and employment and economic development benefits discussed above, the NECEC transmission project will provide Maine resource adequacy and transmission system reliability benefits at no cost to Maine customers."

CMP argued in its initial filing that "transmission upgrades to permit an additional 1,200 MW of generation to interconnect" ensures that NECEC's power "will be deliverable to the New England Control Area. The addition of this non-natural gas-fired capacity (and related energy) will help ensure that ISO-NE has adequate generation resources available to meet load and reserve requirements throughout the year, including especially during periods when natural gas supplies are constrained."

The intervening generators said "it is abundantly clear that the integration of

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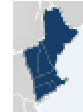
ISO-NE NEWS



Generators Challenge HVDC Line at Maine PUC

Continued from page 8

large-scale, out-of-market (i.e., subsidized) resources within the current ISO-NE market may have profound unintended consequences, which is evidenced by the extensive and challenging stakeholder discussions during the [New England Power Pool's Integrating Markets and Public Policy] debate and subsequent NEPOOL and FERC-related reviews of proposed capacity market reforms." (See *CASPR Filing Draws Stakeholder Support, Protests*.)

Impeding Renewables

Massachusetts issued its MA 83D solicitation for hydro and Class I renewables (wind, solar or energy storage) last July. The selection committee for the clean energy request for proposals issued in July 2017 includes representatives from the state's Department of Energy Resources and from distribution utilities Eversource, National Grid and Unitil.

Any contract awarded under the RFP must be negotiated by March 27 and submitted to the state's Department of Public Utilities by April 25. The New Hampshire SEC voted March 12 to wait until its Northern Pass permit denial is published later this month before considering Eversource's appeal of that decision, effectively killing the project's chance to meet the Massachusetts deadline.

The New England generators told the Maine PUC that they "had good cause for delaying their intervention efforts" in that NECEC had been one of more than 40 bids competing to secure the Massachusetts contract and that "it would have been highly impractical for the [generators] to intervene in siting and/or certificate proceedings for every one."

"At the time, it was widely believed that Eversource Energy, as a member of the state's evaluation team, would favor its own affiliate's project, Northern Pass Transmission in New Hampshire, as subsequently proved to be the case," they said.

The generators also questioned the claim that NECEC will lead to lower prices.

"It is abundantly clear that [NECEC] has been proposed solely to meet a Massachusetts policy goal; it has nothing to do with meeting the needs of Maine ratepayers, and the primary long-term benefits of the project will accrue to Hydro-Quebec and CMP shareholders," they said.

The generators further argued that, should the project go forward, "it will impede the development of alternative renewable energy projects in Maine, such as solar and onshore and offshore wind farms, for the foreseeable future. This result would be contrary to Maine's statutory policy favoring the use of 'renewable, efficient and indigenous resources.'"

The Conservation Law Foundation filed comments asking the PUC to wait until the Massachusetts RFP has been decided before considering the NECEC proposal.

The CLF argued that presumption of the project's selection in the state RFP underlies CMP's cost analysis. It also said CMP's "calculations of benefits including greenhouse gas emission reductions, improvements in system reliability, reductions in electricity prices, and employment benefits … are premised on a baseline scenario in which there is no other project selected in the Mass. RFP."

ISO-NE News

FERC Approves ISO-NE Capacity Termination

By Michael Kuser

FERC on Friday accepted ISO-NE's request to terminate 11 MW of the capacity supply obligations (CSOs) for a Maine wind farm that delayed its commercial operation and reduced its planned output.

However, FERC said the RTO was wrong in executing the termination before commission approval, delaying the effective date to March 24 (ER18-704).

The RTO filed its termination request on Jan. 23, asserting that developer Blue Sky West had delayed its original 2015 commercial operation date multiple times before achieving partial operation in March 2017.

In Forward Capacity Auction 6, the Bingham wind project in Somerset and Piscataquis counties won CSOs of 42.3 MW for summer and 87.3 for winter, beginning with the 2015/16 capacity commitment periods (CCP).

The company agreed to voluntarily relinquish about 20 MW of summer and 22 MW of winter CSOs based on its decision to reduce the number of turbines in the project and change the turbines to a design with a lower capacity. But the company disputed ISO-NE's demand to reduce the summer CSO by 10.3 MW and winter by 0.79 MW following the RTO's audits of the farm's actual output.

The RTO filed to terminate immediately that portion of the resource's CSOs in the 2017/18 through 2020/21 capacity years, and to adjust the facility's qualified capacity for future capacity auctions.

Blue Sky West filed an emergency motion asking the commission to order reinstatement of the disputed CSOs, arguing the grid operator must receive commission approval before the termination could become effective. On Feb. 2, 2018, the commission granted the motion, ruling that the termination could not be made effective prior to March 24, the end of the 60-day notice period.

The RTO's Tariff allows termination of CSOs if a new facility covers its capacity shortfalls through bilateral trades or the reconfiguration auctions for two capacity commitment periods. The developer claimed the audits should not be justification for reducing the CSOs because they are not listed as "critical path" schedule requirements in the RTO's Tariff.

The commission disagreed, saying, "Neither achieving 'commercial operation' nor fulfilling 'critical path schedule milestones' precludes ISO-NE from terminating a resource's CSO under" the Tariff.

The RTO said that if it did not perform terminations in advance of the FCA, a resource that is not fulfilling its CSO could obtain one for another year and potentially suppress auction clearing prices and provide the region with phantom megawatts that cannot produce energy.

FERC agreed with the grid operator's right to manage its capacity resources but departed with it regarding its termination rights. "While the [Tariff] language is ambiguous, we find that under a sensible reading of the provision and as a practical matter, [a Federal Power Act] Section 205 filing is necessary to obtain a 'commission ruling' on any aspect of an involuntary termination," the commission said.

Requiring such approval of involuntary terminations "should not impede the grid operator's administration of the Forward Capacity Auction," FERC said.

"Given that the [FCA] takes place in February of each year, the [RTO] usually submits termination filing in October of the prior year, giving the commission enough time to rule on the termination filing before the Forward Capacity Auction is conducted," the commission said.

MISO NEWS

FERC OKs MISO Plan to Expand Storage

By Amanda Durish Cook

FERC on Friday gave MISO the go-ahead on a second type of market definition for energy storage, though the commission warned that the RTO must address several more issues before storage can participate without obstacles.

MISO proposed the creation of a Stored Energy Resource Type II Tariff definition last April following Indianapolis Power & Light's complaint against the RTO's restrictive storage participation rules. (See *MISO Ordered to Change Storage Rules Following IPL Complaint*.)

FERC approved the new definition effective Dec. 1, 2017, but noted it lacked unique bidding parameters for storage resources, a path for storage to receive make-whole payments and an outline detailing how storage could provide voltage support and black start services (EL17-8, *et al.*).

But the commission said that all those aspects could wait until MISO's compliance filing on Order 841, which requires RTOs and ISOs to allow energy storage resources full access to their markets. (See *States, Utilities, RTOs Push Back on Storage Order*.)

"Even though the SER-Type II category will not fully accommodate the unique physical and operational characteristics of such resources, our action allows Indianapolis Power and other electric storage resources to participate in MISO's markets while MISO develops and files with the commission proposed Tariff revisions that facilitate electric storage resource participation in compliance with Order No. 841," FERC said.

A MISO compliance filing detailing a storage participation model consistent with Order 841 is due to FERC in December. From there, RTOs will have one year to implement the rules they have proposed.

FERC's Friday order gave MISO 30 days to establish whether its new storage category is eligible to provide up and down ramp capability and to specify whether storage is subject to day-ahead energy must offer obligations.

An SER-Type II must be able to continuously discharge for four consecutive operating hours across a coincident peak each day; in return, it can function as demand response in the day-ahead market and can participate in the annual capacity auction. It can operate in front of the meter and supply energy, capacity, spinning reserve, supplemental reserve and regulating reserve. When it was created last year, MISO officials acknowledged that there was more to be done to remove barriers to entry. Prior to FERC's ruling, storage could participate in MISO markets only as behind-the-meter regulating reserves (SER-Type I).

FERC agreed with IPL's critique that it's unreasonable for the SER-Type II to rely on "rules that were designed for other types of resources."

SER-Type II is modeled on MISO's existing DR resources for offer and dispatch purposes and treated as generation resources for settlements.

"Those participation models do not accommodate the unique features of electric storage technologies … and thus MISO's proposed interim SER-Type II category has a number of significant technical deficiencies," FERC said. MISO's lack of bidding parameters left the commission unsure of how the RTO will use state-of-charge management to economically clear the resource in the day-ahead or real-time market.

"Storage resource-specific bidding parameters are an integral part of accommodating the unique physical and operational characteristics of electric storage resources," FERC said.

The commission also said it was unreasonable for MISO to settle SER-Type II resources as generation resources without determining whether storage would be eligible for make-whole payments. "MISO has not explained why electric storage resources should not be provided with uplift payments in appropriate circumstances," the commission said.

FERC's order wasn't all criticism; the commission acknowledged that in the interim, the SER-Type II category "improves market access for electric storage resources compared to the existing options under the MISO Tariff." The commission also said it understands that MISO is limited by its current software and systems and the 60-day deadline it imposed on the RTO to create the new definition.

"Thus, although we find that MISO's proposed interim SER-Type II category … does not fully accommodate the participation of electric storage resources as required … we find that MISO can address some of these Tariff deficiencies in its Order No. 841 compliance filing," the commission said. MISO should turn to its stakeholders to solve the issues raised over the resource definition, FERC said. (See *MISO Rules Must Bend for Storage, Stakeholders Say*.)

No Rehearing for IPL

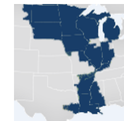
Last week's order also contained a denial of a rehearing request from IPL.

Though FERC's first order on IPL's com-

Continued on page 12

Indianapolis Power & Light's Harding Street Station storage facility | *U.S. Department of Energy*

MISO NEWS



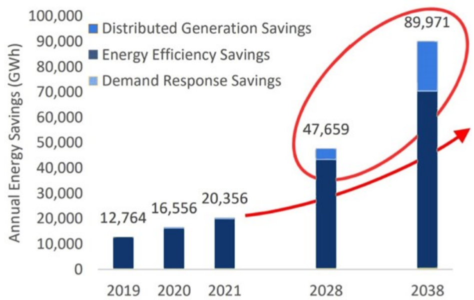
Study Predicts Growth in MISO Demand Management

By Amanda Durish Cook

An energy consulting firm thinks MISO has the potential for several gigawatts of demand-side energy savings by 2038, stakeholders learned Thursday.

The 20-year estimates of MISO's future demand response, energy efficiency and distributed generation were produced by Applied Energy Group (AEG), with near final results presented to stakeholders at a special March 22 conference call. The commissioned study will inform the RTO's 2019 Transmission Expansion Plan, with researchers using the conditions from four MTEP future predictions to project likely demand-side management.

By 2038, total demand-side management could reduce MISO peak summer demand by 22.5 GW, or about 15%, with 11.3 GW of the energy savings from energy efficiency, 7.2 GW from DR and 4 GW from



Annual energy savings | *AEG*

distributed generation. Next year, AEG predicts MISO will save about 8.2 GW on summer peak demand from demand-side management.

In two decades, energy efficiency will be responsible for a 69,899-GWh annual energy savings in MISO; distributed generation will account for a 19,566-GWh annual savings; and DR programs will yield a 539-GWh annual savings. The 89,971-GWh savings total by 2038 is a more than seven-fold increase from AEG's expected 12,764-GWh savings in 2019.

AEG predicts that Michigan, Minnesota, Iowa and Wisconsin have the most potential for energy savings through the next 20 years.

Some stakeholders commented that there was virtually no way to verify AEG's forecasted values with what transpires because behind-the-meter activity is expected to remain largely undocumented.

AEG Managing Director Michael Daukoru said his firm examined both regional and state-specific customer adoption trends along with various state incentives, costs of programs, utility-provided forecasts and capacity growth rates in the study.

MISO staff have said the trickiest part of load forecasting is capturing and projecting

Continued on page 13

FERC OKs MISO Plan to Expand Storage

Continued from page 11

plaint directed MISO Tariff revisions that accommodate the participation of all storage resources in markets that they are technically capable of, FERC did not order the RTO to compensate providers of primary frequency response or rule that its current dispatch rules could harm the life of a storage battery, as IPL had requested.

IPL sought rehearing last year, arguing that FERC disregarded 1996's Order 888 when it refused to unbundle regulation service and primary frequency response. Keeping the two together, IPL argued, is preferential against its battery when compared to other generators. The utility also continued to contend that participation in MISO's regulation market will degrade the useful life of its battery.

FERC didn't bite at either argument.

"Beyond that alleged (and unsubstantiated) harm to the battery facility from offering regulation service, a service Indianapolis Power is technically capable of providing, Indianapolis Power does not explain why we should undo the determination in Order No. 888 by unbundling regulation service and primary frequency response service," FERC said. "Nor does Indianapolis Power argue that the battery facility lacks the equipment necessary to provide regulation service. Moreover, contrary to Indianapolis Power's assertion, the commission in Order No. 888 did not explicitly bundle regulation and primary frequency response services together because resources providing one of these services could recover its costs by providing the other service."

FERC also found no merit in IPL's complaint that MISO's state-of-charge management protocol would compel market participants to either limit their state of charge or their output capability to 50%.

"We find that MISO's proposal to allow individual market participants to control their own state of charge is reasonable because it will allow market participants, who are more familiar with the unique technical characteristics of their facilities, to control state of charge while MISO studies the issue," FERC said.

