RTO Insider

Your Eyes and Ears on the Organized Electric Markets

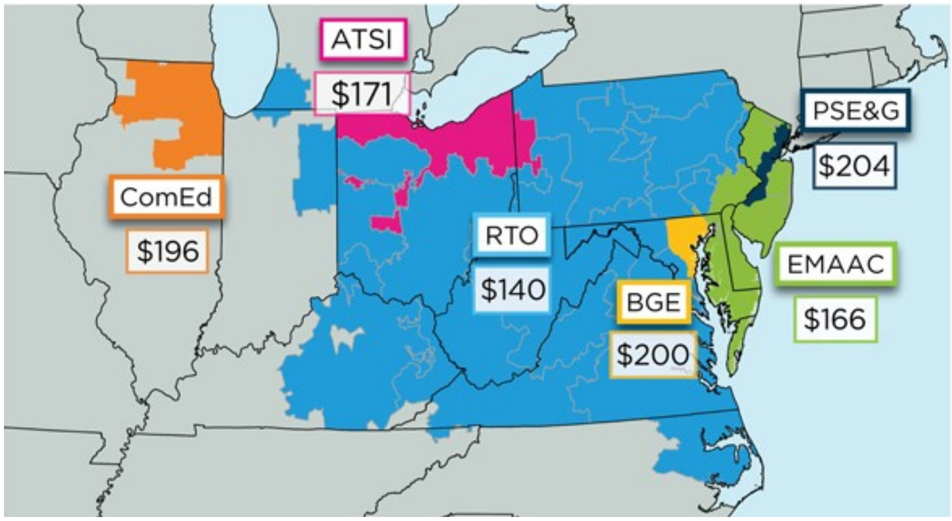
CAISO ■ ERCOT ■ ISO-NE ■ MISO ■ NYISO ■ PJM ■ SPP

ISSN 2377-8016 : Volume 2018/Issue 22 May 29, 2018

Capacity Prices Jump in Most of PJM

DR, EE Up; Nukes Down

By Rory D. Sweeney and Rich Heidorn Jr.



PJM 2021/22 capacity auction results | *PJM*

Capacity prices increased sharply in most of PJM for delivery year 2021/22, with prices for the RTO rising to $140/MW-day from $76.53 last year, an increase of 83%.

The ComEd zone increased $7 to $195.55/MW-day, while Eastern MAAC dropped to $165.73 from $187.87 last year (-12%). The PSE&G zone, which cleared as part of EMAAC last year, rose to $204.29.

The ATSI zone, which cleared along with the rest of the RTO last year, separated this year, jumping to $171.33. BGE, which was part of MAAC last year, separated at $200.30. MAAC cleared at $86.04 last year. (See Capacity Prices down in Most of PJM in 1st Year of 100% CP.)

The Base Residual Auction procured 163,627 MW for 2021/22, resulting in a 21.5% reserve margin. That was down from 165,109 MW last year and a reduction of almost 2 percentage points from last year's 23.3% reserve margin. That was still substantially above PJM's 15.8% reserve requirement. About 192,450 MW offered

Continued on page 23

Gov. Signs NJ Nuke Subsidy, Renewables Bills

By Rich Heidorn Jr.

New Jersey Gov. Phil Murphy (D) on Wednesday signed legislation to subsidize the state's nuclear generating fleet, raise its renewable generation targets, boost storage and offshore wind, and revamp its solar program.

In a press conference staged in front of solar panels in South Brunswick, N.J., Murphy signed Senate Bill 2313, which will create zero-emission certificates for three of Public Service Enterprise Group's nuclear generators, and Assembly Bill 3723, which will raise the state's renewable portfolio standard to 35% by 2025 and 50% by 2030. Murphy also signed an executive order to update the state's Energy Master Plan with a goal of 100% "clean" energy by

Continued on page 34

Mass., R.I. Pick 1,200 MW in Offshore Wind Bids

By Michael Kuser

Massachusetts and Rhode Island on Wednesday awarded procurements for 1,200 MW of offshore wind energy from what will become the two largest offshore projects in the U.S.

Vineyard Wind, a partnership between Avangrid Renewables and Copenhagen Infrastructure Partners, won the contract to supply Massachusetts with 800 MW of offshore wind energy, while Rhode Island selected Deepwater Wind to build the 400-MW version of the company's Revolution Wind proposal.

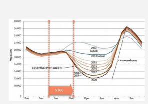
Financial details for the fixed-price bids have not been disclosed.

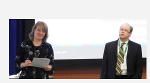
Continued on page 35

NECPUC Annual Symposium

Sen. Angus King (I-Maine) addresses the conference via video from D.C. | *© RTO Insider*

Also in this issue:





10837 Deborah Drive Potomac, MD 20854 (301) 299-0375 info@rtoinsider.com www.rtoinsider.com

RTO Insider
CAISO ERCOT ISO-NE MISO NYISO PJM SPP

Editorial

Editor-in-Chief / Co-Publisher
Rich Heidorn Jr. 202-577-9221

Deputy Editor / Senior Correspondent
Robert Mullin 503-715-6901

Production Editor
Michael Brooks 301-922-7687

Contributing Editor
Peter Key

CAISO/West Correspondent
Jason Fordney 571-224-8960

ISO-NE/NYISO Correspondent
Michael Kuser 802-681-5581

MISO Correspondent
Amanda Durish Cook 810-288-1847

PJM Correspondent
Rory D. Sweeney 717-679-1638

SPP/ERCOT Correspondent
Tom Kleckner 501-590-4077

Subscriptions and Advertising

Chief Operating Officer / Co-Publisher
Merry Eisner 240-401-7399

Account Executive
Marge Gold 240-750-9423

Marketing Assistant
Ben Gardner

RTO Insider LLC
10837 Deborah Drive
Potomac, MD 20854
(301) 299-0375

Subscription Rates:

Payment Frequency	PDF-Only	PDF & Web
Annually:	$1,350.00	$1,650.00
Quarterly:	380.00	475.00
Monthly:	150.00	175.00

See details and Subscriber Agreement at rtoinsider.com.

In this Week's Issue

CAISO News

EIM Entrance Fees Bump CAISO Revenue

By Jason Fordney

CAISO's first-quarter revenues were $1.2 million more than it had budgeted, primarily because of entrance fees it collected for the Western Energy Imbalance Market, the ISO reported last week.

About $1.6 million in EIM entrance fees were partially offset by grid management charge (GMC) revenues that were $400,000 less than budgeted. CAISO did not specify from whom it had collected the EIM fees, but Idaho Power and Canadian power marketer Powerex both began transacting in the market last month. (See *Idaho Power, Powerex Begin Trading in Western EIM*.)

The ISO's operating costs, capital expenditures, debt service and an operating reserve are recovered through the GMC. Most charges other than the GMC collected by the ISO are distributed to the appropriate market participants.

CAISO "monitors changes in GMC revenues and will adjust rates, if necessary, to align actual GMC revenues closer to budget, as required by the Tariff," the ISO said in its first-quarter report.

Total market settlement transactions collected by the ISO were about $4 billion last year, including about $3.8 billion in market settlements and $200 million collected through the GMC, according to the ISO's continuing disclosure report posted May 22. This compared with $3.4 billion in settlements and GMCs collected in 2016.

CAISO reported audited operating income of $26 million for the year, compared with $14 million in 2016. Operating expenses were at $195 million, "other expenses" were $5 million and operating revenues were $221 million.

The ISO in February had reported unaudited operating income of $47.4 million for 2017. (See *CAISO Sees 2017 Revenue Boost*.) The new operating income figure of $26 million includes depreciation and amortization of about $29 million.

Each year, CAISO establishes a revenue requirement that is allocated to the three GMC service categories: market services, system operations and congestion revenue rights services. Other financial collections come from EIM participants, generator interconnection studies and for operation of the California-Oregon Intertie.

The two largest of the 160 participants in the market, Pacific Gas and Electric and Southern California Edison, paid a little more than half of GMC revenue in 2017. The 10 largest participants were responsible for about 75% of the charge and the top 25 participants paid 89%. These levels have remained about the same since 2015.

Operating expenses last year included $118 million in salaries and benefits, $20 million in communications and technology costs, $18 million legal and consulting and $12 million in leases, facilities and administrative costs.

The ISO increased its number of full-time employees to 599 in 2017 from 584 in 2016.

CAISO NEWS

California to Require Sharp EV Charger Growth by 2025

By Jason Fordney

California will need between 229,000 and 279,000 electric vehicle chargers at locations other than single-family homes by 2025 to meet the state's goals for adoption of zero-emission vehicles, the Energy Commission said in a new report.

The higher range of the estimate includes 133,000 workplace and public chargers, 9,000 to 25,000 fast chargers and 121,000 chargers at multifamily dwellings, the commission said. The numbers do not include chargers in single-family homes.

A March 2012 order by Gov. Jerry Brown directed the commission to support the goal of 1.5 million zero-emission vehicles on state roadways by 2025. Another January 2018 order by Brown called for the construction and installation of 250,000 zero-emission vehicle chargers, including 10,000 DC fast chargers, by 2025.

According to the new CEC study, the state's goal is to allow drivers to maximize the number of electric miles they can drive, provide guidance on plug-in electric vehicle (PEV) and plug-in hybrid charging, and ensure the effectiveness of private and public sector investments. As of the end of last year, the state had about 14,000 public chargers — 1,500 of them DC fast chargers — serving 350,000 PEVs.

For the study, CEC staff worked with the National Renewable Energy Laboratory to develop a computer simulation tool known as the Electric Vehicle Infrastructure Projection Tool (EVI-Pro). The commission plans to add an EVI-Pro portal to its website to allow users to view charging station quantities, load shapes, infrastructure cost estimates and other information.

At a CEC workshop on Tuesday, analysts discussed three central questions around charging infrastructure: how many chargers to deploy, what kind of chargers and where to locate them. A big part of determining where to place chargers is understanding the behavior of vehicle operators and studying patterns such as worker commutes and rural versus urban settings.

"What we're really talking about is trying to reduce range anxiety as a barrier to increased PEV sales," NREL's Eric Wood, one of the study's authors, said at the workshop.

EVs charging at San Francisco City Hall

EVI-Pro focuses on behaviors of mainstream drivers, such as origins, destinations and schedules, as opposed to those of early EV adopters. Mainstream drivers are more likely to favor convenience and less likely to alter driving habits, for example. The modeling also studied how different charging locations such as home or work might be chosen based on the price of electricity, and how users charging for free at work might block other chargers and drive up costs of workplace charging.

The study used four major inputs: vehicle attributes, charger attributes, county-level household travel data and composition of the vehicle fleet. It calculated several charger-per-1,000-PEVs ratios under differing technology and market scenarios.

The transportation sector is the largest polluter in California, responsible for 80% of nitrogen oxide emissions and 90% of diesel particulates. Including indirect emissions from fuel refining and production, transportation accounts for 80% of greenhouse gas emissions.

The study showed that weekday charging peaks occur when vehicles arrive at work in mornings and when they arrive home in evenings. By 2025, workplace chargers on weekdays will draw more than 200 MW at 9 a.m. and residential chargers nearly 900 MW at 8 p.m. By 2025, aggregate demand from residential, workplace and fast-chargers will push up demand by 500 MW from 4 to 7 p.m., with a maximum demand of nearly 1,000 MW before 8 p.m.

The commission said that an important conclusion of the study is assuring drivers that charging infrastructure will be visible, accessible and reliably maintained, with real-time networking technologies being a valuable tool. Networked technologies will enable shared usage of chargers and reduce the size of the network needed to support the growing electric fleet.

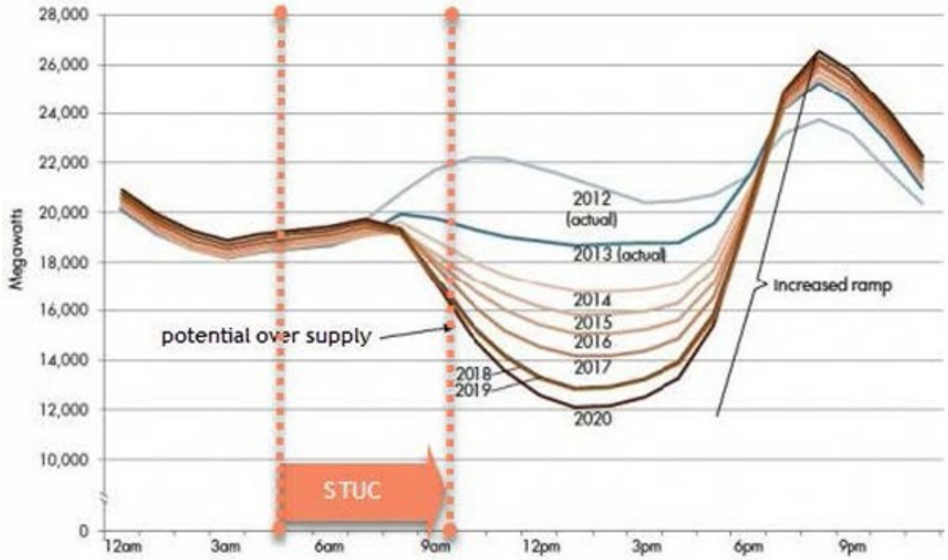
CAISO News

CAISO Moves to Optimize Short-term Unit Supply

By Jason Fordney

CAISO is proposing to quadruple the number of hours in its time horizon for short-term commitment of generation units to better address load peaks that occur later in the day when solar output drops off the grid.

Extending the short-term unit commitment (STUC) horizon to 18 hours from 4.5 hours will better recognize morning, afternoon and evening peaks, CAISO said when it introduced the proposal Tuesday. The ISO described the need for a longer unit commitment horizon in a May 15 issue paper/straw proposal.



Limitations in short-term unit commitment (STUC) planning horizon in relation to the "duck curve." | *CAISO*

"The purpose of the STUC modifications is to provide earlier notification to resources that are needed to meet the evening peak, which increases the probability these resources will be available, and better optimize the use of resources with limited starts over the entire day," the proposal said. These changes will increase market efficiency and reliability."

The STUC is the procedure run about 52.5 minutes before a trading hour to commit medium-start units for delivery within a forward-looking horizon — currently 4.5 hours. The STUC produces a unit commitment solution for every 15-minute interval within the horizon and issues binding start-up instructions based on units' start-up times.

According to a CAISO presentation, the grid operator is currently "unable to make informed commitment and optimization decisions" because the current process considers only short- or medium-start resources and has limited resources for the real-time market.

Under current rules, a resource might be committed to a morning peak when it should be used for the evening peak, CAISO said. Resources with a start-up and minimum run time greater than 4.5 hours cannot be committed by the current STUC process.

With the proposed changes, generation resources will have earlier notification regarding meeting the evening peak, leading to increased efficiency and reliability "by better equipping the real-time market to meet system needs," the ISO said.

CAISO floated the initiative in part because it foresees below-average hydro resources this summer, contributing to a tight supply situation. CEO Steve Berberich discussed some of the issues last week at the ISO's Board of Governors meeting. (See *CAISO Board Approves Forecast Error Measures*.) California mountain snowpack was at 51% of the normal April 1 average, the grid operator said. There is a 50% probability of a Stage 2 emergency for at least one hour this summer, when operating reserves drop below 5% after dispatching all resources, including demand response.

Shasta Dam. CAISO says hydro output will be below average this summer, contributing to a tight supply situation. | *Apaliwal*

The proposed new changes will improve the efficiency of the real-time market by optimizing resource dispatch and dealing with "the duck curve," the load profile that shows how the system is affected by large amounts of solar output. By 2020, the ISO predicts the generation ramping need on a typical spring day will grow to about 14,000 MW (from about 12,000 MW in 2017) between early afternoon and about 9 p.m. The "belly" of the duck curve is getting deeper each year as rooftop solar proliferates during mid-day hours, requiring a steeper ramp-up of resources in evening hours as solar generation goes offline. The ISO does not have visibility into rooftop solar but still must manage its effect on the grid.

Aside from expanding the STUC to 18 hours, CAISO plans to revise real-time market bid cost recovery for long-start units and extend EIM non-financially binding base schedule and bid submission requirements to 20 hours from the current 6 hours.

CAISO management has prioritized the initiative for implementation by fall of this year. Comments on the proposal are due today, with review by the Energy Imbalance Market Governing Body and CAISO board set for July.

ERCOT NEWS

Texas PUC Issues Final Order for SPS Wind Farm

AUSTIN, Texas — It's finally official. Southwestern Public Service can now begin construction on its 478-MW wind farm in West Texas.

The state's Public Utility Commission on Friday quickly approved a second draft order of the utility's request for a certificate of convenience and necessity and a power purchase agreement with Bonita Wind Energy. The commissioners had given their verbal approval in April but delayed a final order to allow parties in the docket additional time to provide written responses to their questions (No. 46936). (See *Texas PUC Delays Final Approval of SPS Wind Farm*.)

David Hudson | © RTO Insider

"We're just pleased we now have a resolution in hand and a final order," said SPS CEO David Hudson, noting it was the fourth time the utility has appeared before the commission in hopes of receiving a final order. "We can now begin construction on the Hale [County] project and the Sagamore project" in New Mexico.

SPS expects to have the Hale project in service no later than 2019, at a cost of $769 million, so that it will be able to receive 100% of its federal production tax credits.

