RTO Insider
Your Eyes and Ears on the Organized Electric Markets
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Powelson Sees 'Erosion of Confidence' in Stakeholder Process

Calls for RTO Transparency, Board Diversity, Term Limits

By Rich Heidorn Jr. and Michael Brooks

WASHINGTON — FERC Commissioner Robert Powelson on Wednesday reiterated his defense of organized markets but said he sees an "erosion of confidence" in RTO stakeholder processes.

Powelson | *© RTO Insider*

Powelson, who made the observation in a speech at a PJM issues workshop sponsored by the Great Plains Institute and Duke University's Nicholas Institute for Environmental Policy Solutions, elaborated afterward in an interview with reporters.

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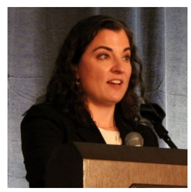
Can RTO Stakeholders Reach Agreement on the Big Issues?

When FERC set out the requirements for RTOs in Order 2000 in 1999, it put stakeholders at the center of the rulemaking process, guaranteeing that generators, transmission operators, electricity buyers and public interest groups would have a voice in any rule change filed for commission approval.

The stakeholder process works well for many routine issues, but it has shown an inability to reach consensus on major contentious issues, says Christina Simeone, who authored a May 2017 study on PJM's governance.



Simeone | *© RTO Insider*

Simeone, director of policy and external affairs for the Kleinman Center for Energy Policy at the University of Pennsylvania, says some of the shortfalls in PJM's stakeholder process resulted from compromises made under the Governance Assessment Special Team (GAST) process created in 2009.

Last week, the issues Simeone's paper raised were back in the news, following complaints by FERC Commissioner Robert Powelson and regulators from Pennsylvania and Illinois over PJM's decision in February to file two competing proposals for insulating its markets from state-subsidized generation. (See *Powelson: 'Erosion of Confidence' in Stakeholder Process*.)

RTO Insider's Rich Heidorn Jr. talked last week with Simeone about her study on PJM's governance, which asked "Can Reforms Improve Outcomes?"

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PJM Capacity Proposals Widely Panned

By Rory D. Sweeney and Rich Heidorn Jr.

If it were a Broadway show, PJM's "jump ball" proposals for protecting the capacity market from subsidized resources would have closed after one night.

Monday was the deadline for the critics to file their comments on PJM's proposal and the reviews were almost uniformly negative. *RTO Insider*'s initial review of the filings found almost no commenters wholeheartedly endorsing either PJM staff's capacity repricing proposal or the Independent Market Monitor's MOPR-Ex plan to extend the minimum offer price rule to existing resources in addition to new entries (ER18-1314). (See *PJM Board Punts Capacity Market Proposals to FERC*.)

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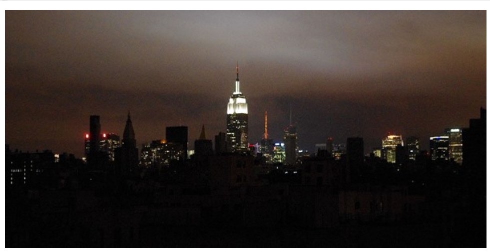

New York City following Hurricane Sandy. Plant retirements have not caused a shortage of black start resources, but grid operators should consider expanded testing, FERC and NERC say. (p.32)

Also in this issue:

CPUC Cautions of Return to Bad Old Days

By Jason Fordney

California could return to the conditions preceding the energy crisis of the early 2000s if the transition to fragmented decision-making and electricity procurement is not managed correctly, the Public Utilities Commission said in a report issued last week.

The report on California retail electricity choice, entitled "An Evaluation of Regulatory Framework Options for an Evolving Electricity Market," is meant to guide the discussion as the CPUC, state lawmakers and other entities work to manage the disaggregation of energy procurement from traditional utilities to an environment with much more residential rooftop solar, community choice aggregators (CCAs) and private elec-

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In This Week's Issue

CAISO News

Peak Details Vision for 'Transitional' RC

By Jason Fordney

Peak Reliability last week outlined a vision for reworking its current structure and reducing costs as it tries to prevent a mass exodus of customers to CAISO.

The reliability coordinator (RC) said the cost reduction will require reducing the size of its board of directors to three members from six, cutting executive jobs, and eliminating some manual and administrative processes. Its current membership and board would need to approve the changes. Peak has been an RC since 2009 and had a $45 million budget for 2018.

After Peak announced last year it would attempt to establish a West-wide energy market in a partnership with PJM, CAISO said it would depart the organization to become its own RC and offer the services to other utilities in the West. (See *'Horse is out of the Barn' for CAISO RC Effort*.) CAISO said recently that most of the load in the Western Interconnection has signed nonbinding letters of intent to take RC services. (See *Most of West Signs up for CAISO RC Services* and *Peak/PJM Enter Western Market 'Commitment Phase'*.)

An RC provides member utilities services that help them meet NERC standards and requirements, and is entirely different from a market operator. Choosing Peak as an RC would not prevent an entity from joining CAISO's market, and vice versa.

Peak said its funding amount will fall to $28.7 million if CAISO leaves and all other funders stay; it would be $31.2 million if CAISO remains with Peak under the transitional structure. If CAISO departs, remaining members would see a 10% cost reduction under the transitional RC, but if the ISO remains, all members would see a 30% cost reduction.

Peak spokeswoman Rachel Sherrard told *RTO Insider* that "the [transitional RC] is not a separate organization. It is how Peak would be structured and funded post 2019. It is not a dramatic change in terms of the tools and services that we as the RC currently provide."

When asked last week about the likelihood of CAISO remaining with Peak, ISO spokesman Steven Greenlee said, "We are moving ahead with our plans to become a RC and offer those services to other entities in the West."

Peak would operate under the transitional RC structure in 2020/21 and have a $23.5 million operating budget for 2020. It would offer core RC services that ensure reliability and meeting NERC standards, as well as optional services such as Hosted Advanced Applications and the WECC Interchange Tool, which validates E-Tags and confirms power transactions throughout the region. It would also offer interconnection-shared services that support reliability in the West, such as the Reliability Messaging Tool and Enhanced Curtailment Calculator.

After 2021, Peak and PJM would offer bundled market and RC functions, as well as RC-only services at a reduced price.

Peak CEO Marie Jordan last week provided stakeholders a presentation explaining the transitional structure. She also sent an April 27 letter to the organization's funding parties, member advisory committee and reliability member representatives, touting its experience maintaining reliability of the entire Western Interconnection.

"Over the past decade, in collaboration with its stakeholders, Peak Reliability has built and operated that RC," Jordan said in the letter. "CAISO has not. SPP has not."

Peak said it will issue a straw proposal on May 21 that will describe how the transitional structure could be implemented.

CAISO said it expects to begin shadow operations with Peak in May 2019 and become the RC of record for its balancing authority by the end of June 2019.

CAISO NEWS

CAISO, PacifiCorp Gain Most EIM Q1 Benefits

By Robert Mullin

Region	January	February	March	Total
APS	$1.98	$1.84	$2.08	$5.90
ISO	$2.99	$5.74	$6.12	$14.85
NV Energy	$0.87	$2.07	$1.23	$4.17
PacifiCorp	$2.36	$4.00	$4.15	$10.51
PGE	$0.95	$1.21	$1.48	$3.64
PSE	$1.01	$1.00	$1.00	$3.01
Total	$10.16	$15.86	$16.06	$42.08

EIM benefits in Q1 2018 | *CAISO*

CAISO and PacifiCorp reaped the majority of the Western Energy Imbalance Market's (EIM) $42.1 million in gross benefits during the first quarter, according to a report released by market operator CAISO.

The ISO earned $14.85 million in EIM benefits over the quarter, followed by PacifiCorp at $10.5 million. Trailing those two market players were Arizona Public Service ($5.9 million), NV Energy ($4.2 million), Portland General Electric ($3.6 million) and Puget Sound Energy ($3 million).

Total quarterly benefits were up nearly 26% from the fourth quarter of 2017 and 31% from the same period a year ago — before Portland General Electric began transacting in the EIM last October. The market has yielded $330.5 million in benefits since it was launched with PacifiCorp in November 2014, the ISO estimates.

The report again illustrated an established pattern with the arrival of spring: that CAISO becomes a net exporter of energy as increasing output from solar resources coincides with modest electricity demand during mild weather in California. (See *CAISO EIM Exports Rise with Spring, Report Shows*.)

The ISO's EIM exports surged from 94,769 MWh in January to 325,664 MWh in March, with imports falling from 299,586 MWh to 185,008 MWh, the report showed. First-quarter exports totaled 608,416 MWh, compared with 362,774 MWh the previous quarter.

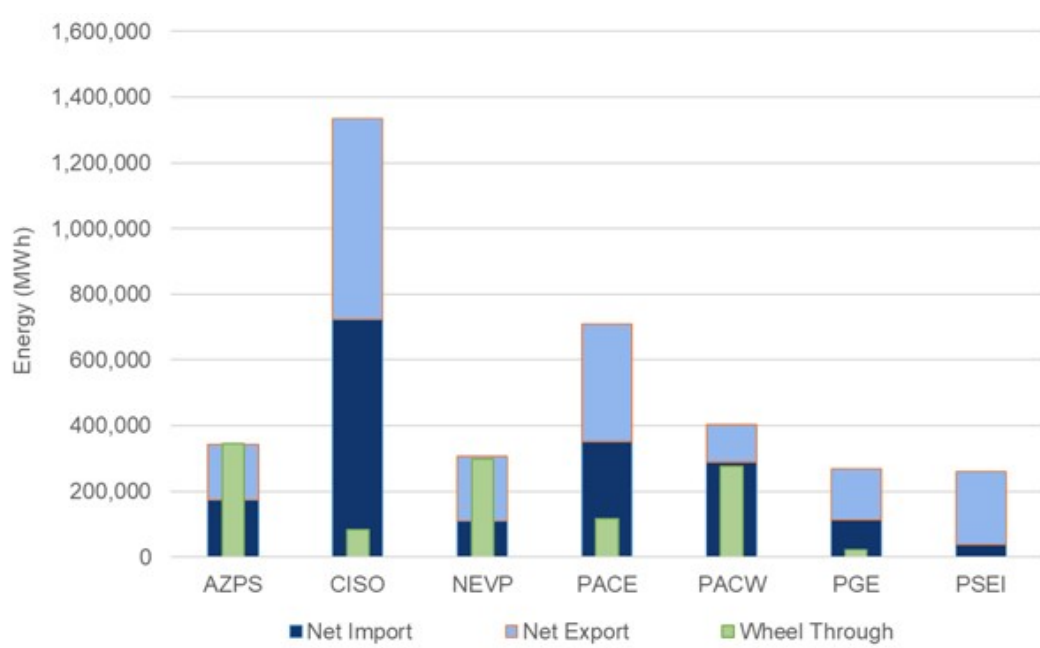
CAISO said the energy transfers facilitated by the EIM allowed it to avoid curtailment of 65,680 MWh of renewable output during the quarter, up 24% from the same period last year. That was still down sharply from the nearly 113,000 MWh of avoided curtailments in the second quarter of 2016, which the ISO attributed to improved hydroelectric conditions and advancements in how EIM participants are deploying their resources.

The avoided renewable curtailments translated into the displacement of 28,188 metric tons of carbon dioxide, based on an assumed default emissions rate of 0.428 metric tons CO_2/MWh from other sources of generation. By avoiding curtailments, the EIM has helped to displace 250,845 metrics tons of CO_2 since 2014, the ISO said.

The report also showed that APS and NV Energy functioned heavily as "wheel through" areas during the first quarter, meaning their transmission networks facilitated many transactions for which the utilities received no financial benefits because they were neither source nor sink. (See graph.) During February and March, energy volumes wheeled through APS' territory exceeded the utility's combined EIM net imports and exports, as significant amounts of energy flowed between the CAISO and PacifiCorp-East balancing authority areas during what is typically a period of low demand in Arizona.

The ISO has "committed to monitoring the wheel-through volumes to assess whether, after the addition of new EIM entities, there is a potential future need to pursue a market solution to address the equitable sharing of wheeling benefits," the report said.

A CAISO proposal to provide transmission revenue to EIM participants that wheel energy through their BAAs last summer drew stiff opposition from current and future stakeholders concerned about the impact of new charges on the economic dispatch of generating resources. (See *EIM Member Wary of Need for Wheeling Charge*.)



Estimated wheel-through transfers in Q1 2018 | *CAISO*

CAISO NEWS

FERC Approves CAISO-Calpine RMR Settlements

By Jason Fordney

Yuba City plant | *© RTO Insider*

FERC last week approved settlement agreements among CAISO, Pacific Gas and Electric and Calpine covering reliability-must-run contracts for three Northern California gas-fired plants, reducing the revenue they will receive and making them subject to a must-offer requirement.

FERC's orders covered two proceedings, one for Calpine's Metcalf plant (ER18-240) and another for the company's Feather River and Yuba City plants (ER18-230). A FERC Administrative Law Judge last month recommended the commission approve the agreements. (See *FERC ALJ Certifies Calpine RMR Settlements* and *PG&E, CAISO Protest Calpine RMR Terms*.)

While the commission said the agreements resolved all issues in dispute in the proceedings and appeared to be "fair and reasonable and in the public interest," the out-of-market RMR payments are not popular with many CAISO stakeholders and were opposed by the California Public Utilities Commission after the ISO's Board of Governors reluctantly approved them in November. (See *Board Decisions Highlight CAISO Market Problems*.) The CPUC in January voted to require PG&E to hold solicitations to replace the agreements with energy storage. (See *CPUC Retires Diablo Canyon, Replaces Calpine RMRs*.)

The Metcalf settlement reduces the plant's annual fixed revenue requirement from about $72 million to $43 million through 2020 if it retains its RMR status and makes

Feather River plant | *Calpine*

the plant operator responsible for routine repairs and capital expenses. Under the agreement, the plant will recover $8 million in 2018 capital items in 12 installments of $675,000 beginning on Jan. 1, 2018. If the RMR agreement is extended, capital recovery would remain at about $8 million per year. The settlement also grants the plant $8 million in 2019 and 2020 if the revised agreement is not renewed and the unit shuts down.

The Feather River and Yuba City settlements would reduce each plant's 2018 revenue to about $3.5 million from the previous $4.4 million, with a 2% hike for 2019 and 2020, if the RMRs are renewed.

The settlements would also take all three plants from Condition 2 (eligible for full cost-of-service payments) to Condition 1 (eligible for only a portion of their revenue requirement) status and impose a must-offer requirement, which the ISO's Department of Market Monitoring has recommended for all RMR units. CAISO is working to revise its RMR program to establish a must-offer requirement for resources. (See *CAISO, Stakeholders Debate RMR Revisions*.)

CAISO Tariff Waivers

In a separate order, FERC also granted CAISO a limited Tariff waiver to permit nine scheduling coordinators (SCs) to submit out-of-time requests to recertify 18 resources for the 2018 resource adequacy compliance year (ER18-857). CAISO said the SCs had failed to renew an exemption related to its Resource Adequacy Availability Incentive Mechanism (RAAIM) program by the Nov. 15, 2017, deadline because of confusion about the recertification process for acquired resources within the program.

FERC said the waiver grants certainty to those resources that they their RAAIM exemption will not be unwound. CAISO replaced its Standard Capacity Product with RAAIM in November 2016. SCs must present an affidavit for each resource adequacy year testifying that each resource meets eligibility for exemption from certain performance incentives.

Energy Crisis Settlement

The Commission also approved an uncontested settlement filed Feb. 6 among CAISO, Wayzata Opportunities, PG&E, Southern California Edison and San Diego Gas and Electric related to the 2000/01 California energy crisis (EL02-18). The agreement ensures the payment of interest to the resource owners who had received delayed compensation for certain power supply contracts because of the default of the California Power Exchange. The filing parties said approval of the settlement would avoid further litigation, eliminate regulatory uncertainty and enhance financial certainty.

CAISO NEWS

CPUC Cautions of Return to Bad Old Days

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tricity sellers through the state's Direct Access program, which allows nonresidential customers to purchase directly from a competitive supplier.

According to the paper, decision-making around reliability, affordability and safety is splintering from central authorities such as the CPUC to multiple entities.

"In the last deregulation, we had a plan, however flawed," the report says. "Now, we are deregulating electric markets through dozens of different decisions and legislative actions, but we do not have a plan. If we are not careful, we can drift into another crisis."

The paper examines how electric delivery can remain reliable as the market fragments, particularly from the growth of CCAs. It expresses concerns about reliability, affordability and ability to decarbonize the electric system if the transition is not managed effectively.

During the energy crisis, market design flaws, insufficient monitoring and "gaming" by market participants caused price spikes, collapse of competitive suppliers and rolling outages. The state became the model for how not to manage electricity restructuring and received much attention, particularly regarding the artificial shortages created by the Enron energy trading firm.

Splintering Model

The current model was developed after the crisis, with load-serving entities required to demonstrate each year that they have contracted for adequate energy supply. The paper poses the question of whether there needs to be a single entity responsible for policymaking, implementation and enforcement.

It also explores how new technologies could be financed, how to reduce the use of fossil fuels such as natural gas and how to properly compensate utilities. It also asks whether there should be a state entity to manage "behind-the-meter" generation and other entities that are not under the jurisdiction of the CPUC, as well as evaluating other regulatory models that evolved in New York, Illinois, Texas and Great Britain.

"I think there are solutions to a lot of the potential problems, although there is not a single or a dominant design to target them," CPUC President Michael Picker told *RTO Insider* last week. He added that some customer choice models are built around a particular technology such as rooftop solar, battery storage, demand response or natural gas fuel cells that can be obtained through small generator incentive programs.

"We have to do something to address the disaggregation of supply and the splintering of decision-making," Picker said. About 13% of load across the state is provided through the Direct Access program to commercial and industrial customers.

It's not the CPUC's job to get in the way of CCA growth, Picker said, but "we do have to do something to respond to the growing disaggregation."

CCAs Respond

The CPUC got pushback from CCAs in February when it approved an order implementing a registration process for them along with other changes to the regulatory structure. (See *CCAs Oppose CPUC Decision, Process*.)

In a statement Thursday, the California Community Choice Association said the CPUC report "wrongly asserts today's energy system lacks regulation and adequate planning."

"Highly regulated locally controlled CCAs were designed to help correct the problems from the energy crisis, and they are performing as intended — delivering reliable, affordable and clean energy to local customers, while exceeding the state's [greenhouse gas] goals," Executive Director Beth Vaughan said. "It is important to recognize in this report that other states use energy-choice program models that differ widely from those used by CCAs in California." She said CCAs are committed to "reliability, affordability, decarbonization and social equity."

The CPUC said the report is not meant to advocate specific policy actions but seeks instead to "jumpstart a conversation." Comments on the report are due on June 4, which can be filed at customerchoice@cpuc.ca.gov, and the commission has also set up a webpage for the initiative.

Technology	2013	2016/17	Percent Change
Energy Efficiency (GWh)	1,693	3,197	89%
Demand Response (MW)	2,187	1,997	-9%
Behind-the-Meter PV (MW)	2,102	5,900	180%
Plug-in-Electric Vehicle (PEV) (number of registrations)	69,999	266,866	281%
Distributed Advanced Energy Storage (MW)	54	350	548%
Microgrids (MW)	122	390	220%

DER in California, 2013 vs. 2017 | *California PUC*

ERCOT News

ERCOT Gains Additional Capacity to Meet Summer Demand

By Tom Kleckner

ERCOT will have more breathing room as it prepares for record demand this summer after an additional 525 MW of generation recently came online in Texas.