Order 841

Earlier this month, MISO asked for a six-month extension on Order 841's deadlines and sought clarification regarding bid parameters and the minimum storage size to be eligible for wholesale market participation.

MISO attorneys have said the RTO is concentrating on whether it's "operationally feasible" for it to complete FERC's directive to include all storage resources above 100 kW in a participation model. MISO's participation model is finite in how many market participants it can accommodate, staff said at a March Market Subcommittee meeting.

Meanwhile, MISO's Energy Storage Task Force will clarify with the Steering Committee this week as to whether it will help influence the RTO's December compliance filing. (See *MISO Storage Task Force Talks Order 841*.) Throughout 2018, the Energy Storage Task Force will discuss ways storage can participate further, including generator-and-storage interconnection combinations and competitive bidding on storage projects that solve transmission issues. (See *MISO Staff, Stakeholders Envision Expanded Storage Participation*.)

MISO NEWS

Study Predicts Growth in MISO Demand Management

Continued from page 12

the footprint's unknown amount of demand-side management. (See *MISO Looks to Align Load Forecasting, Tx Planning*.)

The study found that energy efficiency provides the most significant magnitude of demand and energy savings resources.

"Energy efficiency in our view will continue to play a critical role in demand-side management," Daukoru said. "EE is quite significant in terms of savings."

Daukoru predicted that residential behavioral programs that encourage improvements in energy efficiency and home weatherization programs will continue to gain popularity within MISO. New federal lighting standards in 2020 and efficiency upgrades to existing buildings and equipment will also play a role in energy efficiency, the study found.

Distributed resources, driven by rooftop solar, will impact peak loads. MISO will continue to see rapid adoption of distributed generation with the rapidly declining cost of residential rooftop solar, Daukoru said. Distributed wind, on the other hand, is expected to remain prohibitively expensive for most residents.

Combined heat and power is already at high saturation point in parts of MISO, including Texas, Louisiana and Michigan. Expensive installation costs limit more adoption, Daukoru said.

The study found that MISO has room for "significant" DR opportunities, despite "several mature" programs in certain states. AEG expects residents in the footprint to participate in expanded direct load control programs within two decades, installing connected thermostats and smart water heaters that can be automated to turn off in response to reliability threats or energy price spikes.

AEG said utility-led dynamic pricing programs will be emerging only "from isolated pilots."

"There is enormous potential for dynamic pricing, but it requires political will," said AEG Senior Vice President Ingrid Rohmund.

Customized Energy Solutions' David Sapper asked if AEG considered how the federal push to value resilience might affect the adoption of demand-side management in MISO.

"I have not given that much thought," Daukoru said. "That was not accounted for in our analysis."

Daukoru added that demand-side resources could be valuable to resilience given their ability to deliver energy savings and render loads more flexible.

AEG's study will be finalized in June and included in the MTEP studies. MISO and AEG will continue to refine study assumptions for behind-the-meter participation and the potential impact of electric vehicle adoption over the next few weeks.

MISO Under Budget So Far; Expects to Exceed Year-end Target

While MISO is under budget so far in 2018, the RTO's financial staff is forecasting a slight overspend by year-end, members of the Audit and Finance Committee of the Board of Directors learned Wednesday.

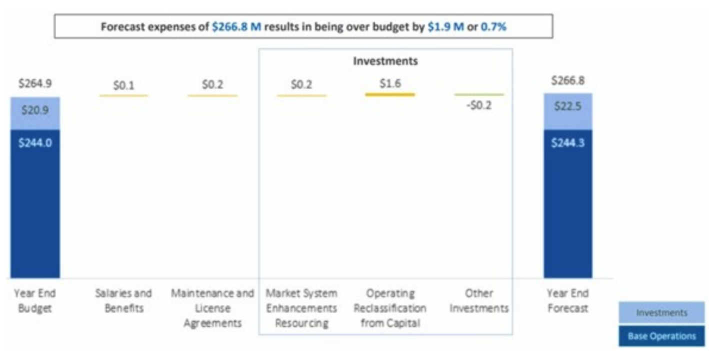
In the first three months of 2018, MISO has spent $41.5 million of its $42.3 million year-to-date budget, under budget by 1.8%. Chief Financial Officer Melissa Brown said the savings were mostly related to belated start times of some of MISO's planned investments.

"A lot of those just had slow starts this year," Brown said during a committee conference call ahead of a March 29 board meeting in New Orleans, where numbers will again be presented.

However, Brown said MISO is forecasting spending $266.8 million by year-end, 0.7% more than its $264.9 million 2018 budget. The expected overspend is because MISO is reclassifying $1.6 million from its capital budget into one-time operating expenses. The reclassification will lower the RTO's projected total capital expenses from $29.6 million to $28.1 million for the year.

So far this year, MISO's capital spending is trending lower, also owing to delayed project starts, Brown said. To date, the RTO has spent $6.1 million of its $7.3 million budget.

In addition to beginning work to replace MISO's aging market platform with a new modular computer system, the 2018 capital budget includes maintaining its cybersecurity team, automating



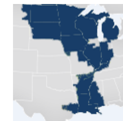
2018 operating budget projection | *MISO*

employee system access revocations, automating its settlements program, replacing software and hardware that fails throughout the year and renovating meeting space at the Carmel, Ind., headquarters.

Board Chairman Michael Curran asked in future meetings to see a separate financial report for MISO's $130 million, seven-year effort to replace its market platform. (See *MISO Makes Case for $130M Market Platform Upgrade*.)

— Amanda Durish Cook

MISO NEWS



Members Skeptical as MISO Explores LSE Load Forecasting

By Amanda Durish Cook

MISO is surveying how to get more information from load-serving entities to create a more detailed load forecast for transmission planning, though stakeholders continue to question the feasibility of the plan.

Senior Policy Studies Planner Temujin Roach said the RTO wants to try "bottom-down" load forecasting, where it relies on data compiled from LSEs to form the basis of its load forecast that informs transmission buildout. For that, MISO's 140-plus LSEs will have to annually assemble four different 20-year load forecasts to fit with each of the RTO's four future scenarios developed for the Transmission Expansion Plan. (See *MISO Looks to Align Load Forecasting, Tx Planning*.)

The approach is one of two MISO is vetting to improve its load forecasts. If LSEs decide they cannot collect that level of information, the RTO will continue its practice of hiring a contractor to put together a load forecast. In that case, Roach said the level of specificity would not be as detailed, though the contractor would take any load information LSEs provide on a voluntary basis. MISO currently uses Purdue University's State Utility Forecasting Group to create an independent load forecast; the forecast is not based on any of the MTEP future scenarios.

MISO has a survey out until April 12 asking LSE owners how feasible it is to put such forecasts together and how much it may cost LSEs to assemble detailed load data.

"For some, it's negligible so far, and for others, it may be a burden," Roach said during a special March 21 conference call on improving MISO's load forecast.

"What we're looking for from load-serving entities is if this is information they already have, or if they're willing to provide it," Roach added.

Stakeholders asked what share of LSEs had to participate in the forecasting before MISO would pursue the new approach. Roach said he didn't know.

"We're looking for a feel of who has got problems with it and how feasible it is — most specifically it's the small munis and co-ops that might not have the ability to forecast already in place. … We'd be willing to work with them and make this as painless as possible," Roach said. "I don't have an answer. It depends on who is struggling with it, and how big their loads are. We need more information to make … a prudent decision."

Stakeholders Skeptical

Several stakeholders said they still weren't convinced MISO had put enough thought into how it would align 140-plus disparate data sets into a cohesive load forecast.

Minnesota Public Utilities Commission staff member Hwikwon Ham said that LSEs don't understand how MISO expects them to adapt their base-case loads to fit into the "limited fleet change," "continued fleet change," "accelerated fleet change" and "distributed and emerging technologies" MTEP futures.

Roach said MISO would most likely hold workshops and develop a Business Practices Manual to describe how to approach the data.

"I'd like to hitch onto [the] exasperation," said WPPI Energy's Steve Leovy. "I don't know how to provide what MISO is asking, because I don't think the data question is adequately specified. I don't think multiple LSEs have the same idea about it."

MISO NEWS

MISO to Recycle Tx Planning Scenarios for 2019

By Amanda Durish Cook

MISO is moving ahead with a proposal to largely recycle last year's 15-year transmission planning predictions for use in its 2019 Transmission Expansion Plan, but some stakeholders are urging the RTO to at least expand the plan.

During a March 20 workshop to gather stakeholder input on MTEP 19, MISO Planning Manager Tony Hunziker said the futures were developed for reuse over multiple planning cycles, with small updates to cover uncertainties such as the capital cost of building generation, demand growth rate and projected fuel prices. (See *MISO: Minimal Change to 2019 Tx Planning Futures*.) Stakeholders generally support the idea, he said.

MISO last year created four future scenarios for use in MTEP planning, including:

- A limited fleet change future, in which the fleet remains relatively static with coal units retiring at the end of their useful life;
- A continued fleet change scenario, in which the grid develops according to the trends of the past decade;
- An accelerated fleet change future driven by a strong economy that increases demand and motivates carbon regulations and increased renewable use; and
- A future in which distributed and emerging technologies become more widely used.

MISO planners are proposing small adjustments to some MTEP 19 assumptions, namely to account for sluggish load and higher-than-expected renewable penetration.

With energy growth currently outpacing load growth, planners say MISO should abandon its previous practice of assuming energy will grow at 0.5 to 1.5 times the base growth rate (extrapolated from load-serving entities' current forecasts) in its transmission planning, and instead plan for anything from no growth to twice the base growth rate. Preliminary demand forecasts from LSEs show a 0.3% average growth rate through 2027, down from 0.5% in MTEP 18 and 0.6% in MTEP 19, while energy is expected to grow at a 0.5% rate.

MISO staff are also considering raising projected renewable penetration by 5% across all futures — from 10-30% to 15-35% of capacity. They acknowledged that the low end of the MTEP 18 range does not reflect the number of renewables on track to complete the interconnection queue.

The RTO also plans to update its base futures model to include planned units holding a certificate of public convenience and necessity, as well as units that have a signed generator interconnection agreement.

MISO will take stakeholder input on MTEP 19 futures through April 20 and expects to have futures finalized by September.

Fifth Future

But some stakeholders are asking MISO to create of a fifth future. Investment firm Veriquest requested the RTO develop an additional scenario that focuses on the regional siting of distributed resources, while MISO's Environmental sector asked for a standalone future showing how possible federal or state carbon regulations drive fleet evolution.

Veriquest's David Harlan said he'd like to see futures more informed by future capacity needs.

"I still don't have a good picture where the source of needs is and where the capacity is," Harlan said. He urged MISO planners to make projections to share with stakeholders about who benefits from cost-effective transmission requirements to move wind from North Dakota to Mississippi, for example.

"None of that is visible in this process," Harlan said.

MISO Director of Policy Studies J.T. Smith said the RTO does account for future capacity movement when building MTEP models.

The Transmission Owners sector said the potential industry changes depicted in the four MTEP futures adequately capture future impacts to the transmission system. "While some of the currently defined futures, such as the limited fleet change, may not align well with the current industry projections, those futures provide valuable information … as well as provide a counter to the more aggressive generation change assumptions implemented in other futures," it said.

Apex Clean Energy's Richard Seide asked if MISO is accounting for commitments from utilities that intend to eliminate the use of coal, such as Consumers Energy, which recently announced its plans to go coal-free by 2040. (See *CMS Energy Plans a Zero-Coal Future by 2040*.)

"I don't know how to say it, but the world has changed … and it occurred very quickly. You're sitting on the largest queue ever," Seide said.

Shane O'Brien, of MISO's resource forecasting group, said stakeholders have so far said the RTO's retirement projections are adequate. The RTO does not hold utilities to retirement announcements or include them in planning until owners submit Attachment Y retirement notices.

Proposed MTEP 19 futures | *MISO*

MISO NEWS

Rehearing Denied on MISO South Cost Allocation

By Amanda Durish Cook

FERC last week rejected state and local regulators' rehearing request over MISO's plan to include its South region in cost sharing for its new category of interregional projects with PJM.

The commission on March 19 said it was not convinced by the regulators' reasoning for rehearing MISO's planned regional cost allocation on its targeted market efficiency projects (TMEPs), a new, smaller breed of interregional project developed with PJM that targets historical congestion along the RTOs' seams (ER17-2246-002).

All based in MISO South, the regulators — the Arkansas, Louisiana and Mississippi public service commissions; New Orleans City Council; and the Public Utility Commission of Texas — argued that the RTO's filing was flawed because it had not named a termination date of the TMEP regional cost-sharing proposal when Entergy's five-year transition period that limits cost-sharing in the region ends in December.

By that time, MISO has promised to have a comprehensive post-transition period cost allocation proposal filed with FERC. The RTO has been working with stakeholders on a preliminary proposal that would make cost sharing available to 100-kV projects along the PJM and SPP seams but limit it to internal market efficiency projects of 230 kV and above. (See *Stakeholders Debate MISO Cost Allocation Plan*.)

The regulators wanted assurances that MISO's TMEP regional cost-sharing plan would not apply beyond the transition period or to MISO South. When it approved the plan late last year, FERC said that if MISO does not have a cost allocation plan readied as promised, the regional TMEP cost allocation would continue to be in effect even after the transition period expires. The RTO proposed to assign its regional share of the costs of TMEPs to transmission pricing zones based on their historical contribution to the market-to-market congestion relieved by the project.