PUC Chair DeAnn Walker had expressed concerns over SPS' proposal to recover costs by flowing PTCs through fuel, but she was satisfied with the parties' responses.

The wind farm is part of a 1.23-GW project by SPS parent Xcel Energy that will provide renewable energy to SPS customers in Texas and New Mexico. The utility says the project will save its retail customers about $1.6 billion in energy costs over its 30-year life.

SPS had reached a settlement agreement in February with all parties in the docket but two, the International Brotherhood of Electric Workers Local 602 and Lea County Electric Cooperative. However, neither opposed the settlement.

Commission Streamlines Smart Meter Texas Portal

The PUC also approved a final order streamlining Smart Meter Texas (SMT), the state's web portal, and aligning it with national data-transfer standards (Docket No. 47472).

SMT is maintained by utilities AEP Texas, CenterPoint Energy Houston Electric, Oncor and Texas-New Mexico Power. It allows customers to download and view their energy data or share them with competitive service providers (CSPs), companies that market energy efficiency, demand response, distributed generation and other services.

Transmission and distribution providers are prohibited from selling, sharing or disclosing advanced meter data but are required to provide "convenient, secure, read-only access" to a customer, the customer's retail electric provider and other entities authorized by the customer. The data include meter readings used to calculate charges for service, historical load and other proprietary customer information.

The order requires the utilities to support the portal's home area network (HAN) functionality through their advanced metering systems. It also forbids them from disconnecting an existing HAN device from the meter without the customer's requests. The HAN devices are costly and have had few takers for their services.

PUC staff last year requested the commission determine what changes, if any, should be made for SMT's continued operation while its contract was being renegotiated. The four utilities signed a joint development and operations agreement for SMT that dates back to December 2008.

The utilities reached a unanimous settlement agreement in January, with the only contested issue related to the maximum time period that a residential customer or smaller commercial customer may grant a CSP access to the customer's SMT data, without the customer affirmatively renewing the access.

The commission adopted an administrative law judge's recommendation that the maximum time period remain 12 months.

PUC to Intervene in SPP-AEP Filing Before FERC

Following its executive session, the PUC moved to intervene in SPP's recent FERC filing on behalf of American Electric Power (ER18-1541, ER18-1542).

SPP made a compliance filing on May 8 to revise AEP West's transmission formula rate to reflect the recent change in the federal corporate income tax rate (ER18-63). The filing was made on behalf of AEP Service Corp. and its AEP Oklahoma Transmission and AEP Southwestern Transmission affiliates.

The Oklahoma Municipal Power Authority and DC Transco have already intervened.

— Tom Kleckner

| © RTO Insider

ERCOT NEWS

TAC Briefs

Staff Again Delays Vote on Amendment, Bylaw Revisions

AUSTIN, Texas — ERCOT's legal department again delayed votes endorsing final changes to the grid operator's bylaws and articles of incorporation, saying it needed additional time to evaluate a last-minute comment from Luminant.

Assistant General Counsel Vickie Leady told the Technical Advisory Committee last week that legal staff would delay final votes on the revisions until the August set of leadership meetings. She said ERCOT and Luminant are "on the same page," but they are trying to figure out the language.

"We appreciate having people poke holes in the language," Leady told the TAC during its May 24 meeting. "Given the importance and relative permanence of the language, we need more time to address it. Once we put stuff in the bylaws, it's there for a long, long time."

Legal staff had originally planned to put the proposed changes up for votes in April but pushed the final recommendation back to the June Board of Directors meeting. (See "ERCOT Legal Staff Delays Bylaw Revisions," *ERCOT Technical Advisory Committee Briefs: March 22, 2018*.)

Luminant sent its comments after working hours on May 23, suggesting clarifications to the proposed affiliate definition. The generating company added language to the definition that read:

"A person who is not controlling, controlled by or under common control with another person as described above may nonetheless be determined to be an affiliate of another person, if ERCOT or a member alleges that such exercises directly or indirectly, through one or more intermediaries, substantial influence over another person. Such a determination may be made by the board only after notice and an opportunity for hearing at an ERCOT board meeting. The burden of proof to show substantial influence is on ERCOT or the member alleging such influence."

Luminant's Ian Haley apologized for the late filing, saying it was the first time the company had been able to gather together its legal counsel.

ERCOT TAC members pose for their annual Red Nose Day, a fundraiser for child poverty. | © *RTO Insider*

The company also suggested a central repository for the various clean and redlined documents, which Leady said ERCOT would follow. Legal staff also plan to hold a workshop following the June board meeting to "facilitate a final set of comments."

Leady said she has received no stakeholder comments on the articles of incorporation but that they should "travel together" with the bylaw changes.

Southern Cross Transmission (SCT) also filed comments requesting a delay of a decision regarding in which market segment it should be placed. SCT believes it should be included in a newly created DC Tie Operator segment.

Cratylus Advisors' Mark Bruce, who represents the project's developers, said SCT hopes that when the market segment question is revisited, "greater stakeholder familiarity with the SCT project will ease some of the controversy currently associated with the question of the appropriate market segment assignment for DC tie operators."

Bruce wrote that he saw no harm in delaying the membership decision. Leady said staff would "reinitiate" stakeholder discussion of the segment definition "upon further certainty that the SCT project will be interconnected" to ERCOT.

Southern Cross is a proposed HVDC transmission project in East Texas that would be capable of shipping more than 2 GW of energy between the Texas grid and Southeastern markets. (See "Members Debate Southern Cross' Bid to be Merchant DC Tie Operator," *ERCOT Technical Advisory Committee Briefs: Feb. 22, 2018*.)

Texas' Public Utility Commission last year directed ERCOT to address several issues as a condition for energizing SCT's project. The conditions include determining "the appropriate market participation category for [SCT] and for any other entity … for which a new market-participant category may be appropriate" (Project No. 46304).

Staff Recommend 2 Transmission Projects

The committee endorsed staff's recommendation of a $327.5 million Oncor project that addresses reliability concerns in ERCOT's Far West region.

If approved by the Board of Directors in June, Oncor's work will include building 40 miles of new 345-kV lines on double-circuit structures, adding two new 600-MVA, 345/138-kV autotransformers at a switch station, installing a second 345-kV circuit between Odessa and Riverton, and building two 20-mile segments of 138-kV line on double-circuit structures.

Construction is expected to begin next year, with completion in 2023.

Staff said the project will provide operational flexibility and resolve potential reliability issues in the face of oil and gas-related load growth.

Staff also shared with TAC members an additional study evaluating a Rayburn Country Electric Cooperative proposal to

Continued on page 8

ERCOT NEWS

TAC Briefs

Continued from page 7

transfer its existing facilities and load into ERCOT, a plan filed last year with the PUC (Docket No. 47342).

The ISO said it is now recommending a "modified alternative option" to integrating Rayburn's load, following an Oncor study of a transmission alternative than eliminated a 345-kV interconnection.

Staff concluded the second option, which still includes two 138-kV interconnections, has "similar reliability and long-term load-serving capability." However, the modified alternative has a lower estimated capital cost of $31.7 million, leading ERCOT to propose the Oncor suggestion.

Staff's initial study indicated capital costs of $41.7 million.

Rayburn, which sits on the ERCOT-SPP seam in East Texas, has proposed transferring load and transmission facilities into ERCOT. The co-op is an SPP member, but only about 150 MW (or less than 20%) of its load and 160 miles of its transmission sit in the Eastern Interconnection. (See "ERCOT, SPP Agree to Rayburn Country Migration Studies," *Public Utility Commission of Texas Briefs: Aug. 31, 2017*.)

Members Approve Subcommittee's Restructuring

Members unanimously approved a task force's recommendation to designate the Commercial Operations Subcommittee (COPS) and several of its working groups as inactive, agreeing that it has reached a "steady state" situation concerning market communication and settlement issues.

The Wholesale Market Subcommittee will inherit the Settlement Working Group and the Commercial Operations (COP) Market Guide, while the Retail Market Subcommittee will pick up the Profiling Working Group, Load Profiling Guide and market communications.

The TAC Subcommittee Restructuring Task Force brought its recommendations to the committee in February. (See "Committee Endorses Task Force Restructuring Recommendations," *ERCOT Technical Advisory Committee Briefs: Feb. 22, 2018*.)

The restructuring will require the following changes for the COP Market Guide and the Load Profiling and Retail Market guides:

- COPMGRR047: Relocates the COP guide to the WMS, moves other portions of the manual to the retail guide and removes language that is no longer applicable from the COP guide.
- LPGRR064: Moves the Load Profiling Guide and load-profiling responsibilities from COPS to the RMS and removes language from the guide that no longer applies.
- RMGRR151: Incorporates the market notice communication process and renewable energy credit information from the COP guide into the retail guide.

The task force will continue its development of a "three strikes" attendance policy for TAC and its subcommittees, whereby seated segment representatives that miss three meetings or fail to assign an alternate for those meetings will lose their seats. It will also aid the RMS with moving RMGRR151's market notice process language into a standalone Other Binding Document.

TAC Re-elects Helton as Chairman

TAC once again elected Bob Helton as its chair, an action required following the latest change in his employment status and market segments.

Helton moved from ENGIE to Dynegy last year when the latter bought the former's 17 U.S. power plants. He left Dynegy when it was subsequently acquired by Vistra Energy, recently rejoining ENGIE as its director of government and regulatory affairs.

B.J. Flowers |

"I know you guys may not know this person, and I know we've elected him three times in the last seven months," began Sharyland Utilities' B.J. Flowers as she teasingly nominated Helton for the vacant chair position.

Helton thanked the members for their support, saying he hopes to finish out the year as committee chair.

"Of course, you never know, the way jobs change around here," he joked.

Committee Endorses 4 NPRRs, 7 Other Changes

The committee endorsed four Nodal Protocol revision requests, a revision to the Nodal Operating Guide, a pair of Other Binding Document revisions, two changes to the Planning Guide and two changes to the Verifiable Cost Manual.

- NPRR847: Incorporates an intraday or same-day weighted average fuel price into the mitigated offer cap to ensure that resources are capped at the appropriate cost during high fuel price events and LMPs reflect the true

Continued on page 9

ERCOT News

TAC Briefs

Continued from page 8

incremental cost of fuel.

- NPRR851: Establishes a clearly defined disconnection process within the market rules applicable to a transmission voltage connection to the grid that uses one electrical connection for both generation and load services.
- NPRR867: Caps the amount of each counterparty's available credit limit locked for congestion revenue rights auctions at the pre-auction screening credit exposure amount.
- NPRR870: Deletes the gray-boxed requirement for ERCOT to post a forward adjustment factors summary report on the Market Information System's certified area. The information in this report is already provided on each counterparty's estimated aggregate liability summary report.
- NOGRR176: Clarifies that all transmission owners and qualified scheduling entities representing resources can participate in ERCOT hotline calls.
- OBDRR004: Revises the risk-weighting factors available for assignment to each emergency response service (ERS) time period; describes the process for updating the ERS time period expenditure limits for any subsequent standard contract terms (if money is needed to fund) and the ERS renewal contract period; and updates a table to reflect the risk-weighting factors' proposed changes.
- OBDRR005: Revises the generic transmission constraint (GTC) shadow price cap that is used in SCED for base case constraints from \$5,000/MWh to \$9,251/MWh. The revision also updates the associated examples in SCED and makes an administrative edit to a protocol reference.
- PGRR059: Includes Regional Planning Group-related changes intended to improve and clarify existing processes.
- PGRR060: Updates the reliability performance criteria by defining a DC tie's unavailability as a new contingency and clarifies the voltage level of transformers referred to in the reliability performance criteria.
- VCMRR020: Delays VCMRR014's sunset date to permit stakeholders additional time to find a long-term solution that determines an appropriate adder for coal- and lignite-fired generation resources.
- VCMRR021: Aligns the VCM with the language proposed in NPRR847 by removing language providing for make-whole payments for exceptional fuel costs. The costs will be recovered in NPRR847.

— Tom Kleckner

ISO-NE News

Mystic Waiver Request Spurs Strong Opposition

By Rich Heidorn Jr. and Michael Kuser

Mystic Generating Station, on the Mystic River in Everett, Massachusetts. A wind turbine owned by the local water authority to power a pumping station is on the right.

Comments filed with FERC last week indicate most stakeholders oppose ISO-NE's Tariff waiver request to keep the Mystic generating plant running despite Exelon's plans to retire the facility (ER18-1509).

Commenters also questioned the RTO's rationale that an out-of-market mechanism is needed to financially support the nearby Distrigas LNG terminal being acquired by the company.

Massachusetts Attorney General Maura Healey raised "significant questions regarding the legality of using the commission waiver process in the expansive way ISO-NE seeks to do here."

The RTO is asking to do something it has never been allowed to do before, Healey said, namely to "retain a generation facility pursuant to the [Forward Capacity Market] process not for capacity needs but to ensure 'fuel security,' a term that is not defined in the Federal Power Act, and a concept for which there is no settled or universally accepted definition."

Healey also opposed the request as "sweeping in its breadth" in seeking to waive for one generator almost all of the Tariff's FCM retirement requirements and existing retirement deadlines, and take away its existing limits on Exelon's ability to recover costs under a cost-of-service agreement.

New England local distribution companies supported the waiver request in order to maintain reliability in the region and took no position on the cost-of-service representations made by Mystic.

"The lack of sufficient natural gas infrastructure makes facilities that rely on LNG particularly valuable in the region," the LDCs said. "There is no immediate, viable replacement should the [Distrigas] terminal shut down and efforts to replace the products and services provided from Distrigas would be lengthy and difficult."

ISO-NE's Reasoning

ISO-NE last month announced the plan to keep Mystic running after Exelon said in March that it planned to retire the 2,274-MW plant when its capacity obligations expire on May 31, 2022. (See *ISO-NE Moves to Keep Exelon's Mystic Running*.) On May 1, the RTO filed a motion to waive its Tariff to retain resources to address fuel security risks — an option currently allowed only in response to local transmission security issues.

The RTO said the loss of Mystic 8 and 9's 1,700 MW of combined cycle capacity that don't rely on pipeline gas would lead to it depleting 10-minute operating reserves — a violation of NERC standards — "on numerous occasions" and shedding load during the winters of 2022/23 and 2023/24.

Shuttering Mystic also would mean the loss of the Distrigas LNG facility's biggest customer, raising doubts about its financial viability, the RTO said.

Exelon's proposed cost-of-service agreement for Mystic, filed May 16, seeks an annual fixed revenue requirement of almost $219 million for capacity commitment period 2022/23 and nearly $187 million for 2023/24 (ER18-1639).

ISO-NE asked the commission to approve the waivers by July 2 to meet market participants' deadlines for committing to Forward Capacity Auction 13.

Exelon said it would continue operating Mystic 8 and 9 only if it receives a two-year reliability-must-run contract ensuring it can recover its full cost of service for 2022/23 and 2023/24.

While ISO-NE will not implement the full payments and penalties under its Pay-for-Performance program until 2025, even then the program "cannot be expected to resolve the region's fuel security challenges by itself, particularly in light of the significant opposition in the region to investments in fuel supply infrastructure," the RTO told FERC in its waiver petition.

ISO-NE could implement a market-based fuel security solution as early as 2020, if it is decoupled from the FCM, or as late as 2024 if it's included in the capacity market, but it's still unclear what form the solution will take and therefore difficult to predict when the market will mature enough to resolve the fuel security issues that require Mystic 8 & 9's retention, the petition said.

Market Failure?

New England Power Pool said it took "no substantive position" on the RTO's request and that its "keen interest is in ensuring that ISO-NE engages fully with its stakeholders before seeking any change to the New England Tariff or market rules."

NEPOOL said it expected the RTO to honor its commitment that the full participant

Continued on page 11

ISO-NE NEWS

Mystic Waiver Request Spurs Strong Opposition

Continued from page 10

processes would be completed prior to any filing of a longer-term market-based approach to fuel security issues.

The Environmental Defense Fund said in its filing that “the need for cost of service is indicative of market failure. Cost of service for the purpose of ensuring fuel availability (i.e., maintaining Distrigas’ natural gas supply capability), compels the commission and New England stakeholders to assess whether the market elements relevant to fuel supply for electric generators are functioning effectively. It is clear they are not.”

EDF recognized the Mystic/Distrigas units play a critical reliability role in the region but asserted that the “out-of-market workaround runs counter to ISO-NE’s dual mission of ensuring reliability and the long-term sustainability of competitive markets.”

The Northeast Gas Association said that while the waiver is a short-term solution supporting market reliability, “a longer-term remedy still needs to be enacted.” It urged the commission to consider “the importance of maintaining regional LNG access” over the coming capacity commitment periods.

Price Suppression

The Electric Power Supply Association said the “premature and overbroad” request should be rejected without prejudice, allowing the RTO to submit another short-term proposal if it is unable to develop a market-oriented solution.

The RTO “is being too quick to give up on such a solution for the nearer term and, specifically, for the 2022-2023 and 2023-2024 commitment periods,” EPSA said. “Additionally, this near-term fix may have the adverse effect of hastily establishing a new reliability criteria to be used to underpin RMR-type arrangements going forward, in the absence of any formal process, stakeholder input or Tariff revision proceeding.”