The ISO said last week it now has 78.2 GW of capacity available to meet an expected peak demand of 72.8 GW, which would break the 2016 record of 71.1 GW. The additional capacity has boosted ERCOT's planning reserve margin from 9.3% to 11% since the previous seasonal assessment of resource adequacy (SARA) report.

"That definitely improves the situation," said Pete Warnken, ERCOT's manager of resource adequacy, during a media call April 30.

The additional generation comes from the 225-MW, gas-fired Denton Energy Center that recently went into service in North Texas and the return of the mothballed 300-MW gas unit at Barney Davis in Corpus Christi.

Warnken said rotating outages are still possible under extreme scenarios, "but that risk has been reduced a little bit with those resources."

ERCOT has approximately 2.3 GW of capacity available through load-control measures with transmission or distribution service providers. Tight reserves could also trigger the need for the ISO to deploy ancillary services and contracted emergency response service capacity to maintain sufficient operating reserves.

Staff also expects industrial facilities to make voluntary load reductions and increase the power they sell into the market during peak demand.

"We expect the market to respond to scarcity conditions," Warnken said. "It's a good bet to expect they'll be looking at summer conditions and making decisions appropriately before they bring their resources on."

Dan Woodfin, the ISO's senior director of system operations, said the grid will also benefit with the completion of the Houston Import Project, a $590 million effort that will allow more power to be imported from the north.

"All the pieces are in service at this point," Woodfin said. "That will help reduce congestion into the Houston area because it improves the transfer capability."

ERCOT also released its latest Capacity, Demand and Reserves (CDR) report, which includes planning reserve margins for the next five years. The reserve margin peaks at 12.3% in 2020, before dropping to 8.9% in 2023.

The CDR report adjusts the 2019 summer demand forecast down to 74.2 GW, reflecting a delay in a new industrial facility on the Texas coast. Staff expects the load forecast to eclipse 77 GW in 2023. That number includes the planned integration of Lubbock Power & Light's customers, which is scheduled to take place in 2021.

The ISO's target planning reserve margin is 13.75%. Warnken said staff is studying an economically optimal reserve margin, which would balance the amount of generation needed to maintain reliability with its cost.

The next CDR report will be released in early December.

ISO-NE NEWS

Maine Lawmakers Signal Opposition to NECEC

By Michael Kuser

The leaders of two key Maine legislative committees told Massachusetts regulators Friday that they oppose a proposed transmission project that would cross Maine to deliver a large amount of Canadian hydropower to Massachusetts.

In a letter to the Massachusetts Department of Public Utilities, the chairmen of Maine's joint Environment and Natural Resources Committee and Energy, Utilities and Technology Committee objected to Central Maine Power's (CMP) New England Clean Energy Connect (NECEC) project on economic and environmental grounds.

The Avangrid subsidiary is set to sign a contract this month with Massachusetts for the state's 9.45-TWh clean energy solicitation, which was awarded to NECEC — a partnership between CMP and Hydro-Quebec — after the original winner, Eversource Energy's Northern Pass project, was rejected by siting officials in New Hampshire. (See *Mass. Picks Avangrid Project as Northern Pass Backup*.)

The Maine lawmakers wrote that recent expert testimony to their state's Public Utilities Commission "indicates that Hydro-Quebec will not produce any additional hydroelectricity for NECEC and will instead divert power it now sells to other markets, such as Ontario and New York, to Massachusetts. In fact, NECEC may result in increased greenhouse gas emissions if markets like Ontario or New York have to use dirty fuel mixes to replace the lost electricity from Hydro-Quebec."

The lawmakers also faulted NECEC for planning to build its line

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

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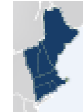
ISO-NE News



Maine Lawmakers Signal Opposition to NECEC

Continued from page 8

across the Kennebec Gorge, a "world renowned" whitewater rafting and fishing area.

"It has not proposed burying any portion of the 53 miles of new transmission line, even at this iconic spot that is critical for Maine's tourism economy," said Republican Sens. Tom Saviello and David Woodsome, and Democratic Reps. Ralph Tucker and Seth Berry.

AC Better than DC

Among those testifying to the Maine PUC on April 30 was Stephen Whitley, former NYISO CEO and ISO-NE COO, who appeared on behalf of NextEra Energy Resources.

Whitley said that, unlike other proposed HVDC transmission lines in the region, CMP's project is completely overhead, and that it would be much more useful to build an AC line "that can be looped, serve load and interconnect other renewable generators." A DC line would not support interconnecting multiple generators located at different points of interconnection along its route, he said.

In addition, Whitley said, NECEC is not traditional utility transmission, but a merchant project dependent on the market. If contracted by Massachusetts, it will execute only a 15- to 20-year power purchase agreement with the electric distribution companies for a DC transmission line that has at least a 40-year life.

"Thus, even if one accepts the purported needs and benefits CMP attributes to the transmission line for Maine and Massachusetts, there is a cliff on those needs and benefits once the PPA expires," Whitley said.

Fair and Equal

The Maine lawmakers also faulted CMP for offering "far less to Maine than Eversource offered New Hampshire during the Northern Pass process."

New Hampshire would have received more than $210 million in benefits from Northern Pass, they said, while the TDI New England Clean Power "project would have resulted in direct payments of $372 million to Vermont for clean water, habitat conservation and clean energy development. CMP has not offered comparable mitigation for Maine."

Maine State House

They cited other testimony before the PUC that the NECEC project "will suppress existing and future renewable energy generation in Maine due in part to increased congestion on the transmission system."

The lawmakers concluded: "We are unwilling to sacrifice future development of Maine's solar and offshore wind industries, which would provide real greenhouse gas benefits and more jobs for Maine citizens, just to provide Hydro-Quebec the ability to market its electricity in Massachusetts."

Hydro-Quebec partnered separately with Eversource, Avangrid and TDI-NE on three different transmission projects for the MA 83D clean energy solicitation last summer.

MISO NEWS

Stakeholders Urge MISO to Reconsider Seasonal Market

By Amanda Durish Cook

CARMEL, Ind. — The Reliability Subcommittee's effort to explore how MISO should address increasingly uneven availability of resources could revive a discussion on developing a capacity market divided by season, stakeholders learned last week.

MISO kicked off its "resource availability and need" effort last month with a white paper on changing availability and an announcement that it would devise specific rules to counter the effects of increasing generation retirements, poor outage coordination, growing volumes of emergency-only capacity and the rising use of intermittent resources. (See *MISO Looks to Address Changing Resource Availability*.)

During a May 3 RSC meeting, MISO Executive Director of Market Operations Jeff Bladen said the new effort has prompted some stakeholders to ask the RTO to revisit its 2015 proposal to create seasonal capacity auctions, a move that was put on indefinite hold last year after stakeholder pushback.

At the time, seasonal capacity auctions seemed like "a single point solution to a broader set of issues that called for a more holistic approach," Bladen said, noting that the new effort wasn't intended to preclude a re-examination of the possible need for the auctions.

Near-term Solutions

Bladen also said several stakeholders urged MISO to focus on near-term solutions to ensure that an adequate amount of resources is at the ready, including improving outage coordination, modifying the rules of emergency-only resource types and creating forecasts that provide a better picture of resource availability in the footprint.

A utility's cash flow influences the lumping of outages, Bladen said, with fleet operators grouping outages when they expect low energy prices, especially in spring and fall.

"When prices are low, operators tend to take outages. It's expected," he said. "This is not as simple as, 'well, everybody takes outages throughout the year.' It's much more complicated than that." MISO said that most of its planned outages are scheduled less than a week before they are taken.

MISO might turn to a solution that requires more accountability from operators, Bladen said.

"Maybe there's some expectation for generators to replace themselves [during an outage]? That's pretty extreme," Bladen said, stressing that MISO has not seriously discussed that measure.

Bladen said MISO could examine its existing load-modifying resource contracts to include staggering availability times and provide incentives to resources that offer during emergencies outside of summertime.

"Does it make sense to expect non-summer participation when it's not compensated like in summer?" Bladen asked.

He pointed out that this summer, MISO faces an 80% chance of entering emergency conditions. (See *MISO: Summer Reserves Adequate, but Emergency Likely*.) He also said that a reduction in zonal resource credit offers has reduced the number of uncleared zonal resource credits in capacity auctions since the 2014/15 planning year.

"While we don't think the platform is burning, the temperature is certainly rising," Bladen said. "I want to be clear. The system is not unreliable. There's just a better chance of emergencies."

Storage Mentions

The Advanced Energy Management

Continued on page 11

MISO Reliability Group Examines Order 841 Impacts

CARMEL, Ind. — FERC's extensive energy storage order has handed MISO's Reliability Subcommittee a new set of to-dos, including devising a storage capacity accreditation process and deciding whether storage will be subject to a must-offer requirement.

The subcommittee will also vet a proposal that will determine whether energy storage owners or MISO will manage the state of charge for resources. The group will additionally consider broader issues around storage, including:

- What information MISO needs about batteries to manage real-time operations;
- The risks of allowing market participation of energy storage at times when it's not dispatched; and
- Whether MISO should employ reliability improvements to mitigate risks of storage use.

Finally, the group could lay out rules to clarify that energy used for charging is not considered "station power," which MISO defines as the power a generating facility uses for operating electrical equipment. MISO's current definition of station power does not include energy used for pumping at a pumped storage facility.

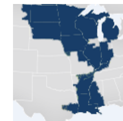
The items were handed down from MISO's Steering Committee based on recommendations made from the Energy Storage Task Force after discussions on Order 841 and storage's potential in the RTO.

At a May 3 RSC meeting, MISO Market Design Manager Kevin Vannoy said the RTO will bring storage participation straw proposals to a June 6 joint meeting of the RSC, Resource Adequacy Subcommittee and Market Subcommittee. He said MISO will vet storage proposals throughout summer to prepare for a December compliance filing.

Vannoy said MISO still hopes FERC will allow it to set a limit on the number of storage resources that can participate in its markets. FERC's order set a 100-kW minimum size requirement for participation, causing RTO staff to worry that small resources will flood markets with finite capabilities.

— Amanda Durish Cook

MISO News



Stakeholders Urge MISO to Reconsider Seasonal Market

Continued from page 10

Alliance and other stakeholders called out MISO's white paper for not explicitly mentioning the help energy storage could provide during tight operating.

Bladen said the omission was deliberate in order to remain technology- and resource-neutral.

"I would say that was intentional. We didn't intend to reference technologies, but rather we were recognizing the resource availability profiles without going to where solutions could be found," Bladen said.

Nevertheless, Bladen said MISO must consider the impacts that FERC's Order 841 may have on its resource availability.

DTE Energy and the Organization of MISO States also asked the RTO to consider revising its loss-of-load expectation (LOLE) study process to include more availability risks associated with its resource mix.

Bladen said MISO envisions more stakeholder discussion before proposing changes to the LOLE study. He said altering study methods could produce a larger planning reserve margin requirement.

"It raises the prospect of socializing the risk by requiring everyone to procure more capacity," Bladen said. "That's a choice we can make as a community, but we have to be completely transparent about that choice."

Consumers Energy's Jeff Beattie cautioned MISO against risking some of its value proposition to its members by creating an insurance-sharing pool.

Bladen agreed that MISO needs to carefully consider balancing the sharing of resources in the footprint. "I'm glad you raised it because that's something that needs to be front and center in the conversation," he said.

He also said the RTO must also investigate shifting loss-of-load risk as part of resource availability. A recent renewable integration study by MISO found that as more intermittent renewable resources join the fleet, the loss-of-load risk becomes shorter but steeper, occurring later in the day after sundown. (See *MISO Renewable Study Predicts Later Peak, Narrower LOLE Risk*.)

Developing solutions to MISO's resource availability issues could stretch well into 2019, Bladen said, and he expected that parts of the solution will be handled by the Market Subcommittee and Resource Adequacy Subcommittee as well as the RSC. He asked for more stakeholder opinion on what approaches the RTO should take.

NYISO News

Report Highlights Fast-changing New York Grid

By Michael Kuser

New York faces increasing penetration of intermittent distributed energy resources, declining load, all-time low energy prices and the need to replace aging generation as the state moves toward achieving its Clean Energy Standard goal of producing 50% of its electricity from renewables by 2030, according to a NYISO report.

"Compared to other regions in the U.S., New York enjoys a fairly diverse fuel mix, but we've identified a real disparity between the upstate and downstate regions … with upstate [being] where just about all the hydro and renewable resources are located," NYISO Executive Vice President Richard Dewey said Thursday while presenting Power Trends 2018, an annual report covering how technology, economics and public policy are influencing the state's wholesale electricity markets.

The state's imbalance of renewable energy supplies means the downstate region (consisting of the Hudson River Valley and New York City area) will become increasingly reliant on natural gas-fired generation, the report said.

Low Capacity Factors

The operational challenge for the ISO is to keep the lights on 100% of the time when the capacity factors for onshore wind and solar are just 26% and 14%, respectively — compared to 89% for nuclear, Dewey said.

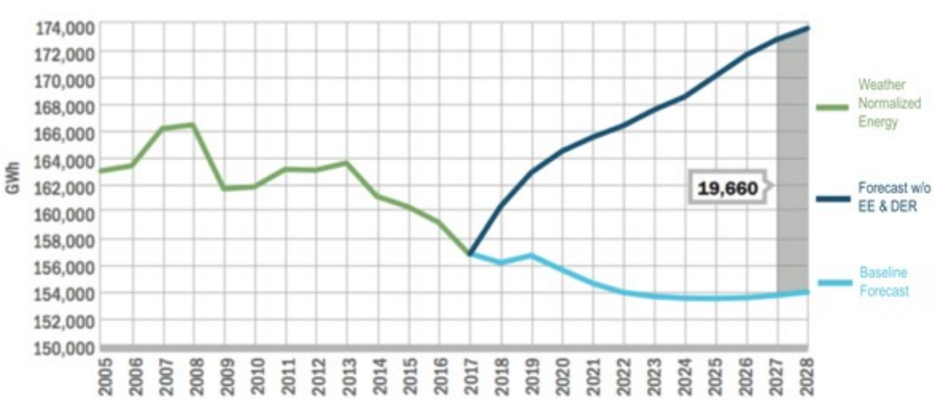
"We need to think about having the right type of generation capacity available so that we can meet the load requirement at the grid and provide the right kind of incentives so that generators are available," he said.

Offshore wind differs from onshore in that it gives higher output during the daytime hours, which is more consistent with New York's load profile. Offshore wind also operates at a higher capacity factor, sometimes in the 40% range or higher, Dewey said, adding that the ISO is modeling how that higher capacity factor might affect grid and market operations.

Offshore wind also has the added advantage of being located closer to demand centers in Long Island and New York City, he said.

According to data compiled from the Danish Energy Agency and Denmark's state-owned utility, the Anholt 1 wind farm, which only opened in 2013, reached an average capacity factor of 53.7% for the full year 2017.

Asked whether New York could expect such higher capacity from its offshore installations, Dewey said, "A lot of that depends on the local environmental studies. I can't comment on the wind currents off Long Island as opposed to what the Danish have experienced, but I will say that technology is continuing to work to our advantage where some of the newer turbines are both in terms of the height, turbine design and some of the technology around how they place and manage them. Increasingly, the industry is learning lessons from some of the existing installations."



Electric energy usage trends and forecast, 2005-2028 | *NYISO*

Region	2016 GWh	2017 GWh	% Change
New York State (NYCA)	160,798	156,370	-2.75%
Upstate (Zones A-E)	54,286	52,938	-2.48%
Downstate (Zones F-I)	31,268	30,351	-2.93%
New York City (Zone J)	53,653	52,266	-2.59%
Long Island (Zone K)	21,591	20,815	-3.59%

Annual electric usage by region, 2016-2017 | *NYISO*

Low Market Prices

Dewey noted the impact that historically low wholesale electricity prices — largely correlated to falling natural gas costs — are having on the state's generating fleet.

"When you talk about wholesale markets that really are at the all-time lows, this is great for consumers, from the standpoint of energy prices, but it creates some concerns when you start thinking about the viability of the generation fleet and the willingness of suppliers to make investments to some of those assets," he said. "We really need to think about the revenue adequacy of some of those plants to the extent that natural gas prices are projected to be at or near these levels for the foreseeable future."

Changing Demand

New York's electricity demand experienced steady growth for many decades, but it has now flattened out and in many respects is starting to decline, Dewey said.

Energy usage is expected to decline over the next decade at a rate of 0.14% per year, and peak demand — a critical element to reliable system planning — is expected to fall by 0.13% per year through 2028, the report said.

"Increasingly our demand is impacted by the weather," said Dewey. "We're a summer peaking system that relies heavily on the load of air conditioning in the summer, and when we have a cool summer like we had last year, that has significant impacts on the overall consumption."

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NYISO NEWS

NYISO Study Identifies Key Areas of Tx Congestion

By Michael Kuser

Preliminary results from a biennial NYISO study show high congestion in three areas of the New York bulk power system, mainly in the eastern part of the state, ISO officials said last week.

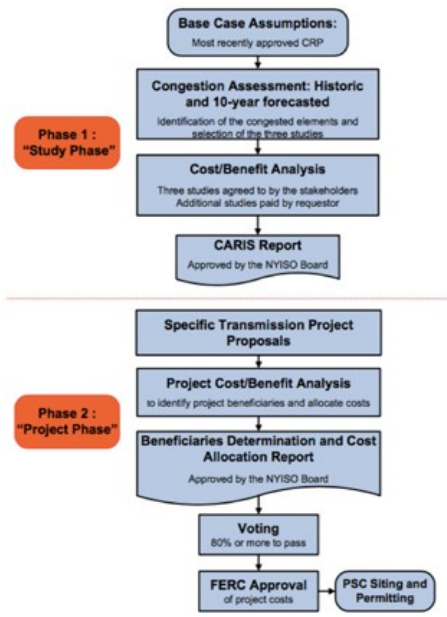
The 2017 Congestion Assessment and Resource Integration Study (CARIS) found congestion on the Central East interface, through the line eastward to Albany, and from the capital down the Hudson River Valley toward New York City.

"These are not necessarily surprising, being consistent with what we've seen in past studies," said Timothy Duffy, the ISO's manager of economic planning. "We also did find one interesting piece, which was a small line, referred to as Edic-Marcy, which we have found in the past year or so to have some significant contribution to congestion on the system."

The Edic-Marcy line is located in the central part of the state.

The CARIS process requires planners to identify the top congestion elements on the system. "That's obviously a key indicator of where developers ought to be thinking in terms of building additional transmission to provide value in terms of reduced congestion," Duffy said.

The ISO's Tariff calls for the CARIS to



| *NYISO*

identify four solutions for each case study. Planners start with a generic solution such as transmission, demand response, energy efficiency and generation, then model those solutions and develop specific costs associated with them, calculating high-level cost-effectiveness tests and benefit-to-cost ratios.

The only benefit the CARIS process factors into its benefit-to-cost calculation is a reduction in statewide system production costs. While the study reports other benefits such as reductions in emissions, capacity market payments and consumer energy payments, it does not reflect them in the benefit-to-cost ratios.

"In terms of Phase I, there's a whole host of data that's presented," Duffy said. "We look at historic, we look at its projected congestion on the system, we identify what the key drivers are, and we look at a number of different scenarios in terms of gas prices; for example, other load forecasts, other big macro changes on the system and how they affect system congestion."