The regulators said FERC's decision improperly modified MISO's proposal, citing the D.C. Circuit Court of Appeals' 2017 ruling that the commission overstepped its authority in prescribing revisions to PJM's minimum offer price rule. (See *On Remand, FERC Rejects PJM MOPR Compromise*.)

However, FERC said the MISO South regulators did not have a case for rehearing because they could not prove its decision had caused a concrete injury, or "aggrievement." TMEP costs could be assigned to MISO South once the transition period expires, FERC acknowledged, but it also said that it was not clear a "mere potential for future harm" is substantial enough to amount to aggrievement.

FERC also said MISO has already outlined a plan for if it does not follow through on a finalized comprehensive cost allocation. In that case, certain projects included in the annual Transmission Expansion Plan, including TMEPs, will be subject to the RTO's existing cost allocation Tariff language.

"Commission precedent is clear: In the event of a conflict between pleadings and proposed tariff language, the tariff language controls," FERC said.

The commission also disagreed with the regulators' contention that by specifying that MISO's plan could continue past the transition period expiration, it "transform[ed] the proposal into an entirely new rate of FERC's own making." It noted that MISO has committed to filing a new regional cost-sharing method for assigning MISO's share of the costs of TMEPs prior to the end of the transition period.

"While we understand MISO South regulators' desire for certainty regarding future assignment of MISO's share of the costs of TMEPs, MISO has provided no indication that it intends to deviate from the commitment in its pleadings to convene stakeholder proceedings to develop a post-transition period proposal," FERC said.

MISO and PJM's TMEP portfolio, approved last year, comprises five congestion-relieving interregional upgrades to existing systems in Illinois, Indiana, Michigan and Ohio. The projects, which have individual $20 million cost caps, will coincidentally cost $20 million combined. On average, the projects' costs will be allocated 69% to PJM and 31% to MISO, based on projected benefits, which are expected to reach $100 million. (See *FERC Conditionally OKs MISO-PJM Targeted Project Plan*.)

FERC: ITC Subsidiary Can Buy Tx Assets from Mich. Muni

FERC has cleared an ITC Holdings subsidiary to buy nearly a quarter million dollars' worth of transmission assets from a Michigan municipal power agency as part of a settlement over transmission system access.

The $247,225.99 sale of transmission assets in southern Michigan from Michigan South Central Power Agency (MSCPA) to Michigan Electric Transmission Co. (METC) is consistent with public interest, FERC said on March 19 (EC18-35).

The sale satisfies part of a settlement approved by the commission last year after a 2016 MSCPA complaint alleging METC was trying to restrict the agency's ownership entitlements to the transmission system and improperly collect annual payments as high as $1.7 million for transmission use, in violation of a contract struck in 1980. METC's change to the contract's terms was prompted by the 2016 retirement of MSCPA's 62-MW Endicott Generating Station.

FERC said the transmission sale will have no impact on rates or competition. METC also committed to hold customers harmless from any costs related to the sale.

— Amanda Durish Cook

Endicott Generating Station | *MSCPA*

PJM NEWS

PJM Stakeholders Debate Frequency Response Rules

By Rory D. Sweeney

PJM is at odds with some stakeholders over whether existing units should be under the same obligation to provide primary frequency response (PFR) that FERC ordered for new units in February.

Sides clashed at last week's meeting of the Primary Frequency Response Senior Task Force (PFRSTF) over what Order 842 actually requires.

Though it has evolved since Order 842 came out in February, the debate has been raging in PJM since the commission issued a Notice of Proposed Rulemaking on the topic in November 2016. Staff want to require PFR from all units capable of providing it, but some stakeholders believe PJM is overreaching. (See *FERC Finalizes Frequency Response Requirement*.)


Burlew in November | © RTO Insider

PJM argues it doesn't preclude being applied to existing units, while generation owners say it doesn't explicitly order it either. Stakeholders questioned the RTO's confidence in its stance, given that staff have filed a request with FERC to clarify the order. Jim Burlew, a PJM attorney, said staff is confident but made the request "out of an abundance of caution." He said the RTO's position is that FERC felt the issue was addressed by ordering new units to provide PFR because it assumed current units are already providing it.

Staff attempted to counteract an argument that PJM would be shouldering others' frequency response responsibilities by showing how other balancing authorities are handling FERC's order. However, the presentation seemed only to strengthen some stakeholders' belief that it's unnecessary for existing units to have the capability.

PJM's presentation showed that surrounding BAs maintain some PFR requirement for existing units, but stakeholders argued those procedures were more collaborative than the RTO's plan, which includes referrals to FERC's Office of Enforcement for units that don't measure up.

"They're not looking at a FERC hammer" in the other BAs, GT Power Group's Dave Pratzon said.

AEP Energy, a subsidiary of American Electric Power, presented a proposal that would maintain the status quo for existing units to provide PFR if they are capable. It would also allow for seeking cost-of-service revenues from FERC for providing the service. A PFR performance evaluation like one that PJM has proposed would go into effect in 2021, and there would be a recommendation that transmission owners and the RTO study localized restoration-related issues.

Compensation

Jim Fletcher with American Municipal Power pointed out that several of the other BAs are regulated utilities that can unilaterally implement changes — unlike PJM, where individual unit owners will need to make economic decisions.

"They seem to have an advantage about how they optimize frequency response," he said. "I think it's important that we continue to keep some form of compensation in the mix here as we talk about [implementation]."

Howard Haas with the Independent Market Monitor noted that regulated utilities have a different cost-recovery model than ISO/RTO markets. Regulated utilities have cost-of-service arrangements subject to regulators' approval or rejection while PJM's approach uses markets, where recovery is possible but not guaranteed, he said. The Monitor's position is that units are already compensated to have and provide PFR through PJM markets and that the cost of new entry (CONE) unit includes the costs of having the capability because the service is a requirement of new units.

"PJM's markets provide opportunities to recover these costs; and if you don't, you have to make a business decision about whether or not to exit," Haas said.

A stakeholder who asked not to be identified asked whether PJM was implying that units that can't provide PFR should retire.

"That's the IMM's position. I don't think PJM has ever said that," PJM's Dave Souder said.

However, Haas noted after the meeting that PJM's proposal for exemptions from offering PFR specifically states that "economics cannot be used as exemption criteria."

Pratzon called it "a bit of a stretch … to lay a sidebar obligation" of PFR on a resource that was designed and built for "the primary value" of producing energy, but Haas argued that if it's a rational decision within PJM's markets for new units, it's a "rational decision for existing resources as well."

Where to Recover?

Pratzon noted concerns that recovering the costs of PFR was also affected by another ongoing stakeholder discussion about variable operations and maintenance (VOM) costs. Stakeholders will vote at the April meeting of the Market Implementation Committee on three proposals that revise how cost-based offers can be submitted. (See "Maintenance in Cost-Based Offers," *PJM Market Implementation Committee Briefs: March 7, 2018*.)

PJM's Tom Hauske assured stakeholders that none of the proposals disallows including PFR costs in offers, but Pratzon noted they differ with whether they are recovered through the capacity or energy market.

"Some generators might think they have more certainty recovering [the costs] in [the energy market] than [in the capacity market]," he said.

Pratzon also questioned PJM's plan to exempt units that have wholesale market participation agreements (WMPAs) rather than interconnection service agreements. WMPAs are for resources that are governed by state tariffs and aren't under FERC's jurisdiction.

"By doing what you're doing, you're setting up a system where people who are first in get a break that nobody else gets," he said.

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PJM NEWS

Ky. Rejects AEP Supplemental Tx Project

By Rory D. Sweeney

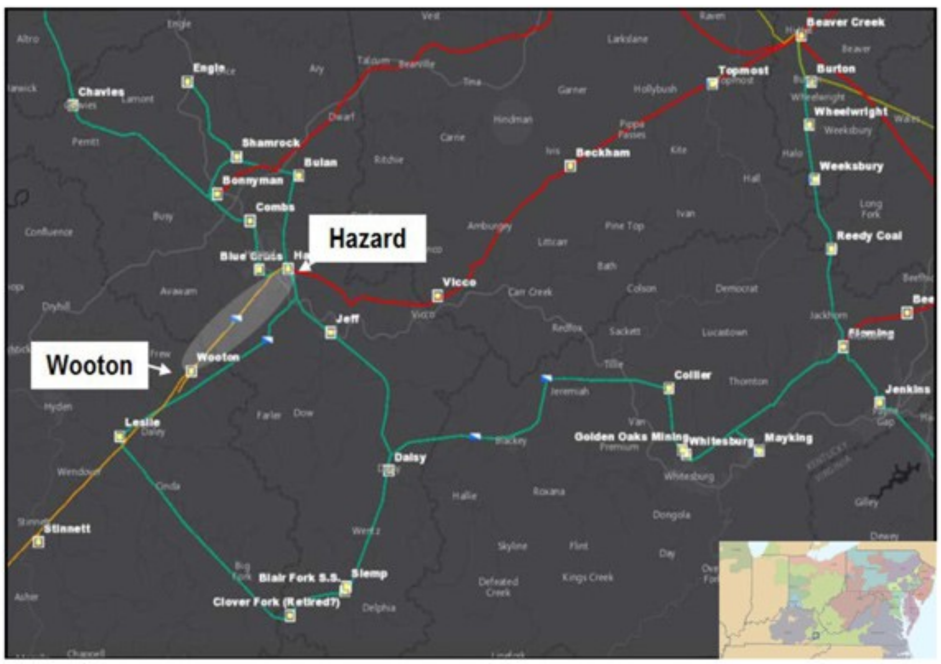
Citing FERC's concerns over supplemental transmission projects, Kentucky regulators have rejected upgrades to two substations, ruling that Kentucky Power failed to prove they were needed.

The Kentucky Public Service Commission released an order on March 16 granting a certificate of public convenience and necessity (CPCN) to Kentucky Power for a baseline project to rebuild a 161-kV line between its Hazard and Wooton substations but denied a CPCN for a more expensive supplemental project to make upgrades at the substations. Kentucky Power, a subsidiary of American Electric Power, estimated the baseline project to cost $20 million and the supplemental project another $24 million.

Baseline projects are administered by PJM to address violations of publicly available reliability criteria, while supplemental projects are developed internally by transmission owners and are not driven by RTO criteria. Supplementals are included with baseline projects in PJM's Regional Transmission Expansion Plan to allow staff to identify possible reliability or operational performance issues, but they are not subject to staff oversight or approval. For years, several organizations representing demand-side interests have been clashing with TOs over the projects, arguing that TOs are incentivized by their formula rates to build as much as possible and that regulators' oversight is not adequate to corral the impulse. Spending on supplementals has been on the rise, and critics believe TOs see them as an unsubstantiated way to build more. (See *PJM TOs, Customers Await Ruling on Supplemental Projects*.)

The PSC was unpersuaded by Kentucky Power's contention that the supplemental made sense because engineering and construction resources would already be focused in that area. "This may speak to efficiency but not to necessity," the commission said, noting that consideration of the projects happened through a PJM stakeholder process that FERC has since determined requires revision.

FERC ruled in February, following a 2015 technical conference and subsequent show-cause order in 2016, that TOs' processes for receiving "meaningful input" from stakeholders on supplemental projects need additional structure to comply with Order 890 (EL16-71). TOs, through PJM, have subsequently submitted a proposed timeline for project consideration, but opponents have challenged the order as not sufficient. (See *Group Contests 'Supplementals' Ruling as PJM, TOs Advance*.)



AEP transmission zone: baseline Hazard-Wooten 161-kV circuit | *PJM*

PJM Stakeholders Debate Frequency Response Rules

Continued from page 17

Pratzon also had concerns with parts of PJM's proposal to assess PFR performance. Staff will be able to perform assessments up to 30 times per year but would aim for two or three events per month. Staff agreed to accommodate an AEP request to make the factors triggering an event less sensitive, which would reduce the number of events to assess, but said they would need at least three quarterly events for the assessment.

Pratzon in August | *© RTO Insider*

Pratzon argued that it was unfair to allow units that lack real-time telemetry capability to submit data from a selected event because they could cherry-pick their best performance.

Units would receive a pass/fail grade, and PJM would discuss the issue with failing units. If units that fail are intentionally not responding, they could be referred to FERC. PJM plans to put the details in its operating manuals so they can be revised as necessary; the requirement to provide PFR will be in its Tariff so units are required to respond.

Stakeholders agreed to update their proposals based on feedback and have them prepared for a nonbinding poll that will be open between April 4 and 11. The results will be reviewed at the task force's next meeting on April 26.

PJM News

MRC/MC Briefs

Markets and Reliability Committee

Additional Reserves Needed?

WILMINGTON, Del. — Moments after stakeholders approved the charter for the Energy Price Formation Senior Task Force (EPFSTF) without comment at last week's Markets and Reliability Committee, PJM moved to revise the issue charge on which it's based to also address concerns about insufficient secondary reserves.

"The topic of potential new reserve products has been raised in our discussion around energy price formation," PJM's Dave Anders explained. "We realized that it would really be beneficial for the Operating Committee to provide some input to those considerations around reserve products."

The EPFSTF decided that the first step is for the OC to define the "reliability-related aspects" that need to be addressed so they can be incorporated into the market-structure changes the task force is contemplating. To include that, they recommended adding a "key work activity" to the task force's issue charge and assigning it to the OC.

The initial proposal tasked the OC with identifying the factors a 30-minute real-time product should have and how it would interact with synchronized reserves. However, stakeholders — led by the Independent Market Monitor Joe Bowring — eventually replaced that with a more generalized task to analyze secondary reserves and any "interdependencies" it would have with primary reserves.