While the two-year term of the proposed RMR or cost-of-service agreement “is both

ISO-NE generation at risk | *ISO-NE*

unprecedented and will severely suppress capacity prices over that longer term,” EPSA said it also risked, by artificially dampening capacity prices, creating “the very dynamics” that cause the fuel security concerns raised by the RTO.

The New England Power Generators Association said allowing the RTO to offer the Mystic units as $0/kW-month price takers in FCA 13 would suppress prices by $214 million to $652 million, displacing 1,050 to 1,285 MW of other resources, “with the potential for even greater price suppression and displacement in FCA 14.”

Instead, NEPGA said ISO-NE should conduct a Substitution Auction to reprice Mystic, the same way it plans to reprice state-sponsored renewable resources under the Competitive Auctions and Sponsored Policy Resources design approved by the commission. The trade group made the same arguments in a Section 206 complaint (EL18-154) also filed last week.

Why Hurry?

Calpine said it did not oppose the RTO’s request but questioned the need for action now, as the Mystic units have capacity supply obligations through May 31, 2022.

Nevertheless, Calpine said the waiver request “is a symptom of broader price formation issues that are preventing” the FCM from attracting sufficient investment in new and existing resources to maintain reliability.

Continued on page 12

Distrigas Terminal | *ENGIE*

ISO-NE NEWS

Mystic Waiver Request Spurs Strong Opposition

Continued from page 11

Until these issues are resolved, Calpine said, it is likely that New England "will continue to experience premature retirement of resources critical to ensuring fuel security and that ISO-NE will increasingly be forced to rely on out-of-market procurement to maintain reliability."

NRG Energy said waiver of the RTO's capacity market rules "is not the appropriate approach to address the lack of fuel security in New England" and that the commission should order the RTO to develop a market response to procuring the necessary attributes.

Rejecting the waiver "does not mean blacking out New England," NRG said. "Even should efforts to develop a market-based solution to the fuel security conundrum fail, the Federal Power Act includes a reliability 'fail safe.'"

NRG concluded that the reliability product the RTO wants is not what the waiver aims to procure: "ISO New England argues that the waiver will allow it to procure additional winter energy production from non-pipeline gas-fired resources; yet the waiver is focused on allowing Mystic to continue selling a capacity product."

Pipeline Constraints

The Industrial Energy Consumer Group said the RTO has warned of the danger of gas pipeline constraints since 2001. "Despite the obvious nature of this need, ISO-NE has repeatedly either brought forward market-based solutions that have failed to provide sufficient financial support to promote the construction of necessary pipeline facilities or offered interim out-of-market solutions, such as its Winter Reliability Program and the waivers requested in this proceeding," the group said. "None of these have succeeded in causing pipeline capacity to be built."

It asked FERC to order ISO-NE to file Tariff amendments allowing electric utilities to collect gas pipeline capacity costs.

"In addition, the commission should open a proceeding to facilitate new gas pipeline capacity resources into and within the New England region," the group said. "Such a proceeding could also address, if necessary, the apparent refusal of New York to issue federally delegated permits for pipelines from Pennsylvania to New England."

The Eastern New England Consumer-Owned Systems said the proposal could cause "permanent, structural damage" to ISO-NE's capacity market.

"The waiver requested by ISO-NE is actually a stalking horse for injecting an untested, undefined and undebated construct of 'fuel security' into the pricing of capacity in New England," the group said.

It said it believes Exelon is overstating Mystic's financial problems and that the company's planned acquisition of Distrigas from ENGIE raises competitive concerns because of the facility's role in providing east-to-west gas when high heating demand constrains west-to-east capacity.

"The market power implications of consolidating that kind of critical-period capability with significant regional generation ownership deserve careful evaluation before the consolidation occurs," the group said.

NECPUC 71st Annual Symposium

New England Regulators Wary of ISO-NE Plans on Fuel Concerns

What Happened to Pay-for-Performance?

By Rich Heidorn Jr.

Mark Vannoy (left) and Gordon van Welie | *© RTO Insider*

CAPE NEDDICK, Maine — New England state regulators agreed last week that their region faces a growing winter reliability challenge but expressed skepticism over ISO-NE's proposed solutions.

Speaking at the New England Conference of Public Utilities Commissioners' (NECPUC) 71st annual symposium May 21, a panel of regulators pressed ISO-NE CEO Gordon van Welie on the need for an out-of-market contract for Exelon's Mystic Generating Station, asking why it can't be replaced through the capacity market and its Pay-for-Performance program.

The proposed Mystic contract represents the first of ISO-NE's "three-track" plan for addressing its winter fuel reliability concerns. Last week, dozens of intervenors filed comments in response to the RTO's request for a Tariff waiver needed to authorize the procurement, most of them in opposition (ER18-1509). (See related story, *Mystic Waiver Request Spurs Strong Opposition*, p.10.)

'A Point at Which We Can't Hold Things Together'

Van Welie said that Pay-for-Performance — which was premised on gas plants adding oil-fired capability — has been hampered by its stop-loss provisions and states' resistance to oil-fired generation.

The CEO also said there isn't enough oil storage or allowable air permits to rely on the fuel as the region's backstop. During the Dec. 26-Jan. 8 cold snap, oil prices fell below gas, making oil-fired generation effectively baseload for two weeks, he said. The region burned about 2 million barrels of oil during that period — more than it used in all of 2016 and 2017 — drawing down supplies from 68% of tank capacity on Dec. 1 to 19% by Jan. 9. "The ISO had to step into the market to slow down the burn rate," he noted.

Fuel delivery logistics also are a concern. Heating customers get priority for oil as well as gas. Oil deliveries can be delayed by storms and drivers' working hour limits.

Van Welie said the RTO must firm up fuel deliveries and ensure that the market "uniformly" values all resources with such service, including its Millstone and Seabrook nuclear plants, which produce one-quarter of the region's power during winter.

In addition to the region's precarious fuel infrastructure, ISO-NE is concerned that state-sponsored renewable resources will reduce energy market revenues, causing increases in capacity market costs and plant retirements.

"Our concern is there's a point at which we can't hold things together," van Welie told the regulators.

ISO-NE is seeking to delay Mystic's retirement because its analysis indicated the loss of Units 8 and 9's 1,700 MW of combined cycle capacity that don't rely on pipeline gas would leave the RTO depleting its 10-minute operating reserves "on numerous occasions" — a violation of NERC reliability rules. The analysis also predicts load shedding during the winters of 2022/23 and 2023/24.

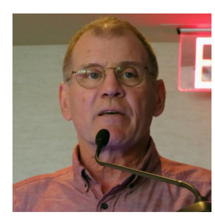
The RTO has asked FERC to waive its Tariff to retain resources to address fuel security risks — an option currently allowed only for local transmission security issues (Track 1). It hopes to file a Tariff change by the end of the year to make fuel security a reason resources can be retained (Track 2). In addition, the RTO is seeking a long-term plan to ensure sufficient firm energy for winter that would compensate needed resources through the market rather than reliability contracts (Track 3).

A Menu, not a To-Do List

Despite the hand he's been dealt by the region's resistance to oil generation, additional gas pipelines and electric transmission, van Welie was careful to couch his comments not as a "To Do" list but as a series of questions and menu choices for the states.

"We are an energy-constrained region. Do we want to maintain that constraint going forward, or do we want to do something about that? And specifically, can the states shape their resource procurements … in a way that they get at the winter constraint? Because I think in doing that the states can help us as well as maintaining or meeting their other policy goals."

'A Very Expensive Future'



"The magnitude of that problem is in [question] but there is a problem," said **Bob Stein**, vice chair of the New England Power Pool's Reliability Committee, who joined regulators on the panel.

NEPOOL has "a range of positions [on the RTO's plans], and they're not fully formed," said Stein, principal of Signal Hill Consulting Group. The range, he noted, is framed by the two types of NEPOOL members: "Those

Continued on page 14

New England Regulators Wary of ISO-NE Plans on Fuel Concerns

Continued from page 13

that are long and those that are short. And you can instantly tell what people are going to say by where they are."

Maine Public Utilities Commission Chairman Mark Vannoy and other commissioners pressed the RTO for a "definition" of the problem, saying he is concerned that "New England is on a course to a very expensive future."

"I'm not arguing that there is not a problem," Vannoy said. "But we need to define what the problem is and then — if our intent is to use market mechanisms to solve that — we have to be precise … so that we can move to those market solutions.

"We have a very complex and dynamic market, and as price signals drive fuel procurement questions … [as fuels] substitute for other fuels … we need to understand how that dynamic market reacts before we move to the Markets Committee for a solution."

Vannoy said New England helped create its dilemma by "separat[ing] itself from the rest of the country's energy … potentially, to our economic peril." He cited states using their EPA-delegated authority under the Clean Air Act to prevent access to Marcellus shale and other gas supplies.

As an example, Vannoy later cited the Atlantic Bridge pipeline project. In the face of local opposition, Massachusetts officials said in December that they would take up to a year to review the impact of a compressor station in Weymouth, Mass., that is part of the project.

Seeking an Honest Conversation

Angela O'Connor, chair of the Massachusetts Department of Public Utilities, called for an "honest" conversation.

"Whether you want to reduce greenhouse gases or simply reduce the rising outrageous cost of energy … burning 2 million barrels of oil in five days and killing baby seals to get to expensive Russian gas cannot and should not be part of any intelligent conversation about energy policy in this region," she said. "It clearly does not meet any of our New England collective goals for the states. We need to have an intelligent and honest — emphasis on honest — conversation to develop the right solutions, and we need to do it all together."

Is Pay-for-Performance Broken?

New Hampshire Public Utilities Commissioner Kathryn Bailey said her state is not convinced that the out-of-market contract with Mystic is the only possible solution to the region's near-term concerns. She said the Operational Fuel-Security Analysis released by ISO-NE in January suffered from "problems with the assumptions and the lack of analysis on how likely scenarios are to play out." (See *Report: Fuel Security Key Risk for New England Grid*.)

She said maintaining Mystic could create incentives for other non-gas generators to seek cost-of-service agreements.

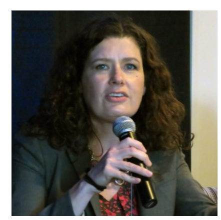
Angela O'Connor (left) and Kathryn Bailey | *© RTO Insider*

"I have to ask: What happened to the market-based solution to fuel security? Just a few short years ago, ISO-NE reported to FERC that Pay-for-Performance was a long-term, market-based solution designed to address generator availability concerns and the region's vulnerability to interruptions in gas supply. … What changed? Why does the ISO think it won't work, even before the incentives take effect next month? Where's the analysis that demonstrates it won't work? When the ISO originally brought this plan to FERC, there was a lot of analysis.

"If Pay-for-Performance had worked as expected … and Mystic announced its retirement, prices in [Forward Capacity Auction] 13 would likely separate to provide incentive for new resources to take on the supply obligation in that zone. But apparently Pay-for-Performance can't work."

Bailey also noted "the irony that ISO-NE refused to allow a 200-MW renewable exemption backstop to integrate state public policies because of the impact it would have on the market. But now they want to waive the Tariff and allow a 1,700-MW out-of-market contract."

'Buck up, Little Soldiers'



In a period of low gas and renewable prices and flat load growth, Connecticut Public Utilities Regulatory Authority Chair **Katie Dykes** asked: "Why is everybody so unhappy?"

Her theory: "Legacy" deals, conflicting state policies, and overlapping jurisdictional authority between FERC, state legislators, state commissions, siting councils and the courts make it difficult for economic regulators to achieve the "fairness" they seek.

"We were one of a few states that got our legislature to give us fresh, brand new authority to procure not only gas pipelines but LNG storage. We got all of that authority. We opened a [request for proposals]. …

"We opened up the bids. We were ready to go. [Then] we looked at the costs and we realized that if we didn't have all the states

Continued on page 15

NECPUC 71st Annual Symposium

New England Regulators Wary of ISO-NE Plans on Fuel Concerns

Continued from page 14

moving with us that Connecticut was going to pay 100% of the cost of these resources and only get 25% of the benefit because that's our share of load. And so, the bids are still sitting in a desk drawer somewhere.

"The challenge of the multi-jurisdictional process is it is guaranteed to be unfair to some parties. … There's a temptation to retreat within our own borders and pursue this sort of righteous unilateralism. … But that's not really an acceptable tactic. If it comes to those outcomes, everyone in this room is going to be blamed for that occurring. No matter how hard you've been working on this issue, no matter how small your slice of the jurisdictional pie is, you're all going to share responsibility for [reliability problems], which will hurt people and drive businesses out of New England," she said, raising her arms like a cheerleader waving pom-poms. "So, what we really need to do is buck up, little soldiers. We can do this. This is New England."

16,000 Terminations

Rhode Island Public Utilities Commissioner Abigail Anthony stressed affordability, saying customers are best served by investments that "prioritize highly cost-effective measures that improve the reliability resiliency of both the distribution system and the [transmission] system."

"So, the resources that we invest in need to do double or even triple duty to improve the energy system on multiple levels," she said. She added, "Some of the best solutions to maintaining and improving reliability resiliency and affordability may lie outside the power system."

She noted that 16,000 of her state's residential electric accounts were terminated for nonpayment in 2016. "Rhode Island's experience, consistent with national data, shows that the vast majority of customer outages are the result of disruptions of the distribution system or due to affordability," she said.

Vermont Public Utility Commissioner Sarah Hofmann said she would like more data on resilience risks, the costs of reducing them and residential customers' willingness to accept outages.

"The tolerance of consumers for the bad thing happening, such as rolling blackouts, that's a conversation that … I don't think we have as much as maybe we should, in terms of what can a residential customer tolerate as opposed to … a commercial customer."

Enough LNG? Rewrite Capacity Market?

Van Welie said the two top sensitivities for its fuel study was the timing of retirements of its non-gas fleet and the size of LNG injections.

Over the last five winters, ISO-NE says the region has received an average LNG injection of 0.2 Bcfd, only occasionally spiking to the 1-Bcfd level assumed in the baseline case. In its recent analysis, Synapse Energy Economics said import terminals could handle 1.5 Bcfd.

"We're talking about unprecedented levels of LNG imports into this region," van Welie said. "And the big question is: Is the market signal strong enough to incent that behavior?"

Of New England's 17 GW of combined cycle capacity, only 5 GW have dual-fuel capability. "There are three with large tanks. The biggest one is 10 days' [capacity]. The next one down is five or six days. The next one down from that is three days. The tanks that are being built, if they do get built today, are [only] two days."

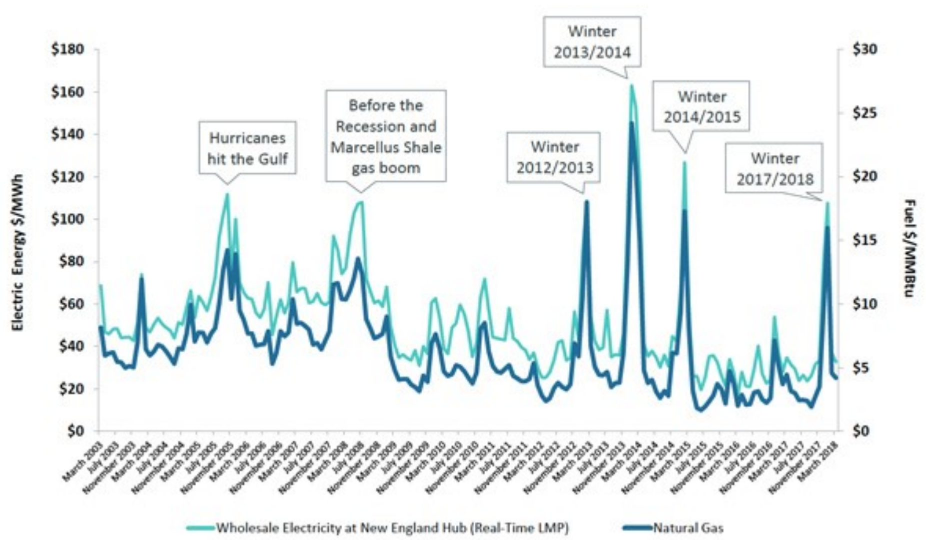
"So, the issue is, Pay-for-Performance was calibrated to the economics around dual fueling, [which] may not be a good assumption in the long term."

Van Welie also questioned Pay-for-Performance's annual and monthly stop-loss limits for generators that fail to perform, which he said has many of them rolling the dice that they won't need firm fuel. "Is that the right incentive to send generators? That they could end up still collecting capacity payments without necessarily having to feel that they need to run for the winter?"

Van Welie also said the decisions the RTO made when it designed its capacity market 14 years ago need to be reconsidered. The market's design is based on meeting the summer peak rather than the winter peak, which is now the bigger risk. A seasonal construct that acquires resources separately for the winter and summer would be preferable, he said.

"Do we throw out the capacity market — go back to blank sheet of paper and redesign the seasonal capacity market? Or do we … do something complimentary, really specifically targeting … the firmness of energy that we required during the winter period?

"We have not landed on … the specific solution to this problem. … But we recognize that … some of the things that we assumed as far back as 14 years ago may not be valid."