Six Studies

The ISO studied the three congested areas under six scenarios:

- Study 1: Central East-Edic-Marcy
- Study 2: Central East
- Study 3: Central East-New Scotland-Pleasant Valley
- Study 4: Study 3 with Edic-Marcy relaxed
- Study 5: Study 3 under the System Resource Shift Case
- Study 6: Study 5 with Edic-Marcy relaxed

Planners began with a "business as usual" (BAU) case consistent with past practices. In most such cases, the ISO is very

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Report Highlights Fast-changing New York Grid

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The proliferation of rooftop solar and demand response is flattening that load, resulting in "substantive impacts on our planning and our markets," he said.

"The impact solar has on energy demand is actually quite a bit different than the impact it has on the peak," Dewey said.

Solar production fades just at 4 to 5 p.m., when the electric system is hitting its peak, "so what we end up getting is high ramp periods in the afternoon when we've got to get response from our suppliers to meet that high electric peak when the solar production is dropping off," Dewey said.

The ISO expects the problem to grow as solar installations increase and extend throughout the state, he said. In addition, energy efficiency efforts continue to displace the amount of energy supplied by the grid, with the New York State Energy Research and Development Authority last month outlining plans to accelerate the state's energy efficiency goal by 40%. (See *NY Sets 40% Hike in EE Goal*.)

"DERs hold tremendous value in that, if sited properly, they could address some of the resiliency issues at both the retail and the wholesale level, and provide a whole lot of options for both distribution companies and grid operators, but [they] do add a whole lot of complexity to the grid," Dewey said.

As a wholesale market administrator, NYISO is working with the state and utilities to come up with market incentives to appropriately price the resilience attributes DERs bring to distribution companies and ensure those costs are incurred by the retail system. And to the extent that DERs provide value to the wholesale market, the ISO will make sure those revenues are appropriately allocated, he said.

The report notes that over the past year, the ISO has received proposals to connect more than 400 MW of battery storage to the grid.

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NYISO Study Identifies Key Areas of Tx Congestion

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constrained in terms of what it can model and assume, so the BAU results are of limited value, Duffy said.

A second set of results is more forward-looking, the product of the ISO "taking a step further, beyond the confines of the Tariff, in terms of the minimal amount of work required by the tariff," Duffy said. "We created this system resource shift case, which essentially allowed us to use our judgment to identify a set of assumptions so that the results of the study would provide additional meaning."

In including the system resource shift case, Studies 5 and 6 differed from the first four by modeling the Indian Point nuclear plant and all New York coal units as retired by 2020/21. In addition, the studies forecast that the state would meet its Clean Energy Standard 2030 goal of 50% renewable resources by 2026.

The study's model included 4.6 GW of onshore wind, 10.8 GW of utility-scale solar and 250 MW of offshore wind in service by 2026, annually producing 28.5 TWh of renewable energy. ISO planners supplemented this with annual energy reductions of 10.5 TWh from energy efficiency.

Phase II of the CARIS process invites developers to propose specific transmission projects to address congestion on the system. The ISO will perform a benefit-to-cost analysis for each proposed transmission project to assess eligibility for regulated cost recovery.

While estimates of production cost savings will still dictate project eligibility, Phase 2 will examine zonal locational-based marginal pricing (LBMP) load savings to identify beneficiaries and determine cost allocation. The LBMP value used is net of transmission congestion contract (TCC) revenues and bilateral contracts.

To qualify for cost recovery under the ISO's Tariff, a transmission project must have a capital cost of at least $25 million, benefits that outweigh costs over the first 10 years of operation and received approval to proceed from 80% or more of the actual votes cast by beneficiaries on a weighted basis.

Having met these conditions, the developer must also file with FERC for approval of the project costs and rate treatment.

Public Policy Tx

Switching gears from discussion about the CARIS process, Zach Smith, NYISO vice president for system and resource planning, said the ISO's planning process has three core pieces: reliability, economic and public policy.

Among the steps taken so far on the public policy front, the ISO "last year selected the Western New York Public Policy Transmission project, and we're currently going through stakeholder discussions on the AC transmission public policy, and we anticipate a selection of those projects in July this year," Smith said. (See "MC Approves Western New York Tx Proposal," *NYISO Management Committee Briefs: Sept. 27, 2017*.)

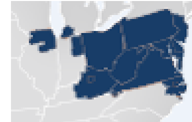
The proposed AC projects include the $1 billion Edic-Pleasant Valley 345-kV line and the $246 million Oakdale-Fraser 345-kV line, which are intended to relieve downstate congestion by upgrading the AC transmission systems north and west of New York City. (See *Downstate NY to Pay 90% of AC Tx Projects*.)

Smith highlighted one change in the ISO's planning process, noting that under FERC Order 1000, "an interregional transmission project can be proposed under any of our planning processes."

An interregional project is one physically located in two regions, such as transmission that ties PJM to New York.

"That project could then get a joint cost allocation, where customers within the PJM system might bear some costs, and New York might bear some cost," Smith said. "To date we have not had an interregional project, but there is that potential there."

PJM NEWS



Can RTO Stakeholders Reach Agreement on the Big Issues?

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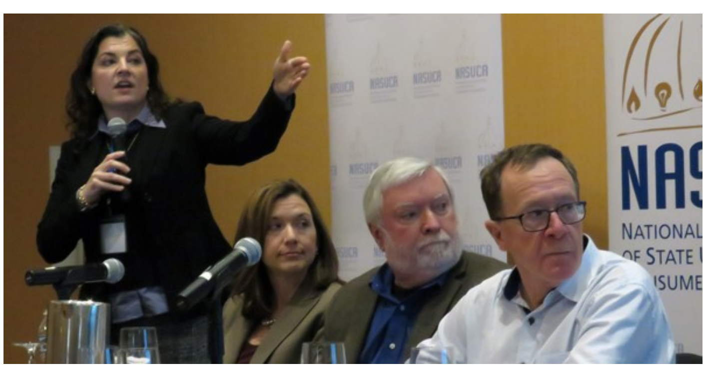
Simeone points to PJM's lower committees, where generation and transmission owners with multiple affiliates can dominate the voting on proposed solutions. The power dynamic is largely reversed at the RTO's senior Markets and Reliability and Members committees, she says, because sector-weighted voting often results in buyer-side stakeholders (the Electric Distributor sector and End User sectors) exercising veto power over proposals resulting from the lower committees. PJM's rules require a two-thirds vote from the members of the five sectors to recommend a rule change to the Board of Managers.

Simeone recommends that states have a vote through their governors and that PJM review the makeup of its five sectors, noting the dispersion of stakeholders representing the fastest-growing industry segments: renewable energy (Generation Owners), energy efficiency (Electric Distributors, Transmission Owners and Other Suppliers) and demand response (Other Suppliers). She says FERC should require RTOs to re-evaluate their governance processes regularly to comply with the "ongoing responsiveness" principle of FERC Order 719. The researcher is now working on a second phase of the study, expected to be published in the fourth quarter, that will explore the issues further.

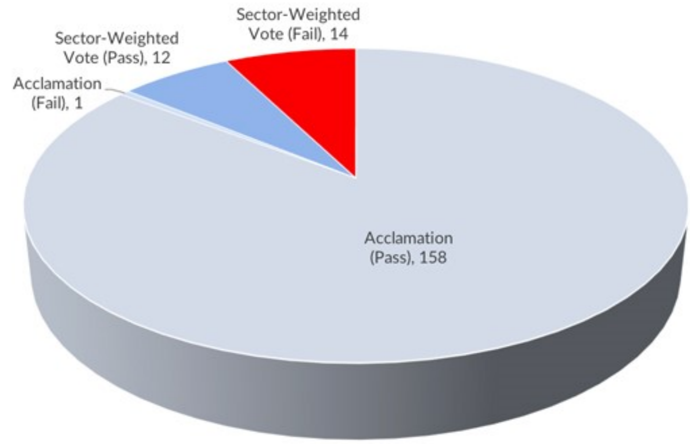
This interview has been edited for clarity and length.

RTO Insider: So, it's been about a year since you issued this report, and you made some recommendations that you acknowledged probably would require a FERC order, because the existing sectors are unlikely to give up whatever advantages they have. I'm curious, have you gotten any feedback from PJM to your findings?

Simeone: I have not received formal feedback … I have briefed the Members Committee on the report, and I've briefed various different groups, [including the National Association of State Utility Consumer Advocates and the Organization of PJM States Inc. (OPSI).] (See Policy Churn, Voting Rules Raise Questions on RTO Governance.)



Panelists discussing the RTO stakeholder process at the 2017 annual meeting of the National Association of State Utility Consumer Advocates. Left to right: Christine Simeone; Denise Foster, PJM; John Hughes, Electricity Consumers Resource Council; and Bill Malcolm, AARP. | © RTO Insider



Of 185 votes by the Markets and Reliability Committee in 2015-16, 158 (85%) were by acclamation and all but one passed (99.4%). But only 12 of 26 sector-weighted votes passed (46%). | *Simeone*

The shortcomings of the stakeholder process I think are starting to gain more attention. I would say there [has] been some general acknowledgement that the stakeholder process could use improvements; I think there's disagreements on what those improvements could be.

RTO Insider: In your study, you have a continuum that shows pure market efficiency at the left side, and at the right axis, pure politics. What do you mean by politics in that context?

Simeone: On one side it's pure market efficiency: What would an academic economist say [about] how the market should be designed? On the complete opposite end of the spectrum, design choices could be made [based on] pure politics. You know, this stakeholder wants this, or this state wants this. The decision that ends up happening on market design falls somewhere on that continuum. And there was always a role for politics to interject in that process, because FERC had always envisioned the role of stakeholders.

Generally, these really controversial issues are about who pays and who is getting paid — and then fairness and power balance issues. And it just sets up this legitimacy compromise. If PJM chooses market design that goes too far toward an efficient market, it is going to be seen as illegitimate to some of the people who have politically motivated priorities. If it goes too far on politics, it's going to be seen as illegitimate to the people who are prioritizing a competitive market outcome.

So, finding the right place on this continuum is critical to the organization that's being seen as legitimate. This is very difficult … and the hypothesis is: Could a reform improve the effectiveness of the stakeholder process in finding that sweet spot on the decision continuum that preserves legitimacy?

RTO Insider: Your report mentioned sector self-selection. You said

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voting in the wrong sector can complicate caucusing and reduce trust among members. Did you hear examples of that in your research, or is this more a theoretical concern?

Simeone: Yeah, I think that this is not … a top concern. I think the bigger issue is making sure the sectors reflect the actual stakeholders in the market. Those five sectors have been in place since the RTO was formed. So, you're talking about 20 years. In 2009, you had the Other Supplier, and the Generation Owner sector at about 300 members, and 117 members, whereas the other three sectors were between 30 and 60 participants. Fast-forward [to] 2016, and the growth in the Other Supplier [and] Generation Owner sectors has been huge. … This is where all the new market entrants are coming in — renewable energy, demand response, energy efficiency, marketer traders — and they're all kind of being lumped in to these two supply-side sectors. … As they become more diverse, it's not clear that any kind of sub-sector has its own voice.

To me that's one of the most important things — making sure the sectors reflect the participants. That will have some impact on sector-weighted voting; you may have to adjust weighting. But getting the sectors right, and then the weights right, is important.

The other thing is looking at some of these legacy deals [from GAST]. At the higher-level committees, only the voting members can vote. At the lower level, it's the voting member, and all of the affiliates. … There's going to be a huge supply-side bias through the effect of affiliates at the lower level. … The lower level voting data is completely opaque. You have no idea what's going on there.

At the lower level, you only need 50% majority to get something passed. Ten companies, through their use of affiliates — [based

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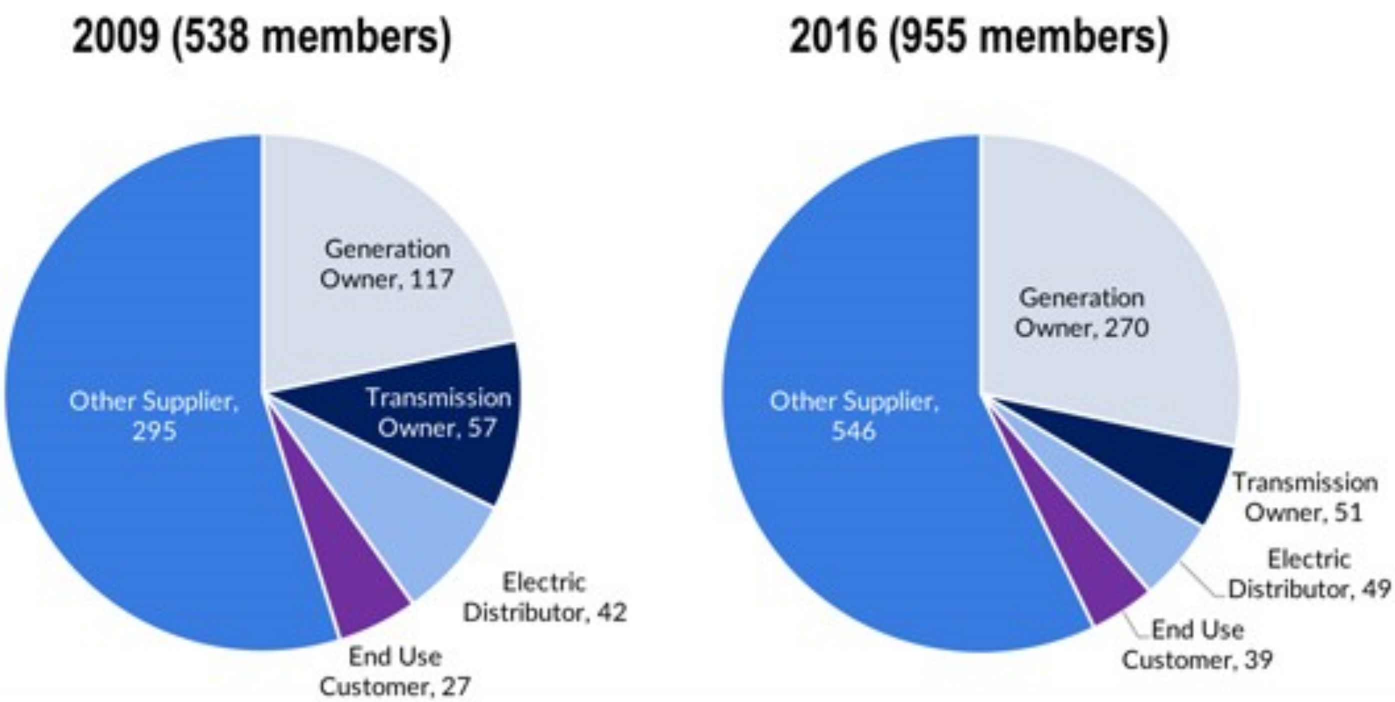

Generation Owners' share of votes at lower level committees increased from 22% to 28% of the total between 2009 and 2016, while Other Suppliers' share increased from 55% to 57% — mostly because of an explosion in the number of affiliates. The three other sectors saw their shares decline. | *Simeone*

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Parent Company	Parent Voting Sector	# Affiliates	Generation Owner	Transmission Owner	Electric Distributor	End User	Other Supplier	Total (non-renewable) MW
Appalachian Power	Transmission Owner	17	1	12			4	6,167
Dayton Power & Light	Transmission Owner	6	5			1		2,690
Exelon Business Services	Transmission Owner	14	5	3	3		3	20,580
FirstEnergy Solutions	Transmission Owner	15		15				14,975
Public Service Electric & Gas	Transmission Owner	6	4				2	9,790
Virginia Electric Power	Transmission Owner	4	4					18,644
Calpine Energy Service	Generation Owner	6	2				4	5,036
Dynegy Marketing and Trade	Generation Owner	9	8				1	10,546
NRG Power Marketing	Generation Owner	12	6				6	15,250
Talen Energy Marketing	Generation Owner	19	18				1	7,187
							Combined capacity:	110,864
							PJM Summer Peak (2015):	143,698

In 2015, more than 77% of the generation needed to meet PJM's summer peak was controlled, in full or in part, by only 10 companies. Although each company had only one vote at PJM's senior committees, their multiple affiliates gave them more power at the lower committees. Note: Capacity totals and affiliate counts for companies may have changed since 2015. | *Simeone*

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on] one of the Seasonal Capacity Resource Task Force votes, where I know there was 190 votes cast — in theory, could have prevented anything from passing, because they had 108 votes out of 190 cast. Now, I have no idea if any of these companies voted, let alone all of these companies, but it's just an illustration.

RTO Insider: Right. And then at the upper level, you've got the buy side — End Use Customers and Electric Distributors — which can effectively block a two-thirds vote.

Simeone: Right. ... Because the higher-level committee data is transparent, researchers from Penn State have been able to empirically measure the strong voting coalition on the load side. They can't get anything passed [themselves], but they can block. And so, to me, this is a clear area of reform, where there should not be this splitting of power between the different committees.

Now, I've heard some people say, hey, well, this is kind of Congress, where you have an upper chamber and a lower chamber. But in the House and Senate, a proposal can originate from either chamber. Here ... all the creativity in the proposal development happens at the lower level. Yes, you need a problem statement approved at the higher level, but all of the creativity — all of the details of the proposal — happen at the lower level.

So, if there were sector-weighted voting at the lower and the higher level, that might be a better alternative — more neutrality, and less bias, in the process. The next area of reform is transparency. And I think that's critically important.

RTO Insider: Transparency of votes at the lower level?

Simeone: Transparency in votes at the lower and the higher level. Especially when you think about these larger companies, who own generation and distribution, what type of behavior are these firms exhibiting? Could they be using their votes on the regulated distribution side to advance proposals that would [benefit] their generation? You know, that's an interesting question to look at. But because the data is protected, you can't determine if that's going on or not.

RTO Insider: Among your recommendations, you cited fairness issues, and you said to ensure RTO/ISO neutrality, there should be procedures in place to monitor, and correct for behaviors that create preferences, or prejudices. What kind of procedures might

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be effective at that?

Simeone: I think that's an area to look into further. There have been some researchers at Penn, led by Cary Coglianese, a professor in Penn's law school. And he found a variety of projects that talked about regulatory excellence. One of the sub-initiatives in some of these regulatory excellence projects talk about how you monitor organizational culture and how you put management processes and metrics in place to achieve the kind of culture that you want.


Cary Coglianese | *UPenn*

FERC has said that the RTO needs to be independent from any market participant. But the RTO also has to be responsive to participants at the same time.

So, what kind of processes can you put in place to acknowledge that, yes, an organization could potentially be biased? I think there's a lot of work to do to dig further into that topic.

RTO Insider: So, you would put this more in the category of areas needing more research, as opposed to having real recommendations for such procedures at this point?

Simeone: Yeah. And I wouldn't put that as the top-tier reform at this point. I think it's important, but not quite as important as things like getting the sectors right, looking at some of these legacy deals, like the split of power, transparency and then the role of the states. I think that's another really big one.

RTO Insider: Let's talk about getting greater state participation. That was one of your strong recommendations. Is that related to your observation that it can be difficult to determine what the public interest is because it's diverse and often conflicted?

Simeone: Exactly. … There are some stakeholders who have strong accountability over the RTO. FERC has this kind of legal accountability, but not the political accountability of the RTO. FERC can't appoint a CEO to an RTO. Nor can they appoint board members to the RTO.