Calpine's David "Scarp" Scarpignato asked that the discussion include any reserve requirement changes that would interact with the reliability assessment and commitment (RAC) process and the day-ahead and real-time markets. Anders said the language had been added to the EPFSTF's charter.

Dave Souder | © *RTO Insider*

PJM's Dave Souder said the reserve considerations are an extension of the gas-electric coordination and pipeline-contingency initiative that he has been leading since late last year. He said he plans to "set aside an hour" at each monthly OC meeting to create a recommendation on the appropriate inputs and what revisions might need to happen in real time. (See "Resilience Update," *PJM Operating Committee Briefs: March 6, 2018*.)

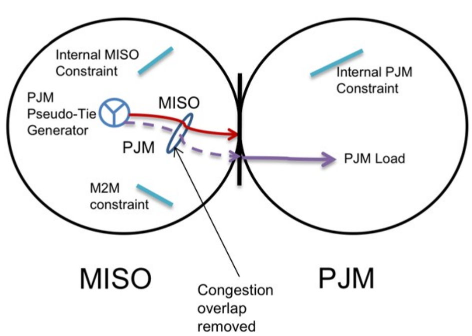
"I think it's within our purview at the OC to see if we have reliability need, and we can recommend that the product be developed, but how that's developed would be through the [EPFSTF]," Souder said. "There may be times where the gas contingency is larger than our largest 30-minute requirement. Under those conditions, we may need to ensure we have sufficient 30-minute reserves."

Congestion Overlap

Tim Horger | © *RTO Insider*

Stakeholders endorsed the second phase of an initiative with MISO to address overlapping congestion. The first phase was filed with FERC in December, but PJM had to respond to a deficiency notice in January and it was not approved by the proposed March 1 implementation date. With the endorsement of the second phase, staff hope that both phases can be approved for implementation by June 1, PJM's Tim Horger said.

The proposal addresses the potential for pseudo-tied resources to pay twice for congestion charges as their energy crosses the market borders. The first phase eliminated the charges, and the second phase allows hedging of potential congestion charges through day-ahead transactions, auction revenue rights and financial transmission rights. Owners will be refunded or charged for deviations between day-ahead submittals and real-time operations. (See *MISO, PJM Pursue Pseudo-Tie Double-Charge Relief*.)



| *PJM*

Generation Transfer

Concerns with PJM's proposed deadlines for notifying the RTO of generation transfers are being ironed out, PJM's Rebecca Stadelmeyer said. A vote on the issue was deferred at February's MRC meeting because some generation owners felt PJM's timeline was too onerous. (See "Generators Hesitate on Ownership Transfer Rules," *PJM Markets and Reliability Committee Briefs: Feb. 22, 2018*.)

Stadelmeyer said stakeholders have sent in redlines, and a group of generation owners, coordinated by GT Power Group's Dave Pratzon, are engaged on the issue.

"It definitely appears PJM and the generator owners are coming to a mutual understanding," she said.

The group has another call scheduled for March 28.

Stakeholders Approve Variety of Actions

Stakeholders endorsed by acclamation several manual revisions and other operational changes:

- Manual 1: Control Center and Data Exchange Requirements. The revisions were developed as part of a periodic review and encompass real-time system monitoring and communication requirements, including external resources.
- Manual 3A: Energy Management System (EMS) Model Updates and Quality Assurance (QA). The revisions were developed to implement new NERC standards for transmission owners to monitor and report the quality of its real-time assessments in intervals of at most 30 minutes.
- Manual 14A: New Services Request Process and Manual 14E: Additional Information for Upgrade and Transmis-

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PJM NEWS

Del. Group Seeks to Block Artificial Island Project

By Rory D. Sweeney

Could PJM's Artificial Island project get any more complicated? Apparently, yes.

A Delaware demand-side group has asked the PJM Board of Managers to again suspend the project because of announcements from Exelon and Public Service Enterprise Group that that they will cancel future capital investments at the two Salem nuclear units they co-own and shut the plants down if New Jersey doesn't provide them $300 million annually in subsidies to keep the plants open. (See NJ Lawmakers Advance Latest Nuke Subsidy Bills.)

The project was developed to address transmission stability problems at the Hope Creek and Salem nuclear units in southern New Jersey and allow them to operate at full power without a book-size compilation of operating constraints.

PJM's first competitive solicitation under Order 1000, the Artificial Island project has long been mired in controversy. In June, the RTO announced several cost allocation alternatives that would shift much of the $280 million price tag from Delaware ratepayers to those in New Jersey and Pennsylvania. (See *PJM: AI Costs Would Shift to NJ, PA Under New Allocations*.)

The Board of Managers had two months earlier restarted the project and ordered the analysis of alternative allocation methods. It also re-awarded the project to LS Power, which was selected when the board approved the project in July 2015. Complaints over mounting costs, scope changes and a cost allocation that Delaware felt was unduly burdensome caused the board to suspend it in August 2016.

But the announcements from Exelon and PSEG in February cast doubt over whether the plants are long for this world. PSEG said it might also cancel spending on the Hope Creek reactor, which shares Artificial Island with the Salem units.

"These actions call into question the long-term operational viability of the Salem and Hope Creek plants," wrote Michael K. Messer, president of the Delaware Energy Users Group, noting that Delaware consumers stand to pay "a significant share" of the project's cost. "The cost increase is at a level that will severely impair the competitiveness of Delaware businesses. This scenario becomes far worse should the driving reason for the transmission project, Salem and Hope Creek reliability, cease to exist."

He asked the board to consider whether the project is necessary or if its scope changes if any or all of the plants close and whether the project's timeline should be delayed "to minimize expenditures until a long-term commitment is established for the Salem and Hope Creek plants." LS Power's award has an in-service date of June 1, 2020.

PJM's Dave Anders, who oversees stakeholder relations, said it's unclear what the board's response will be. "At this point, I do not have a sense for when/if there will be a formal response," he said in an email.

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sion Interconnection Projects. Revisions developed to implement previously approved revisions to PJM's transmission service and upgrade requests. (See "Transmission Issues," *PJM PC/TEAC Briefs: Feb. 8, 2018*.)

- Manual 33: Administrative Services for PJM Interconnection Agreement. Revisions developed as part of a comprehensive periodic review to clarify and streamline language.
- Manual 37: Reliability Coordination. Revisions developed to clarify language and simplify references to NERC standards.

Members Committee

Overlapping Congestion Endorsed Through Consent Agenda

The Tariff and OA revisions to address the overlapping congestion issue were added to the consent agenda, which stakeholders endorsed by acclamation without comment.

The issue was brought for a vote at both committees on the same day because stakeholders agreed to that arrangement when they deferred the vote at February's MRC. The dual vote allows PJM to maintain its preferred timeline for filing and implementation.

Monitor Recommends Redrawing Market Lines

Monitor Bowring believes the lines that define regional price separations within the RTO in the capacity market are antiquated and that price separation should be dynamic based on the actual characteristics of the market. He discussed the recommendation while briefing members on the 2017 State of the Market report. (See *IMM Report Says PJM Prices Sufficient*.)

Bowring's thoughts on redefining locational deliverability areas (LDAs) in the capacity market came in response to a question from Ruth Ann Price of the Delaware Division of the Public Advocate. She had asked him to expound on his recommendation that LDA definitions be dynamic and market based.

"We think that it should be based on a nodal definition so that the price separation is a function of the actual transmission characteristics of the system as well as the relative offer prices of the system," Bowring said. "LDAs are arbitrary lines … [that are] almost without exception the old-fashioned transmission zones. There's no reason to believe that those are the right way to have prices separate."

He said the first step to addressing the issue is modeling every LDA to see if any prices separate. He said he hasn't done the analysis to determine how many LDAs would price separately, but that he would investigate it.

Bowring said another "work in progress" is examining the nature of the competition to provide transmission upgrades and expansions.

— Rory D. Sweeney

PJM NEWS

Group Contests 'Supplementals' Ruling as PJM, TOs Advance

Continued from page 1

Order 890 Compliance Plan.) The projects include transmission expansions or enhancements not required for compliance with regional or national reliability, operational performance or economic criteria.

A coalition of customers calling themselves "the load group" requested rehearing of the order, arguing that it still doesn't hold TOs accountable for their obligations under FERC Order 890. They took issue with FERC's approval of TO-proposed language to delineate the supplemental planning process and move it from the PJM Operating Agreement — which requires a supermajority endorsement from PJM stakeholders to make changes — to a new Attachment M-3 of the Tariff. The TOs have exclusive filing rights under Section 205 of the Federal Power Act to make changes to the Tariff; other stakeholders would need the PJM Board of Managers to file a complaint under Section 206. (See FERC Orders New Rules for Supplemental Tx Projects in PJM.)

Additionally, PJM's Independent Market Monitor has asked to intervene in the docket, wading into a clash the IMM has largely stayed out of since it was touched off with a 2015 technical conference and subsequent FERC show-cause order in 2016 (EL16-71).

Compliance Filing

PJM submitted proposed Tariff and OA revisions to address FERC's determination that the TOs were failing to provide stakeholders with adequate notification, information and opportunities to engage in discussions over supplementals. While PJM includes the projects in its Regional Transmission Expansion Plan to allow staff to identify possible reliability or operational performance issues, they are not subject to staff oversight or approval.

TOs had proposed there be a minimum of 25 days between meetings covering the three parts of project planning: assumptions, needs and solutions. They also offered to post information to be discussed at that meeting 10 days ahead of time and allow 10 days after meetings to receive comments. Finally, they proposed a 10-day waiting period to consider written comments before incorporating their local transmission plans into the RTEP.

In response to stakeholder feedback, PJM and the TOs agreed to extend to 20 days the period before the initial assumptions meeting.

"While the [TOs] are sensitive to the desire of some stakeholders for additional time between meetings and for more time to review the materials presented for discussion at the meetings, they determined that, in most cases, longer minimum time periods would compromise their ability to coordinate the supplemental project planning process with PJM's planning of baseline projects [that address regional or national criteria violations] for inclusion in the [Regional Transmission Expansion Plan]," the filing said. "PJM apprised the [TOs] that minimum periods between supplemental project planning meetings of more than 28 days would have the potential to cause problems by preventing effective coordination with meetings of the PJM Transmission Expansion Advisory Committee."

TOs said the deadline for feedback on a project's first meeting about assumptions can be pushed back "without impeding the subsequent steps in the process."

Rehearing Request

The load group's request argues that Attachment M-3 doesn't resolve Order 890 issues in the first place and that it's inappropriate for PJM to add the attachment to the Tariff rather than the OA. It also took issue with the commission not requiring TOs to provide more information to stakeholders, such as the models and data necessary to replicate the analyses identifying the need for supplemental projects. FERC also should have subjected supplementals to the same obligation-to-build, milestone requirements and PJM impact analyses as RTEP baseline projects, the group said.

The group criticized FERC for what they said was allowing TOs "to disregard their obligation to respond to comments from stakeholders."

"The commission is not free to ignore problems with a Section 205 filing that a party identifies simply because that party proposed an alternative to particular filed terms and conditions," the group wrote. "But that is precisely what the commission did in the order. … Given the PJM TOs' track record in failing to meet their obligations under Order 890, the PJM TOs should be required to respond to stakeholder comments. Otherwise, stakeholders will have no way of knowing whether the TOs have honored their obligation to consider these comments. … The commission should ensure that any such process is robust and offers stakeholders recourse if their comments are ignored."

The group includes American Municipal Power, Old Dominion Electric Cooperative, the Delaware Division of the Public Advocate, the PJM Industrial Customer Coalition, the Illinois Citizens Utility Board, the D.C. Office of the People's Counsel and the Public Power Association of New Jersey.

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SPP News

SPP Team to Take 'Holistic' Look at Processes

By Tom Kleckner

SPP said last week that its Board of Directors has created a Holistic Integrated Tariff Team (HITT) comprising directors, regulators, staff and stakeholders to take an all-encompassing look at the different challenges facing its footprint and develop a set of high-level recommendations in response.

The team is hoping to replicate the success of a "synergistic" planning project team created nine years ago. That team produced a report that led to SPP's integrated transmission planning process and the "highway/byway" cost allocation methodology for new transmission upgrades.

The 16-member HITT includes Directors Larry Altenbaumer and Graham Edwards and state commissioners Shari Feist Albrecht (Kansas Corporation Commission) and Dennis Grennan (Nebraska Power Review Board).

The Nebraska Public Power District's Tom Kent will serve as chair of the team and Dogwood Energy's Rob Janssen as vice chair. SPP Legal Counsel Paul Suskie will serve as the team's staff secretary.

Kansas City Power & Light's Denise Buffington said she is looking forward to being one of four investor-owned utility representatives on the team. Buffington chaired a task force that was unable to reach consensus on improvements to SPP's methodology for assigning financial credits and obligations for sponsored transmission upgrades under Attachment Z2 of its Tariff.

"Based on my experience with the Z2 task force, I anticipate there will be a lot to learn and it will be a multiyear process," Buffington said.

The 16-person HITT will assess:

- SPP's transmission planning and study processes, including generation interconnections, the interconnection queue, energy resource and network resource interconnection service, aggregate studies, capacity requirements, and related FERC planning requirements.
- Transmission cost allocation issues, including regional and zonal funding, directly assigned costs, Attachment Z2 credits, cost allocation impacts on transmission pricing zones with large wind resources, and state-by-state supply resource mix requirements and goals.
- Effects on the Integrated Marketplace from a changing resource mix, access to lower cost generation and potential changes in production tax credits.
- Disconnects or potential synergies between transmission planning and real-time reliability and economic operations.
- Any other areas and issues seen as appropriate and reasonably related to the scope of work.