ISO-NE CEO Gordon van Welie says New England's growing price volatility since the winter of 2012-13 reflects the region's increasingly constrained fuel infrastructure. | *ISO-NE*

NECPUC 71st Annual Symposium

Overheard

CAPE NEDDICK, Maine — The future of the grid, electric vehicles, high costs, and the tension between state and federal jurisdiction were among the topics discussed at the New England Conference of Public Utilities Commissioners' (NECPUC) 71st annual symposium last week.

New England faces "some of the highest costs in the country, resource constraints, reliability concerns, retirement concerns, storm costs, increasing resiliency needs — and that's just right now," said **Elin Katz**, Connecticut consumer counsel and president of the National Association of State Utility Consumer Advocates.

"I get really frustrated when people dismiss the advocate perspective and say all you care about is cost, because I love technology," Katz said. "But I'm really worried about the cost."

Katz serves on a scholarship board for the University of Hartford, where she said this season's applicants are poorer, needier and have higher needs than the year before.

"That's happening all over the country … so I worry about the consumer and what is happening with respect to our consumers and what they can afford," Katz said.

Maine Wants Lower Prices

Cost was also on the mind of Maine Gov. **Paul LePage**, who told NECPUC on May 22 that he is looking to Canada to help supply his state with natural gas because his state has so far been unable to access the plentiful Marcellus gas in Pennsylvania because of environmentalists' opposition to pipelines.

"You can live in Montreal, have a flat in the most expensive part of town and heat with electricity" because of low-cost Canadian hydropower, LePage said.

Maine enjoys the cheapest electricity prices in New England, but the region has the highest prices in the country, so the distinction means nothing when the state competes against Alabama for a new manufacturing plant, he said.

LePage brought up the case of an aircraft manufacturer looking to site a new plant. The $600 million cost of building in Alabama beat the $200 million cost in Maine because of the cheaper electricity rates in Alabama, he said.

LePage said high power prices are particularly challenging for the aging demographic in Maine, where many residents are retired and live on fixed incomes.

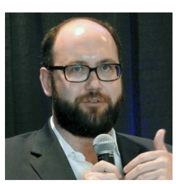
Resilience and the State/Federal Divide

The debate over grid resilience has highlighted new tensions in the line between state and federal jurisdiction, former FERC Commissioner and North Dakota PSC Chairman **Tony Clar**k said.

"We thought [resilience] was basically about black start resources — the grid goes down and you have to have certain resources available that can bring the grid back up fast," said Clark, now an adviser with law firm Wilkinson Barker Knauer.

Now regulators are asking about the value of fuel diversity, onsite fuel storage, dual-fuel units and the risk of gas generators with single-source pipelines.

"Some of those things begin to look an awful lot like resource adequacy, and once you start straddling that resource adequacy divide, you're right in the middle of that state-federal jurisdictional pull," Clark said.



Montana Public Service Commission Vice Chair **Travis Kavulla** said, "There's no honest man in the conversation or debate about which jurisdiction is better, because utilities will opportunistically latch onto either side that's perceived to maximize their profit, and the same goes for the rest of the stakeholders.

"This jurisdictional strife should probably be understood to be, as much it's a function of law, as a function of rent-seeking or its first cousin, regulatory arbitrage," Kavulla said.

In the absence of federal authority, there's only so much states can do, said **Kate Konschnik**, director of the Climate & Energy Program at Duke University's Nicholas Institute for Environmental Policy Solutions.

"One things states cannot do is reach into other states and dictate policy across state lines," Konschnik said, referring to the Supreme Court's 2016 *Hughes v. Talen* decision, which found that Maryland's contract for differences with a generator could distort price signals in PJM.

Konschnik said the zero-emission credit cases in Illinois and New York are interesting because "in those two states alone, the state itself steps in and actually runs the [renewable energy credit] programs and now the ZEC programs, so there is this funny exception to the dormant Commerce Clause if the state itself is a market participant.

"So, if a state is building a public property and decides to only hire union workers from in-state, they can do that because they are acting as a purchaser or purveyor of goods rather than a regulator," Konschnik said. "So, Illinois and New York may prevail, as they have so far in the lower courts." (See *2nd Circuit Hears New York ZEC Appeal*.)

Sen. King Calls for 'Offensive' on Cyberthreats

Speaking to NECPUC via video from D.C., U.S. Sen. Angus King (I-Maine) told regulators that the federal government needs to develop an "offensive response" to attacks on the grid and other critical infrastructure.

"I'm deeply concerned about the vulnerability of the grid to cyberattack either by malicious individuals, or more particularly, by international adversaries," said King, a member of the Intelligence and Energy and Natural Resources committees. "We are not going to defeat this threat simply by defensive measures. As I've heard in numerous hearings, one of the great problems here in Washington is that we have no cyber doctrine. We have no cyber strategy that involves a response — an offensive response. … People that are taking advantage of those vulnerabilities essentially now pay no price. We are only trying to patch and defend.

"I believe until we develop an effective deterrent — and this is a federal responsibility — that these attacks are going to keep coming, they're going to escalate and

Continued on page 17

Overheard

Continued from page 16

they're going to become more and more serious. We have to communicate to the world that there is a price to be paid for attacking America, whether its cyber or kinetic."

King said he is seeking to build bipartisan support "to push the administration … to form some kind of rational response so that our adversaries know there will be a price to be paid if they're going to attack our critical infrastructure."

Along with Sen. Jim Risch (R-Idaho), King is sponsoring a bill to partner the National Laboratories with industry to develop ways to "simplify and isolate automated systems" to holes in software systems that could be exploited by hackers.

Powelson Chides on Pipelines

FERC Commissioner **Robert Powelson** told regulators that New England's pursuit of greenhouse gas reduction is being undermined by its aversion to adding natural gas pipelines.

"We have a lot of natural gas we'd like to share with you," the former Pennsylvania regulator said. "During the recent bomb cyclone, this region, that's very committed to GHG reductions, in order to keep the lights on … burned 2 million barrels of oil."

Last year, he said, the U.S. put 763 miles of new gas pipeline into service, but only 20 miles of it, representing less than 3 Bcfd, were built in New England.

"That's a problem," Powelson said. "You can't have it both ways in this conversation. The renewable portfolio standards are states' rights, and you can … adopt those policies. But if you don't want to deal with resource adequacy, that's our problem. And we're kind of hitting these little friction points that pretty soon we might as well just hand the keys over and go back to the integrated resource planning model."

EVs and Psychology of Resistance

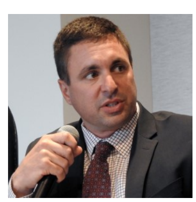
Matthew Stanberry, vice president of market development at Advanced Energy Economy, an organization of businesses promoting clean energy, said electric vehicles represent "a market that fuels vehicles differently than we have in the past and plugs into our electric system, so you have an increase in regulatory activity and examination across the country."

Twelve states have set EV charging rates, and 13 states have opened proceedings for public feedback on the topic, he said.

Vermont Department of Public Service Commissioner **June Tierney** said regulators have to start thinking about what it means for every single American to be driving an EV: "Who bears the risk of bringing the supply to fuel those EVs? Who pays for the infrastructure? What do you do about the loss of [gasoline tax] revenues from the transportation fund?"

Michael Brown, manager of EV infrastructure for Nissan, said the key to EV adoption is lowering the total cost of ownership. "That includes not just the financial cost but also the customer experience, which in some ways, especially in the light-duty market, is almost the most important piece," Brown said.

"We see in surveys that over 50% of people say they're interested in buying an EV, and then 85% say they're concerned about charging infrastructure not being there," Brown said. "Just yesterday, one of our colleagues in the industry, a huge supporter, who really wanted to buy an EV, said 'Well, it's 100 miles to the place I go to take my vacation, and I can't take the risk that I might not find a charging station.'"



Massachusetts Energy Secretary **Matthew Beaton** said regional coordination is important on an issue like EVs, which "doesn't really know state boundaries," to develop charging infrastructure efficiently and ease drivers' range anxiety.

"We need to know that if we're going from point A to point B, the infrastructure is there," Beaton said. "That's going to be an amazing thing and a switch that will get flipped in the psychology of the consumer … people just need to get over range anxiety."

Choosing Technology

PowerOptions CEO Cynthia Arcate said her organization, an energy-buying consortium for nonprofits and the public sector in Massachusetts, Connecticut and Rhode Island, has learned to be selective in the technology it uses.

"When we talk about all these nifty things that we're going to be able to do with all this technology, you really have to think about and make sure that a) the market's not going to deliver it anyway for free; and b) that you don't pick the wrong technology, which a lot of these companies are doing on the data analytics side," Arcate said.

PowerOptions' more than 400 members range from large universities and hospitals to churches and YMCAs.

Four years ago, billing analytics was the hot new thing, with everyone eager to put sensors on their circuits and know exactly what's going on, she said.

"We spent a lot of time and money working with big sophisticated institutions, and uniformly they came back and said 'we're not interested,'" Arcate said.

She said customers told her, "'I'm sick of getting reports. I don't need another report to read. Don't send me a report unless you're going to tell me what it says, what I'm supposed do with it. And then do it for me.'"

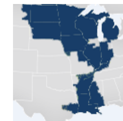
PowerOptions offers customers several ways to pay for their electricity or gas service, including a fixed all-in contract, fixed price with capacity pass-through, or "two products that let the customer get visibility into the wholesale energy market without becoming a member of" New England Power Pool.

Gas customers can also purchase a "layering portfolio" to hedge prices.

"I have spent nine years … trying to get customers to move off the fixed all-in," Arcate said. "They listen to me very patiently. They say, 'I understand what you're saying, but I'm going to go with the fixed price.' That's what customers want. They want predictability, they want certainty, they want to fix their budget and forget about it."

— Michael Kuser and Rich Heidorn Jr.

MISO News



Steering Committee Advances MISO Market Improvement Ideas

By Amanda Durish Cook

MISO's Steering Committee this week submitted eight new possible market improvement ideas to the Market Subcommittee for stakeholder discussion.

During a May 23 conference call, Steering Committee Chair Tia Elliott said all new Market Roadmap ideas will receive more in-depth discussion at the subcommittee, which could assign them to other stakeholder committees. MISO will also hold a stakeholder workshop on June 7 to discuss the new ideas.

Originated by the Independent Market Monitor and stakeholders, the suggestions include:

- Creating financial incentives for members that provide frequency response service, as suggested by Indianapolis Power and Light.
- Allowing dispatchable intermittent resources to provide regulation service, a suggestion Xcel Energy submitted with the support of several other market participants.
- Evaluating the feasibility of implementing a day-ahead market on a 15-minute basis rather than on an hour-to-hour schedule under MISO's market platform replacement project. Monitor David Patton claims that a more specific schedule would reduce make-whole payments.
- Removing transmission charges from coordinated transmission service transactions with PJM, another Monitor suggestion. MISO currently applies transmission charges to these transactions when they are offered, not just when they are scheduled, and the Monitor said the charges discourage CTS offers and "undermine the potential for substantial savings."
- Expanding modeling to include equipment operating characteristics and constraints of other types of generation resources, much like MISO is improving modeling for combined cycle generators, as suggested by Ameren Missouri.
- Requiring that the installed capacity of planning resources be guaranteed as deliverable through firm transmission service, as suggested by the Monitor.
- Allowing load-modifying resources and emergency-only resources to receive Planning Resource Auction capacity credit "if they are expected to be reasonably available in an emergency," according to the Monitor.
- Creating a look-ahead dispatch tool for generators. DTE Energy said MISO's current practice of publishing the next dispatch instructions on a five-minute basis "can lead to inefficiencies with generators who need to bring on or off equipment to meet this dispatch." DTE said it has support from several other market participants on the idea.

MISO Senior Manager of Market Strategy Mia Adams said that, after the workshop, the RTO and stakeholders will begin to rank the ideas in order of importance to determine when — if at all — MISO will begin to propose market changes to address them.

The Steering Committee has the authority to veto Market Roadmap improvement ideas before they reach the Market Subcommittee if they do not fit the definition of market improvements — although it cannot discuss the merits of the ideas — but it has never exercised that power.

Ind. Court Favors Duke in Cost Recovery Suit

By Amanda Durish Cook

The Indiana Court of Appeals ruled last week that Duke Energy can recover from its ratepayers the cost of damages associated with not fulfilling the terms of a wind energy purchase agreement.

The court said it found sufficient evidence to let stand the Indiana Utility Regulatory Commission's original approval of the recovery plan (93A02-1710-EX-2468).

In 2006, Duke and Benton County Wind Farm in Indiana entered into a power purchase agreement for which the IURC authorized full cost recovery from Duke ratepayers. However, in 2013 Benton sued Duke in federal court over what it claimed was a breach of contract when Duke failed to purchase energy from the facility. Benton interpreted the agreement to mean that Duke was responsible for lost production costs in addition to the power Benton delivered.

The 7th U.S. Circuit Court of Appeals ruled that Duke was obligated under the PPA to "pay for power not taken," and the parties settled for $29 million, with the IURC deciding last year that the money should be recovered from Duke's ratepayers over a 12-month period.

The IURC "recognized that Duke would be incurring significant costs in connection with the PPA," the 7th Circuit found. "Consequently, in order to further the commission's policy of encouraging the development of renewable resources, the commission authorized Duke to recover all of its PPA costs from ratepayers for the entire 20-year term."

Two ratepayers, Michael Mullett and Patricia March, appealed the IURC's decision, arguing that its order was "contrary to law because the damages are 'liquidated' and 'hypothetical' and amount to impermissible retroactive ratemaking."

But state court Judge Cale J. Bradford on said there was no case law to support the appellants' claim that "purely hypothetical" liquidated damages prevent Duke from ratepayer recovery for the PPA.

The Indiana court also noted that the $29 million settlement "is no more than customers would have paid had a different offer been submitted to MISO from March 2013 through June 2017 and is less than what potentially could have been awarded has [sic] a settlement not been reached."

Bradford also found no merit that the recovery would amount to retroactive ratemaking. "The fact that the damages arose from a past dispute regarding a contract interpretation does not automatically make the commission's order contrary to law," he wrote. He added that although the case was not a rate case, even rates "are subject to subsequent reconciliation after historical costs have become known."

Bradford also noted that paying lost production costs under wind farm PPAs is consistent with past cases involving Indianapolis Power & Light and Northern Indiana Public Service Co.

FERC Seeks More Detail in Entergy Cost Equalization Dispute

By Amanda Durish Cook

FERC last week ordered Entergy and the Louisiana Public Service Commission to provide it with more information to determine whether its past decision not to order refunds in the ongoing dispute over the company's equalization of production costs remains appropriate.

FERC's voluntary remand of its decision revives the possibility that Entergy may be required to issue refunds over its multistate system agreement (EL01-88-019).

"Having re-examined the matter, the commission seeks further submissions by the parties on whether refunds are appropriate given the circumstances presented in this case," FERC said in a May 22 order.

The commission set the matter to a paper hearing and ordered Entergy and the Louisiana PSC to submit initial briefs and evidence on refunds within 30 days.

The issue dates to 2001, when the PSC and the New Orleans City Council filed a complaint with FERC, arguing that Entergy's allocation of production costs among its operating companies in its 1982 multistate system agreement had become unfair.

In the past, the operations of Entergy's subsidiaries were more integrated, with different transmission and generation facilities functioning as a single electric system. Entergy's system agreement consisted of several service schedules that allocated costs among the operating companies according to a responsibility ratio.

In a 2005 order, FERC found that Entergy's allocation of production costs across its subsidiaries was no longer in rough equalization. And while the commission required Entergy to employ a "bandwidth" remedy that ensured no operating company had production costs more than 11% above or below the system average, it declined to order refunds for the years prior to the bandwidth calculations.

The commission originally found that the Federal Power Act prohibits refunds among electric companies of a registered holding company "to the extent that one or more of the electric companies making refunds cannot surcharge its customers or otherwise obtain retroactive cost recovery." FERC also said that there was no evidence in the record that the operating companies making refunds could receive a retroactive recovery of their costs and rejected the PSC's request for a rehearing over refunds.

The D.C. Circuit Court of Appeals in 2008 remanded the case back to FERC, questioning whether the commission had adequately supported its decision not to order refunds. However, by 2014, FERC had again declined to order refunds in another rehearing requested by the PSC.

FERC now says the PSC's past arguments are influencing its decision to revisit the possibility of refunds.

In March, the D.C. Circuit decided that no refunds were necessary in a closely related case involving Entergy's multistate system agreement. In that case, FERC also determined Entergy's practices were unfair because the company's formula for determining peak load responsibility included interruptible load in addition to firm load. (See *No Refunds in 20-Year-Old Entergy Rate Complaint*.)

NYISO News

NY Task Force Examines Carbon Pricing Impacts

By Amanda Durish Cook

New York's adoption of a carbon charge will likely increase the state's wholesale energy prices, decrease prices for zero-emission credits and boost energy revenues for new "Tier 1" renewable resources supported by renewable energy credits, industry stakeholders heard last week.

NYISO is aiming for its carbon charge to be "reasonably transparent and predictable," ISO staffer Nathaniel Gilbraith told a May 21 meeting of the Integrating Public Policy Task Force, which is examining the impact of carbon pricing on New York's wholesale market. The charge should also "avoid distorting dispatch decisions away from grid power that can create emissions leakage," he said.