Transmission owners tend to be the stakeholders that are thought to have the most accountability over the RTO, because their participation is voluntary but needed to run the system — and also because PJM is operating their assets. And then the state has the ability and the right to put policies in place that affect the market. So, these are the stronger accountabilities. And everybody else has maybe comparatively weaker accountabilities.

This raises the question of, does this reduced political accountability benefit certain private interests to the detriment of public interest? And it's a really complicated question, because what is the public interest? Some people identify [it] as competition, lowest cost, new technologies. Others may say it's economic development or preserving industry that's important to my state. Or pursuing this particular environmental goal. And the public interest can change over time.

… So, I think as market design becomes more political, the importance of states participating in the process increases. Not to make things more complex, but actually to kind of integrate those opinions in earlier on in the process. And it is not clear — it's just a hypothesis — that this would improve outcomes.

I think OPSI should always be a part of the process. …The only problem is that OPSI can only speak [when all members are in] consensus. And clearly the issues in PJM are numerous, and there's not always consensus on the part of the states.

So, is there an opportunity to have a complement to OPSI, where states can present their opinions on an individual basis, early on in the process? I don't have all the answers to what that looks like, but I think it's an important thing to look into. Part of the phase two research will be presenting to the stakeholders a little survey about how these other RTO/ISOs integrate state opinions into the process … and then trying to get stakeholders to think about what they feel would be options for a revised approach.

RTO Insider: You reference the D.C. [Circuit Court of] Appeals' decision on [the minimum offer price rule]. [See *On Remand, FERC Rejects PJM MOPR Compromise*.] What's your perspective on that?

Simeone: NRG [Energy] brought [the appeal challenging FERC's order] where there was a supermajority stakeholder agreement on design changes to the minimum offer price rule, and FERC —

RTO Insider: — kind of undid the compromise.

Simeone: Not only did they undo the compromise, but they kind of went the other way. … And [the court] basically said, no, FERC, you can't do that — you can disagree with the stakeholders and kick it back to them. But you can't renegotiate the compromise.

So, for me, I think it has some interesting implications, because it raises the value of supermajority agreement. Could it spark some behavior that might yield some interesting outcomes? Sure. You know, if there's certain stakeholders who are really motivated to achieve certain outcomes. Could they strike *quid pro quo* deals with stakeholders that don't typically vote in the system? So, for example, the financial traders participate in the process, but not very frequently — only on issues that are important to them. So, if you're trying to give the stakeholders supermajority, does it then become

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OC Briefs

Gens Get Commercial Realities into Gen Transfer Processes

VALLEY FORGE, Pa. — The PJM Operating Committee last week unanimously approved revisions to Manual 14D to tighten the notification rules for transferring the ownership of generation units.

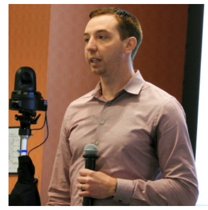
Generation owners and PJM staff hammered out the language over the past month after owners expressed concerns over an earlier proposal. (See "Gen Transfer Vote Postponed," *PJM Operating Committee Briefs: April 3, 2018*.)

PJM's Rebecca Stadelmeyer presented the revised proposal, which sets deadlines on how long prior to the sale the buyer and seller must provide the RTO with certain information. Sellers must now simultaneously provide PJM with the application they submit to FERC to change ownership, which starts a clock on several other submissions.

At least five days before closing on the sale, sellers must provide PJM with information including the name and W9 form of the buyer, and a list of its current officers.

GT Power Group's Dave Pratzon, who organized generation owners' engagement on the issue, said the result addresses owners' concerns about commercial realities and the need for flexibility that earlier drafts did not.

Synch Reserve Changes



Eric Endress | © RTO Insider

PJM's Eric Endress presented proposed Manual 11 revisions that would change how the RTO estimates the synchronized reserve maximums for Tier 1 units. The revisions would set a unit's maximum at the lesser of the economic maximum or synchronized reserve maximum, though an owner could submit a request for a synchronized reserve maximum less than the economic maximum if a physical limitation exists. The economic maximum can be updated intra-hour as necessary.

PJM is targeting a July 1 implementation of the changes.

Carl Johnson, who represents the PJM Public Power Coalition, was one of several stakeholders who voiced concerns about "moving the earth under our feet" while several other larger issues related to the topic are being debated in other stakeholder forums — notably the Energy Price Formation Senior Task Force and PJM's initiative to increase grid resilience.

He acknowledged that the proposal "makes sense" but cautioned that "we may be changing this entirely."

Pratzon asked staff to analyze how the different initiatives overlap because they could "benefit from better coordination."

PJM's Chris Pilong acknowledged the concern but urged stakeholders to "make sure we don't just sit on our hands" and not implement a solution to the issue. The RTO has been analyzing stakeholder concerns about significantly overestimated Tier 1 reserves. (See "Changing Tier 1 Reserve Estimates," *PJM Operating Committee Briefs: March 6, 2018*.)

"In the interim, I think we still need to make sure that the reserves are accurate," Pilong said.

PJM's Eric Hsia confirmed that a "very limited amount of resources have a spin max greater than [its economic] max." The RTO agreed to Johnson's request to provide comparisons of units' spin max versus economic max for all operating states, not just during synchronized reserve events.

Later in the meeting, PJM's Becky Davis explained that the RTO uses the synch reserve ramp rates that units specify if

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Can RTO Stakeholders Reach Agreement on the Big Issues?

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more valuable to court voters like that to [say] 'Hey, if you vote for me on this issue, I'll help you out on your issue.' That was not explored in the report, because the decision came after.

RTO Insider: So, it raises additional questions. You don't necessarily see it impacting stakeholder reforms at this point.

Simeone: Right. I think it raises the importance of getting the stakeholder process right. To be clear, there are some people who think the PJM stakeholder process is a complete mess that can never be right. And I disagree with that wholeheartedly. I think it's really important that the stakeholders are involved. And I think there are many, many things about the stakeholder process that are very strong and critically important to informing these decisions.

But, like anything, the markets have evolved, the stakeholders have evolved, circumstances have evolved. The stakeholder process needs to evolve, and it hasn't for almost 10 years now. So, it's time. I think this should be seen as reform consistent with improving the process — which is a normal part of evolution rather than an attack on the stakeholder process, or kind of a judgment that the stakeholder process is somehow bad. I've just heard some people just be hyperbolic in their criticisms, and I don't think it's warranted.

> **"There are some people who think the PJM stakeholder process is a complete mess that can never be right. And I disagree with that wholeheartedly."**
>
> **Christina Simeone**

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Becky Davis | © RTO Insider

they're greater than specified energy ramp rates. However, generators aren't required to provide either of those. If neither is specified, PJM uses the default ramp rate.

She noted an analysis of events over the past two years that showed 10% of units with synch reserve ramp rates greater than their energy ramp rates met or exceeded PJM's Tier 1 estimate. The RTO contacted the other units to either remove the synch reserve ramp rates, match them with the energy ramp rates or justify why it should remain higher by submitting actual unit performance following a synch reserve event.

In response to a question from Pratzon, Davis said that most generators' reserve rates match their energy rates.

Black Start Fuel Assurance

PJM's David Schweizer presented proposed fuel-assurance requirements that will be required of black start units starting next year. The requirements would go into effect at the end of the year following the finalization of PJM's current black start request for proposals and be in place for any incremental solicitations and the next RTO-wide RFP in 2023, he said.

Units would have to show one of the following:

- Dual-fuel capability with onsite fuel storage for a 16-hour run-time at its rated black start output;
- Onsite fuel storage for a 16-hour run-time at its rated black-start output for units that can store fuel, such as pumped hydro, batteries or oil;
- Connection to multiple interstate gas pipelines with primary firm transportation contracts on at least two lines. This wouldn't include local distribution company lines, which don't offer firm service; and/or
- That run-of-river hydro units can run at their black start rating for 16 hours.

Existing units would be entitled to a five-year transition plan starting in delivery year 2020/21. Units would be allowed to include the capital costs in the incremental black start capital cost component in their costs and would convert to the base formula rate after capital costs have been recovered.

Schweizer suggested that addressing previous concerns about the minimum tank suction level (MTSL) might be "more relevant" now. David Mabry, who represents the PJM Industrial Customer Coalition, agreed and requested a concrete proposal from PJM, but Calpine's David "Scarp" Scarpignato argued against rehashing the issue. Prompted by the Independent Market Monitor, stakeholders spent several months earlier this year debating revisions to the MTSL calculation but eventually decided there were other issues of potentially greater significance to address. (See "MTSL 'Not Going Away,'" PJM MRC/MC Briefs: Oct. 2, 2017.)

Pratzon asked if existing black start units that begin but don't complete upgrades required by the new rules would have to voluntarily cancel the black start contract or if PJM would cancel it. He said his concern is if the difference will affect whether such units are able to recover their costs fully. Staff weren't prepared to respond definitively; Pratzon asked that it be determined "sooner rather than later" so generators can make decisions about participating in the current RFP. (See "Black Start Fuel Assurance," PJM Operating Committee Briefs: April 3, 2018.)

Base Becomes CP

All capacity resources will be subject to Capacity Performance requirements at the beginning of the new delivery year on June 1. PJM's Susan Kenney provided a preview on what changes regarding unit-specific parameters those resources will experience.

She noted that parameters will be updatable from May 25 through 10:30 a.m. on May 31 and that updates will transfer through to following days. Any parameters that don't comply with new limits will be rejected by the system, she said.

Kenney also reviewed real-time value reporting procedures.

Fuel Security

PJM's Dave Souder addressed the RTO's initiative to analyze fuel security, which was announced April 30. (See PJM Seeks to Have Market Value Fuel Security.)

Souder said staff will analyze the grid under "stressed conditions" that include an extended cold spell, nuclear and coal retirements and the lack of availability of dual-fuel or onsite storage.

The plan has created concern on all sides of the industry.

Joe DeLosa, who represents the Delaware Public Service Commission, voiced "major concerns about the amount of time that's going to be able to be devoted to this over the next year."

"End-use customers especially have communicated to PJM their lack of a desire for criteria in the resilience field. I think that's been pretty unanimous from customers, as well as substantial discussions about competing priorities in the stakeholder process," he said.

"My mind's racing," FirstEnergy's Jim Benchek said. "You've already got CETO/CETL [capacity emergency transfer objective/capacity emergency transfer limit] constraints. ... It sounds like you're planning to put an additional layer of constraints on the system."

Later, PJM's Brian Fitzpatrick explained the progress in staff's analysis of gas-pipeline risks. The analysis is part of PJM's ongoing effort to prepare for potential interruptions on the pipeline system. (See "Additional Reserves Needed?" PJM MRC/MC Briefs: March 22, 2018.)

Staff have held five meetings with pipelines within its footprint and have three more planned. While PJM had initially identified 63 contingencies that mostly involved potential compressor failures, pipeline companies said those were lower risk and recommended focusing on the ends of lines and laterals connected to main trunk lines.

"Right now, we have about seven [contingencies], so really, really decreased that list quite a bit," Fitzpatrick said. "And that number will change because we're still meeting with pipelines."

Additional analysis will occur over the next

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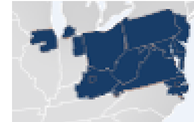

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Virtual Bidding

VALLEY FORGE, Pa. — PJM's Market Implementation Committee approved manual revisions reducing the number of virtual bidding locations by almost 90%, a change approved by FERC in February to address uplift (ER18-88). (See *FERC OKs Slash in Virtual Bidding Nodes for PJM*.)

PJM's Keyur Patel presented the revisions to Manual 11, which include a link to a list of the eligible locations. The changes reduce the number of bidding locations for increment offers (INCs) and decrement bids (DECs) from 11,727 to 1,563, retaining all hub and interface nodes but eliminating some aggregate and generator nodes. The number of up-to-congestion transaction (UTCs) trading points was reduced to 49 from 418.

Stakeholders approved the revisions by acclamation.

Intraday Offers

PJM's Susan Kenney discussed other proposed revisions to Manual 11 that staff are trying to move quickly through the stakeholder process to expand the window for submitting generation offers.

Procedures implemented by PJM on April 5 to accept intraday offers limited when generators could submit offers with hourly differentiated minimum run time, notification time and minimum downtime to after the day-ahead reliability run and up to 65 minutes before the dispatch time.

Generators asked that PJM also allow submitting that information before day-ahead offers are due and during the afternoon day-ahead rebid window. PJM plans to make this change by eliminating manual language that restricts the submission timing but also clarifies that those values are used only in real-time commitment and dispatch.

"I appreciate PJM's efforts to reinstate what I think were some unintended consequences," NRG Energy's Neal Fitch said. "The alternative right now is I don't have an ability to tell PJM this information absent calling them up about every unit."

Adrien Ford with Old Dominion Electric Cooperative agreed the revisions restore efficiency.

Offer Cap Resolution

Responding to stakeholder reservations about returning to previous language on cost-based offer caps, PJM has developed a new plan that members found acceptable. The Manual 11 revisions, which were approved by acclamation with two abstentions, will cap all offers at $1,000/MWh by default. Generators will be able to submit requests for higher cost-based offers, which PJM will screen and allow if validated.

For price-based offers, generators will have a choice: Either select "Switch to Cost" to exclude price schedules from dispatch — the option that PJM "strongly" suggests — or request the ability to submit price-based offers in line with verified cost-based offers. Kenney cautioned that sellers will be responsible to ensure the price-based offer at each segment remains compliant with verified cost-based offer caps.

Kenney acknowledged that the interaction between cost- and price-based offers is

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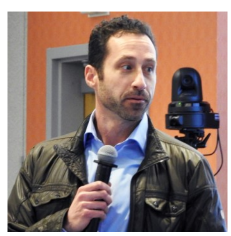
six months.

PJM's Augustine Caven said conditions during January's "bomb cyclone" cold snap hit triggers to evaluate the need for any contingencies but that none were necessary. Caven also explained PJM's plan to add detail to its operational parameters for gas units. The expanded parameters will help support automating PJM's response to contingencies.

PJM is also planning to expand its ability to track units' limitations on run time, including fuel inventory, emissions limitations, and supplies of demineralized and cooling water. PJM's Natalie Tacka explained plans to add ways for units to report "hours remaining" for specified time windows and for RTO dispatchers to keep track of those potential restrictions. PJM is seeking generation owner input and asks those interested to let it know by May 11.

Automating Generator Notification



Aaron Baizman | © *RTO Insider*

PJM's Aaron Baizman explained a plan to automate the dispatch of resources onto the system. The current procedure involves calling the generator directly, but PJM plans to have that notification and verification process become electronic.

The transition will start with combustion turbines through a pilot planned to begin at the end of the year and ramp up in 2019. PJM plans to expand it to all units but has not yet set a target date.

Baizman said the plan is similar to programs at ISO-NE, CAISO, SPP and MISO.

CIR Questions

PJM wants to switch from using average to median capacity factors to calculate units' unforced capacity. The RTO says the median is closer to units' actual performance but acknowledges it will reduce units' capacity injection rights (CIRs). (See "CIR Revisions," *PJM Operating Committee Briefs: April 3, 2018*.)

The proposal has created concern among some stakeholders, and PJM's plan to address the unease has only created additional concerns. PJM's Jerry Bell outlined the current plan, which gives generation owners until Aug. 31, 2024, to notify the RTO that they plan to convert the CIRs that will be lost into incremental deliverability rights (IDRs) that they will use in an interconnection queue project within one year of the notice to PJM. The CIRs will convert to IDRs on Sept. 1, 2024. The plan is like the procedures already in place for reusing CIRs from retiring generators.

Initially, after stakeholders questioned the value of CIRs without a project, Bell suggested they could be sold at the point of interconnection, used to expand the existing project or allocated to a new project in the same area. However, he

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"very intertwined" and that staff are still seeking better ways to help verify offer validity.

Catherine Tyler from the Independent Market Monitor unsuccessfully urged stakeholders to oppose the stop-gap revisions and instead push for a holistic solution that automatically validates offers. She said there were instances during January's "bomb cyclone" cold snap in which offer rules were violated, and that software options should be explored "to ensure there's automatic compliance."

"I think everyone would like to see Markets Gateway [PJM's offer-submission software] take care of this problem," Tyler said. "We all want to be in the same place at the end, but we do think there's a different path forward."

Modeling Node Changes

PJM's Brian Chmielewski presented staff's proposed manual language for replacing terminated nodes that are part of financial transmission right paths. An overview of the plan was presented at last month's meeting but lacked proposed language. (See "Nodal Mapping," *PJM Market Implementation Committee Briefs: April 4, 2018*.)

Brian Chmielewski | *© RTO Insider*

Direct Energy's Marji Philips, who has repeatedly raised concerns with PJM's previous plans to address this issue, voiced her approval for the updated plan and thanked PJM for working through it.

Long-term FTR Considerations

Chmielewski also presented PJM's proposal to change the RTO's long-term FTRs auction process and modeling practices. The IMM's Howard Haas called the proposal a "vast improvement" but also offered two proposals that he said "may be better."

Both of the IMM's plans would follow PJM's proposal for the first year forward, but years two and three wouldn't be biddable. Both proposals would remove the "year all" option that allows bidding on a compilation of all three years. Haas suggested this would give bidders "optionality" should system conditions change unexpectedly because "right now, you can be locked into three years."

Revenue would be allocated to load in either plan, though FTR volume in the second proposal would only be available through counterflow FTRs.

"The model would start with a net-zero transfer capability on a path, so any created capability for years two and three would have to come from counterflow positions," Haas said. "In that case, the expectation is that there would be no net revenue available to allocate anywhere, but if there was any, you'd allocate it to load."

Chmielewski said PJM would have to analyze the IMM's proposals before deciding whether to support them.

Stakeholders pushed back on the IMM's proposal.

"I encourage people to take a look at Package A [PJM's proposal] and consider supporting it," said Exelon's Sharon Midgley, who called for preserving the priority rights for load and retaining the term of the existing long-term FTR construct. "The value and the importance of having the financial hedging instrument for market participants with physical generation and customers ... is probably equally important to maintaining load's priority rights, which is why we prefer A. ... Firms

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eventually conceded that "I don't know what you'd do with them."

Stakeholders also questioned why PJM would want to force generators to purchase less transmission capacity than they otherwise would. Bell said he'd have to come back later with an answer.

30-Minute Reserves Target Set

PJM has determined that it should secure roughly 3,800 MW of 30-minute reserves in real time, PJM's Vince Stefanowicz said. The determination comes after analyzing how other RTOs/ISOs handle such longer-term reserves. Stefanowicz noted that ISO-NE, NYISO and the Tennessee Valley Authority all have a similar requirement.

Staff came to the number by considering several factors and making some assumptions. First, they assumed the largest unit would be about 1,500 MW and determined that the appropriate reserve should equal 200% of that. They added the load, wind and solar forecast errors for each season and came up with a value for each season. They averaged to 3,784 MW.

The number would be recalculated annually, and Stefanowicz said it's often already online much of the time. PJM's emergency management system calculates 30-minute reserves and found that, over the past four years, the system has been below 5,000 MW of reserves less than 10 hours total.

"We don't expect this to come into play a lot," he said. "In reality, the number we're proposing is not overly aggressive. It's realistic to what we've seen. ... We have those reserves on the system normally, through our normal scheduling processes today."

He noted that resources with a start time of less than 30 minutes could qualify.

PJM's synchronized reserve requirement is 100% of the largest energy contingency and the primary reserve target is 150%, but the 30-minute "operating" reserve is currently undefined. Stefanowicz said the proposed calculation produces a number like the 30-minute reserve that PJM procures in day-ahead and is comparable to the calculations other RTOs/ISOs make.