The HITT will report to the board's Members Committee and provide status reports to the Regional State Committee, Markets and Operations Policy Committee and Strategic Planning Committee. SPP expects the team to complete its work with a written report by April 2019. It can request additional time, if needed.

SPP stakeholders will be able to listen to the meetings and discussion through teleconference.

The group's creation was approved during a board executive session March 13. During that same meeting, the board approved 18 policy statements that will guide Mountain West's pending membership into SPP. (See *SPP Begins Work of Integrating Mountain West*.)

Joint Petition on SPP RE's Dissolution Filed with FERC

NERC, the Midwest Reliability Organization and SERC Reliability Corp. have submitted to FERC a joint petition in connection with the SPP Regional Entity's dissolution.

The filing follows the NERC Board of Trustees' February vote to dissolve the SPP RE by terminating the RTO's regional delegation agreement, ending a reliability oversight role that concerned both the reliability organization and FERC. (See *NERC Board Approves Dissolving SPP Regional Entity*.)

The petition requests FERC approval of:

- The termination of the amended and restated delegation agreement (RDA) between NERC and SPP.
- The proposed transfers of SPP RE registered entities to MRO and SERC by July 1, 2018.
- The amendments to RDAs between NERC and MRO and between NERC and SERC to reflect the changed geographic footprint resulting from the transfer.

NERC requested that the commission expedite consideration of the petition and shorten the comment period to no more than 14 days "to allow a timely transition of registered entities from SPP RE to MRO and SERC with minimal disruption."

Multiple Entities, Markets Now Beckon in West

Continued from page 1

SPP and Mountain West have been working on their combination since January 2017. Mountain West members in January 2018 signed a nonbinding letter of intent to explore getting RC service from SPP by Sept. 1, 2019. In February, they sent revocable notices of withdrawal to Peak, effective that same date.

Just after New Year's Day, CAISO gave Peak, the Western Electric Coordinating Council's (WECC) RC, 20 months' notice that it is leaving Peak to offer its own reliability services for half the price. Peak, meanwhile, is continuing with its plans to offer market services in the Western Interconnection through a joint effort with PJM called PJM Connext. (See *CAISO to Depart Peak Reliability, Become RC* and *Peak, PJM Detail Western Market Proposal*.)

"Clearly, we're interested in how this region is shaking out," said PUC Chair Jeffrey Ackermann. "People are keeping their feet in different prospects. Where are the points of no return from the Mountain West perspective, in terms of SPP? Are we

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SPP NEWS

FERC Approves Vermillion, NextEra Settlements

FERC last week approved an uncontested settlement between SPP and several of its members to add an annual revenue requirement and implement a formula rate template and protocols for a new member (ER17-428).

The settlement resulted from SPP's 2016 filing that amended its Tariff governing transmission facilities owned by Vermillion Light & Power (VLP). The changes concerned VLP's base rate of return on equity, payment in lieu of taxes, plant depreciation rate, payment of refunds dating back to Feb. 1, 2017, with interest, and other related adjustments.

VLP, which is owned by the town of Vermillion, S.D., is a member of Missouri River Energy Services (MRES).

MRES and VLP said the settlement included three concessions: a 10-basis-point reduction from the as-filed base ROE of 9.7% to a settlement base ROE of 9.6%; an agreement that VLP is prohibited from seeking a change in the ROE until March 1, 2020; and a provision requiring VLP to make a Section 205 filing to participate in certain regionally cost-shared projects.

SPP filed the settlement offer in December on behalf of itself; MRES; Basin Electric Power Cooperative; East River Electric Power Cooperative; Heartland Consumers Power District; Mountrail-Williams Electric Cooperative; and the Western Area Power Administration.

Commission Approves NextEra, KCC Settlement

FERC last week also approved an uncontested settlement between NextEra Energy Transmission Southwest (NEET Southwest) and the Kansas Corporation Commission over the company's base ROE (ER16-2720).

FERC accepted NEET Southwest's base ROE of 9.8% to recover costs associated with the transmission assets it develops in SPP. The company's total ROE, including incentives and adders, will not exceed 10.8%.

NEET Southwest had requested a base ROE of 10.5% with a 50-basis-point incentive adder in 2016, but the Kansas commission protested the ROE portion of the filing.

— Tom Kleckner

Multiple Entities, Markets Now Beckon in West

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having basically sidebar conversations, or are we still in a state of flux?"

Peak CEO Marie Jordan's comments seemed to imply that SPP's integration of Mountain West is a done deal. She referred to sharing data with SPP, which she called a "good operator," and working to ensure that Peak smoothly coordinates the transition of its RC responsibilities to SPP and CAISO.

Peak and SPP already have a seams agreement in place that Jordan said has "worked great" over the years. The entities share four DC ties, over which they are capable of exchanging 720 MW of energy.

"It's going to be important [that SPP] gets to the data, so they can start building their model," Jordan said. "They need to be able to interface with our model to have a really good strong handoff for reliability coordination. There will be a tremendous amount of interaction between us.

"The horse is out of the barn," she said. "CAISO set this in motion when they issued the notice to leave Peak. Our intention is to ensure [that] as we make this transition, we do this well for the reliability of the Western Interconnection."

Stu Bresler, PJM senior vice president of operations and markets, and Peak Reliability CEO Marie Jordan. | *© RTO Insider*

Between CAISO and the Mountain West members, Peak stands to lose almost 40% of its $45 million annual operating budget. Jordan said Peak's core RC costs are estimated at 5.5 cents/MWh, or about 60 cents/MWh per customer annually. To protect its investment in RC support tools, she said Peak must separate those costs from its RC-only costs to take on its new competition.

"As it relates to the overall reliability of the West, I'm a little bit concerned that it's a race to the bottom with a focus on costs," she said. "But if we're going to compete, that's an important step."

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Multiple Entities, Markets Now Beckon in West

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Enter, then, PJM, and its collaboration with Peak.

"We are proposing an alternative that provides an opportunity for entities in the West to participate in a market that is for the West and by the West," said PJM's Stu Bresler, who also serves as board chair for PJM Connext. "They can determine what they want on their own, including a potential pathway or roadmap to an RTO, if that's what they want."

Bresler and Jordan proclaimed PJM Connext to be a perfect fit. Bresler pointed to Peak's expertise in the West and its existing infrastructure as presenting the "fundamental foundation" in establishing a market, while Jordan noted PJM's market has a 20-year history and low costs.

"They're the largest market in world, but also the lowest cost," Jordan said.

"We think leveraging the expertise of Peak with PJM's expertise in markets represents a true value proposition," Bresler said. "We believe we can deliver a market the stakeholders in the West want. We're not plopping down PJM's market design in the West. The idea is that the stakeholders will determine the market that is implemented, as opposed to joining one that already exists."

Peak and PJM hope to complete a business case for PJM Connext by March 30 that "sets expectations for Day 1" and projects the cost of standing up the market and ongoing operations.

CAISO is taking a similar approach, saying it will work with Western companies to determine what level of market or RTO services to offer. The ISO has begun a rate design project with its stakeholders as it works at getting WECC RC certification by August 2019. It also is continuing development of its Energy Imbalance Market (EIM).

"Out of the gate, we think there is value in leveraging the EIM market," said Stacey Crowley, CAISO's vice president of regional and federal affairs. "Is there potential to expand that authority into certain day-ahead rules? We want to find out if that's enough, or if that's the right way to go."

CAISO's Mark Rothleder, vice president of market quality and renewable integration, and Stacey Crowley, vice president of regional and federal affairs. | © *RTO Insider*

Koncilja asked what she called the "ultimate question" — "Why do you think your proposed services are the best option for Colorado utilities and their ratepayers?"

Mark Rothleder, CAISO's vice president of market quality and renewable integration, responded that his organization is offering an incremental way of developing a market.

"From that perspective, we can structure our proposal so maybe you start with an energy imbalance market, then move to a day-ahead market," he said. "Then, we'll see if there's a need, a value, to full RTO participation."

Koncilja then asked SPP COO Carl Monroe what Colorado would lose out on "if we say we want to ease into this?"

Monroe said that question was better suited for the Mountain West entities, who first began looking at RTO membership in 2013 to collapse their multiple rates into one system tariff. They also will realize additional benefits through the efficient exchange of energy over the DC ties, regional transmission planning and SPP's other RTO services, he said.

"You would give up the benefits that you could get by going the full length with a RTO," Monroe said. "The EIM is just part of the CAISO proposal. They haven't solved all the issues. You still see them trying to plan that. In some regards, you're leaving money on the table."

Koncilja has emerged as the PUC's most vocal skeptic of Mountain West's move into SPP. She opened the meeting by questioning the integration's value to her state.

"Is this the best fit for Colorado? Is now the best time to do it, and what will it cost?" she said. "There are allegedly millions of dollars in savings, but I haven't seen a cost-benefit study since Brattle, which is almost a year old."

She was referring to a 2016 Brattle Group study, which indicated that Mountain West participants would see an $88 million annual reduction in production costs by moving to a regional market without must-run generation.

Mountain West and SPP also commissioned The Glarus Group to conduct a second study on the economic benefits from scheduling power over the four DC ties. Glarus said Mountain West and SPP could expect to see net production cost savings ranging from $11.7 million to $28.8 million yearly.

"That's not a big number, in light of what we're talking about," Koncilja said of the Glarus study. She said she would like to see the studies supplemented, "because they don't give me the information I want."

"You're talking about two studies that I think have holes in them," Koncilja said.

Monroe said the Glarus study doesn't consider the benefits that members get from participating in the market and its diverse resources. Glarus said its results did not reflect real-time market optimization, ancillary services or regional through-and-out transmission revenues that may be available because of better use of the ties.

"Our transmission planning reduces the cost of transmission, because we can do it more effectively regionally, and find projects that reduce the cost of energy to our customers," Monroe said.

SPP has conducted its own 10-year cost-benefit analysis of the integration, which indicates its existing members could see benefits as high as $548 million in net present value from 2020 through 2029. Members will see a phased-in, reduced administrative fee that drops from 48 cents/MWh to 43 cents for 2020.

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FERC Filings to Begin in August-September

Monroe said Friday that SPP intends to bring a "whole package" of proposed Tariff changes to the RTO's July leadership meetings, with FERC filings beginning as soon as August or September. He said the changes will be batched together as appropriate.

"It will rely on us keeping FERC involved throughout this process," Monroe said. "We will spend more time with FERC than we would normally do at this point in the process."

Monroe said FERC is revising its filing processes following the D.C. Circuit Court of Appeals' ruling last year that the commission had overstepped its authority in undoing a PJM compromise on its minimum offer price rule. (See *On Remand, FERC Rejects PJM MOPR Compromise*.)

"We anticipate multiple filings, but we want them treated together," Monroe said.

His comments came during a webinar reviewing the recently approved 18 policy statements that will guide Mountain West's pending membership into SPP. The RTO's Board of Directors approved the statements during a March 13 executive session, and directed staff and stakeholders to begin revising SPP's Tariff, bylaws, membership agreement and other governing documents. (See *SPP Begins Work of Integrating Mountain West*.)

The first Tariff changes related to Mountain West's integration have already begun bubbling up through the stakeholder process, with a revision request updating day-ahead make-whole payment charge types going out for comment.

Stakeholders were a little taken aback by an offhand comment during a discussion about the possibility of a Mountain West member pulling out of the integration.

"We've talked about how intertwined [Mountain West's members] are. That's why they are working together on this. If one wanted to [withdraw], and it was a small enough entity, and it didn't affect the others," it might not hurt the effort, Monroe said. "But we won't know until we get to that point."

"That would affect the entire analysis we have been working on," Oklahoma Gas & Electric's Greg McAuley said.

FERC & FEDERAL NEWS

DC Circuit Denies Review of EPA Haze Rules

By Michael Kuser

A clear (left) vs. hazy day at Great Smoky Mountains National Park | *EPA*

The D.C. Circuit Court of Appeals last week denied several petitions for review of final EPA action on steps to cut pollution from electric power plants in order to restore to "natural conditions" the air quality and visibility in "Class I" national parks and wilderness areas.

EPA, under the 2012 Clean Air Act, issued its Regional Haze Rule, which revised its guidelines on Best Available Retrofit Technology (BART) for stationary pollution sources, usually power plants, installed before August 1977. The new rule also specified that the agency's 2011 Cross-State Air Pollution Rule (CSAPR) had requirements stringent and effective enough for it to serve as a better-than-BART alternative, thus excusing states from compliance with BART itself.

EPA also disapproved portions of certain State Implementation Plans (SIPs), designed to achieve reasonable progress under the Regional Haze Rule because those plans relied on a soon-to-be-defunct predecessor of CSAPR, the Clean Air Interstate Rule (CAIR).

The National Parks Conservation Association and the Sierra Club challenged allowing states to treat CSAPR compliance as a better-than-BART alternative.

Multiple power companies and the Utility Air Regulatory Group, as well as the state of Texas and the Louisiana Department of Environmental Quality, challenged EPA's disapproval of SIPs relying on CAIR as a better-than-BART alternative.

"Except to the extent that the challenges are moot, we affirm EPA's actions," said the March 20 opinion by Judge Stephen F. Williams.

The three-judge panel also included Thomas B. Griffith and Nina Pillard.

Useful Life

Dealing with the conservationists' petition first, the court said that "the attack on EPA's use of presumptive BART ... is jurisdictionally foreclosed by the 60-day filing window provided by the Clean Air Act."