The ISO earlier this month proposed to incorporate the carbon costs into its market by deducting a uniform carbon emissions charge from each energy supplier. (See *NYISO Floats Carbon Pricing Straw Proposal*.) Resources with zero point-of-production carbon emissions — including nuclear, conventional hydro, wind and solar generation — would not be assessed a carbon charge.

Existing Policy Interaction

A Brattle Group analysis, released at the meeting, shows that NYISO's proposal would increase wholesale energy prices but decrease ZEC prices "on a dollar-for-dollar basis."

Brattle also concluded the charge would increase energy revenues for new Tier 1 renewables (resources supported by RECs), thereby driving down REC prices on an equivalent basis, although it cautioned that the offset could be lower because RECs are solidified in contracts while the carbon charge is subject to revision. But the proposal would not reduce prices for fixed-price REC contracts already in place, the group said.

The report also speculated that the Regional Greenhouse Gas Initiative may already be causing a leakage of allowances and emissions to other states not under the mandatory program. To combat leaks from a future New York program, Brattle suggested the state impose border charges and reduce the number of allowances it offers.

NYISO staff acknowledged that potential changes to RGGI make it difficult to predict exactly how New York's carbon pricing will interact with the program. A new RGGI cap is set to take effect in 2020, and New Jersey and Virginia are both contemplating joining the program.

Consumer Impacts

The impact of a carbon charge on consumers is even less clear at this point.

NYISO Manager of Economic Planning Timothy Duffy said the ISO is working with Brattle on a consumer impact analysis that

Continued on page 21

Brookfield Granted NYISO ICAP Waiver

FERC last week granted Brookfield Energy Marketing a one-time NYISO Tariff waiver allowing the company to avoid paying a penalty for a clerical error related to its external capacity resource interconnection service (CRIS) rights offer obligation (ER18-1177).

External CRIS rights provide their holder with a long-term ability to import capacity into the New York Control Area but require the holder to commit to supplying a specified number of megawatts of external installed capacity (ICAP) to the NYCA for a period of at least five years through one of NYISO's auctions.

Holtwood Hydropower Station | *Brookfield*

Any entity failing to offer capacity in accordance with Tariff requirements incurs a financial penalty equal to 1.5 times the ICAP Spot Market Auction clearing price, multiplied by the number of megawatts committed.

Brookfield said that an employee submitting the company's offer for the ISO's January 2017 ICAP auction inadvertently omitted a detail that would have automatically associated the offer with the company's CRIS rights and satisfied the remainder of its offer obligation. The company contended that it discovered the error too late to be remedied by other means.

Brookfield claimed it acted in good faith and that the waiver would be limited in scope. The ISO did not oppose Brookfield's waiver request, stating the problem did not affect market outcomes or impair other market participants' capacity import offers.

The commission agreed but reminded "Brookfield, and other entities holding external CRIS rights, of the importance of fulfilling NYISO's Tariff requirements in a careful and timely manner."

— Michael Kuser

NYISO News

NY Task Force Examines Carbon Pricing Impacts

Continued from page 20

will study 2020, 2025 and 2030 using a reference case scenario from its annual Congestion Assessment and Resource Integration Study. The study assumes the existence of 250 MW of offshore wind and attainment of New York's Clean Energy Standard by 2030, and also incorporates the latest large-scale renewable procurements issued by the New York State Energy Research and Development Authority.

The ISO will also study impacts on locational-based marginal pricing and other metrics in 2030 using a model assuming 2,400 MW of offshore wind coming online by 2030, and another scenario in which the R.E. Ginna nuclear plant and Unit 1 of the Nine Mile Point Nuclear Station retire by 2029. The NYISO/Brattle study will use NYMEX futures and prices in the U.S. Energy Information Administration's Annual Energy Outlook to project natural gas price estimates.

Duffy said more assumptions for the analysis will be presented in early June.

Weekly Reporting

NYISO is also considering requiring generators to self-report emissions data on a weekly basis for billing, with true-ups occurring against reported emissions in a trusted database, such as those maintained by EIA or EPA.

NYISO 2017 Generation by Resource

	Units	2017 Net Generation (GWh)	2017 Net Generation (% of total)
Fossil Generation			
> 25 MW	140	36,536	28%
< 25 MW	114	98	0%
Cogeneration	18	14,675	11%
Zero-Emitting Generation			
Nuclear	6	42,175	32%
Conventional Hydro	347	29,554	23%
Wind	22	4,219	3%
Biomass	48	3,084	2%
Solar	1	47	0%
Storage Resources			
Pumped Hydro	5	795	1%
Energy Storage	1	0	0%
NYCA Total	**702**	**131,183**	

Covered by RGGI

Mostly covered by RGGI

NEW YORK INDEPENDENT SYSTEM OPERATOR

| *NYISO*

Gilbrath pointed out that the "vast majority" of New York's fossil-fuel suppliers are already subject to emissions reporting through RGGI. NYISO's 140 generators over 25 MW and 18 cogeneration plants are required to report under the program, leaving 114 generators representing 98 GWh of net generation in 2017 without existing reporting obligations.

NYISO's carbon pricing would cover "burner tip" carbon emissions directly attributable to wholesale energy and ancillary services, including start-up times and no-load levels, GIlbraith said, but he asked stakeholders for other suggestions about how the ISO should manage emissions reporting.

Gilbrath said NYISO will not charge upstream carbon emissions, emissions associated with compressing natural gas for use in power plants or other greenhouse gasses, including methane and nitrous oxide. He said excluding those emissions would help keep carbon pricing predictable and gives suppliers certainty.

PJM NEWS

Cost Containment Coming to PJM Transmission Bids

By Rory D. Sweeney

VALLEY FORGE, Pa. — PJM stakeholders resoundingly endorsed LS Power's controversial proposal to bring cost-containment measures into the RTO's transmission planning process following more than two hours of debate before the Markets and Reliability Committee on Thursday.

The proposal will require PJM to evaluate cost commitments — including construction costs, return on equity and capital structure — in its analysis of competitive bids for transmission construction.

The approval came after a last-ditch attempt to delay a vote fell short.

TOs, who have been fighting the proposal for months, overwhelmingly opposed the measure, but stakeholders were won over by the chance to inject more competition and transparency into the process.

"We stand for markets. We stand for competition. We believe this … expands competition even further into the PJM processes," said LS Power's Sharon Segner, one of the main sponsors of the endorsed proposal.

LS Power's Sharon Segner and the D.C. Office of the People's Counsel's Erik Heinle | *© RTO Insider*

Amendments

Thursday's standoff was set in motion at January's MRC, when stakeholders voted to defer a vote on an earlier LS Power proposal.

While LS Power had been heavily involved in special sessions of the Planning Committee that focused on the issue, the company had not sponsored a full-fledged proposal through PJM's stakeholder process. It instead focused on attempting to change the RTO's less comprehensive proposal. On the night before that proposal was set for a vote at the January MRC, LS Power submitted an alternative motion that differentiated between cost estimates and cost commitments and required PJM to weigh guarantees in its evaluation of bids.

When PJM's proposal failed, TOs scrambled to bury the alternative LS Power proposal, eventually succeeding in having its vote deferred until the May MRC meeting with more special sessions scheduled in the interim for stakeholders to work toward consensus.

As its dispute with the TOs escalated, LS Power found allies among state consumer advocates, who pushed PJM into developing evaluation templates to standardize the bid process. TOs continued to fight the LS Power initiative and rallied behind a new RTO proposal that incorporated the templates but limited consideration of cost commitments to construction costs. LS Power also incorporated PJM's templates but maintained its wider analysis of all cost guarantees.

At the Planning Committee meeting earlier this month, stakeholders endorsed PJM's newest proposal, along with a recommendation that the MRC remand the issue back to the PC for further discussion. An effort to strip LS Power's proposal of being the first voting item on the issue ultimately failed. (See *Cost Containment Proposal Survives; Headed to MRC*.)

In a final special session, just days before the MRC, LS Power teamed with Erik Heinle of the D.C. Office of the People's Counsel to add several "friendly amendments" to the proposal. The revisions removed consideration of operations and maintenance cost guarantees but pushed for additional transparency and instructed PJM to work with its Independent Market Monitor to develop "comparative frameworks" for analyzing cost commitments versus cost estimates.

One would focus on construction costs, while the other would analyze ROE and capital structure commitments. While the friendly amendments were motioned and endorsed, opponents complained the repeated revisions subverted the stakeholder process.

"Once again, we haven't followed the full process to vet the alternative motion," Exelon's David Weaver said.

LS Power attorney Mike Engleman of D.C. firm Engleman Fallon stridently refuted that argument, calling it "absolutely not true."

The PC's recommendation to remand the issue received substantial discussion at the MRC on Thursday, but supporters of the LS Power proposal opposed the delay, saying they feared it might never return for a vote.

"We are asking for a vote on the LS Power proposal, and we are strongly opposed to this notion of remanding this back to the PC," Segner said. "Maybe it will get a vote at the PC, and maybe it won't be based on how [the remand proposal was] drafted."

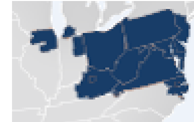
"I think we have very different philosophical views, and I think we do need to vote" on the proposal, Heinle said. "Some things we're not going to solve in the [stakeholder] process."

Weaver said forcing a vote "will give an impression that the [stakeholder] process was a waste of time."

"We do feel like that it's not intractable," he said, noting that TOs endorsed the templates. "But we do feel strongly that we do need time to understand impacts … so we can make sure that all stakeholders' inter-

Continued on page 23

PJM News



Cost Containment Coming to PJM Transmission Bids

Continued from page 22

ests in cost containment are brought forward."

Susan Bruce, who represents the PJM Industrial Customers Coalition, expressed "grave misgivings" with deferring the vote again, saying she felt the stakeholder process had worked. The conversation during the meeting was "very reasonable … but I worry," she said.

"I've seen the conversations at the PC. I've read the letter," she said, referring to a letter send by TOs to the Board of Managers requesting it order the MRC to not vote on the proposal. "With that lens, it's a tough thing to be asked to defer this again."

Several stakeholders, including the Monitor, urged members to reject the remand, which received a 1.95 sector-weighted vote, far short of the 3.335 threshold necessary for approval.

Following the vote, PJM's Steve Herling said the proposals share many aspects and that while he "obviously … would have preferred" the RTO's proposal, he was confident LS Power's proposal is feasible.

"We believe we can implement their proposal, so at the end of the day, we'll implement whatever is approved," he said. "We have concerns, but we believe we can implement it."

TOs' Letter to Board

The sides then argued the legality of the LS Power proposal. Just a day before the meeting, 10 PJM TOs sent the board a letter arguing the proposal would infringe on the TOs' rights under the Consolidated Transmission Owners Agreement, the Tariff and Section 205 of the Federal Power Act.

Proponents of the proposal disagreed, saying it only created a framework for PJM to evaluate bids that include cost guarantees, and that it doesn't require TOs to include such guarantees in their bids. Heinle described the proposal as a "three-legged stool": transparency through the evaluation templates; cost caps on ROE and capital structure; and comparative analysis informed by the Monitor.

"If incumbent transmission owners don't choose to make a cost guarantee they don't have to, but if they do, this puts some parameters around it," Engleman said.

"At the end of the day, PJM looks at all relevant factors — cost just being one of them — and decides which is the right one to move forward with," Segner explained.

American Municipal Power offered another friendly amendment, which added several small clarifications and confirmed that "neither PJM, the designated entity [winning bidder] nor any stakeholders are waiving any of their respective FPA Section 205 or 206 rights through this process." An additional clarification on whether agreements between PJM and the winning bidder, known as designated entity agreements, would be filed at FERC was removed after PJM noted legal concerns. The remaining amendments were approved by LSP and the proposal's other sponsors.

PJM's board did not respond to the TOs' letter before the LS Power proposal was brought to a vote, where it received 92 votes in favor versus 17 votes opposed, or 3.79, well above the 3.335 threshold needed for approval.

The RTO must now work with the Monitor to develop the comparative frameworks, the first of which on construction costs is expected to be introduced in September and endorsed at the MRC on Dec. 6. It would be effective for long-term transmission proposal submission window, which runs from November to March. The second framework comparing ROE and capital structures is expected by May 1, 2019, to be effective for all submission windows going forward.

Capacity Prices Jump in Most of PJM

Continued from page 1

into the auction, an increase from 189,918 MW that offered in last year.

The RTO obtained 893 MW of capacity from new generation and 508 MW from uprates to existing or planned generation, a 50% drop from the new capacity acquired in the 2017 auction.

"We did see a decrease in offers from new capacity resources. That certainly was not unexpected given the trends we have seen in the last several years," Stu Bresler, PJM's senior vice president for operations and markets, said during a news conference Wednesday.

PJM said the higher prices in most locations reflected continued low energy market prices, which causes generators to make higher capacity offers; an increase in the net cost of new entry, reflecting depressed energy revenues; and a drop in cleared capacity and the number of new generators. Partially offsetting those factors was a lower reliability requirement reflecting lower demand forecasts.

The auction, the second under 100% Capacity Performance, also saw increases in cleared demand response, energy efficiency and renewable resources.

DR cleared 11,126 MW, up 3,305 MW, while EE cleared 2,832 MW, a jump of 1,100 MW.

Wind cleared 1,417 MW, an increase of 529 MW. Solar cleared 570 MW, more than quadrupling from 125 MW last year.

Coal generators increased their share by 500 MW, while gas rose by 1,000 MW, including one new combined cycle plant.

Cleared imports totaled 4,052 MW, most from west of the RTO. Deducting 1,320 MW in exports resulted in a net import of 3,405 MW.

Nuclear Decline

Cleared nuclear generation totaled 19,900 MW, a drop of 7,400 MW.

"I don't think that came as much of a surprise to the market," Bresler said, noting he had seen estimates of an even higher

Continued on page 24

PJM NEWS

Capacity Prices Jump in Most of PJM

Continued from page 23

drop. "We continue to see a good amount of diversity across the system."

Exelon announced afterward that its Three Mile Island and Dresden nuclear plants, and all but a small portion of the Byron plant, failed to clear in the auction. The company's Oyster Creek plant, which is set to retire by October 2018, did not offer in the auction.

Bresler noted that the three nuclear units FirstEnergy has announced it plans to close missed the deadline to receive an exemption from offering into the auction.

Robbie Orvis of the clean energy consulting firm Energy Innovation said the trend wasn't consistent across all zones.

"Not only did a substantial amount of nuclear not clear (a 7.4-GW decline from last year), but capacity prices in regions with a lot of nuclear didn't necessarily improve much, if at all. In EMAAC, which has roughly 25% of PJM's nuclear capacity, prices actually dropped by $22.14/MW-day," he said. "In ComEd, which has about 32% of PJM's nuclear capacity, prices only increased by $7.43/MW-day. The remaining regions with nuclear capacity saw healthy price increases ranging from $53.96/MW-day to $94.80/MW-day.

"It's unclear how units might have changed their bidding behavior in response to state nuclear subsidy programs, but given the economic hardships for many nuclear plants in PJM, these results don't point to any kind of dramatic change in market conditions," he said.

Jennifer Chen of the Natural Resources Defense Council pointed to a theory that Exelon might have "sacrificed" some nuclear megawatts, effectively holding them out of the auction to maintain a higher price.

Exelon and the Nuclear Energy Institute said the results pointed to the need for changes in market rules to recognize nuclear plants' contributions to greenhouse gas reductions and grid resilience.

The company said it was the fourth consecutive year that TMI failed to clear, and that the plant, which it has threatened to close in October 2019, has not been profitable for six years.

It said its Quad Cities plant cleared "as a result of" Illinois' zero-emission credit program.

Dresden and Byron, which have capacity obligations through May 2021 and May 2022, respectively, are not in immediate risk of retirement, the company said.

NEI CEO Maria Korsnick said the results "demonstrate the economic pressures facing well-run nuclear plants" because of "distorted market forces."