"Each area has a different set of numbers, but a very similar methodology for securing their reserves," he said.

Mabry asked why the target requirement wasn't dynamic based on the largest unit online at the time. Stefanowicz said they would consider that.

— Rory D. Sweeney

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that have generation and customers, their ability to secure hedges is going to severely limited" in the IMM's plans, she said.

Philips endorsed PJM's request for quick action on the proposal, urging stakeholders to "not let the perfect get in the way of the good." She hoped to have the revisions in place for the upcoming FTR auction in June.

"If we go the method of using counterflow to provide liquidity in the auction, we're actually going to reduce liquidity," Vitol's Joe Wadsworth said, noting that use of counterflow to match prevailing flow resembles how the over-the-counter market works. "There's not much liquidity in the over-the-counter markets."

He also voiced concerns about losing transparency. "I fear that if we go the route of relying on counterflow in order to get prevailing flow in an auction, we would lose a lot of the transparency that exists today," he said.

ODEC's Ford said she favored PJM's proposal since the IMM also endorsed it, even if it thought it had a better idea, American Municipal Power's Steve Lieberman said, "any of these packages is preferable to the status quo."

FTR Forfeitures

Midgley and Mike Borgatti, representing NextEra Energy, proposed sensitivity tests for analyzing PJM's FTR forfeiture rule to determine if it's overly restrictive and foreclosing legitimate trading. Exelon won MIC endorsement in March for a problem statement and issue charge to analyze the rule. (See "Exelon-backed Analyses Approved," *PJM Market Implementation Committee Briefs: March 7, 2018*.)

Borgatti and Midgley argued that an overly restrictive forfeiture rule might cause competitive suppliers to add a "risk premium" to customer costs and could reduce the value of load's auction revenue rights if market participants bid less for affected FTRs.

"You can't efficiently hedge off the cost of load in the energy market, and so the result of that FTR forfeiture is inefficiency that's going to show up ultimately as an additional cost to consumers as a risk premium," Borgatti explained.

"We're trying to become better educated on why we're seeing the market outcomes [of increased forfeitures] that we're currently seeing," Midgley said. "We're not really sure exactly what is wrong. I know that my firm is being impacted, and we're seeing significant levels of forfeitures that we've never seen before. And it's preventing us from using INCs and DECs and FTRs to manage legitimate business risks."

The stakeholders proposed doing sensitivity analyses to test components of the forfeiture procedure. Borgatti compared it to determining school-zone speeds that are both safe for pedestrians and equitable for drivers.

However, IMM Joe Bowring argued that the rule is curbing behavior as it's intended to. He offered to discuss with individual market participants how the rule was applied to their portfolio and pointed out that forfeitures have declined since the introduction of the new rule as participants have come to understand it better.

"Simply the fact that somebody is doing something doesn't make it legitimate. The fact that somebody is managing risk doesn't make it legitimate," he said.

Bowring also questioned whether the intent of the initiative is to figure out how to bypass the rule.

Midgley and Borgatti denied that motivation. "I don't think it's either of our companies' intent to create a cookbook for how to game the rule," Borgatti said.

Chmielewski said PJM remains confident in its compliance filing to address FERC's January 2017 ruling on the issue, though the commission has yet to rule on it (EL14-37, ER17-1433). (See *FERC Orders Portfolio Approach for PJM FTR Forfeiture Rule*.)

Stakeholders approved manual changes supporting the compliance filing in September. (See "Stakeholders Endorse Manual Revisions," *PJM MRC/MC Briefs: Oct. 2, 2017*.)

Despite that, he said PJM is willing to consider alternative perspectives. He presented an analysis that showed changing the rule's sensitivity for its virtual test from 0.1 MW to 10 MW — or 10% of the line's day-ahead binding limit if it's greater — would have cut forfeitures in half and eliminated forfeitures for 12 of 67 market participants penalized. Forfeitures for September 2017 would have been reduced by half, from roughly $2 million to roughly $963,000.

"Really what this trigger is doing is if you're looking at any binding constraint in the day-ahead market with a 100-MW limit or less, you're basically saying it has to have a 10-MW or more impact, which may or may not make sense depending on how you look at it," Chmielewski explained.

Under questioning from stakeholders, he acknowledged that the issue could benefit from further analysis.

"If 10 MW is too high, what's too low? Is 0.1 too low?" he asked.

Mike Borgatti and Sharon Midgley | © RTO Insider

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He said he couldn't determine whether there would be any market resettlements if the rule is changed again, but that "it's possible."

Balancing Ratio

PJM's Pat Bruno reviewed the RTO's proposal to address concerns with calculating the balancing ratio (B) used in the default market seller offer cap (MSOC). The calculation became an issue after PJM was unable to determine a MSOC for 2018 and was forced to implement a stop-gap number. (See "Balancing Ratio Study Changed," *PJM Markets and Reliability Committee Briefs: April 19, 2018*.)

PJM's proposal would calculate average hourly balancing ratios from as many performance assessment intervals (PAIs) as have occurred within the past three years and supplement them with estimated hourly balancing ratios from as many of the remaining peak hours as is necessary to meet the required number of hours of PAIs. Currently, that number is 30. The balancing ratios would be averaged together for a final balancing ratio for the year.

PJM argues the proposal is straightforward, reasonable and able to be completed within the necessary amount of time.

Bowring suggested in his proposal that the balancing ratio can be estimated using a forward-looking model of performance assessment intervals.

"If there are no performance assessment [intervals], there is no B and we don't need to make one up by inventing various weird ways of pretending there really was one," Bowring said. "It's still possible to get to an offer cap. ... Let's not make things up. Let's actually do a model ... based on PJM's current modeling to determine what we expect to happen."

Quadrennial Review of VRR Curve

Stakeholders asked PJM to justify its recommended revisions to key parameters for the annual capacity auction following its quadrennial review of the demand curve. PJM reviews the calculation of its demand, or variable resource requirement (VRR), curve every four years and makes recommendations based on an analysis of the curve's performance. (See *PJM to Consider Revisions to Demand Curve Design*.)

Among PJM's more controversial recommendations is that stakeholders ignore the recommendation of the Brattle Group, which performed the performance analysis, and continue to base the VRR curve on the cost of new entry (CONE) calculations for a gas-fired combustion turbine. Brattle recommended changing to the CONE for a combined cycle unit, which it said is cheaper.

"This curve has proven over the past years to be reliable and robust," Bruno said in defense of the CT-based curve.

"I really expected some evaluation of the shape of the curve ... and there wasn't any of that," said James Wilson, who consults for several consumer advocates within the RTO's footprint.

Bruno argued that Brattle reviewed the curve's shape, as the Tariff requires.

AMP's Lieberman asked why PJM thought it was appropriate to shift the curve right four years ago based on Brattle's recommendations — increasing the expense to consumers and profits to generators — but not back when they recommend it four years later. ODEC's Ford echoed the concerns.

Calpine's David "Scarp" Scarpignato said he wasn't "convinced" that the curve reduces excess capacity.

"There are a lot of barriers to exit going on. ... I don't think you can study the curve in isolation like that," he said.

PJM is not recommending a change in the cap, so it would remain 1.5 times net CONE or 0.7 times gross CONE.

Order 844 Revisions

PJM briefed the MIC on its response to FERC's April order requiring RTOs to submit monthly reports detailing their uplift payments and operator-initiated commitments (Order 844, RM17-2). PJM has until Sept. 7 to make its compliance filing implementing the changes, which have to go into effect by Jan. 7. (See *FERC Orders RTOs to Shine Light on Uplift Data*.)

RTOs/ISOs are required to report:

- total uplift payments for each transmission zone, separated by day and uplift category;
- total uplift payments for each resource monthly; and
- megawatts of operator-initiated commitments in or near real time and after the close of the day-ahead market, broken out by transmission zone and the reason for the commitment.

In addition, the order requires PJM to add to its Tariff the transmission constraint penalty factor values used in market software; the circumstances under which the penalty factors can set LMPs; and the procedures for temporarily changing transmission constraint penalty factor values.

A discussion on the topic is planned for a special MIC meeting May 10.

— Rory D. Sweeney

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PC/TEAC Briefs

The PJM Planning Committee on May 3. | © RTO Insider

Winter Modeling Changes

VALLEY FORGE, Pa. — PJM's Patricio Rocha-Garrido last week briefed the Planning Committee on proposed Manual 20 changes to revise how winter peak weeks are calculated.

Staff say the new methodology is necessary because the current "theoretical" approach used in PJM's PRISM modeling software to estimate RTO-wide generator outage levels during the winter peak does not reflect historical outage levels. Staff proposed using historical outage data to build the winter peak week's capacity model.

Stakeholders asked for additional data to confirm that PJM has determined the best option.

Rocha-Garrido added that the revisions are only necessary for winter peaks and that he didn't see any "far-right tail" indicating problems with PRISM's analysis of summer conditions.

"We took a look at the summer, and we were comfortable with what we saw. What PRISM is doing reasonably matches historical data," Rocha-Garrido said.

AMP Disappointed with Cancellation of Ratings Discussion

American Municipal Power's Ed Tatum said he was "exceptionally disappointed" that staff and PC members decided to skip discussion of NERC Standard FAC-008-3, which governs how transmission owners must document their methodologies for calculating facility ratings.

Committee members decided to table it until next month's meeting after the discussion on incorporating cost containment in transmission planning ran long. (See related story, *Cost Containment Proposal Heads Back to MRC Despite Concerns*, p.27.)

TEAC Redesign

PJM's Aaron Berner walked through revisions to Transmission Expansion Advisory Committee processes to increase transparency and opportunities for stakeholder input.

Stakeholders at the May 3 TEAC meeting. | © RTO Insider

Greg Poulos, executive director of the Consumer Advocates of the PJM States, voiced his approval of the changes.

"It's very noticeable. You've done a great job," he said of PJM's efforts to provide information sooner.

Tatum suggested adding information to templates that addresses repeatedly asked questions.

"That is definitely one of the things on our mind to try to short-circuit … the need for some of those questions," Berner said.

Reliability Upgrades Needed for Nuclear Deactivations

Staff said they completed an analysis on the reliability impact of the retirements of FirstEnergy's Davis-Besse, Perry and Beaver Valley nuclear plants, which the company announced last month. (See *FES Seeks Bankruptcy, DOE Emergency Order*.)

While the plants can retire as scheduled, transmission upgrades will be necessary, staff said. All projects that will need to be accelerated have been identified. Staff plan to bring details for all upgrades to next month's TEAC meeting.

All projects will be classified as "immediate need" so they can be in place by the plants' planned shutdown by the end of 2021, which means they won't be competitively bid and will be awarded to FE to build.

— Rory D. Sweeney

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PJM Capacity Proposals Widely Panned

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PJM's plan would allow state-subsidized generators to bid into capacity auctions but ensure they don't suppress prices by removing those offers in a second "repricing" stage of the auction.

Numerous commenters said PJM had failed to prove the need for the proposed changes, arguing there was little evidence state subsidies, such as nuclear plants receiving zero-emission credits, were suppressing prices. Several commenters said the proposals would increase prices while failing to address the capacity and energy markets' fundamental flaw: the failure to capture attributes valued by states, such as carbon-free generation. PJM's state regulators, led by the Organization of PJM States Inc. (OPSI), were unanimously opposed.

While almost no commenters endorsed either proposal, some hedged their positions. Dominion Energy and American Electric Power said FERC should reject both options but that if forced to choose, they preferred PJM's proposal. Exelon opposed both options but called the Monitor's proposal "particularly indefensible."

Old Dominion Electric Cooperative — seeking to protect its self-supply resources procured outside of the capacity market — said both proposals should be rejected but that it would accept MOPR-Ex if it were amended to include the municipal/cooperative entity exemption from the capacity repricing proposal. "ODEC's primary position remains that the commission should avoid layering yet another significant design change onto the already complex [Reliability Pricing Model] construct," it said.

Several commenters questioned why PJM was pushing for swift action on the proposals while it is conducting its quadrennial review of the variable resource requirement curve and launching a fuel security initiative. (See *PJM Seeks to Have Market Value Fuel Security*.)

"In light of other, overlapping initiatives currently underway, it is unwise and unnecessary for PJM to push forward with either of the proposed capacity market modifications — particularly when both modifications failed to obtain stakeholder consensus," AEP said.

American Municipal Power said FERC should order PJM to reconvene the Capacity Construct/Public Policy Senior Task Force "without arbitrary deadlines to complete the evaluation of whether and what types of changes are needed to accommodate state actions."

"The commission should reject the proposal and direct PJM to reconvene the stakeholder process in its administrative resource adequacy construct, as well as the current quadrennial review process and the novel fuel security proposal," AMP said.

"Rather than seeking multiple arbitrary commission deadlines and guided processes for the additional work needed to resolve issues with PJM's proposal, the commission should direct PJM to address the issues with the two proposals and create a supportable proposal that achieves the first principles identified by the commission in the [ISO-NE Competitive Auctions with Sponsored Policy Resources] proceeding." (See *Split FERC Approves ISO-NE CASPR Plan*.)

Rare Endorsement

The only full-throated support for either proposal came from comments filed jointly by Starwood Energy Group and Direct Energy, who argued MOPR-Ex "is narrowly tailored to mitigate artificial price suppression in PJM's capacity market while retaining core market fundamentals" and "preserves the ability of both customers and investors to bring new capacity resources, and offer existing economic capacity, into the market on a competitive basis."

The companies opposed PJM's repricing proposal and repeatedly juxtaposed the two to argue for MOPR-Ex, which it said "does not thrust the capacity repricing costs onto the market generally."

The Natural Gas Supply Association was less outspoken in its support but nonetheless urged approving and suspending implementation of MOPR-Ex, then directing those involved to engage in settlement discussions to consider "how exemptions are provided and the appropriateness of unit-specific exemptions, including exemptions provided for units subject to a renewable portfolio standard."

The group pointed to the nuclear subsidies recently passed in New Jersey as evidence "that the time is now to address state subsidies given that the number of subsidies in the market continue to grow." (See *Exelon to Push for Laws, Rules to Boost Profitability*.)

Vistra Energy and its Dynegy Marketing and Trade subsidiary took a similar position, saying "an appropriately designed" MOPR is the best way to support competition.

The Electric Power Supply Association said it opposed capacity repricing but agreed "100%" with PJM that changes are needed.

"The commission should summarily reject the 'capacity repricing' proposal … which would enable and encourage state interfer-

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Quad Cities nuclear plant

PJM News

Cost Containment Proposal Heads Back to MRC Despite Concerns

By Rory D. Sweeney

VALLEY FORGE, Pa. — In light of the amount of debate that proposed cost-containment provisions provoked at last week's Planning Committee meeting, it might come as a surprise that both sides seemed pleased with the outcome of the session.

Proponents of LS Power's proposal to require consideration of cost-containment provisions in PJM's analysis of transmission construction bids are relieved that the package remains largely intact and on schedule to return for a vote at this month's Markets and Reliability Committee meeting. Opponents were happy the measure got the standing committee scrutiny it never received the first time around.

The debate has been building to a confrontation since LS Power surprised some stakeholders by presenting the plan with little forewarning at January's MRC as an alternative motion to Manual 14F changes developed by PJM. The RTO took its proposal, which had been debated at special sessions of the PC, to the MRC, which rejected the plan and deferred a vote on the LS Power alternative, remanding it for more discussion at the PC in the hope of finding consensus. (See "Transmission Flashpoint," *PJM MRC/MC Briefs: Jan. 25, 2018*.)

In follow-up special sessions, LS Power has removed operations and maintenance costs from the list of categories in which developers can offer cost-containment provisions, but the company has resisted most other revisions promoted by transmission owners.

At last week's PC, PJM's Sue Glatz presented two proposals the RTO is developing. The first would require staff to consider commitments on construction costs and evaluate the risk of costs exceeding the estimate based upon specified project risk factors identified in templates that PJM and stakeholders have been developing over the past two months. PJM has yet to fully flesh out how the consideration will be implemented and what weight such commitments will receive in project evaluations.

PJM's alternative is continuing the status quo, in which the RTO evaluates cost-containment measures included in transmission development proposals as it sees fit.

Greg Poulos, the executive director of the Consumer Advocates of the PJM States, reiterated his support for the LS Power proposal, which would require the RTO to consider several other types of cost commitments and provides evaluation guidelines.

"As you know, consumer advocates have been clearly voicing their opinion that they would like to see more than the construction costs included" in the analysis, Poulos said. "I do think this is a significant step and [PJM's] efforts to compromise on this will be greatly appreciated by the advocate offices."

Tension grew when Public Service Electric and Gas' Alex Stern moved for a vote on PJM's proposals.

"Alex, you're a good man," American Municipal Power's Steve Lieberman responded before criticizing Stern's call for a vote, noting that Stern had objected when LS Power's Sharon Segner sought to bring her proposal unannounced for the January MRC vote. Lieberman had teed up his critique by receiving clarification at the outset of the meeting that any items that weren't on the agenda for endorsement weren't prepared for a vote.

"What I heard from Sue [Glatz] is there are a number of things here that PJM is thinking about," he said. "It's not in a situation where the information being presented is finalized."

NextEra Energy's Steve Gibelli agreed.

"This to me doesn't feel right. It feels like we're trying to force a decision through. I'm uncomfortable voting on something without seeing the Tariff changes. I'm not sure how we can vote a motion without seeing those details here," he said.

Stern defended himself, saying PJM's proposals have been part of discussions for two months while the LS Power proposal was "completely out of the blue." He argued that he would prefer to have more time to discuss the proposals "on an even footing" and follow the standard committee protocol of readings at no less than two meetings, but he recognized there are no other PC meetings before the LS proposal is scheduled for a vote at the MRC. Manual 34 rules allow for proposals to be brought straight to the MRC without input from lower committees, he acknowledged, while contending that "all stakeholders believe that such an approach should be the exception and not the norm."

"Trust me when I say my motives were pure. I was trying to restore some balance to the stakeholder process. I was trying to allow the standing committee to do what it's supposed to do," he said.

PJM Capacity Proposals Widely Panned

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ence with the commission-jurisdictional RPM market, and should instead focus on a MOPR approach, consistent with its recent commitment to 'use the MOPR as [its] standard solution' where state policies threaten the organized capacity markets."

EPSA noted that the Monitor's MOPR-Ex plan received more support among stakeholders than PJM's alternative. If the commission does not find MOPR-Ex just and reasonable, EPSA said, it should find PJM's current MOPR rules are not just and reasonable because they don't cover existing resources.

Exelon, however, said MOPR-Ex "would prevent state-supported clean generators from clearing at all, replacing them with polluting units. Perversely, that will not just force customers to pay higher electricity prices but also will inflict on customers the additional costs of grappling with the pollution [MOPR-Ex] has created."

'Externalities'

Exelon said PJM's premise — that states

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making payments to recognize the environmental benefits of renewable and nuclear generators states are "distorting" price signals — is incorrect.

"Sound economics understands that when states tax polluting generators, or pay clean generators for their environmental value, they do not 'distort' price signals. They reduce distortions and account for true economic costs and benefits. The only distortion comes from treating clean and polluting generators as the same when they are not."

The Institute for Policy Integrity at New York University School of Law, a nonpartisan think tank that says it is dedicated to improving the quality of government decision-making, also cited the markets' failure to value environmental externalities.