Furthermore, the court described "a cavalcade of attacks on alleged modeling errors," wherein "the conservation petitioners fix on a comment that EPA failed to address in its response to comments, specifically an assertion that EPA's model does not take into account the remaining 'useful life' of specific BART-eligible sources."

The agency did not contest that it overlooked these comments.

"It argues now — reasonably, in our view — that the effects of a plant's useful life are too speculative to model and not significant enough to make any modeling a useful enterprise," the court said. "We see no need to remand on this point for EPA to move this bit of *post hoc* rationalization into a rulemaking record."

The conservation petitioners finally argued that, in comparing CSAPR and BART, EPA compared the wrong averages.

The court disagreed, referring to its reasoning in an earlier petition from the Utility Air Regulatory Group.

The E. Barrett Prettyman Courthouse, home of the D.C. Circuit Court.

"It is in the nature of averages that some particular sites may underperform while others overperform," the court said. "EPA's rule requires aggregate average improvement, and its comparison of the CSAPR-region Class I areas as well as all Class I areas nationwide was reasonable."

State and Industry

The state and industry petitioners in essence argued that if compliance with CAIR had for years allowed them to achieve greater reasonable progress than BART would have, their continued enforcement of emissions standards in line with the now-defunct CAIR must necessarily be found an adequate alternative to BART.

"But, of course, without CAIR — which all parties agree is dead and beyond revival — there is no legal basis for a requirement that states control their sources at CAIR levels; indeed, for states that are not part of CSAPR, there is no legal basis for requiring states to participate in any haze-related interstate trading program," the court said.

The court cannot order EPA to consider CAIR an alternative to BART without resurrecting CAIR itself, "a rule that we have already stricken and ordered to be vacated," it said.

The petitioners saved themselves from mootness only by couching their request for relief as "a contingency," the court said.

FERC & FEDERAL NEWS

Hearing on Panda Reactive Services Moving Forward

FERC last week dismissed two requests for rehearing of a 2017 decision to hold a hearing on a Virginia facility's reactive services tariff (ER17-1821). The commission, made by staff last July while it lacked a quorum, ordered a hearing on the proposed tariff for Panda Stonewall, a gas-fired combined cycle facility in Leesburg, Va., to settle complaints that components of the tariff — including return on equity and depreciation, administration and general expenses — were "unreasonably excessive."

Panda Power Funds argued that a hearing was unwarranted because none of the complaints was about material facts, but FERC ruled that it has discretion to set hearings on issues other than factual discrepancies. The commission also denied a rehearing request from Northern Virginia Electric Cooperative, which had argued that Panda shouldn't have been granted a waiver of the 60-day prior notice requirement and that staff lacked the authority to make the decision. The commission disagreed and noted that it usually grants such waivers because otherwise the plant would be obligated to provide reactive service without compensation.

Settlement Judge Patricia E. Hurt reported earlier this month that Panda Stonewall circulated a counteroffer to commission trial staff and customers at a settlement conference Feb. 6. A conference scheduled for March 21 was canceled.

FERC Denies Rehearing, Approves ODEC Rate Schedule

FERC last week approved a compliance filing from Old Dominion Electric Cooperative on revisions to its cost-of-service rate schedule filed in 2013 and denied a request from a demand response provider to reconsider the commission's 2017 ruling in the proceeding, confirming an effective date of Jan. 1, 2014 (ER13-2483).

Bear Island Paper WB, which is a retail customer of ODEC member Rappahannock Electric Cooperative, protested several components of the original filing but focused on ODEC's proposal to allocate DR "add-backs" directly to the member cooperatives in which the DR occurred. The company said its capacity costs would increase due to the direct allocations.

ODEC made several revisions to its proposal in response to findings from an administrative law judge and argued against others. The commission affirmed portions of the ALJ opinion and overturned others in the 2017 ruling (Opinion No. 553), which generally supported ODEC aligning its cost allocation methods with those used by PJM. In requesting rehearing of that opinion, Bear Island argued that FERC exceeded its authority in making changes to ODEC's proposal, but the commission denied that request because Bear Island failed to show it had been harmed by the DR "add-back" revisions.

FERC Sets Technical Conference on Tariff Changes

FERC on Friday accepted but suspended for five months Southern California Edison's amendments to its transmission owner tariff that creates an annual transmission maintenance and compliance review process (ER18-370). The company's proposed process allows it to share information about certain transmission-related maintenance and compliance activities that are not submitted to CAISO.

Several parties had protested aspects of the proposal, saying that the information-sharing program did not provide sufficient coordination and transparency. Protesters including the Transmission Agency of Northern California had said that portions of the changes needed refinement.

FERC said the amendments might not be just and reasonable and that the tariff is to become effective on Sept. 1 following a technical conference. The commission said that the questions raised in the proceeding are applicable in other proceedings for capital improvements that are not submitted through CAISO's transmission planning process.

FERC & Federal News

Second Thoughts: FERC May Revoke Marketers' Tariff

By Rich Heidorn Jr.

FERC last week rejected a proposed power and gas tariff filed by the North American Energy Markets Association (NAEMA) and indicated it is likely to revoke the group's capacity and energy tariff, which the commission accepted in 2003. The group said Thursday night it will seek an emergency stay to give it time to amend the older agreement.

NAEMA, which claims about 150 members that have 500,000 MW of generating capacity and serve more than 100 million electric and gas customers, developed the power and gas tariff with the International Energy Credit Association.

The group said the tariff, filed in January, was similar to the 2003 tariff but was updated to reflect current industry preferences for contract language and products. It intended to leave the existing tariff in place with the new one available for companies that choose to use it.

But the commission said March 19 that the tariffs should not be on file with it because NAEMA is not a jurisdictional public utility (ER18-676). "Nor does the power and gas tariff filed by NAEMA set forth any rates and charges or terms and conditions that govern the transmission or sale of electric energy. Instead, the power and gas tariff merely contains standard form bilateral sales contracts with a set of standard terms and conditions that NAEMA members may choose to use when they make sales of their own capacity and energy or natural gas to customers."

The commission said NAEMA members that are public utilities should enter separate, standalone bilateral agreements under their own market-based rate tariffs whether or not they comport with NAEMA's standard terms and conditions. Such transactions should be included in the utility's Electric Quarterly Reports, FERC said.

"We make no findings about [the proposed tariff's] specific terms and conditions or whether NAEMA members should or should not use it as a template for any market-based rate bilateral sales agreements," the commission said.

Show Cause

FERC also directed NAEMA to show within 30 days why the 2003 tariff, which was approved by a letter order by a division director, should remain on file with the commission (ER04-22). "If such a filing is not received within the required time, NAEMA's capacity and energy tariff will be canceled in the commission's eTariff system," it said. The commission did not say why it now considered the 2003 order — which NAEMA says was updated as recently as 2011 — an apparent error.

NAEMA was created in 2003 as a successor to the Power and Energy Market (PEM) of the Mid-Continent Area Power Pool (MAPP) after the group expanded. NAEMA said the 2003 tariff was a successor to one approved by FERC in 2001 for MAPP (ER01-3045) and has been updated five times since then.

Emergency Stay Sought

NAEMA attorney K.C. Hairston told *RTO Insider* on Thursday evening that the organization will file an emergency motion seeking a stay of the show cause order to allow it to propose an amendment to the energy and capacity tariff that it said should address the commission's jurisdictional concerns. The motion was filed early Friday.

The amendment would be a cost-based schedule, which NAEMA says will ensure the tariff falls "within the categories of agreements described by the commission in the show cause order where non-jurisdictional entities can submit tariffs on behalf of jurisdictional companies."

The group pledged to submit the proposed amendment within 60 days.

Overwhelmingly Surprised

In its motion, NAEMA says it was "overwhelmingly surprised" by the order, claiming it contacted the commission's Office of General Counsel regarding the jurisdiction issue and incorporated changes it suggested. The group said it realizes that OGC does not speak for the commission but "assumed that the commission would take a consistent view" with the office.

NAEMA said it had cause for the stay because "terminating a tariff that has been repeatedly approved by the commission for over a decade and is currently used by market participants across the United States will be disruptive to the energy markets the commission regulates."

The group also made an unusual request, saying "it will be beneficial to have a designated non-decisional commission staff member that it can consult with should issues arise" in drafting the amendment.

NAEMA, which holds regular conferences, says its goal is to "promote and facilitate a vibrant physical and financial energy marketplace" through "contacts and contracts." Its board members include staff from ACES Power Marketing, AEP Energy Partners, EDF Renewable Energy, MidAmerican Energy, Southern Power, TransAlta Energy Marketing, WPPI Energy and Xcel Energy.

FERC Accepts Idaho Power Rate Authority Analysis

FERC on March 19 accepted Idaho Power's updated application for market-based rate authority (ER16-2091). The company's filing included revisions to its market-based rate tariff and an updated market power analysis for its balancing authority area.

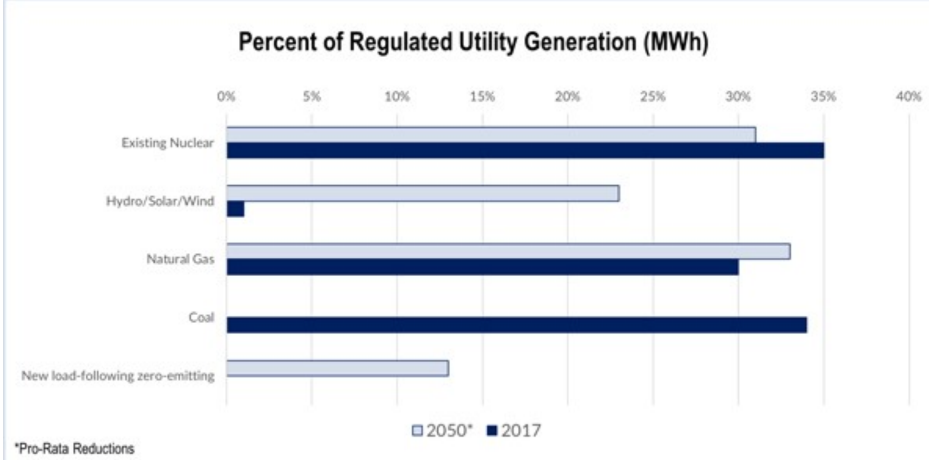
FERC in October 2016 had found that Idaho Power's failure of the wholesale market power screen in its BAA established a rebuttable presumption of market power. It directed the company to show why its MBRA should not be revoked.

"After weighing all of the relevant factors, we find that, on balance, Idaho Power has rebutted the presumption of market power for the Idaho Power balancing authority area," FERC said.

Duke Seeks Tech Advances to Phase out Coal

By Rory D. Sweeney

Duke Energy last week announced an updated carbon-reduction plan that anticipates relying on natural gas and technology advancements to phase out coal-fired generation by 2050.



Duke plans to phase out coal-fired generation by 2050 by increasing production from natural gas, renewables and as-yet-unknown technology that is emissions free and can vary its output with demand. | *Duke Energy*

In a report on climate change to shareholders, the company said it plans to retire nine coal-fired plants, totaling 2,006 MW, by 2024. Between 2011 and 2017, it retired 47 units equaling 5,424 MW.

In the short term, gas-fired generation will pick up the slack. Duke projects natural gas generation will increase from about 30% of the company's total generation today to 42% in 2030, while coal generation will decrease to 16%. Generation from wind, hydro and solar renewables will double to 10%.

2030 Goals

Duke says it has committed to spend $11 billion by 2026 to build new gas-fired, wind and solar generation with the goal of reducing carbon dioxide emissions 40% from 2005 levels by 2030. That would put companywide carbon dioxide emissions around 91.8 million pounds per year.

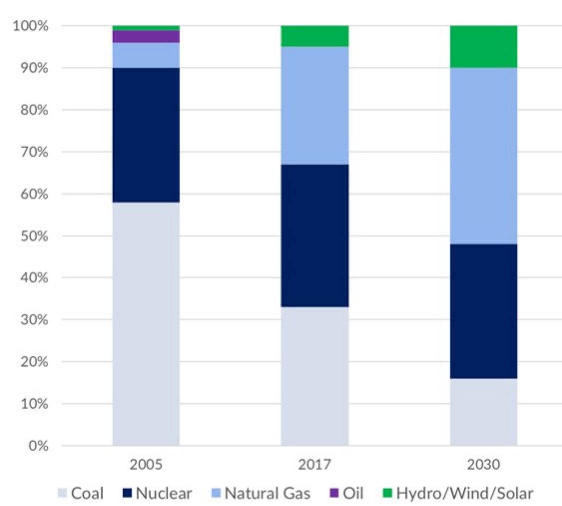
The goal would include reducing carbon intensity — pounds of carbon dioxide created per kilowatt-hour of production — by 45% compared to 2005 levels, equaling about 0.7 pounds/kWh. As of 2016, according to the company, it has already reduced its carbon dioxide emissions 29% and its carbon intensity 25% below 2005 levels.

Coal-free by 2050

To phase out coal by 2050, Duke anticipates generation from renewables more than doubling again to 23% and gas-fired generation falling back to 33%. It would also rely on 13% from currently nonexistent technology that has zero emissions and can vary its output to match demand. Potential candidates are nuclear that can vary its output (current technologies are inflexible), closed cycle biomass-fired facilities and combined cycle gas turbines (CCGTs) with carbon capture and storage.

"In the past 15 years, we've seen dramatic advancements in energy technology, including abundant natural gas due to hydraulic fracturing, and declining prices of solar and wind technology. Given this rapid pace of development, we fully expect technology innovations in the coming decades," the report explained.