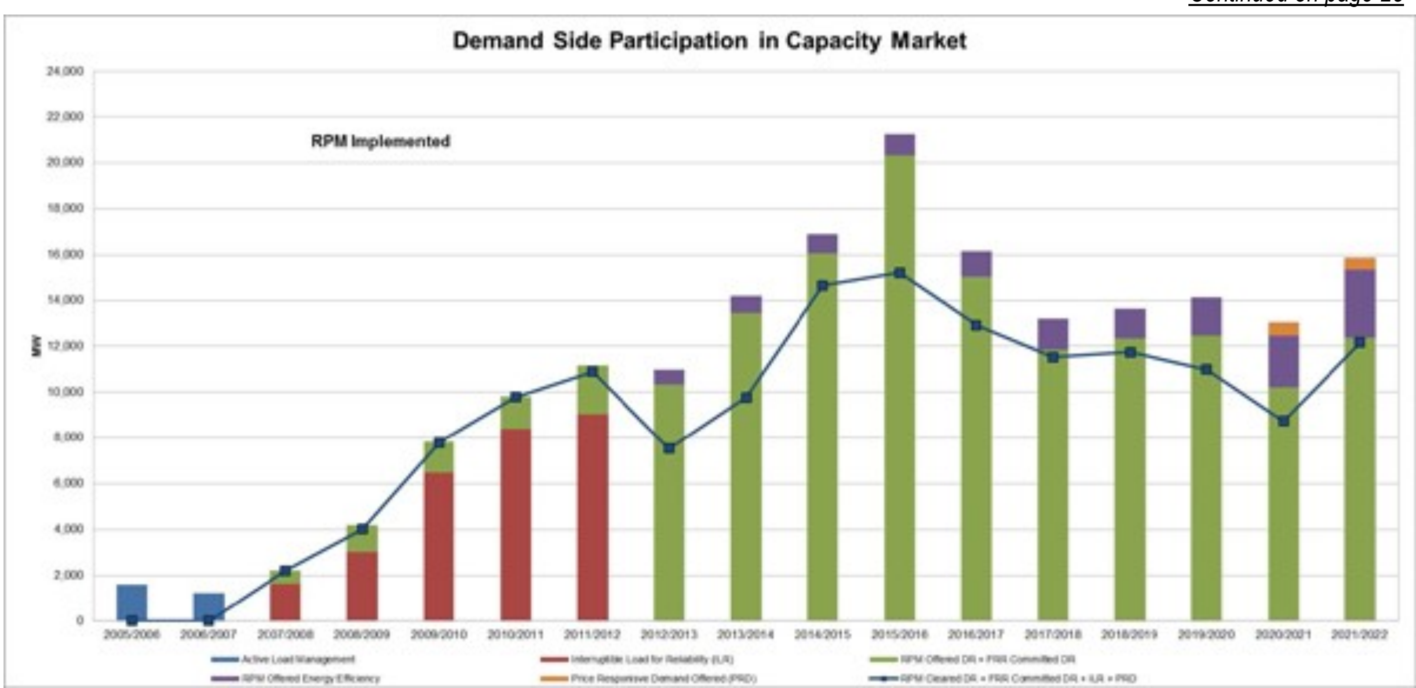
"Energy Secretary [Rick] Perry has been ringing the warning bell that fuel security and resilience are critical to energy security and national security. Only by bringing the capacity and energy markets into better balance will we be able to realize the benefits of a diverse energy supply," she said.

Coal Increases

Although coal's share of cleared capacity increased by 500 MW, Bresler said the auction rewarded only some coal units.

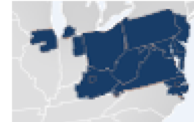
"We did see some fairly large plants that had cleared last year that did not clear this year. On the other hand, we saw … increased cleared capability on a lot of existing units. I think what that may speak to is improvements in efficiency at those

Continued on page 25



| PJM

PJM News



MRC Briefs

Did FERC's Ruling on Incremental Auctions Help DR?

VALLEY FORGE, Pa. — PJM doesn't plan to contest a FERC ruling that may have contributed to the increase in demand response clearing in last week's Base Residual Auction, Senior Vice President of Operations and Markets Stu Bresler told Thursday's Markets and Reliability Committee meeting.

On May 8, the commission rejected rule changes PJM developed to discourage market participants from selling capacity in the BRA and buying back their obligations at lower prices in Incremental Auctions, a practice that has led to concerns that arbitrageurs are offering capacity they have no intention of providing. The Independent Market Monitor says DR providers disproportionately replace BRA commitments in the IA. (See FERC Closes Book on PJM's 'Paper Capacity' Concerns.)

"At this point, PJM does not intend to seek rehearing," Bresler said, noting FERC's "strongly worded" rejection of the filing to revise IA rules, which also terminated a related Section 206 proceeding.

| © RTO Insider

PJM plans to allow the 30-day rehearing window to expire and then meet with FERC to discuss the RTO's next steps, he said. FERC staff had told PJM that they wouldn't entertain a prefiling meeting on the IA revisions because of the outstanding 206 proceeding on the issue. By letting both expire, Bresler said he believes FERC will be willing again to discuss the issue.

"We do intend to bring this back to stakeholders about how to move forward," he said. "We think a discussion with FERC would be very valuable."

FERC's May 8 ruling may have played a role in why more DR cleared as annual resources in the BRA for delivery year 2021-22. DR offered into the auction increased almost 21% to 11,887 MW, nearly 94% of which cleared. Of the 11,126 MW of DR that cleared — up 3,305 MW from last year — 96% cleared as annual Capacity Performance and 452 MW cleared as summer-only resources that were aggregated with other products to meet CP's requirement for year-round commitment. (See Capacity Prices Jump in Most of PJM.)

DR participants have complained that they can't receive a capacity commitment because they struggle to meet CP's year-round requirement and have requested seasonal products. But several MRC members speculated they might have been more emboldened to take the risk because FERC's decision ensured at least one outlet remains. PJM's IA revisions were meant to close a loophole that allows market

Continued on page 26

Capacity Prices Jump in Most of PJM

Continued from page 24

plants that are making them more competitive. I think they're real close right now, in some cases, [to] natural gas. Coal plants that have larger capabilities, that can operate efficiently, that have made the environmental upgrades that are necessary … hung in there this year," Bresler said.

"What this auction showed is — quoting a former colleague of mine — the death of coal has been greatly exaggerated," he added.

Orvis said the outcome "indicates that these units are doing all right in PJM, and it certainly pours some cold water on arguments in favor of providing subsidies for coal units."

End to Seasonal Concerns?

DR offered into this year's auction increased almost 21% to 11,887 MW, nearly 94% of which cleared. Of the 11,126 MW of DR that cleared, 96% cleared as annual CP and 452 MW cleared as summer-only resources that were aggregated with other products to meet CP's requirement for year-round commitment.

"I was a little bit surprised by the magnitude of the increase in annual demand response that was willing to commit to the [year-round] Capacity Performance requirements in this auction," Bresler said.

"There's been a lot of concern expressed in some parts of the stakeholder community about limiting demand response and not allowing that summer-only capability. Frankly, between the increase in aggregation we saw here and the amount of annual that was willing to commit to those Capacity Performance requirements, I have to question whether we still have an issue there."

In total, 715.5 MW of seasonal capacity resources cleared as part of aggregated packages, an 80% increase from the 398 MW of seasonal resources that cleared last year. This year's total included 452.3 MW of summer DR, 209.3 MW of summer EE and 53.9 MW of summer intermittent resources, which were packaged with 715.5 MW of winter resources — mostly wind.

Chen and Orvis questioned whether the higher-than-necessary reserve margin made seasonal resources less concerned about potential CP penalties and willing to take the risk to cash in on the auction revenue.

"There's a structural issue and maybe PJM has a point that there's always innovation … but the issue is if you have a structural issue, there is the potential for even more seasonal resources to participate and at lower clearing prices," Chen said.

Orvis speculated that resources might have

Continued on page 26

PJM NEWS

MRC Briefs

Continued from page 25

participants to receive higher prices for supply obligations in the BRA and pay less in subsequent IAs to offload those commitments.

VOM Remanded

Stakeholders at last week's MRC meeting were spared an expected showdown on variable operations and maintenance (VOM) cost accounting after Rockland Electric's Brian Wilkie indicated an interest in deferring the vote. The idea ended up being motioned and seconded by others, but stakeholders were happy to endorse it and return the issue to the Market Implementation Committee.

Monitor Joe Bowring was prepared to make a presentation in defense of his proposal on the issue, but stakeholders preferred to address it at the lower committee, where the proposal earlier failed to receive an endorsement to be considered at the MRC. (See "VOM Proposal," *PJM Market Implementation Committee Briefs: April 4, 2018*.)

Left to right: Monitoring Analytics' Catherine Mooney and Joe Bowring, EnerNOC's Brian Kauffman, Howard Haas of Monitoring Analytics, and Rockland Electric's Brian Wilkie listen at the MRC. | *© RTO Insider*

Offer Cap Revisions Stalled Again

Two sets of changes to Manual 11: Energy & Ancillary Services Market Operations were approved by acclamation, but a third set dealing with offer caps was sent back to the MIC for additional review.

The approved changes focused on bidding and unit-parameter submissions. The first

Continued on page 27

Capacity Prices Jump in Most of PJM

Continued from page 25

had trouble aggregating and bid in less megawatts than they have available to leave headroom if a CP assessment occurs in the winter.

"PJM should be careful not to imply that these results mean seasonality is not an important factor and should think carefully about why the resources participated in the way they did, and how to create a more efficient and optimized market down the road," he said.

Katherine Hamilton, executive director of the Advanced Energy Management Alliance, attributed the increase in DR to "the more reasonable amount of time that providers had to work with their customers in preparation for the new capacity market rules; to improvements in customer-sited technologies; and to investments customers have made in their back-up generators to be compliant with an EPA rule."

"We have yet to determine the real potential of consumer load response capability, which is expanding significantly this year," she added. "Consumer participation and choice are critical for managing cost and reliability."

DR provider EnerNOC said it will collect more than $180 million in capacity payments from the auction.

Vistra Energy said it will receive $559 million in capacity revenue after clearing almost 9,800 MW at a weighted average clearing price of $156.47, including 2,450 MW in ComEd and 6,435 MW in the rest of RTO.

Revenues Still Down

The increase in capacity prices won't fully make up for lower energy prices, which account for the "vast majority" of wholesale costs, Bresler said. Capacity prices are perhaps 20 to 30% of wholesale costs, while energy revenues make up between 60 and 70%, he said.

"The increase in capacity prices certainly does not outstrip ... the reduction in energy prices, however there is a relationship between the two," he said.

Chen said she was "surprised that the prices increased so much given the oversupply."

Orvis said the near doubling of prices for most of the RTO is good for generators in general but agreed with Bresler that they don't represent large increases.

"For a 1-GW nuclear plant running at a 90% capacity factor, a $63.47/MW-day capacity market price increase is roughly equivalent to a $3/MWh increase in the average energy market price. For a 1-GW coal plant running at a 45% capacity factor, it's roughly equivalent to a $6/MWh increase," he wrote in an email. "Those are pretty small in the grand scheme of things, especially for nuclear plants."

He said the "healthy" reserve margin, even with the reduction in nuclear, was "more evidence that Trump administration claims that losing generation will cause a grid disaster are complete nonsense."

PJM NEWS

MRC Briefs

Continued from page 26

set includes conforming changes regarding bidding locations for virtual transactions. The second set expands the window for when generators can make intraday offers. (See "Intraday Offers," *PJM Market Implementation Committee Briefs: May 2, 2018*.)

The revisions returned to the MIC were developed to ensure consistency between the manual and Operating Agreement regarding price-based offers over $1,000/MWh. The change was necessitated by FERC Order 831, which required RTOs and ISOs to raise their hard caps for verified cost-based incremental energy offers to $2,000/MWh. (See "Offer Cap Resolution," *PJM Market Implementation Committee Briefs: May 2, 2018*.)

PJM's Susan Kenney said the discrepancies occurred because the Order 831 compliance filings failed to appropriately update the Tariff and OA, so the manual's $1,000/MWh cap conflicts with the OA, which permits price-based offers to exceed $1,000/MWh if they are less than a verified cost-based offer. As an immediate fix, PJM is proposing capping all offers at $1,000/MWh by default and allowing higher offers to submit a request for verification. The system will be automated once the capability has been developed.

For price-based offers, PJM is "strongly" suggesting operators allow a "switch to cost" option that excludes price schedules from dispatch. Otherwise, they can request the ability to submit price-based offers in line with verified cost-based offers, but they are then on the hook to ensure price-based offers at each segment remain compliant with verified cost-based offer caps.

The Monitor argues the solution should be holistic to include a full implementation in PJM's offer submission software and related manual changes. Until then, PJM should seek an exception from FERC to use the revised "switch to cost" method, which includes the $1,000/MWh cap, the Monitor said.

Last month, Manual 11 revisions to correct inconsistencies with PJM's governing documents regarding offer caps failed to receive MRC endorsement and were sent back to the MIC as well.

Long-term FTRs

PJM and the Monitor presented members with separate proposals to revise the long-term financial transmission rights market.

The proposals are meant to correct current processes that allow participants in the long-term FTR market to obtain the rights to congestion on transmission paths before the owners of the underlying auction revenue rights. Both proposals would do away with the "year all" product in the market and only offer annual products for each of the next three years.

PJM's proposal would model all ARRs that clear in the annual model as fixed injections and withdrawals in the long-term auction model. Any transmission outages that would impact the ARRs would be removed. PJM argues this would accurately represent any residual capability left on the system.

The Monitor's proposal would set the residual capability for the auction at zero and require all prevailing-flow capability to be generated from counterflow FTRs. The Monitor's Howard Haas argued this would eliminate the risk of any overallocation between the long-term auction and annual auctions and establishes counterparties in the market.

| © RTO Insider

"We think it's going a little too far," PJM's Tim Horger said of the Monitor's proposal.

"We think PJM's going in the right direction … but it does not go far enough," Haas said in response.

Horger said he was interested in seeing what the "true capability" is in the long-term model.

Members will be asked to endorse one of the proposals at the June MRC.

Stakeholders Approve Changes to Manuals, Operations

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

- Manual 36: System Restoration. Revisions developed as part of the manual's annual review; includes clarifications regarding synchro-check relays, blocking governors and black start generators.
- Manual 3: Transmission Operations. Biannual review to update operating procedures. Revisions update remedial action schemes, sectionalizing schemes and definitions for the Cleveland and Eastern interfaces; designate voltage limits for Ohio Valley Electric Corp.'s impending integration; add language regarding reactive reserve check submittals; and clarify notes on load shed activity.
- Manual 14A: New Services Request Process. Annual review. Revisions developed to introduce the Queue Point software for submitting data for feasibility and system impact studies.
- Manual 7: Protection Standards. Revisions developed by the Relay Subcommittee to add clarity, update terms and add reliability requirements.
- Manual 14D: Generator Operational Requirements. Revisions developed to define procedures and notification deadlines for transferring ownership of generation resources. (See "Gens Get Commercial Realities into Gen Transfer Processes," *PJM Operating Committee Briefs: May 1, 2018*.)
- OA revisions allowing PJM to share member confidential information with the Eastern Interconnect Data Sharing Network (EIDSN) in addition to NERC and other reliability entities. EIDSN was created in 2014 to develop industry tools that NERC has decided it no longer wants to create and maintain.

— Rory D. Sweeney

PJM News

PSE&G on the Hook for Bergen-Linden Costs

By Rory D. Sweeney

Public Service Electric and Gas appears to be out of targets to help it pay for its $1.2 billion Bergen-Linden Corridor (BLC) project. FERC last week denied a complaint from the New Jersey Board of Public Utilities to reallocate the project's costs, leaving PSE&G to pay for most of the project meant to support the "wheeling" arrangement Consolidated Edison terminated in April 2017 (EL18-54).

For decades, Con Ed paid to wheel 1,000 MW of power through PSE&G's facilities in northern New Jersey for delivery to New York City. But Con Ed terminated the deal after PJM attempted to allocate $720.4 million of the project's costs to it through the RTO's Regional Transmission Expansion Plan. Two merchant transmission facilities that connect northern New Jersey to New York City — Hudson Transmission Partners and Linden VFT — were allocated $103.2 million and $9.6 million, respectively, and PSE&G was assigned $88.4 million.

FERC initially approved reassigning $530.8 million of Con Ed's allocation to Hudson and $122 million to Linden. But that was nixed after the merchants successfully petitioned FERC to amend their interconnection service agreements and reduce their responsibility. (See *NJ Merchant Tx Operators Win Relief on Upgrade Costs*.)

The BPU filed its complaint just days after FERC allowed the ISA changes, arguing that PJM's Tariff and its joint operating agreement with NYISO don't properly allocate the costs of some RTEP projects to merchant transmission facilities and other transmission customers.

After the "wheel" was canceled, PJM and NYISO agreed to maintain a smaller 400-MW version, called the operational baseflow (OBF), until the separate systems were stabilized to operate without the flow. The BPU argued that the way the grids interact provides a benefit to NYISO for which PJM customers, specifically those in New Jersey, aren't being compensated.

"NYISO continues to model flows over the lines previously used for the Con Edison wheeling arrangement for purposes of determining its resource adequacy requirement, while PJM models its system with little or no support from NYISO," the BPU told FERC.

Therefore, NYISO doesn't need to maintain as much capacity while New Jersey must procure more. PSE&G's zone often clears separately from the rest of the RTO in PJM capacity auctions. In last week's Base Residual Auction for the 2021/22 delivery year, for example, it cleared at $204/MW-day versus $140/MW-day for much of the RTO. (See *Capacity Prices Jump in Most of PJM*.)

The BPU complaint said that without the relief the regulators requested, the PSE&G locational deliverability area's capacity costs will jump by as much as 78.6%, "or an increase of $275 million in a single year and reoccurring annually for the foreseeable future."

Because the Bergen-Linden project was meant to address reliability issues created by the "wheel," it's only fair those beneficiaries should pay for them, the BPU said.

"Parties have sought to escape those costs by terminating or otherwise amending contracts," the BPU told FERC.