FirstEnergy, in a joint filing with East Kentucky Power Cooperative, also agreed that the capacity market is failing to account for externalities — but defined those uncompensated attributes as "resilience, fuel diversity and fuel security."

"The simple facts are, notwithstanding numerous amendments and market design enhancements through the years, PJM's wholesale capacity market has never worked as intended. States are compelled to address the needs of their constituents. It therefore should be no surprise that states within the PJM footprint are responding to this long-term market failure by implementing policies that are designed to preserve important generation units and their associated attributes, including generation and zero-emissions attributes."

They said FERC should reject PJM's proposals and require the RTO to "develop a holistic solution to the fundamental issues facing its markets."

Resume Negotiations

Several commenters called on PJM to return to stakeholder negotiations.

Dominion said it opposes both proposals because they extend mitigation to existing capacity resources. "Dominion Energy does not agree that existing capacity resources have the same pricing effects as new capacity resources and warrant identical treatment," it said. FERC should insist the RTO resume stakeholder discussions to develop rule changes "that focus on actual distortive pricing effects stemming from state public policies," Dominion said.

Talen Energy Marketing and its fleet of generation subsidiaries argued both proposals are "inadequate" and asked FERC to "direct PJM to engage with its stakeholders in a broader price reform effort, including necessary revisions to the energy market, that would seek to appropriately compensate generators for other, non-price attributes that provide measurable value to the grid."

States Unanimous

In a rare unanimous vote, OPSI urged FERC to reject both proposals and argued that PJM should "respect the resource choices of state policymakers unless there is a legal determination that a state policy impermissibly intrudes" on federal jurisdiction. State subsidies aren't impacting the market's ability to attract resources and provide adequate returns, and PJM's evidence to the contrary is purely "speculative" and anecdotal, OPSI said.

"Data shows that adequate numbers of generation resources are consistently able to recover their costs, while receiving rational price signals, from PJM markets," OPSI said. "PJM abandons the cost-minimizing principle and instead proposes an exceedingly complex design change that will place more weight on administratively determined artificially inflated prices rather than actual market participant offers."

It noted that the Monitor's State of the Market report found the average age of at-risk units is 42 years while a Department of Energy-funded report found that the average lifespan for coal units in the Eastern Interconnection is 40 years.

"Such findings seem less indicative of market failure, than of rational market signals of entry and exit. ... Rather than rising, there is significant data that shows capacity prices should be falling," OPSI said, noting the results of PJM's recent quadrennial analysis of its demand curve and recommendations to reduce the expected cost for a new unit to enter the market.

OPSI said the CCPPSTF was flawed because its charter limited it to only consider the capacity market.

The Maryland Public Service Commission said PJM's proposed changes would "obscure resource clearing, increase uncertainty and raise customer prices."

The Pennsylvania Public Utility Commission noted that neither proposal received a two-thirds majority at the Markets and Reliability Committee and that both "could result in subsidized resources in one state, significantly increasing market prices in another state." (See "No Consensus on Capacity Revisions," *PJM MRC/MC Briefs: Jan. 25, 2018*.)

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Clinton nuclear plant

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It said capacity repricing would incent market sellers to underbid in the first stage of the auction "causing further price volatility" while MOPR-Ex could cause states to pay twice for capacity even as it suppresses energy prices.

The Public Utilities Commission of Ohio said FERC should preserve the current rules "until a direct path to addressing state subsidies, if at all, can be determined."

"The commission, state commissions and other parties have taken significant steps to resolve perceived capacity market design deficiencies that have not been fully implemented. Yet, in less than three years, PJM is again before the commission proposing another significant overhaul of the capacity market under far less certain circumstances," PUCO said. "While PJM has provided information on the price suppression effect of subsidies, it has not similarly substantiated the level of penetration of state-subsidized resources that would trigger the need to depart from the status quo with another major overhaul of RPM. Furthermore, the PUCO notes that there is no analysis as to the cost impacts of either proposed option on load."

The New York Public Service Commission, which is working with the NYISO to incorporate a carbon adder into its wholesale market to accommodate state-subsidized nuclear plants, sought assurances that the commission's ruling on the PJM proposal "will not serve as binding precedent for other control areas."

"This is critical for other control areas to have the autonomy needed to develop market mechanisms that address their regions' unique circumstances," the PSC said in a joint filing with the New York State Energy Research and Development Authority.

Environmental Groups Oppose

A joint filing from the Sustainable FERC Project, Sierra Club, Natural Resources Defense Council and Environmental Defense Fund asserted that "PJM wrongly puts the commission in the position of policing the efficiency of state policies." The proposals put "wholesale market rules on a collision course with states' core duty to protect the public."


Doug Kaplow

The filing included a report from "subsidy expert" Doug Koplow that argued energy subsidies "have long been pervasive at both the federal and state level without attendant impacts on PJM's wholesale markets that have prevented that market from attracting record levels of investment."

"Even if one state's policies were to somehow to harm customers in other states, that would not justify commission intervention to countermand those laws where they are lawfully within the state's authority," the filing argued.

The Solar RTO Coalition, a newly formed group of solar developers and capital providers, said it is "challenging" to address supply-side subsidies.

"The sheer scope of some of the issues that are associated with how to best incentivize the 'proper' development of generation resources … are part of the reason why PJM's stakeholders were unable to come to a consensus."

Both OPSI and the Solar Coalition sought to distinguish PJM's filing from ISO-NE's CASPR proposal, which the coalition said "was much narrower in scope."

Ari Peskoe, of the Harvard Electricity Law Initiative, said, "PJM fails to explain why it equates state support for legacy assets with competitive state programs for environmental attributes, even though it concedes that the latter affect wholesale rates 'to a lesser degree.'"

"Commission approval would substantially expand RTO authority in a field of shared authority. … States did not sign up to have a regional system operator pick and choose among their generation procurement programs, and any assertion to the contrary is unsupportable," he said. "If the commission approves one of PJM's proposals, it should expect a steady stream of [Federal Power Act Section] 206 complaints about laws and regulations ensnared or uncaptured by PJM's arbitrary rules."

Self-supply Concerns

Dayton Power and Light said either of the two proposals are improvements over the status quo but that FERC should correct "deficiencies" in the proposals by adopting changes to the fixed resource requirement (FRR) option that allows state regulators and regulated utilities to supply their own load with their own capacity resources outside the RPM.

"With the minor tweak to the FRR rules, Dayton believes that market price outcomes will be preserved and states wishing to subsidize varying attributes of generation can be accommodated," it said. "The only changes needed is to allow for a partial or overlay FRR within a state as opposed to a full zone as the rule exists today. If a state subsidizes 1000 MW of generation for any reason it deems appropriate, it would remove a corresponding amount of load including reserve requirements from the PJM RPM auction."

In its own filing, EKPC asked FERC to force PJM to change MOPR-Ex's "public entity" exemption to recognize that the co-op is the only winter-peaking load-serving entity within PJM's footprint. The proposal uses LSE's zonal summer-peak demand forecasts to calculate the LSE's eligibility for the exemption. The LSE cannot own more than 600 MW of generation above the peak summer load it serves. However, EKPC procures generation to cover its higher winter peak, which would put it beyond the 600-MW cap.

The Illinois Municipal Electric Agency avoided comment on MOPR-Ex and focused on criticizing the repricing proposal, which it said would hurt load in the ComEd zone by reducing capacity transfer rights allocated to load "due to the predictable decreased clearing of lower-priced imported generation under stage one."

The National Rural Electric Cooperative Association reiterated its opposition to PJM's mandatory capacity market. "However, recognizing that the commission may not at this time unravel PJM's mandatory capacity construct, NRECA urges that the commission … mandate that any outcome of this proceeding must contain specific exemptions for self-supply by cooperative utilities and other load-serving entities."

SPP NEWS

Seams Steering Committee Briefs

Members Endorse Change to Tx Service During Outages

SPP's Seams Steering Committee on Wednesday endorsed a staff-proposed Tariff change that would grant some transmission customers a four-hour exception from taking SPP transmission service in the case of an unplanned transmission outage that leaves them reliant on the RTO's system.

The proposal encountered minor turbulence from members who wanted an exception exceeding four hours. It eventually passed by an 8-3 margin, with Kansas City Power & Light and Sunflower Electric Power abstaining.

Staff drafted the proposal to address the committee's concerns about the current requirement that transmission customers along the SPP seams obtain service from the RTO during an unplanned outage, even if the customer may not normally be required to take the service. Customers that do not prearrange for the service from SPP are charged for unreserved use, and the Tariff does not currently allow the RTO to waive those charges even when a customer unknowingly takes transmission service immediately after an outage.

The proposed change would allow SPP to waive the unreserved use charges during the first four hours of an unplanned outage. Staff said the revision will avoid burdening customers with having to arrange for transmission service during the initial moments of an unplanned outage, while still allowing transmission owners to be compensated.

Staff will now take the proposed change through SPP's revision-request process. The Regional Tariff Working Group will be responsible for the measure's progress.

MISO M2M Payments to SPP Exceed $50M

MISO's market-to-market (M2M) payments to SPP surpassed $50 million in March when the Midwest RTO incurred $3.4 million in charges, increasing its total to $51.4 million since the two neighbors began the process in March 2015.

It was the eighth straight month and 16th of the last 18 that MISO has paid SPP.

SPP's Nashua-Hawthorn and Riverton-Neosho-Blackberry flowgates — in Kansas and Missouri, respectively — were once again the main culprits, binding for a combined 267 hours and racking up $2.2 million in charges. The flowgates have accounted for more than $32 million in M2M payments to SPP, with the Riverton-Neosho-Blackberry flowgate responsible for $26.5 million.

A shadow-price override was put in place in early April to mitigate that flowgate's power swings.

SPP, MISO Evaluating Feedback on Joint Studies

SPP and MISO staff are evaluating feedback gathered from their members on how best to improve their interregional planning process. Staff recommendations based on the feedback will be shared with members in May and June, before any tariff changes or joint operating agreement revisions are made.

The RTOs agreed in February to develop a new process for their coordinated system plan. SPP and MISO have conducted two joint studies, but have yet to approve any joint projects. (See *MISO, SPP Look to Ease Interregional Project Criteria*.)

— Tom Kleckner

FERC Approves Dissolution of SPP Regional Entity

By Tom Kleckner

FERC on Friday approved the dissolution of the SPP Regional Entity (RE) and the transfer of its members to the Midwest Reliability Organization and SERC Reliability Corp., ending a reliability oversight role that had been a source of concern at the commission and NERC (RR18-3).

The commission found that a proposal submitted by NERC, MRO and SERC in March "reflects the transfers of registered entities will 'promote effective and administration of bulk power system reliability'" in accordance with the Federal Power Act.

The order terminates the amended and revised delegation agreement between NERC and SPP, effective Aug. 31, and revises the delegated agreements among NERC, MRO and SERC to reflect their new geographic footprints. The transfer is effective July 1.

FERC said it was "satisfied" that the petitioners and SPP "have considered and established mechanisms to mitigate against the risk of material gaps in oversight of compliance and enforcement activities due to the transfer of registered entities."

Most of the RE's 122 registered entities have been reassigned to the MRO, with the remainder joining SERC. NERC will assume the compliance monitoring and enforcement of the SPP RTO for two years following the delegated agreement's termination date, after which it will determine a successor.

SPP was appointed by NERC as an RE in 2007. The RTO said last July it had reached an agreement to dissolve the RE, citing a mismatch between the RE's footprint and SPP's. FERC and NERC had both expressed concerns that SPP failed to ensure the RE's independence from the RTO.

NERC approved the dissolution in February. (See *NERC Board Approves Dissolving SPP Regional Entity*.)

NERC, MRO and SERC filed the joint petition with FERC in March.

The RE said it will address transitional and wind-down costs using its approved 2018 statutory assessment funding. Any funds left over will be transferred to MRO and SERC, allocated according to the transferred load-serving entities' relative net energy for load.

FERC & FEDERAL NEWS

FERC Accepts Southeast Transmission Import Limits

By Amanda Durish Cook

FERC last week approved simultaneous transmission import limits for several balancing authority areas in the Southeast, stretching from Kentucky to Florida.

The 16 simultaneous import limits (SILs) were submitted with non-public market power analyses by several transmission-owning companies, including eight subsidiaries each of Southern Co. and Duke Energy; seven NextEra Energy affiliates (including Florida Power & Light); PPL affiliates Louisville Gas & Electric and Kentucky Utilities; Tampa Electric Co.; and South Carolina Electric & Gas (ER10-1325-008, *et al.*).

FERC will use the SIL values to evaluate market power analyses submitted by the region's transmission owners and non-transmission-owning sellers.

The limits range from a 10.7-GW import capability during winter in the Tennessee Valley Authority balancing area down to a 0-MW year-round import limit in the Florida Power & Light balancing area. The limits were created based on a study period extending from December 2014 to November 2015.

While FERC accepted most of the transmission owners' own SILs, it said it selected Tampa Electric's calculated values for a few Florida balancing areas where various TO SIL values conflicted with one another.

The commission commended the TOs for coordinating to create the SIL values but said in the future SIL calculations must follow a commission-ordered procedure.

"The Southeast transmission owners generally performed their SIL studies correctly. However, the review of these filings, as well as the review of filings for other regions, leads the commission to conclude that it is appropriate to remind sellers of its expectations, and provide clarification, with respect to the calculation of SIL values," FERC said.

FERC said TOs should abide by the tariff-approved methodologies to calculate SIL capability and should take into account voltage and stability limits, capacity benefit margins and transmission reserve margins.

"The commission emphasizes here that each transmission owner's SIL values must reflect [transmission reserve margins] and [capacity benefit margins] in the same manner as utilized to calculate and post [available transfer capability] and to evaluate requests for firm transmission service," FERC said.

Powelson Sees 'Erosion of Confidence' in Stakeholder Process

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He cited concerns over escalating transmission rates and PJM's February "jump ball" filing of two competing proposals for insulating its capacity market from state-subsidized generation. (See AMP Seeks More PJM Scrutiny of TO Projects and PJM Board Punts Capacity Market Proposals to FERC.)

"You talk to certain state commissioners; you talk to consumer advocates; there's a concern that voices are not being heard," he said. "I think PJM — [CEO] Andy [Ott] has heard me say this — has to do a better job with their state outreach. ... A lot of states right now are not happy."

Left to right: John Rosales, ICC; Andrew Place, PA PUC; Willie Phillips, D.C. PSC. | © *RTO Insider*

Illinois Commerce Commissioner John Rosales and Pennsylvania Public Utility Commission Vice Chairman Andrew Place, who also spoke at the workshop, agreed with Powelson's characterization. "PJM is swimming and drowning in capacity. ... And capacity repricing only worsens that," Place said.

PJM spokeswoman Susan Buehler said Powelson's "concern about our stakeholder process ... is valid and has been recently discussed with members."

Regarding complaints about the "jump ball" filing, Buehler said: "PJM believes this is a policy question and that FERC should make policy calls. Based on the recent New England ruling, it appears evident that commissioners are divided." (See Split FERC Approves ISO-NE CASPR Plan.)

'Awkward Position'

Powelson said PJM's decision to file both the two-tier capacity repricing proposal RTO staff prefer and the Independent Market Monitor's proposal to extend the minimum offer price rule (MOPR) to all units indefinitely "puts us in an awkward position."

The former Pennsylvania regulator contrasted the filing with the RTO's Capacity Performance proposal, which was supported by his state as a response to the 22% generator forced outage rate during the

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FERC & FEDERAL NEWS

FERC, NERC Recommend Expanded Black Start Testing

By Rich Heidorn Jr.

Coal plant retirements have not caused a shortage of black start resources, but grid operators should consider expanded testing, FERC and NERC said last week.

NERC, its eight Regional Entities and the commission released a study May 2 based on information from a representative sample of nine volunteer registered entities, a follow-up to a 2016 joint report. (See *Utilities' Restoration Plans Pass FERC, NERC Review*.)

"Although some participants have experienced a decrease in the availability of black start resources due to retirement of black start-capable units over the past decade, the joint study team found that the participants have verified they currently have sufficient black start resources in their system restoration plans, as well as comprehensive strategies for mitigating against loss of any additional black start resources going forward," the new report says. "The joint study team also found that participants that have performed expanded testing of black start capability, including testing energization of the next-start generating unit, gained valuable knowledge that was used to modify, update and improve their system restoration plans."

A next-start unit is the first generator in the cranking path to be energized using power from the black start generator.

The report recommends that:

- Black start generators dependent on a single fuel develop alternative fuel capability or take other steps such as signing firm pipeline contracts. "Furthermore, the joint study team recommends that these black start resource owners work with their regulators as necessary, to develop alternative solutions to address potential fuel constraints."
- RTOs and ISOs consider further study of the adequacy of compensation for black start and other resources supporting system restoration, "including any potential threat or impact on black start resource procurement and retention under current compensation mechanisms."
- Grid operators coordinate transmission and generation registered entities to verify model data and ensure the accuracy of black start simulations. "The joint study team recommends that registered entities performing simulations of their system restoration plans, especially those with cranking path auxiliary loads at a next-start generating unit that are large relative to the black start unit, closely coordinate with generator owner(s) to ensure that the associated modeling data used to perform restoration plan simulations [are] accurate. For instance, the dynamic simulations should include energizing the cranking path and next-start generating unit start-up, using generator and load models that have been verified against electrical data captured during various normal system operations or disturbances."
- Transmission operators perform expanded testing of black start cranking paths, including testing during planned maintenance outages.

The report emphasized that its recommendations — while "appropriate for all registered entities responsible for system restoration" — are voluntary and "not subject to mandatory compliance with the recommendations, separate and apart from any obligations of mandatory reliability standards."

The report also noted "beneficial practices" used by some that may not be universally appropriate. "The joint study team recommends that registered entities consider incorporating these practices, or variations thereof, as appropriate," it said.

These practices included:

- Coordinating the use of black start facilities across multiple transmission service footprints, allowing a black start unit to aid an adjacent area's critical load.
- Providing additional personnel to staff substations and perform safety watches on transmission lines during expanded testing. "At control centers, additional operators would manage and coordinate expanded testing so that system operators can focus on essential system operations with minimal distractions."
- Having black start generators sign agreements with next-start units to facilitate expanded testing.

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2014 polar vortex. "I want to see more of that synchronization as these constructs come down [to FERC]. It makes the commission's job a lot easier if there's those kind of alignments.

"It's hard to build consensus, and that's a concern too," he added. "I don't know how to change that, but I'd like to see us at least look at it more."

Adam Keech, PJM executive director of market operations, who spoke after Powelson, also addressed his comments.

"I think the stakeholder process is a great process for getting feedback and vetting proposals and understanding the interests," Keech said. But he acknowledged the RTO has difficulty advancing "big ticket items" and navigating some "larger issues."

"And so, are there are ways we can make the process more efficient? I'm sure there are, but there's value to the process

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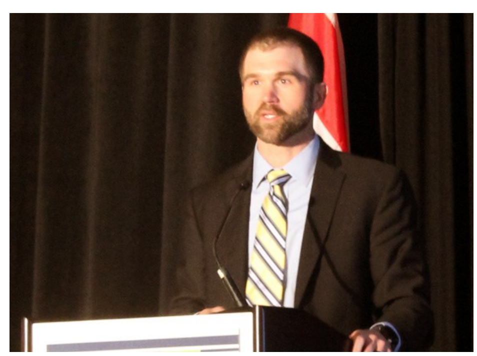

Adam Keech | © *RTO Insider*

FERC & Federal News

FERC Denies Bayonne NYISO Tariff Waiver Request

By Michael Kuser

FERC last week denied Bayonne Energy Center in New Jersey a waiver of several NYISO Tariff provisions, which the plant said it needed to enter the ISO's monthly installed capacity (ICAP) auction in June.