The report assumes that, including efficiency programs, load increases 0.45% each year. It also relies on natural gas prices remaining flat through 2028 and increasing 4% annually after that, along with 20-year license extensions for its 9,000 MW of nuclear generation. The estimates are based on limiting global warming to no more than a 2-degree Celsius increase and assume that all emissions sources throughout the world reduce by the same amount: 74% compared to 2005 levels.



% of total generation (MWh) | *Duke Energy*

100% Renewables Unrealistic

The report explains that renewables have diminishing returns because of lower capacity factors and sides with academics who — in a recent white-paper war — argued there are cheaper ways to achieve zero carbon dioxide emissions in the energy sector than switching completely to renewables.

"As the adoption of renewables grows to between 20 and 30% of total generation, the value of the resource begins to diminish due to extended periods of excess energy in the spring and fall and insufficient output during the winter months," Duke said. "We do not believe 100% renewables can reliably deliver the power required by a modern economy. Similarly, we do not advocate for 100% natural gas or nuclear energy. An analysis published in the *Proceedings of the National Academy of Science[s]* concluded that a decarbonized energy system would very likely need other technologies besides renewables, including nuclear and carbon capture and sequestration."

Another analysis concluded "that the high-renewables scenario was likely the most costly, while both the mixed scenario (renewables, nuclear and carbon capture on fossil) and the high-nuclear scenario would likely cost less," Duke's report said.

COMPANY BRIEFS

Failed Nuclear Project Will Boost Santee Cooper's Rates

Santee Cooper's rates will rise as the utility pays off the debt it incurred in the failed attempt to expand the V.C. Summer Nuclear Generating Station, according to it and a conservative think tank.

The utility, which was trying with SCANA to add two reactors to the South Carolina plant, said March 20 it expects its rates to increase by 7 to 8%. Santee Cooper, which is owned by the state of South Carolina, said it won't increase its rates until at least 2020.

The Palmetto Promise Institute said the same day it expects Santee Cooper's rates to increase by at least 11.7%. The group said its estimates provide evidence that the state should sell Santee Cooper.

More: *The Post and Courier*

$529M in SCANA Dividends Came From Failed Nuclear Expansion

SCANA has paid out $529 million in dividends with money it collected from customers for its failed attempt to expand the V.C. Summer Nuclear Generating Station, according to a document released the week of March 19 by the South Carolina Office of Regulatory Staff.

The document was produced by SCANA last month for the South Carolina Senate.

SCANA's quarterly dividends have grown more than 50% since the utility started the ultimately failed attempt to expand the V.C. Summer power plant, which it did in concert with Santee Cooper, a utility owned by the state of South Carolina. Nearly all the increase stems from the effort to build two new reactors at the plant.

More: *The Post and Courier*

Burns & McDonnell to Build Entergy New Orleans Plant

Burns & McDonnell said March 20 that Entergy New Orleans has selected it to be the engineer-procure-construct project manager for the New Orleans Power Station, a 128-MW gas-fired power plant that will be built on the same site as the now-retired Michoud power plant.

The company said it has begun design work and expects to begin construction later this year. It expects the $210 million plant will be up and running by 2020.

Wartsila said Burns & McDonnell has selected its Smart Power Generation solution to power the plant.

More: *Burns & McDonnell; Wartsila*

Pilgrim Still Offline, No Restart Date Set

Entergy's Pilgrim Nuclear Power Station remains in cold shutdown after it was shut down on March 6, and an Entergy spokesman said the company had not determined when it would be restarted.

The plant was taken offline because of a suspected leak in a system needed to heat water before it's pumped into the reactor vessel. While that was being addressed, the plant lost offsite power on March 13 because of a blizzard. Power was restored two days later, but while tests were being performed prior to bringing the plant back online, workers determined they would need to replace its start-up transformer.

An Entergy spokesman said the replacement was underway.

More: *Cap Cod Times*; *Cape Cod Times*

NM Regulators Approve Xcel's Massive Wind Project

The New Mexico Public Regulation Commission on March 21 voted unanimously to approve Xcel Energy's plan to spend $1.6 billion building two giant wind farms in New Mexico and Texas.

The approval came after Xcel proposed a different way of recovering its costs in the period between when the wind farms come online and when the PRC approves new rates that include cost recovery for the projects. A PRC hearing examiner last month challenged Xcel's initial plan.

Xcel expects Texas regulators to approve the project quickly, enabling it to begin construction on the Texas wind farm in the next few months. It expects to begin construction on the New Mexico wind farm, which is the larger of the two, next year.

More: *Albuquerque Journal*

Microsoft Makes Single Largest Solar Purchase in US

Microsoft on March 21 said it will buy 315 MW of power from two solar farms being built in Virginia in what the software developer said was the single largest purchase of solar energy in the U.S.

The company said the purchase will help it make significant progress toward its goal of having 60% of the electricity for its data centers come from renewable sources by 2020.

The two solar farms are part of a 500-MW solar development that will be owned and operated by sPower, which is owned by AES and AIMCo.

More: *Microsoft*

Georgia Regulators Approve Dominion's SCANA Purchase

Dominion Energy said March 21 that the Georgia Public Service Commission has unanimously approved its $7.9 billion acquisition of SCANA.

The deal was approved by the Federal Trade Commission in February, and it still must be approved by FERC, the Nuclear Regulatory Commission and utility regulators in North and South Carolina.

Dominion expects the deal to close by the end of the year.

More: *WTOP*

Layoff Notices Sent to Workers at 2 DP&L Coal Plants

AES Ohio Generation, the parent company of Dayton Power and Light, has begun sending layoff notices to workers at the coal-fired J.M. Stuart and Killen plants in Manchester and Aberdeen, Ohio.

The company says in the notices that it

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COMPANY BRIEFS

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expects to begin layoffs June 1.

DP&L said in November 2016 that the coal-fired plants might close because of market-driven challenges to their financial viability.

More: The Ledger Independent

Enerfab, FirstEnergy Appealing Citations in Power Plant Deaths

Enerfab and FirstEnergy are appealing citations issued this month by the U.S. Labor Department in response to the August deaths of two workers at the Bruce Mansfield Power Plant in Shippingport, Pa.

The citations carried fines of $129,340 for Enerfab, a contractor, and $77,604 for FirstEnergy, which owns the plant.

During an investigation at the plant, the department found 14 serious violations by Enerfab and 11 by FirstEnergy, according to the citations. All were corrected during the investigation.

More: Pittsburgh Tribune-Review

Energy Northwest Executive Board Names Interim Nuclear Plant CEO

Sawatzke

The Energy Northwest Executive Board on March 20 named Brad Sawatzke interim CEO of the Columbia Generating Station, effective at the end of the month.

Sawatzke is the plant's chief operating officer and chief nuclear officer. He replaces Mark Reddeman, who is leaving March 30 to become CEO of Nawah Energy, which is located in the United Arab Emirates.

The board is not expected to be ready to name to a permanent replacement for Reddeman until next month.

More: Tri-City Herald

FEDERAL BRIEFS

FERC Extends Comment Period in Resilience Docket

FERC on March 20 issued an order extending to May 9 the deadline for submitting comments in the proceeding it initiated to evaluate the resilience of the bulk power system in the territories of the nation's RTOs and ISOs.

FERC initiated the proceeding after rejecting Energy Secretary Rick Perry's notice of proposed rulemaking, which would have required RTOs and ISOs with energy and capacity markets to make cost-of-service payments to generators that have a 90-day on-site fuel supply and are able to provide "essential reliability services." (See FERC Rejects DOE Rule, Opens RTO 'Resilience' Inquiry.)

The RTOs and ISOs submitted information on the resilience issues and concerns identified by FERC on March 9. FERC originally had given interested entities 30 days after that to submit comments on the filings by the bulk power system operators.

Eleven associations, including the American Council on Renewable Energy, the American Petroleum Institute, the American Public Power Association and the Electricity Consumers Resource Council, filed a motion on March 14 asking FERC for a 30-day extension.

FERC said that, although it originally had characterized the comments it would accept as replies to the filings by the RTOs and ISOs, it realized that, in addition to replying to the filings, interested entities also may want to provide their own perspectives and recommendations on resilience.

"It is imperative that we base our next steps on the best available information, and we encourage input from stakeholders across the energy spectrum," FERC said in the order. "Extending the time for comments will help us achieve those objectives."

More: AD18-7

FERC Approves BPA Transmission Rates

FERC on March 19 approved the Bonneville Power Administration's proposed wholesale power and transmission rates for Oct. 1, 2017, through Sept. 30, 2019, over the protests of several environmental groups and Northern California utilities.

The Sierra Club, the Montana Environmental Information Center and Renewable Northwest said the Montana Intertie rate should be eliminated for generators seeking to access the BPA grid through the Eastern Intertie. The utilities opposed BPA's proposal to increase the hourly Southern Intertie rate by 170%.

FERC said that its review of BPA's rates is governed by the Northwest Electric Power Planning and Conservation Act of 1980, which, among other provisions, stipulates that the commission determine whether the power marketing administration is recovering all of its costs for procuring electricity. Unlike the Federal Power Act, FERC said, the Northwest Power Act also does not allow the commission to modify the proposed rates. The commission thus ruled that the Southern Intertie rate satisfied the Northwest Power Act's provisions and that the environmental groups' protest was outside the scope of the proceeding.

More: EF17-2, et al.

Global Energy Demand, Carbon Emissions Grew in 2017

Global energy demand and carbon emissions both grew last year, the latter for the first time since 2014, according to a report released by the International Energy Agency on March 22.

Demand grew by 2.1%, more than twice its 2016 growth rate, while carbon emissions grew 1.4%, according to the "Global Energy

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FEDERAL BRIEFS

Continued from page 31

and CO2 Status Report, 2017."

Fossil fuels met 81% of total energy demand last year, the report found. Renewable power generation grew by 6.3% and met a fourth of the growth in world energy demand, thanks to big expansions in solar, wind and hydropower.

More: *Clean Technica*

Energy Programs Get $1.6B More in Funding Deal

Energy programs within the Department of Energy will see their funding increase $1.6 billion to $12.9 billion in the tentative $1.3 trillion deal to fund the federal government reached March 21 by congressional leaders.

The deal, which was approved by the House of Representatives on March 22, boosts funding for the Advanced Research Projects Agency-Energy by $47 million to $353 million, even though President Trump's first two budgets proposed eliminating it.

The Office of Energy Efficiency and Renewable Energy got a 14% funding increase to $2.3 billion, even though the White House wanted to cut its funding by nearly three-fourths.

More: *The Washington Post*; *CNN*

US Rejects EU Proposals For Solar Tariff Alternative

The U.S. has rejected European Union proposals for an alternative to the tariffs that President Trump imposed on solar energy goods, the two said in a joint filing with the World Trade Organization on March 20.

The tariffs, called safeguard tariffs, are permitted under WTO rules as a form of emergency trade protection that countries can impose in the face of sudden, damaging increases in imports of specific products. In exchange for imposing the tariffs, however, the U.S. is supposed to do one of two things: compensate countries that are major exporters of solar energy products by offering them trade breaks on other products; or accept those countries putting up barriers to some U.S. exports to counterbalance the tariffs.

The EU, China, Taiwan, South Korea and Malaysia all demanded compensation after the tariffs were imposed in January.

More: *Reuters*

US Net Natural Gas Exporter For First Time in 60 Years

The U.S. exported more natural gas than it imported last year for the first time since 1957, the Energy Information Administration said March 19.

EIA attributed the milestone to continuing growth in natural gas production, a reduction in the amount of natural gas imported by pipeline from Canada and an increase in exports of natural gas, both by pipeline and as a liquid.

The U.S. surpassed Russia as the world's top natural gas producer in 2009 because of the growth in shale gas production.

More: *Energy Information Administration*

Fossil Fuel Generation Fell, Renewable Generation Rose in 2017

Fossil fuel generation fell and renewable generation, particularly from hydro, wind and solar, rose last year in the U.S., the Energy Information Administration said March 20.

Natural gas and coal generation fell 7.7% and 2.5%, respectively, in 2017 from the year before. Nearly 6.3 GW of wind turbines and 4.7 GW of utility-scale solar photovoltaic systems were added, with about a third of that capacity coming online in December.

Total net generation fell 1.5% because of decreased demand.

More: *Energy Information Administration*

STATE BRIEFS

ARKANSAS

AECC Agrees to Buy up To 100 MW from Solar Farm

Arkansas Electric Cooperative Corp. said March 20 it has agreed to buy up to the total capacity of a 100-MW solar farm that Renewable Energy Systems Americas plans to build near Crossett.

With the solar farm, 17% of AECC's generation capacity will be renewable.

The solar farm is scheduled to come on line by 2021.

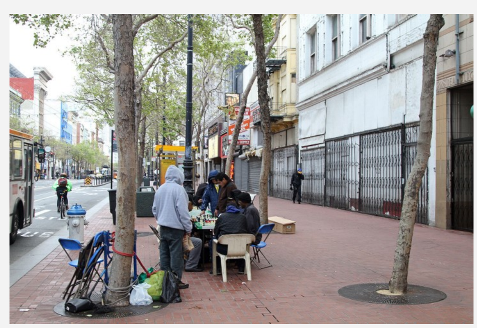
More: *magnoliareporter.com*

CALIFORNIA

FERC Denies San Francisco Rehearing Request in PG&E Dispute

FERC on March 19 dismissed San Francisco's request for rehearing of a commission order that established hearing and settlement judge procedures in a dispute between the city and Pacific Gas and Electric over maintenance work costs.