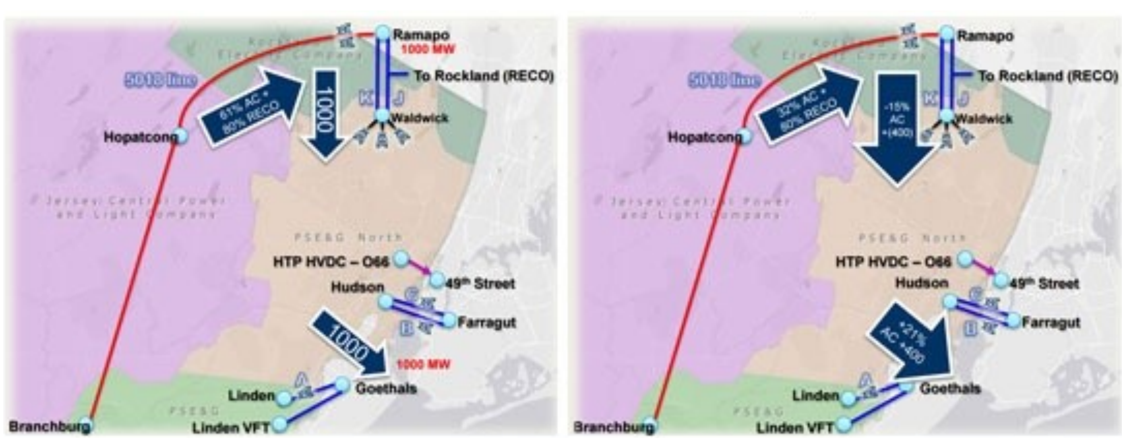
NYISO responded that costs can't be allocated in New York because the project is fully within PJM's boundaries, and that it no longer relies on the facilities for reliability. PJM said that "it is the physical features of the transmission system in northern New Jersey that are driving the need for the BLC project."

Con Ed, Linden, Hudson, the New York Power Authority and several other New York stakeholders argued against the complaint. PSE&G, the New Jersey Division of Rate Counsel, the Public Power Association of New Jersey, PJM's Independent Market Monitor and other RTO stakeholders supported the complaint.

The commission agreed with opponents of the complaint that the BLC was planned solely through PJM's RTEP, that NYISO never agreed to pay for any of it and that the PJM-NYISO JOA "does not preclude the sharing of these benefits without compensation, even if those benefits are not equal at a given point in time."

It also said the merchant transmission facilities can have their service curtailed for reliability or economic reasons now, so they can't effectively replicate the firm priority benefits they had before and therefore shouldn't be held accountable for any upgrades that support that priority.

FERC declined to rule on whether those facilities should be eligible to sell capacity in NYISO, saying that was out of the scope of the complaint.



PJM-NYISO protocol under the "wheel" (left) and after its elimination | *PJM*

Westar-Great Plains Merger Wins Final Approval

By Rich Heidorn Jr.

Kansas and Missouri regulators on Thursday approved Great Plains Energy's merger with Westar Energy, the final hurdles in a stock-for-stock merger of equals with an equity value of about $15 billion.

Shareholders of Kansas-based Westar will own 52.5% of the combined company, with Missouri-based GPE, the parent of Kansas City Power & Light, controlling 47.5%.

The new company, to be called "Evergy," will have about 964,000 Kansas and 611,000 Missouri customers. The new company's board will initially be composed of an equal number of directors selected by Westar and GPE.

The Kansas Corporation Commission approved the deal Thursday afternoon after the Missouri Public Service Commission cleared it in the morning.

"We appreciate that regulators and shareholders recognize the value in combining the companies," said GPE Chairman and CEO Terry Bassham, who will be president and CEO of Evergy. Initially, the company will continue to serve its customers as Westar and KCP&L.

The Kansas commission approved the merger based on a March 2018 settlement agreement among commission staff, the Citizens' Utility Ratepayer Board, Sunflower Electric Power, Mid-Kansas Electric, the Kansas Power Pool, Midwest Energy and solar developer Brightergy (18-KCPE-095-MER).

Westar and KCP&L retail electric customers in Kansas will receive one-time bill credits of $30.5 million and annual credits of $11.5 million from 2019 through 2022. Following their 2018 rate cases, KCP&L and Westar will be subject to a five-year base rate moratorium assuming their authorized return on equity is at least 9.3%.

The Kansas commission imposed an additional requirement that the companies develop an integrated resource plan process to "ensure the merger maximizes the use of Kansas energy resources," it said in a press release.

The new company will maintain headquarters in both Topeka, Kan., and Kansas City, Mo., with the Topeka headquarters guaranteed for at least 10 years. There will be no involuntary severances because of plant closings, and the company's 5,000 employees will receive compensation and benefits at current levels for at least two years.

The Kansas commission approved the deal over the objections of Kansas Electric Cooperative, which said the settlement did not address all its concerns.

Earlier in the day, Missouri regulators approved the deal, which provides initial bill credits of $29 million for their retail ratepayers.

"The merger will create a stronger combined company, with more customers, more geographic diversification, no transaction debt to complete the merger, and the prospect for higher earnings growth rates than either GPE or Westar would be able to achieve on a stand-alone basis," the Public Service Commission said in its order (EM-2018-0012).

Kansas regulators last year pushed back on GPE's original plan to buy out Westar, forcing the companies to recast the transaction as a "merger of equals."

"It's been a circuitous route to get here," the *Topeka Capital-Journal* quoted PSC Chairman Daniel Hall as saying. "We had to fight through the jurisdictional issues, then we had to dismiss the case when our sister jurisdiction ruled it was not in the public interest and start all over again with this one."

FERC approved the merger on Feb. 28 (EC17-171). (See *FERC Greenlights Great Plains-Westar Merger*.)

The deal is expected to close in early June. The company expects to rebalance its capital structure by repurchasing about 60 million shares of its common stock over a two-year period.

Great Plains stock closed Thursday at $19.75/share, up 1%. Westar shares ended the day at $54.58, an increase of 0.66%.

Company Briefs

Top FERC Economist Joining Vistra

Economist Arnie Quinn, the director of FERC's Office of Energy Policy and Innovation, is leaving the commission to join Vistra Energy in early June.

Quinn, who joined FERC in 2003 from The Brattle Group, will be a senior director in Vistra's regulatory policy group, based in D.C. A company spokesman said he "will be responsible for helping develop Vistra's strategy and position for a wide range of policy issues in the various markets where we operate and have assets."

Based in Irving, Texas, Vistra's retail and generation businesses include TXU Energy, Homefield Energy, Dynegy and Luminant. The company operates in 12 states and six of the seven organized wholesale markets, excluding SPP.

Arnie Quinn (third from right) poses with commissioners at FERC's May 17 open meeting. | *FERC*

Documents Puncture SCANA Rationale for not Releasing Audit

Documents released May 23 call into question SCANA's rationale for not releasing a 2016 audit showing problems with the V.C. Summer nuclear power plant expansion that it and Santee Cooper ultimately abandoned.

SCANA had maintained since last September that the audit was performed in preparation for a lawsuit against Westinghouse Electric, the Toshiba unit that was the primary contractor on the expansion, and so couldn't be released to the public.

But in a 2015 message released May 23 by the South Carolina Office of Regulatory

Continued on page 30

COMPANY BRIEFS

Continued from page 29

Staff, former Santee Cooper CEO Lonnie Carter said the audit "is not and has never been intended to position [the power plant's] owners for litigation."

More: *The Post and Courier*

Westmoreland Coal Gets Loan to Pay off PNM Debt

Westmoreland Coal, which supplies coal to the San Juan Generating Station near Farmington, N.M., said Wednesday it has secured a $110 million bridge loan from a group of creditors that holds nearly 80% of its secured debt.

The company will use the loan to pay the balance of a $125 million loan from New Mexico Capital Utility Corp., an affiliate of Public Service Company of New Mexico (PNM), which operates the San Juan power plant. Westmoreland had used the loan from PNM to buy the mine that serves the power plant.

"Operations will continue as normal" at the power plant, and PNM doesn't anticipate any changes in its current business mode after Westmoreland's announcement, a PNM spokesman said.

More: *Santa Fe New Mexican*

ATXI Breaks Ground on Mark Twain Tx Project

Ameren Transmission Company of Illinois (ATXI) said May 23 it has begun construction of the Mark Twain Transmission Project, a 96-mile, 345-kV transmission line and substation in northeast Missouri.

The Ameren subsidiary said that last week it broke ground on the Zachary Substation, which is adjacent to the existing Adair Substation in Adair County, Mo. ATXI said its contractor, L. Keeley Construction, will begin to build various access points along the line's right of way later this month. Once it has done that, it will begin digging and pouring concrete foundations for the transmission towers.

ATXI expects to spend $250 million on the project and anticipates it being in service in December 2019.

More: *Ameren*

Southern Selling Third of Solar Portfolio for $1.2 Billion

Southern Co.'s Southern Power subsidiary said May 23 it has agreed to sell a one-third stake in its solar portfolio to Global Atlantic Financial Group for $1.175 billion.

The portfolio consists of 26 solar projects with 1.7 GW of capacity that sell energy under long-term contracts to customers throughout the country.

Following the closing of the sale, the portfolio will be structured as a partnership, with Southern Power, through its subsidiaries, acting as general partner and maintaining operational responsibilities for the projects.

More: *Southern Co.*

Foreign Investment Committee Blesses Hydro One-Avista Deal

The Committee on Foreign Investment in the United States has concluded that Hydro One's $5.3 billion purchase of Avista doesn't raise any national security concerns, the companies said May 21.

The deal still must be approved by utility commissions in Washington, Alaska, Idaho, Oregon and Montana. Hydro One and Avista expect it to close in the second half of the year.

More: *Hydro One and Avista*

FEDERAL BRIEFS

FERC Extends Comment Deadline On Gas Certificate Review

FERC has extended the comment deadline in its review of its policy on permitting natural gas pipelines 30 days to July 25.

The commission's April 19 Notice of Inquiry (NOI) originally set a 60-day comment period on whether and how its 1999 policy statement on pipeline certification should be revised. The commission asked for input regarding the methodology for determining whether there is a need for a proposed project; its consideration of precedent agreements as evidence of need; consideration of eminent domain and of landowner interests; and the evaluation of environmental impacts.

In an order Wednesday, the commission said it was extending the deadline "given the complexity of the issues, and our desire to ensure the best possible record" (PL18-1).

More: *FERC Outlines Gas Pipeline Rule Review*

EPA Limits Reporter Access to Toxic Chemical Summit

After blocking some reporters from attending the May 22 session of a national summit on toxic chemicals, EPA barred other reporters from attending the May 23 session.

On May 22, the agency allowed a select group of reporters to cover introductory remarks but then escorted them out. EPA reversed its decision after its actions, including a security guard forcibly ejecting an Associated Press journalist, were reported. On May 23, EPA staff barred journalists from *Politico*, E&E News, Crown Publishing and CNN from entering the summit.

EPA Administrator Scott Pruitt (right) at the summit | *EPA*

Sen. Tom Udall, (D-N.M.) sent EPA Administrator Scott Pruitt a letter asking him to "publicly explain and apologize to the excluded media organizations" and direct "EPA staff to allow unbiased press access to EPA events and announcements in the future."

More: *Politico*; *The Hill*

STATE BRIEFS

LOUISIANA

Entergy Proposes Plan to Pass Tax Savings on to Customers

Entergy New Orleans on May 21 proposed a preliminary plan to the New Orleans City Council that would reduce the average power costs for residents by $11/month to reflect its savings from the Tax Cuts and Jobs Act.

If the council approves the proposal, Entergy customers might see the reduction during the first billing cycle of July.

More: The New Orleans Advocate

MAINE

Governor Seeking Input on Integrating State, Canadian Grids

The office of Gov. Paul Le Page (R) said May 22 that the governor is seeking input from experts on how the state can benefit from integrating its grid with Canada's.

LePage has directed his Energy Office to work with the Public Utilities Commission and the Public Advocate to report on the issues the state should consider. He also asked Maine's electric utilities, gas utilities and consumer groups to identify issues and invited contributions from regional, state and international organizations with responsibility for electricity and energy supply and reliability, such as ISO-NE, Northern Maine Transmission Corp. and NERC.

The governor's office is accepting "high-level papers" identifying opportunities and noting benefits, risks and possible concerns through June 30.

More: Maine Office of the Governor; The Maine Wire

MASSACHUSETTS

AG Blasts Utilities' Plans for Passing Tax Cuts Savings

Attorney General Maura Healey's office on May 21 wrote a letter to the Department of Public Utilities saying that the state's electric, natural gas and water companies had inadequately shown how they plan to pass their savings from the Tax Cut and Jobs Act on to their customers.

The DPU in February ordered the state's utilities to revise their cost of service calculations by July 1 to reflect their savings from the act, which reduced corporate tax rates from 35% to 21%.

Healey's office said that it is hiring a private consultant to review the utilities' plans.

More: The Salem News

MINNESOTA

Xcel-backed Nuclear Expenditure Legislation Dies in House

Legislation that would have enabled Xcel Energy to get expenditures at its nuclear power plants approved by utility regulators before, rather than after, it makes them was never brought to a vote in the House after being passed in the Senate by a vote of 37 to 29.

Xcel said the bill would have given it more certainty that it could recover the maintenance costs of at least $1.7 billion it thinks it will incur over the next 17 years at its nuclear plants near Monticello and Red Wing.

Critics said the bill would have given Xcel an incentive to submit high expenditure estimates so it could get reimbursed for cost overruns.

More: StarTribune

NEVADA

NV Energy CEO Criticizes Retail Choice Ballot Measure


Caudill

NV Energy President and CEO Paul Caudill told the May 23 Northern Nevada Development Authority luncheon that if voters approve the Energy Choice Initiative on the November ballot, it will give large power customers a chance to save money, but "the jury is out on whether residential customers as a group will benefit."

"Our company thinks this is a really bad idea, not so much for us and our employees, but for the state of Nevada," Caudill said.

Caudill said the Public Utilities Commission report on the Energy Choice Initiative says transitioning to an open market would cost $3.5 billion to $4 billion, which would boost the average residential customer's monthly bill by $20 to $27 for 10 years.

More: Nevada Appeal

NEW HAMPSHIRE

SEC Rejects Motion to Reconsider Northern Pass Permit Denial

The Site Evaluation Committee on May 24 rejected Northern Pass' motion asking it to reconsider its denial of a siting permit for the transmission project, a partnership between Eversource Energy and Hydro-Quebec that would bring Canadian hydropower to New England.

"We intend to pursue all options for making this critical clean energy project a reality," Eversource New Hampshire President Bill Quinlan said in a statement.

One option would be an appeal to the Supreme Court, which on May 22 overruled a 2016 decision by the Public Utilities Commission barring Eversource from purchasing capacity on a proposed natural gas pipeline as a way of getting the pipeline built so it could supply natural gas to New England power plants.

More: New Hampshire Union Leader

Court Rules Electric Utilities Can Recover Pipeline Costs

The state Supreme Court on May 22 issued a ruling that would allow the state's electric utilities to recover from their customers the cost of purchasing capacity on proposed natural gas pipelines intended to serve electricity generators to finance their construction.

The court overturned an October 2016 ruling by the Public Utilities Commission that Eversource Energy couldn't recover the costs of purchasing capacity on a proposed pipeline to finance its construction cost because the natural gas would be

Continued on page 32

State Briefs

Continued from page 31

used to generate power and the state's electric restructuring law prohibits utilities from being involved in the generation business.

The court's decision was the opposite of the one reached by the Massachusetts Supreme Judicial Court, which in August 2016 ruled that buying long-term natural gas contracts to finance pipeline construction would effectively push electric utilities into the power generation business, which they were barred from under that state's restructuring law.

More: Commonwealth; Concord Monitor; InDepthNH

NEW JERSEY

BPU Votes to Start Economic Analysis of State Rejoining RGGI

Following Gov. Phil Murphy's executive order earlier this year, the Board of Public Utilities voted May 22 to begin an economic analysis to evaluate the costs and benefits of the state rejoining the Regional Greenhouse Gas Initiative.

The economic analysis is meant to ensure that the Department of Environmental Protection's rulemaking process is informed by the potential economic impact that rejoining RGGI could have on ratepayers.

More: Board of Public Utilities

AG Takes FERC to Court Over Pipeline Approval

Grewal

Attorney General Gurbir Grewal filed a petition on May 21 with the D.C. Circuit Court of Appeals asking it to hear the state's arguments that FERC erred when it issued a certificate of public convenience and necessity to the PennEast natural gas pipeline.

In February, Grewal asked FERC to stay the certificate and rehear the case. FERC responded with a tolling order, which ostensibly gave it more time to consider Grewal's request, but which critics say means the commission will do nothing for six months and then dismiss the request.

More: NJSpotlight

TEXAS

Garland P&L's Gibbons Creek to Return to Mothballs

Gibbons Creek Generating Station

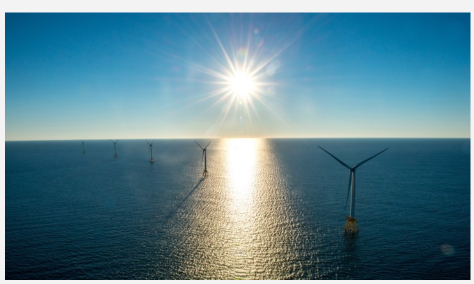
ERCOT last week approved the city of Garland's decision to return its Gibbons Creek Generating Station to mothball status, effective Oct. 1.

The city's municipal utility, Garland Power & Light, said last year that it intends to run the 454-MW coal-fired unit from June 1 to Sept. 30 each year. It returned to operational status for the summer season on May 17.