NYISO clusters project developers that have achieved similar milestones into a "class year," and evaluates the cumulative impacts of all of the projects in a given class year through an interconnection facilities study. The ISO recently adopted process changes authorizing it to bifurcate a class year in order to minimize delays for project developers unaffected by additional upgrade studies, allowing those developers an earlier "exit ramp" from the interconnection process.

Bayonne last month asked FERC permission to waive 11 provisions and add two new natural gas-fired units with approximately 120 MW of summer capacity to its existing 512 MW of capacity in time for the June ICAP auction.


Bayonne Energy Center | *Direct Energy*

The plant said that its 2017 class year study, originally scheduled for completion in December, was now slated to be completed in April. Bayonne would then be potentially subject to an additional 30-day delay while the ISO determined whether it needed to bifurcate the class year, jeopardizing the ability of the new capacity to participate in the June auction. Bayonne contended that it was not seeking waiver of any substantive requirements, but of the timing of certain requirements to allow for timely participation.

The commission's May 4 order (ER18-1301) found that, in seeking waiver of 11 Tariff provisions, "Bayonne's waiver request is not limited in scope," and that granting the request could possibly harm third parties by delaying the ISO's completion of the class year 2017 process for other projects. The commission also pointed out that "it is unclear whether Bayonne will even need waiver of these provisions given that it is not clear yet that whether class year 2017 will bifurcate."

"We also note that Bayonne assumes, without support, that both NYISO and its Market Monitoring Unit can expedite their processes if the commission grants the waiver request," the commission said. "In this way, it is unclear whether granting the waiver request would even provide Bayonne the relief it seeks."

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nonetheless. … We need to not throw the baby out with the bath water," he said.

The challenge of reaching stakeholder consensus was highlighted in a May 2017 paper on PJM's governance by Christina Simeone, director of policy and external affairs at the University of Pennsylvania's Kleinman Center for Energy Policy.

"For these high controversy issues, it seems the stakeholder process is falling short at exactly the time when stakeholder collaboration and joint problem solving is critical to informing profound questions about market design and the future of competitive markets," Simeone wrote.

'Very Disappointing'

Rosales, who is president of the Organization of PJM States Inc. (OPSI), said he agreed that state regulators don't feel PJM is sufficiently responsive. "Absolutely. 100%. Unqualified yes," said Rosales, who called PJM's jump ball filing "very disappointing."

"We were very clear," he told *RTO Insider* in a brief interview. "We thought that the status quo was better than these two really poor options that they put to be filed at FERC."

Rosales elaborated in a panel of state regulators. PJM is "trying to resolve an issue that hasn't become an issue yet. It's a solution to a problem that we don't have."

OPSI sent the PJM Board of Managers a letter in February urging it to take no action on any repricing proposal, saying that if the RTO thought rule changes are necessary, "it should reinitiate a more holistic stakeholder process." The organization said it was not convinced that state policies undermine the RTO's markets and that PJM's proposal does not respect state jurisdiction and may raise capacity prices.

But Rosales said OPSI's concerns have gone unheeded and that PJM has recently adopted a practice of effectively covering its ears and saying, "We hear you."

"It becomes very frustrating for us because they'll say they listen, they'll tell us about the stakeholder process, they'll tell us everything that they've done … and then they'll just throw it out the door and say, 'We're going to go with this anyway.'"

OPSI is not a PJM member, so it has no means of trying to change the stakeholder process at FERC. "We as a group have decided not to be stakeholders," Rosales said. "We try to have a relationship with PJM … [and] play nice in the sandbox. … But for the most part they've not had an open dialogue. … They listen, but the changes aren't there."

Monitor Contract

Rosales also cited the renewal of PJM's contract with its Monitor, Monitoring Analytics. The IMM's current contract expires in December 2019. "We have problems with getting the Market Monitor contract — again. They seem to be going not the right way," he told *RTO Insider*. He

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did not elaborate on his concerns, which he repeated on the panel.

Monitoring Analytics President Joe Bowring, a Ph.D. economist, has served as PJM's Monitor since 1999.

In 2013, the PJM board came under fire over its proposed request for proposals for monitoring services, which OPSI and other critics said contained language that would undermine the independence and quality of the monitoring function. The board dropped the proposal and signed a contract renewal with Monitoring Analytics later that year. (See *Board, OPSI Bury the Hatchet over Monitor Contract*.)

OPSI Executive Director Gregory Carmean did not respond to a request for comment Wednesday on the current contract negotiations. Bowring declined to comment in detail but said he was confident in reaching agreement with the RTO.

PJM's Buehler acknowledged PJM has received questions from OPSI about the contract negotiations. "PJM believes the discussions are productive and ongoing, and we are frankly confused by any other characterization," she said.

Not Just PJM

Powelson said his concerns over the stakeholder process are not limited to PJM, saying all RTO/ISO boards should operate under term limits and ensure diversity among their members. "I'm looking at this … from general business practices as a regulator overseeing those boards and what these RTOs do; making sure they're synchronizing with what's going on in the corporate world.

"In my view, you can't have enough transparency in this [stakeholder] process," he continued. "We're making all these changes. People should have the ability to see it, understand it and feel comfortable with the final outcome."

Powelson also commented on PJM's initiative, announced last Monday, to seek a market-based response to potential fuel security concerns. (See *PJM Seeks to Have Market Value Fuel Security*.)

Based on "the briefing I received from Andy Ott and his team, I think [PJM] is exactly where we need to be," he said.

Powelson said "people should not read into" PJM's announcement that it will end up paying coal and nuclear operators to provide backup for gas-fired generators subject to fuel delivery interruptions. "I think what PJM is saying is 'we're going to look at it and we're going to do it in a market-based approach.' There might be other technologies out there that have the same [fuel security] characteristics. It could be an oxidized fuel cell. It could be storage. It's going to be a level playing field discussion. … It's going to be done in a fuel-neutral, technology-neutral way."

Powelson said it would be a mistake for the Trump administration to use the 68-year-old Defense Production Act to keep financially struggling coal and nuclear power plants operating, as is being considered, according to published reports. The act was used by President Harry Truman to control steel prices during the Korean War.

"I think it would lead to the unwinding of competitive markets in this country," Powelson said. "It would be the wrong direction for us to venture down."

Q1 Earnings News

CenterPoint Touts Vectren Deal in Earnings Call

By Tom Kleckner

CenterPoint Energy executives said Friday they were "excited" about the company's proposed acquisition of Indiana utility Vectren, saying it presents them with future growth opportunities.

"This transaction will continue to advance us towards our vision of being the nation's leader in delivering energy, service and value," CenterPoint CEO Scott Prochazka said during the company's first-quarter earnings call with analysts and investors. "We're excited about CenterPoint's post-merger future."

CenterPoint announced the $6 billion deal last month. The combined company would serve more than 7 million customers, operate electric and natural gas delivery systems in eight states and hold about $29 billion in assets. (See *CenterPoint Energy to Acquire Vectren in $6B Deal*.)

The Houston-based company hopes to close the acquisition in the first quarter of 2019. The deal still requires approvals from Vectren shareholders, FERC, the Federal Communications Commission, and regulators in Indiana and Ohio.

"We are combining two companies with strong capital investment opportunities and rate base growth," said CFO Bill Rogers.

"We believe we also have the right mix of unregulated products and services to meet the customer needs of today and tomorrow. This merger provides us the opportunity to deliver even stronger earnings results than we would as separate entities."

CenterPoint reported first-quarter earnings of $241 million ($0.55/share), compared with $160 million ($0.37/share) for the same period in 2017, beating the Zacks Consensus Estimate of 44 cents.

Investors reacted to the news by driving CenterPoint's share price up 6.1% to $26.88 at the market's open. The stock closed at $26.41.

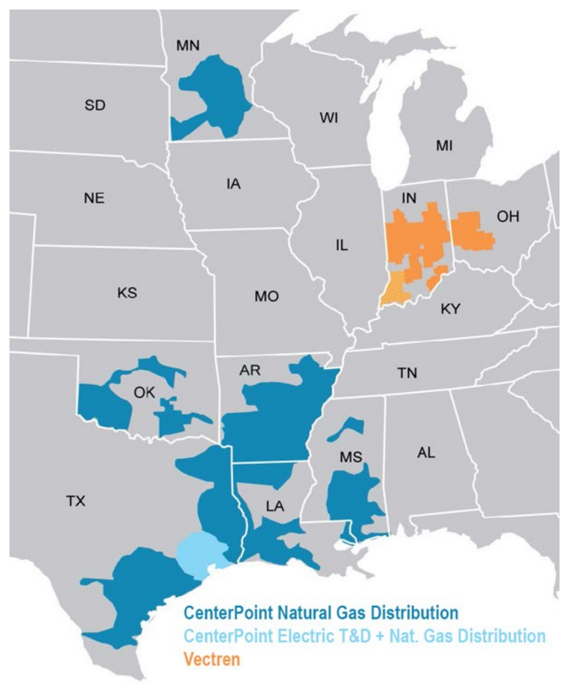
Prochazka said the Vectren acquisition will lessen the company's exposure to the midstream space through Enable Midstream Partners, a gas-gathering and processing joint venture with Oklahoma's OGE Energy. CenterPoint owns a 54.1% share of Enable, while OGE holds a 25.7% limited-partnership interest and a 50% management interest.

"We continue to believe Enable is well-positioned for success," Prochazka said, pointing to Enable's earnings announcement earlier in the week in which it reported all-time highs for quarterly natural gas gathered volumes and processed volumes.

That's not to say CenterPoint isn't continuing to look for opportunities to reduce its ownership in Enable.

"We need to be very thoughtful and do so in a coordinated fashion with Enable, so we don't have a negative impact on Enable," Prochazka said.

Rogers made it clear that CenterPoint will not sell off portions of Enable to fund the Vectren acquisition, saying three times, "We do not intend to sell Enable common units to finance the acquisition of Vectren shares."



OGE Gets Huge Boost from Favorable Weather

OGE on Thursday credited favorable weather for first-quarter earnings that almost doubled analysts' projections.

The Oklahoma City-based company reported earnings of $55 million ($0.27/share), compared with 2017's first-quarter profits of $36 million ($0.18/share). A Thomson Reuters survey of analysts had expected earnings of 15 cents/share.

CEO Sean Trauschke told analysts and investors during a conference call that it was the first time in five years OGE has begun a calendar year with weather that has driven up electricity sales.

"It feels good to have the first quarter behind us with positive weather," Trauschke said. "Weather changes. It's not something you can control. What does not change is our execution and focus on getting better."

Ironically, Trauschke's comments came in the aftermath of severe weather that hit OGE utility Oklahoma Gas & Electric's service territory on May 2.

"Tornadoes, high winds, rain, hail, the full complement," Trauschke said, promising that service would be restored by noon May 3.

OG&E contributed earnings of 16 cents/share, double its performance in 2017's first quarter. Trauschke said its Mustang Energy Center's seven new units have already seen "close to 500 starts" and produced more power this year than its legacy units did all last year.

OGE's revenue for the quarter was $492.7 million, up 8% from last year. Noting the company realizes most of its earnings in the second and third quarters, Trauschke reaffirmed year-end earnings guidance of $1.90 to 2.05/share.

The company's stock price gained $1.41/share with Thursday's earnings release, finishing the day up 4.3% at $34.23/share.

— Tom Kleckner

Q1 EARNINGS NEWS

Edison Hopeful for State Action on Wildfire Liability

By Jason Fordney

Edison International CEO Pedro Pizarro said the company is hopeful that several bills working their way through the California State Legislature will ease the financial pressure stemming from hundreds of millions of dollars in wildfire costs.

The company's main subsidiary, Southern California Edison, is the target of civil lawsuits stemming from the Thomas Fire that began in December 2017 in Ventura County, Calif., burning about 440 square miles and causing two deaths. While the California Department of Forestry and Fire Protection, the Ventura County Fire Department and the California Public Utilities Commission's Safety and Enforcement Division look into the causes of the fire, the utility is conducting it own investigation, Pizarro said.

During an earnings call last Tuesday, Pizarro called for the state to implement wildfire mitigation operating standards to help determine whether a utility properly ran its transmission system prior to a fire.

"An updated standard of liability that considers degree of fault rather than the current standard of strict liability would ensure that there is a fair sharing of the increasing risk of climate change impacts across society," Pizarro said. He said he was "heartened" by Gov. Jerry Brown's comments in March about updating utility liability rules for wildfires. Three related bills have been introduced into the legislature: SB 819, SB 901 and SB 1088.

The third bill, the subject of a Monday hearing at the Senate Committee on Appropriations, would allow utilities to recover wildfire costs if they conform to state-regulated safety plans, but it faces heavy opposition from critics who say it lets utilities off the hook for their contribution to wildfires. (See *Calif. Legislation Shields Utilities from Wildfire Costs*.)

Wildfire costs and the financial health of the state's investor-owned utilities have sparked concerns in the capitol about the impact on utility stock prices and the potential for bankruptcies — shades of the electricity crisis of the early 2000s. (See *Wildfire Costs Ignite Worry at CPUC, Legislature*.)

Edison reported first-quarter net income from continuing operations of $242 million, compared with $392 million in the same quarter last year. Operating revenue was $2.5 billion in the first quarter, and total operating expenses were $2.2 billion. SCE is a waiting for a CPUC decision on its 2018 retail general rate case.

SCE on April 3 filed an application at the CPUC for a Wildfire Expense Memorandum Account to track incremental wildfire costs. The company is in the process of renewing its wildfire insurance for 2018 and 2019 and said the cost of additional insurance may substantially exceed the amount authorized in rates or in the pending 2018 rate case. The utility has proposed a schedule that would see a decision on the account issued by August.

The state's three utilities have banded together on the wildfire issue after the CPUC last year denied San Diego Gas & Electric's request to recover $379 million in wildfire-related costs. (See *Besieged CPUC Denies SDG&E Wildfire Recovery*.)

NRG Posts Q1 Profit on Asset Sales, Cost Savings

By Michael Kuser

NRG Energy is transforming itself by "right-sizing" its generation fleet, reducing costs and expanding its retail business, the company's chief executive said during an earnings call Thursday.

NRG earned $233 million in the first quarter, compared with a loss of $169 million in the same period last year.

CEO Mauricio Gutierrez said the improved results were driven by $80 million in cost savings and higher energy prices caused by cold weather in Texas and the Northeast.

NRG continued to reduce its generation fleet last quarter, closing on the $42 million sale of its 154-MW Buckthorn Solar project to NRG Yield. The company also announced the sale of its Canal 3 peaking plant in Sandwich, Mass., for approximately $130 million, with the deal expected to close in the third quarter. It expects to close $3 billion in asset sales this year.

NRG last quarter also spent $210 million acquiring supplier XOOM Energy, expanding the company's retail sales capabilities and presence in the East.

Texas Shines

While the company has in recent years highlighted the significant risk of retirements and the slowdown in new builds in ERCOT given persistently low power prices, Gutierrez pointed out the situation is showing signs of reversal.

"Last year, we finally saw the retirement of about 4,200 MW of uneconomic coal generation, which tightened reserve margins," Gutierrez said. "As a result, we are entering this summer with the lowest reserve margin on record at around 10%. Prices have responded accordingly with summer on-peak prices currently trading at about $150/MWh."

Asked whether he expects Texas to see an increase in either new gas-fired generation or more utility-scale solar coming online in response to the high peak prices, Gutierrez said one season does not mean much when deciding on a 25-year investment.

"So far, what we have seen is only the expectation on one summer of high prices," Gutierrez said, adding that in an energy-only market such as ERCOT, "price is everything," providing the "right signal and incentive" for developers to invest capital in the market. "So, you need to see two things: You need to see them high enough and you need to see them long enough to

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Q1 Earnings News

Profits Down, PG&E Fights Wildfire Liability

By Jason Fordney

While the wildfires that ravaged California last year have long burned out, the financial implications for Pacific Gas and Electric are just beginning to surge as the utility works to reduce the impact on shareholders.

PG&E last week reported first-quarter profits of $468 million ($0.91/share), compared with $544 million ($1.06/share) in 2017, falling short of expectations of Wall Street analysts. The utility reported $21 million in wildfire-related costs in the quarter under "items impacting comparability."

Central to PG&E's woes is the legal concept of "inverse condemnation," which makes a utility potentially liable for wildfire-related property damage caused by utility equipment even in cases when that equipment has passed inspections and utility negligence isn't proven.

During an earnings call and presentation Thursday, PG&E CEO Geisha Williams said the current treatment of the company's wildfire responsibility is "a strict liability approach that presumes a commensurate cost recovery path for investor-owned utilities that just isn't true." She said that utilities cannot raise rates without regulatory approval, so applying inverse condemnation to utilities "undermines the premise" of the concept.

California's courts have set a precedent of applying the state's inverse condemnation provisions to IOUs, and a state trial court last week denied PG&E's challenge of inverse condemnation related to the 2015 Butte Fire.

The state's IOUs have banded together on the wildfire issue, pressing on legislative, regulatory and legal fronts to change the approach to inverse condemnation. Newly introduced legislation would revise wildfire liability provisions by allowing utilities to recover wildfire costs through rates if they conform to state-regulated safety plans. (See *Calif. Legislation Shields Utilities from Wildfire Costs*.)

Fitch Ratings downgraded PG&E's stock in February because of wildfire risk. Utility liability for wildfires over the last 10 years has created worries among state lawmakers and the California Public Utilities Commission over the potential for IOU bankruptcies. (See *Picker Seeks Guidance on IOUs, Aliso Canyon*.) PG&E awaits other legal rulings regarding inverse condemnation associated with the 2017 fires, and the utility says climate change is playing a larger role in the conditions that led to the massive blazes.

The utility said that is has been working to harden its systems against wildfires, increasing its spending on vegetation management to $440 million in 2017 from $190 million in 2013, increasing inspections in high fire risk areas and acquiring two helicopters to assist in wildfire response, with plans to acquire two more. It plans to add 200 new weather-monitoring stations this year.

Williams also discussed the growth of community choice aggregators (CCAs), which has left remaining bundled customers to foot the costs for legacy contracts. The issue is becoming more prevalent as CCAs grow. She said the California energy landscape is in a period of "dynamic change," mentioning climate change, CCA growth, increasing use of electric vehicles, and growth in carbon-free and renewable energy resources.

NRG Posts Q1 Profit on Asset Sales, Cost Savings

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attract this capital investment."

PJM Capacity Auction

Gutierrez also highlighted the PJM capacity auction for planning year 2021/22 being held this month, with results scheduled to be posted May 23.

"Last auction saw a slowdown in new builds and over 7 GW of announced retirements added to the PJM deactivation list this year," he said. "But there is still uncertainty on how these will play out in terms of market tightening. As you are aware, some generators are seeking compensation for plants that are not needed for reliability and not economically viable.

"While some entities are grasping a bailout in the short run, we see capacity rationalization as a necessary first step towards a healthy market," Gutierrez said. "And we are confident that there will be continued support for the competitive market value proposition. Beyond PJM, our risk portfolio is well-positioned given our fuel diversity and location near load pockets."

Gutierrez referred to the "uncertain" effect of "all these out-of-market conversations that are happening today."