Last September, the city complained that PG&E was overcharging it for operations and maintenance work at 11 points of interconnection on its distribution network, in relation to the city's $4.2 million plan to install new streetlights in the Tenderloin, the city's most dangerous neighborhood. It protested PG&E's filing of 11 unexecuted work performance agreements.



Market Street in San Francisco's Tenderloin neighborhood

In its Oct. 30, 2017, order, FERC found that PG&E's filing raised issues of material fact

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STATE BRIEFS

Continued from page 32

and set the matter for a trial-type evidentiary hearing. In its rehearing request, San Francisco said its protest presented a "straightforward legal issue" that FERC should have ruled on summarily, rather than scheduling a hearing for it. The commission, however, said its order was not final and is thus not subject to rehearing yet.

More: *ER17-2406*

ILLINOIS

McLean County Board Approves 2nd Wind Farm

The McLean County Board on March 20 voted 16-3 to approve the 200-MW, 58-turbine Bright Stalk Wind Farm, which EDP Renewables North America plans to build southeast of Chenoa.

The vote came a month after the board voted 10-8 to approve the 250-MW, 100-turbine McLean County Wind Energy Center, which Invenergy plans to build southeast and north of Lexington.

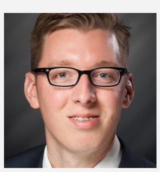
More board members signed on to the second project after they voted to require EDP to offer sound studies to anyone living within 2,000 feet of a turbine and provide more protection for the local environment.

More: *The Pantagraph*

INDIANA

State Rep. David Ober Named to Utility Regulatory Commission

Gov. Eric J. Holcomb said March 19 he has appointed state Rep. David Ober (R) to the Utility Regulatory Commission. Ober will succeed Jim Atterholt, who retired in January.



Ober

Holcomb selected Ober from a list of three nominees that also included IURC Executive Director of External Affairs Stefanie Krevda and Office of Energy Development Director Tristan Vance.

Ober will serve the rest of Atterholt's term, which ends Jan. 31, 2020.

More: *Inside Indiana Business*

IOWA

Senate Working on 2nd Bill Cutting Energy Efficiency Programs

A three-member Senate Ways and Means subcommittee on March 20 began work on a bill that would reduce the scope of the energy-efficiency programs that utilities are required to offer in case the House of Representatives doesn't pass a bill already passed by the Senate that eliminates the programs.

"We want to make sure that something gets passed this year," said committee Chairman Randy Feenstra (R).

The bill being considered would put caps on the programs, allow utility customers to opt out of them and require utilities to show on customers' bills how much they are paying to help fund rebates and other incentives aimed at getting people to buy energy-efficient appliances or insulate their homes.

More: *The Gazette*

KENTUCKY

PSC Reduces KU, LG&E Revenue To Reflect Federal Tax Cut

The Public Service Commission on March 19 issued an order reducing the total revenue that Kentucky Utilities and Louisville Gas & Electric are allowed to collect annually from their customers by $203.8 million to reflect the reduction in the corporate tax rate mandated by the federal Tax Cut and Jobs Act.

In the order, the PSC modified a settlement reached in a case involving the two utilities; the Kentucky Industrial Utility Customers, which had initiated the case through a filing seeking a revenue reduction; and the attorney general's office, which was a party to the case. The settlement had called for a total revenue reduction of $176.9 million, but the PSC boosted that by $26.9 million because of modifications it made to the method of calculating the impact of the tax reduction, which cut the federal corporate tax rate from 35% to 21%.

The PSC said KU and LG&E electric customers will see their monthly bills fall by about 6%.

More: *Kentucky Public Service Commission*

MAINE

Bill Spikes Prompt PUC to Audit CMP's Billing Practices

The Public Utilities Commission voted unanimously on March 19 to begin a management audit of Central Maine Power's billing practices.

The vote was a response to more than 1,000 complaints from the utility's customers about spiking power bills.

Central Maine Power has blamed the increases on severe weather.

More: *NECN*

MISSISSIPPI

Auditor Demands $93 Million from Closed Solar Panel Plant Owner

State Auditor Stacey Pickering on March 20 demanded that solar panel manufacturer Stion repay $92.9 million related to incentives it received for a Hattiesburg factory it closed last year.

Most of the money, $74.8 million, is a loan the company received from the state. The rest consists of $2.1 million in reduced property taxes that Stion failed to pay to Hattiesburg and Forrest County and $16 million in interest on the loan and property taxes.

If Stion doesn't repay the money in 30 days, it faces a civil lawsuit.

More: *The Associated Press*

NEW JERSEY

AG Files to Prevent PennEast from Condemning Preserved Land

Attorney General Gurbir Grewal on March 22 filed a motion in U.S. District Court in Trenton to block PennEast Pipeline Co. from condemning more than 20 properties acquired under open-space and farmland preservation programs.

The New Jersey Conservation Foundation and Hunterdon Land Trust joined the state in asking the court to reject the company's efforts to seize preserved land they own.

PennEast wants to seize 149 of the 211 properties in the path of the state portion

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STATE BRIEFS

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of its proposed 116-mile natural gas pipeline. About half the properties are preserved lands, more than 20 of which are owned in whole or in part by the state.

More: NJ Spotlight

NEW YORK

Program Gave out 5,750 EV Rebates in First Year

More than 5,750 consumers received rebates to buy electric cars in the first year of the state's Drive Clean Rebate program, Gov. Andrew Cuomo said March 22.

The program provides residents with rebates of up to $2,000 for the purchase or lease of a new electric car from participating dealers.

Residents in all the state's 62 counties have received rebates. Of the state's 10 regions, Long Island got the most, 33%, followed by the Mid-Hudson Valley with 17.4%.

More: New York State Energy Research and Development Authority

PENNSYLVANIA

State Rule Reduces Nitrous Oxide Emissions at Coal Plants

Emissions of nitrous oxide by the six power plants in the state that just burn newly mined coal fell 60% to 23,133 tons last year because of a state rule that took effect in January 2017.

The Reasonably Available Control Technology II rule requires power plants to use a potentially costly pollution control, but only during times of high power demand, when it's most cost-effective.

Vince Brisini, director of environmental affairs at Olympus Power, said the regulation provides power plants with enough flexibility to run cost-effectively.

More: The Wall Street Journal

WASHINGTON

Chelan PUD Imposes Moratorium For Cryptocurrency Mining

The Chelan County Public Utility District has implemented a moratorium on taking and processing applications for electric service to mine cryptocurrency.

The PUD's board unanimously imposed the moratorium, which went into effect March 19, at its regular meeting after reviewing the impact that cryptocurrency mining was having on existing loads and applications for service.

The number of service applications and inquiries about large loads for cryptocurrency mining received by the PUD increased significantly after the price of bitcoin rose last fall and has continued to increase since then.

More: iFiberOne News

States, Utilities, RTOs Push Back on Storage Order

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already underway. (See MISO Rules Must Bend for Storage, Stakeholders Say.)

Otherwise, AES requested a rehearing to determine ways "to help alleviate in the interim" the conditions Order 841 is supposed to correct. It argued that "the commission simultaneously predicated participation of … electric storage resources on dispatchability, which … completely fails to recognize the physical and operational characteristics of electric storage resources like" IPL's, which "can provide their services automatically, without a need for direct interface with RTO/ISO dispatch software at all."

FERC required RTOs/ISOs to submit compliance filings detailing how they will implement the order by Dec. 3, with implementation finished a year after they file. MISO asked for a six-month extension of the implementation deadline to accommodate distributed energy resource issues that are still pending.

"Granting the requested clarification, or rehearing, will help ensure that an RTO/ISO has sufficient flexibility to design and implement [a storage] market participation model that is technically and operationally feasible in each RTO/ISO's specific context," MISO said.

The RTO also asked for clarification about how the 100-kW minimum threshold for resource participation should be calculated, noting that giving grid operators flexibility in how they handle charging and discharging limits "can avoid unnecessarily limiting the range for clearing energy or reserve products." It also requested the ability to phase in the number of very small resources that can participate each year "to avoid an unmanageable influx." Grid operators should also be allowed to require storage resources to comply with rules necessary to address any reliability impacts that distribution utilities identify, MISO said.

Finally, the RTO requested confirmation that three potential bidding parameters are acceptable:

- Requiring storage units to provide their state-of-charge forecasts at the beginning of identified market intervals, such as day-ahead, five-minute and real-time.
- Requiring storage units that don't provide minimum limits and can be moved smoothly between negative and positive to submit a single hourly ramp rate for the day-ahead market and "look-ahead commitment" process, or alternatively applying MISO's real-time security-constrained economic dispatch practice if appropriate.
- Requiring units that use their state-of-charge to lock output to a narrow range to be treated as self-scheduled price-takers that can't set prices because they are potentially unable to fulfill capacity obligations, provide ramp products or perform ancillary services.

EEI's Issues

The Edison Electric Institute requested clarification or rehearing on whether relevant electric retail regulatory authorities (RERRAs) would have the ability to opt in or out of allowing distribution-connected resources from participating in wholesale markets because their participation "has significant implications for the operation and reliability of the distribution system."

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EEI pressed FERC on how rates should be calculated, arguing that in situations where storage is paired with a retail load behind a single retail meter, the storage should either pay for any costs to separately measure the retail and wholesale loads or the entire load should be treated as retail. The institute said that storage must still be required to "pay any applicable charges covered under state jurisdictional tariffs in order to adequately reflect their use of state jurisdictional facilities." It also disliked the 100-kW threshold, fearing that an "influx of smaller resources" could create administrative, reliability and cost issues.

DER Technical Conference

Finally, EEI said rules developed through the separate technical conference that FERC ordered on DER aggregation (RM18-9, AD18-10) should also apply to any storage resources covered by Order 841 "to ensure consistency."

Several organizations representing public power filed a joint request asking for the same, adding that any RTO/ISO tariff revisions regarding Order 841 not become effective until after rules from the technical conference are developed.

RERRA Clarifications

Like many other commenters, the public power organizations — which include American Municipal Power, the American Public Power Association and the National Rural Electric Cooperative Association — also focused on state and local authority and requested FERC include an opt in/out mechanism for RERRAs.

"The commission should ... unequivocally state that [its] regulations ... do not authorize an [energy storage resource] to violate state or local laws or regulations or contract rights governing retail electric service or the local distribution of electric energy," the organizations wrote.

Pacific Gas and Electric asked for clarification that "nothing in Order 841 is intended to suggest that the state no longer has jurisdiction to determine how power flowing from the distribution grid, through the customer meter and then into the storage resource located behind the customer meter is to be split between retail consumption and wholesale charging for later discharge into the wholesale markets."

The company warned that "if the commission were to conclude that the state no longer has this authority, then a retail customer could use its behind-the-retail-meter storage resource as a means to completely bypass retail rates for its onsite electricity consumption. The customer could simply claim that all electricity flowing through his/her retail meter went into the storage device for later discharge into the wholesale markets, even if the power were never returned to the wholesale market but instead used to meet on-site electricity demand."

The Organization of MISO States reiterated the request to "clearly" acknowledge "applicable state and local laws, and applicable orders and rules" of RERRAs, disqualify resources that don't comply with those rules and develop a process to confirm that compliance.

The National Association of Regulatory Utility Commissioners filed similar requests, warning FERC to "be careful that its actions do not inhibit or conflict with authority Congress specifically reserved to NARUC's state commission members." The association took issue with wording in the order that barred states from deciding whether distribution-level storage in their jurisdiction can participate in wholesale markets, which it said should be eliminated.

"FERC has exclusive jurisdiction over the wholesale markets and the rules that apply to resources participating in those markets, including how such resources participate," the association said. "Nonetheless, Congress assigned states the task of determining whether resources located behind a retail meter or on the distribution system can, in the first instance, participate in wholesale markets."

Xcel Energy Services, filing on behalf of its four utility affiliates in Minnesota, Wisconsin, Colorado and the Southwest, expressed concern about many of the same issues other stakeholders addressed, including: not providing states with an opt-out option; complications around separate metering for wholesale and retail activity; flexibility in developing an implementation schedule; allocation of integration costs for storage resources; and the inability to institute rules for storage to address reliability issues.

Invenergy's Grand Ridge storage facility

Market Exclusivity

The Transmission Access Policy Study Group (TAPS) noted the RERRA opt-out issue, but it also argued that FERC erred in rejecting the group's proposal that storage resources be required to choose exclusive participation in either wholesale or retail markets.

"To avoid market manipulation, prohibited resales of energy purchased at retail and prohibited end-use consumption of energy purchased at wholesale, distributed storage resources [should] be required to make a binding choice to participate exclusively either in the wholesale markets or at retail," TAPS said.

Grid Operator Responsibility

CAISO requested that FERC clarify several points about grid operators' responsibilities, including that someone — although not grid operators — must directly meter storage resources, that grid operators can require storage resources to resolve retail double-billing issues with their retail energy provider as a condition of wholesale market participation, and that storage resources not incur transmission charges when they are dispatched to charge up because they're performing a service.

Other Clarifications

Several organizations also sought separate clarifications of the order. PJM requested confirmation that the order "does not mandate a particular methodology" for accounting for "the physical and operational characteristics" of storage resources. The California Energy Storage Alliance requested clarity on "when and why transmission charges should apply to wholesale energy purchased for later resale in the same area" because potential "double-billing would be unduly and financially burdensome to the usage of energy storage and unreasonable in the application of the cost allocation and recovery for transmission charges."

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