Located northwest of Houston, the 35-year-old coal-fired unit is operated by the Texas Municipal Power Agency.

VIRGINIA

DMME Issues RFP for Plan to Make State Offshore Wind Hub



Block Island Wind Farm off Rhode Island

The Department of Mines, Minerals and Energy has issued a request for proposals for qualified contractors to develop a plan to position the state as the East Coast location of choice for companies that supply and service offshore wind farm developers and operators.

The selected contractor will develop a report that analyzes the state's maritime infrastructure and assets, identifies how to leverage them and provides advice on overcoming the barriers to the state's goal of becoming a wind farm development and maintenance hub.

The department wants the report to connect wind farm industry members with the maritime industry in Hampton Roads.

More: 4COffshore

DEQ Orders Construction On MVP Halted for Erosion

Artist's rendering of the pipeline | *Appalachian Trail Conservancy*

The Department of Environmental Quality ordered construction on the Mountain Valley Pipeline stopped in Franklin County until proper erosion control measures are put in place.

The agency made the move after heavy rains on May 17 and May 18 swept away much of the soil that had been unearthed by heavy equipment that was being used to cut trees and clear land along the natural gas pipeline's right-of-way, covering nearby Cahas Mountain Road in up to eight inches of mud.

More: The Roanoke Times

WASHINGTON

Avista to Spend $165M On Smart Meter Rollout

Avista said May 21 it plans to spend $165 million giving smart meters to its 450,000 electric and gas customers over the next two years.

The company said it plans to install the meters and then have the Utility Commission determine how it will recover the cost of the installation.

Itron will supply new meters for Avista's electric customers and a smart-meter module that hooks onto existing meters for its gas customers.

More: The Spokesman-Review; KREM2

Environmental Group Sees More Ill. Renewables, Bailout Bids

By Amanda Durish Cook

Illinois is advancing toward a cleaner energy future thanks to two decades of policy and market developments, and new efforts could accelerate the trend, a Midwest environmental advocacy group said Thursday.

Speaking during a May 23 webinar on the evolution of Illinois' energy market, Brad Klein, senior attorney for the Environmental Law and Policy Center, said last year's Future Energy Jobs Act, coupled with increasingly competitive renewable generation prices, will continue to sway the state toward clean energy. The law set renewable and energy savings goals for utilities, created community solar programs and restructured the state's renewable target process and $200 million annual budget.

The ELPC predicts that by 2020, the FEJA will boost Illinois' solar capacity from 84 MW today to 2.8 GW by 2022, and also add 1.3 GW to its current 4.3-GW wind portfolio.

However, Klein said he predicted "growing pains and bottlenecks" in the interconnection process to get the projected amounts of solar generation online.

Klein said although he expects Illinois will be able to meet its minimum new build targets for renewable resources by about 2020, the state will probably need to continue building renewables to meet its 25% use target in the Commonwealth Edison and Ameren territories by 2025.

"We think we're going to hit the minimum thresholds for new wind and solar build-out in the early 2020s … but we're not on track yet to meet that 25% by 2025. We expect that this will be a long-term and sustainable effort over time," Klein said.

He also forecasts more future bailout attempts by nuclear and coal generation operators, particularly Dynegy, which is now owned by Vistra Energy.

Klein said the FEJA favors energy efficiency, renewable energy and nuclear generation, and the final version of the law excluded draft provisions for coal bailouts, demand charges and support for microgrids. He also said FEJA notably lacked any provisions on EV and energy storage, markets he'd like to see developed in Illinois.

There are opportunities for Illinois to develop municipal aggregation programs, which are currently "stagnant," he said. "I'm hoping we'll see a new wave of aggregation."

The Path to FEJA

Klein said the ELPC expects more renewable and decarbonization policies to take hold incrementally in Illinois, as other energy-related state policies have in the past.

"It seems to follow a pattern: Every 10 years or so, there's major legislation," he said.

He noted that Illinois began to restructure its market with 1997's Illinois Electric Service Customer Choice and Rate Relief Law, which cut rates by up to 20% and froze them for 10 years while introducing retail competition in the state.

Klein said the state's next wave of change came in response to the 2006 reverse power auction that saw residential prices jump 20 to 50% after the decade-long price caps expired. The auction sparked a public backlash against utilities and power marketers.

"It led to a political situation that created the next major piece of legislation," he said, referring to the 2007 creation of the Illinois Power Agency, an independent state agency that procures power for utilities, and the state's first renewable portfolio standard.

The 2007 RPS fell short of the state's goals, and utilities became "increasingly hostile" to distributed resources, Klein said, leading to 2017's FEJA.

The IPA said last year that Illinois' first RPS, combined with retail choice, meant customers could toggle between utility service and alternative suppliers, "leading to budget and target uncertainties." As a result of the FEJA, Illinois today uses a single RPS, rather than administering separate rules for customers using alternative suppliers.

Gov. Signs NJ Nuke Subsidy, Renewables Bills

Continued from page 1

2050.

The state's previous RPS requirement targeted 24.39% renewables for the "energy year" ending May 31, 2028, according to the North Carolina Clean Energy Technology Center's Database of State Incentives for Renewables & Efficiency.

Murphy said the new targets represent "one of the most ambitious renewable energy standards in the country."

"Today, we're taking another step forward in rebuilding New Jersey's reputation as a leader in the development of clean energy sources while fulfilling a critical promise to foster our state's energy future," said Murphy, who took office in January. "Signing these measures represents a down payment to the people of New Jersey on the clean energy agenda I set forth at the beginning of my administration."

Murphy replaced Republican Chris Christie, who had balked at plans to develop offshore wind and withdrew the state from the Regional Greenhouse Gas Initiative. Murphy, who has pledged to rejoin RGGI, noted that the legislation codifies his goal of 3,500 MW of offshore wind by 2030 and reinstates tax credits for offshore wind manufacturing that expired during Christie's term.

The bills were approved by the Legislature on April 12. (See *NJ Lawmakers Pass Nuke Subsidies, Boosted RPS*.)

ZEC Program

The ZECs, which are expected to cost up to $301 million annually, will be funded by a 0.4 cents/kWh tariff on retail distribution customers.

The legislation requires the state Board of Public Utilities to issue an order implementing the ZEC program within 180 days. The BPU will award ZECs to nuclear plants licensed through at least 2030 that can demonstrate they are at risk of closure within three years.

PSEG's Salem Unit 1 (licensed to operate through Aug. 13, 2036) and Unit 2 (licensed through April 18, 2040) and Hope Creek (licensed through April 11, 2046) are eligible. Exelon's Oyster Creek nuclear plant, scheduled to be retired in October 2018 under a prior agreement with the state, is not eligible. Exelon also is part owner of the Salem plant.

New Jersey Gov. Phil Murphy speaks at bill signing at New Jersey Resources' New Road solar installation in South Brunswick, N.J., surrounded by New Jersey Resources CEO Laurence M. Downes (left) and Senate President Stephen Sweeney (right). | *New Jersey Office of the Governor*

The plants selected will initially receive ZECs for three years and the balance of the first energy year following selection. They will be subject to review by the BPU for additional three-year periods.

Out-of-state nuclear plants also could seek ZECs, but their approval may be dependent on a premature retirement of one of the remaining in-state plants because the bill caps ZEC eligibility at 40% of the state's total electric usage. In 2016, according to the U.S. Energy Information Administration, the combined generation of the Salem and Hope Creek plants was 25.3 million MWh, 33.6% of the state's 75.4 million MWh usage.

The state's Office of Legislative Services calculated that the 0.4 cents/kWh tariff would generate $301.4 million based on 2016 consumption, translating to a ZEC cost of about $10/MWh.

Storage, Renewable Provisions

The Assembly bill requires the BPU to adopt energy efficiency and peak demand reduction programs and a community solar pilot program, and to revise the solar renewable energy certificate (SREC) program.

By Jan. 1, 2020, 21% of the state's electricity must come from Class I renewable sources. The bill requires the BPU to begin a proceeding to reach the 2025 and 2030 RPS goals and caps the cost of the RPS program — excluding the costs of the offshore wind — at 9% of total costs to consumers in 2019 and 7% afterward.

This bill also requires the BPU, in consultation with PJM, to conduct an analysis determining the amount of energy storage to be added in the state over the next five years to provide the maximum benefit to ratepayers. The analysis will identify the optimum points of entry into the electric distribution system for distributed energy resources and include recommendations for financial incentives that may be required.

The BPU must submit a report on the storage findings within one year; six months after that, it must initiate a proceeding to add 600 MW of storage by 2021 and 2,000 MW by 2030.

The bill also requires electric power suppliers and basic generation service providers to increase the share of solar power in their portfolios to 5.1% by energy year 2021 before gradually reducing the percentage through 2033. The bill also reduces the solar alternative compliance payments beginning in energy year 2019 through 2033. Future solar RECs will be for 10 years, down from the current 15.

Electric customers would be able to participate in solar energy projects remotely located from their properties under the "Community Solar Energy Pilot Program," which is to be converted to a permanent program within 36 months.

Utilities will be required to adopt energy efficiency measures to reduce electric usage by 2% and natural gas consumption by 0.75%.

The bill provides a tax credits for qualified wind energy projects in an eligible wind energy zone and requires the state to establish job training programs to develop a workforce for the manufacture and servicing of offshore wind equipment.

Reaction

The NJ Coalition for Fair Energy — funded by the Electric Power Supply Association and independent power producers Calpine and NRG Energy — criticized the nuclear subsidies and hinted it will seek to overturn them in court. Challenges by EPSA and others to ZEC programs in Illinois and New York are pending in the 7th and 2nd U.S. Circuit Courts of Appeals.

"While PSEG shareholders just became more prosperous, the reality is New Jersey consumers now have to confront higher electric bills for no reason other than to bail out PSEG management's bad business decisions," spokesman Matt Fossen said. "We

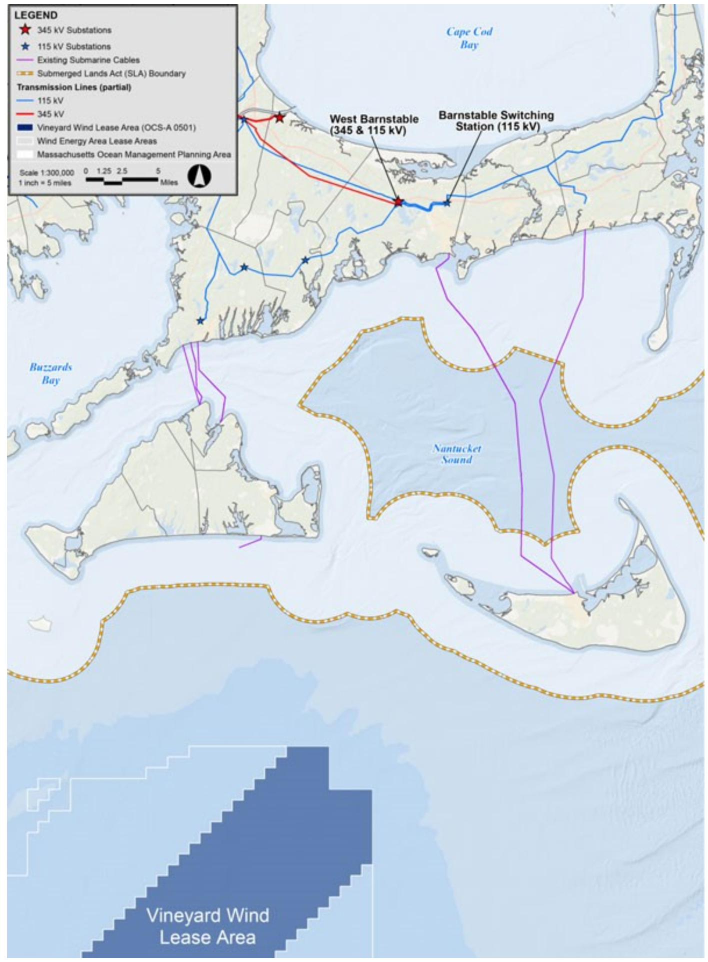
Continued on page 35

Mass., R.I. Pick 1,200 MW in Offshore Wind Bids

Continued from page 1

"With today's landmark decisions, Massachusetts and Rhode Island are ready to pioneer large-scale offshore wind development that will light the way for our industry and nation," American Wind Energy Association CEO Tom Kiernan said in a statement. "With world-class wind resources, infrastructure and offshore energy expertise, the U.S. is primed to scale up this industry and lead it."

Also on Wednesday, New Jersey Gov. Phil Murphy signed legislation codifying his commitment to build 3,500 MW of offshore wind by 2030, surpassing New York's target of 2,400 MW. (See related story, *Gov. Signs NJ Nuke Subsidy, Renewables Bills*, p.1.)



| *Vineyard Wind*

Fast Start

"Vineyard Wind is proud to be selected to lead the new Massachusetts offshore wind industry into the future," company CEO Lars Thaaning Pedersen said Wednesday. "Today's announcement reflects the strong commitment to clean energy by Gov. [Charlie] Baker and the Massachusetts legislature."

The Vineyard project will lie about 15 miles south of Martha's Vineyard and include a transmission component linking back to the ISO-NE grid.

The company plans to begin construction in 2019 and start operating the first 400-MW section of the project by 2021, with the second half slated for completion in 2022. It got a head start on its rivals in the solicitation by beginning state and federal permitting processes in December and submitting the project's draft environmental impact statement with state regulators on May 1.

Vineyard has said its project would generate 3,600 jobs, including 1,500 coming with the start of onsite construction. The company has also promised the project will yield significant CO_2 reductions, displacing 1.25 million metric tons per year upon full operation in 2022.

Massachusetts Sierra Club Director Emily Norton called Wednesday's announcement "terrific news" but said it is only the beginning.

Continued on page 36

Gov. Signs NJ Nuke Subsidy, Renewables Bills

Continued from page 34

wish officials would've waited to make a decision until after the results of PJM's capacity auction were announced, which will be literally only hours after the governor's signing. But this issue is not over — and it's unfortunate the courts may be necessary to bring a dose of reason to the debate."

Environmental activists and solar energy industry groups celebrated the renewable and DER provisions.

"It has never been more important for leaders to stand up for clean energy jobs, local investments, and clean air and climate progress in our communities. We are encouraged that in the face of rollbacks in Washington, Gov. Murphy is stepping up with bold action," said Pari Kasotia, Mid-Atlantic director for Vote Solar.

The Energy Storage Association said the storage mandates put New Jersey in league with California, New York, Massachusetts, Oregon, Nevada and Arizona as states encouraging the technology.

Sean Gallagher, the Solar Energy Industries Association vice president of state affairs, said the bill will give "many more New Jersey residents, businesses and communities … access to solar energy."

"If properly implemented, this legislation will create access to solar energy for consumers and businesses across New Jersey for the first time," said Brandon Smithwood, policy director for the Coalition for Community Solar Access.

"Thanks to this important legislation, New Jersey residents who rent, live in apartments or can't afford the upfront cost to install solar panels will now be better able to get their power from the sun," said Luis Torres, senior legislative representative for Earthjustice.

Mass., R.I. Pick 1,200 MW in Offshore Wind Bids

Continued from page 35

"With the cost of offshore wind falling precipitously, we can transition much more quickly to 100% clean energy than anyone thought possible, and there is no time to lose," Norton said.

"This is such an important milestone. Rather than drilling for oil and gas off of the New England coast, we will find our energy future blowing in the wind," U.S. Sen. Ed Markey (D) said on Twitter.

In December, three developers — Vineyard, Deepwater and Bay State Wind — submitted bids in the request for proposals (83C), which called for a minimum of 400 MW but said the state would consider bids of up to 800 MW if it determined that a larger proposal was both superior to other proposals and "likely to produce significantly more economic net benefits to ratepayers."

All three developers purchased renewable energy leases off the coast from the U.S. Bureau of Ocean Energy Management.

Massachusetts' 2016 Act to Promote Energy Diversity mandated the Department of Energy Resources and the state's distribution utilities — Eversource Energy, National Grid and Unitil — to sign long-term contracts for 1,600 MW of offshore wind by June 30, 2027. All three utilities had a hand in the selection, and an independent evaluator monitored and assisted the bid evaluation process.

Transmission Backbone

Deepwater Wind's 400-MW project will connect to land at the Brayton Point substation in Somerset, Mass., and the company partnered with National Grid Ventures to propose an offshore transmission "backbone" scalable to 1,600 MW that would be open to other wind developers. (See Offshore Wind Developers Ponder Tx Options.)

The Revolution project will firm its output through an agreement with the largest hydroelectric pumped storage facility in New England, the 1,200-MW Northfield Mountain station operated by FirstLight Power Resources.

The company's bid said its grid-scale storage and expandable transmission system would "result in energy market savings of $75 million annually for Massachusetts ratepayers, without counting the benefits of economic development or emissions reductions."

Deepwater developed the first offshore wind farm in the U.S., the 30-MW Block Island project in Rhode Island, which began commercial operation in December 2016.

"Rhode Island pioneered American offshore wind energy, and it's only fitting that the Ocean State continues to be the vanguard of this growing industry," said Deepwater Wind CEO Jeffrey Grybowski. "We applaud Gov. [Gina] Raimondo for her bold commitment to a clean energy future."

| *Vineyard Wind*