But, he said, "I am encouraged by seeing FERC and the different ISOs take a very specific stance in terms of the protection of competitive markets and making sure that they don't negatively impact those markets."

Quotes courtesy of Seeking Alpha.

Q1 EARNINGS NEWS

WEC Delivers Strong Q1 Despite Leadership Uncertainties

By Amanda Durish Cook

Cold weather and a stronger regional economy helped boost WEC Energy Group's first-quarter earnings above expectations, the company reported last week.

The company also addressed uncertainty in its executive suite and described its near-term plans for more renewable investment.

WEC's profits totaled $390.1 million ($1.23/share) during the quarter, compared with $356.6 million ($1.12/share) for the same period last year.

CEO Gale Klappa said the "solid results" were driven by a stronger-than-expected demand for electricity and natural gas. "Colder winter temperatures, a strengthening economy and efficiency gains across our system were all positive factors that lifted our earnings above year-ago levels," Klappa said.

The company's operating revenue for the quarter slipped from $2.3 billion to $2.29 billion this year.

During a May 1 earnings conference call, Klappa praised the company's performance and said it has a plan readied in the event that company President Allen Leverett does not return to his post as CEO after being placed on medical leave in October 2017 when he suffered a stroke. Klappa said Leverett is currently undergoing intensive speech therapy and is in "good physical condition." Should Leverett choose not to resume the role of CEO, WEC will employ a succession plan that would "involve a number of internal promotions," Klappa said.

"I can assure you that we have a solid Plan B in place if Allen does not assume his previous role. ... We would have great continuity going forward, and the board and I are very comfortable with [that]," Klappa said, adding that he and WEC's board of directors will continue to monitor the situation.

Klappa also said WEC is making multiple renewable energy investments throughout 2018. The company on April 30 signed a $280 million agreement to acquire an 80% ownership interest in the 200-MW Upstream Wind Energy Center, currently being built by Invenergy in Antelope County, Neb. Klappa said he expects the wind farm deal to close in early 2019, pending FERC approval — just as Upstream begins commercial operation.

Early last month, WEC closed on its $80 million partial purchase of the 129-MW Forward Wind Energy Center near Brownsville, Wisc. Klappa said WEC now owns 44.6% of the wind farm, which is expected to generate savings for customers.

WEC also plans to file construction requests with Wisconsin regulators by the end of the second quarter to build its first solar farm, Klappa said.

"Over the past few years ... utility-scale solar has increased in efficiency, and prices have dropped by nearly 70%, making it a cost-effective option for our customers, an option that also fits very well with our summer peak demand curve and with our plan to significantly reduce carbon dioxide emissions," Klappa said.

He also said WEC is developing plans to provide natural gas and electric infrastructure to "Wisconn Valley," the moniker for the future site of electronics manufacturer Foxconn's $10 billion plant. In February, MISO expedited review of American Transmission Co.'s proposed, $140 million interconnection project to link the plant into WEC subsidiary We Energies' transmission network. (See *MISO Fast-Tracks ATC Foxconn Project Review*.)

Infrastructure Spending 'Biggest Driver' of NiSource Earnings

By Amanda Durish Cook

NiSource is seeking rate hikes across multiple states to cover hefty infrastructure investments after the company delivered a 13% increase in earnings during the first quarter.

The Merrillville, Ind.-based utility last week reported first-quarter earnings of $259.7 million ($0.77/share), compared to $230.6 million ($0.71/share) over the same period in 2017.

"Our systems performed well throughout the prolonged winter heating season, and we're on pace to deliver on our earnings, capital investment and customer commitments in 2018," CEO Joseph Hamrock said during a May 2 call with investors and analysts.

NiSource filed several rate hike applications with different regulators during and after the quarter, hoping to recoup the approximately $1.8 billion it plans to spend on infrastructure this year.

"The biggest driver of our strong financial performance continues to be the impact of our long-term infrastructure modernization investments, supported by solid regulatory outcomes and established infrastructure trackers," CFO Donald Brown said.

Hamrock said NiSource expects to continue to invest $1.6 billion to $1.8 billion in its utility infrastructure every year until 2020. The investments should boost operating earnings 5 to 7% per year, he said.

Subsidiary Northern Indiana Public Service Co. filed a settlement last month in its pending base rate case with the Indiana Utility Regulatory Commission. Brown said the request is NIPSCO's first natural gas base rate increase in more than 25 years and will improve pipeline safety and reliability (44988). If approved, the settlement would result in an annual revenue increase of $107.3 million through fixed charges on customer bills. NiSource expects a commission decision in the second half of this year.

NIPSCO also filed a seven-year gas infrastructure modernization plan with the IURC in early April that proposes $1.25 billion of investments through 2025. The program would recover the costs of modernizing underground natural gas infrastructure through a customer bill charge (44403). NiSource similarly expects a ruling in the

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Q1 EARNINGS NEWS

Eversource Looks to Offshore Wind, New Rates for Growth

By Michael Kuser

Eversource Energy said Wednesday that it will seek to support earnings growth through offshore wind contracts from its Bay State Wind partnership and a new rate plan in Connecticut that increases the average customer's electricity bill by 3.8%.

The company reported first-quarter earnings of $269.5 million, compared with $259.5 million in the same period a year ago.

Eversource's transmission unit earned $107.4 million in the quarter, up 11.4% from a year earlier because of additional investment in its electric transmission system.

The company's electric distribution and generation business earned $104.2 million in the first quarter, down 6.5% from last year primarily because of the sale of generation assets, as well as higher depreciation, property tax, and operations and maintenance expenses, which were partially offset by higher electric distribution margins. Exceptional storm-related costs drove O&M expenses higher.

CFO Phil Lembo said in an analyst call May 3 that "we had significant storm activity in March this year, very significant, particularly in eastern Massachusetts, as a result of a series of nor'easters that hit us over an 11-day span."

"The vast majority of the restoration costs, about $150 million, was deferred under regulatory mechanisms for future recovery," Lembo said.

Regulatory Updates

Lembo noted the "good news" of a FERC administrative law judge's March 27 ruling that municipal utilities and commission staff failed to prove that the New England Transmission Owners' (NETOs) base return on equity of 10.57% (11.74% with incentives) is unjust and unreasonable. (See *ALJ Rules New England Tx Owners' ROEs not Unjust*.)

FERC last October rejected a bid by NETOs, including Eversource, to increase their ROE to the levels in place before being reduced by a 2014 commission order that was vacated by an appellate court early last year. The commission said it would address the actual rate in a later remand order but has yet to do so (ER15-414, EL11-66).

Executives also discussed the New Hampshire Site Evaluation Committee's (SEC) March 30 decision to formalize its rejection of Northern Pass, a joint venture between Eversource and Hydro-Quebec for a 1,090-MW transmission line to bring up to 9.4 TWh of Canadian hydropower to New England each year. Massachusetts had chosen Northern Pass, but in light of the rejection selected as an alternative a transmission project proposed by Avangrid subsidiary Central Maine Power. (See *Mass. Picks Avangrid Project as Northern Pass Backup*.)

Lee Olivier, Eversource executive vice president for business development, said the SEC has scheduled a May 24 meeting to hear Eversource's request to reconsider the rejection. If rejected again, "the next step would be to appeal to the New Hampshire Supreme Court," Olivier said.

Offshore Wind Hopes

Eversource partnered with Orsted to form Bay State Wind for an offshore wind solicitation in Massachusetts, and in December the company proposed a 400- or 800-MW wind farm 25 miles off New Bedford to be paired with a 55-MW battery storage facility.

Olivier said Massachusetts officials delayed by a month the date to select projects for negotiation, to May 23, 2018, now to be followed by submission of contracts to the Department of Public Utilities by July 31.

Connecticut is also conducting a request for proposals for offshore wind, and the company bid approximately 200 MW last month, Olivier said. A winning bidder is expected by midyear, he said.

Olivier said Bay State Wind can produce up to 2,500 MW of wind energy from its 300-square-mile lease area south of Martha's Vineyard and interconnect it to surrounding states and Long Island, even extending over land to New York City with relatively minor upgrades to existing infrastructure.

"We'll also have returns on these assets, transmission-like returns," Olivier said. "Clearly once you get in, if you're one of the first selected, you'll have a first-mover advantage in every other solicitation."

Infrastructure Spending 'Biggest Driver' of NiSource Earnings

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second half of 2018.

NiSource subsidiary Columbia Gas of Pennsylvania also has a $47 million per year rate increase request on file with the Pennsylvania Public Utility Commission as of mid-March.

Brown said the case would "provide the company with an opportunity to earn a fair return on its infrastructure capital investments and enhance pipeline safety."

In late April, the Public Utilities Commission of Ohio approved a rate increase allowing NiSource-owned Columbia Gas of Ohio to begin recovery on about $207 million of infrastructure investments made in 2017. Columbia Gas of Massachusetts also filed a request with the Massachusetts Department of Public Utilities to increase revenues by about $24 million annually in an effort to recover costs incurred from regulatory mandates and gas distribution infrastructure upgrades. The DPU on April 30 also allowed the Massachusetts subsidiary to recover $84 million of capital investments in its rates. Finally, Columbia Gas of Maryland is seeking a $6 million per year rate hike with that state's regulators as of April 13 for make pipeline upgrades.

Hamrock said corporate tax cuts at the beginning of the year helped to lower its rate hike requests in Indiana, Pennsylvania, Maryland and Massachusetts, as well as the rate request for its gas infrastructure replacement program in Ohio.

Q1 Earnings News

Exelon to Push for Laws, Rules to Boost Profitability

By Peter Key

Exelon's plans for its generation subsidiary rely heavily on a push for new legislation and market rule changes that ensure profitability for plants the company is threatening to close, officials said last week.

During a first-quarter earnings call last week, CEO Chris Crane said Exelon plans to push for subsidies for its nuclear plants in Pennsylvania similar to the zero-emission credit (ZEC) programs in Illinois and New York, and the one recently passed by the New Jersey Legislature but not yet signed by Gov. Phil Murphy.

Crane also said he expects Exelon's generation business to benefit from PJM's adoption of new price formation rules and FERC's resilience initiatives.

Although Crane didn't mention it, Exelon's Pennsylvania nuclear plants could also earn subsidies from a New Jersey plan that takes into account how plants affect the state's air quality, regardless of where they're based. (See *Izzo: Nukes Outside NJ Likely Eligible for State ZECs*.) Efforts to enact nuclear subsidy programs in Pennsylvania have so far failed to gain much traction.

Crane also said Exelon will work with ISO-NE to develop market reforms allowing it to keep open the four units of its Mystic Generating Station in Charlestown, Mass., that it said it would close in June 2022.

The company is "going to look to get to the right reforms to make these assets more economic in the future," Crane said. He noted that ISO-NE "put out a study recently saying that there were five assets in New England needed to ensure reliability into the future, one being the Everett Marine Terminal and the others being the Mystic [units]."

On the same day it said would close Mystic, Exelon announced it was buying the Everett Marine Terminal, an LNG import facility in Everett, Mass., which provides Mystic and other power plants in the area with fuel.

ISO-NE last week asked FERC for permission to waive certain Tariff requirements to allow the RTO to retain Mystic Units 8 and 9 to maintain fuel security, following up on a plan the RTO outlined in an April memo. (See *ISO-NE Moves to Keep Exelon's Mystic Running*.)

Crane, along with Joe Dominguez, the company's vice president of governmental and regulatory affairs and public policy, also addressed a PJM plan announced April 30 to help ensure fuel security. (See *PJM Seeks to Have Market Value Fuel Security*.)

Dominguez said Exelon would like to see PJM incorporate environmental impacts associated with different fuel mixes, pointing out that during the cold snap last winter, New England had to rely heavily on oil to produce power.

"In 2018, emissions need to be going down," he said. "And any resolution of this issue that results in emissions going up is going to continue to create incentives for state actions and, indeed, for other federal actions to correct the flaws in those market."

Crane said that while consumers have benefited from low-cost gas, the industry needs to either build redundancy into the gas delivery system or limit its dependency on gas to make the power production and delivery system more secure.

Exelon had net income of $585 million ($0.60/share) on revenue of $9.69 billion in the first quarter, down from $990 million ($1.06/share) and $8.75 billion in revenues a year earlier. The company's operating earnings were 96 cents/share, beating the Zacks consensus estimate of 93 cents.

Crane said the company plans to target a 7.4% rate base growth for its utilities and 6 to 8% earnings per share growth through 2021.

Exelon is still on the prowl for acquisitions, if it can find smart ones, according to CFO Joseph Nigro.

"To the extent we can add something that we think will be accretive to the bottom line and fits with the value proposition that we're trying to bring both to our shareholders and our customers, we're going to be aggressive with doing that," Nigro said.

Quotes courtesy of Seeking Alpha.

PPL Looks to Raise $2B in Equity for 5-6% Annual Growth

PPL last week said it expects to need to raise only about $2 billion from equity sales through 2020, which would enable the company to come in near the top of its projected 5 to 6% compound annual earnings growth per share over that time.

During its first-quarter earnings call, the company also said it expects calls for nationalization of electric utilities in the U.K. to fade and that it isn't interested in fully or partially divesting its business there.

PPL earned $452 million ($0.65/share) on revenue of $2.13 billion in the first quarter, as opposed to $403 million ($0.59/share) on revenue of $1.95 billion in the first quarter of last year. Its adjusted earnings were 74 cents/share, beating the Zacks consensus estimate of 66 cents. The difference stemmed from a one-time impact of 9 cents/share from foreign currency hedges.

PPL expects to use its "at the market" offering program for most of its equity sales. CFO Vincent Sorgi said the company has a shelf offering that would allow it to sell up to $3 billion in stock.

The company isn't looking to perform acquisitions, but rather to pursue organic growth, with midsized transmission projects such as Project Compass being the kind of opportunities it envisions after 2020, according to CEO Bill Spence.

Quotes courtesy of Seeking Alpha.

— Peter Key

Q1 Earnings News

Con Ed Braces for Possible Regulatory Storms

By Michael Kuser

Consolidated Edison's first-quarter earnings jumped more than 10% on an increased rate base and a weather-related boost in steam revenues, but the company noted Thursday that it faces regulatory scrutiny for its role in subway power outages, its tax accounting and its storm response preparedness.

The company earned $428 million in the first quarter, compared with $388 million in the same period a year ago.

"While we continue to face challenging weather events, we remain focused on our long-term strategy of providing customers with the technology and options they need to live and work today," CEO John McAvoy said in a statement accompanying Con Ed's May 3 earnings release.

Regulatory Update

A company presentation pointed out that, in a proceeding investigating a New York City subway power outage last April, the New York Public Service Commission last year issued orders requiring Consolidated Edison Company of New York (CECONY) to upgrade the electrical equipment that serves the subway system. The utility plans to complete the required actions this year.

The PSC in January also initiated an audit of the income tax accounting of certain state utilities, including CECONY and sister utility Orange and Rockland Utilities (O&R), which serves customers in southeastern New York and northern New Jersey (18-M-0013).

Con Ed noted that two storms in March damaged its utilities' electric distribution systems, interrupting service to approximately 209,000 CECONY customers, 93,000 O&R customers and 44,000 Rockland Electric customers. Con Ed said the recovery of $106 million in storm-related costs is subject to review by the PSC and the New Jersey Board of Public Utilities, both of which are investigating utilities preparation and response to the storms, and may penalize them.

O&R last month updated its January rate filing with New York PSC, asking to increase its electric rates from $20.3 million to $22.5 million.

Tax Cuts and Rates

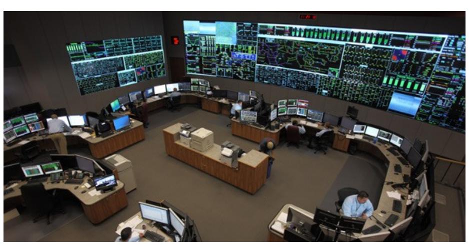
Con Ed expects the federal Tax Cuts and Jobs Act of 2017 to result in customer rates likely being reduced to reflect the reduction in the corporate tax rate from 35% to 21%, elimination of bonus depreciation and the amortization of excess deferred federal income taxes the utilities collected from their customers that will not need to be paid.

The PSC opened a proceeding on the new law (17-M-0815), and commission staff on March 29 recommended that most utilities be required to begin to credit their customers' bills with the net benefits of the tax cuts on Oct. 1.

The company expects a commission decision after the 90-day comment period expires in late June.

Company Briefs

PJM: Summer Peak Forecast Up on Above-normal Temps



PJM control room | *PJM*

PJM is anticipating a peak of more than 150,000 MW this summer, a small increase from last year but nothing the RTO hasn't seen before.

Staff based the prediction on the National Weather Service forecasting above-average temperatures this summer for much of PJM's footprint.

Demand last summer peaked at 145,331 MW on July 19. PJM's all-time highest power use was 165,492 MW in summer 2006.

PJM's required installed reserve margin (IRM) is 16.1% of the forecasted demand level; this summer's IRM is more than 28%, or nearly 41,000 MW. PJM has 184,010 MW of installed generating capacity available.

FERC Approves Emera Maine Settlement

FERC last week approved an uncontested settlement between Emera Maine and the Maine Public Utilities Commission filed in March related to the utility's 2017 annual update of charges.

The commission's May 4 order (ER18-960) recognized the settlement as having resolved all issues concerning the charges under the Maine Public District Open Access Transmission Tariff.

The PUC last October provided a preliminary challenge to Emera Maine regarding the 2017 Annual Update, and the two parties engaged in settlement discussions resulting in the newly approved offer of settlement.

Article 4 of the settlement sets forth the terms regarding the correction of certain errors in the 2017 Annual Update and the Tariff's Attachment J formulas. It also provides for Emera Maine to revise those formulas to reflect the federal Tax Cuts and Jobs Act of last December.

FERC OKs Market-based Rates for Southern Co.

FERC said last week it will allow Southern Co. to maintain its market-based rate authority in the Southern, South Carolina Electric and Gas, City of Tallahassee and Santee Cooper balancing authority areas.

The commission's May 5 ruling terminated

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COMPANY BRIEFS

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Section 206 proceedings it launched in 2015 and 2017, saying it was convinced that Southern's "tailored mitigation" — day-ahead and hour-ahead energy auctions and a cost-based price cap — addressed its market power concerns (ER10-2881, *et. al.*).

Southern reported that their indicative screen market shares are 44.9 to 58.4% for the Southern BAA; 8.2 to 21.3% for SCEG; 17.9 to 29.6% for Tallahassee; and 14 to 19.9% for Santee Cooper.

Entergy Plant Supporters At Hearing Included Actors

At least four of the people who attended a New Orleans City Council hearing last fall to support a gas-fired power plant Entergy New Orleans recently was granted permission to build in the Crescent City were professional actors who were paid to be there.

The four were among about 50 people at the hearing who wore bright orange shirts with the slogan: "Clean Energy. Good Jobs. Reliable Power." One said he recognized 10 to 15 other people who work in the film industry in the New Orleans area. One of two men who recruited and organized the actors said he worked with a Los Angeles company called Crowds on Demand.

Entergy said it didn't pay anyone to attend the meeting.

More: *The Lens*

SWEPCO President and CEO McCellon-Allen Retires

Southwestern Electric Power Co. said May 4 that President and Chief Operating Officer Venita McCellon-Allen has retired.


McCellon-Allen

The company said it has named Malcolm Smoak interim president and chief operating officer until it chooses a permanent replacement. Smoak is SWEPCO's vice president, distribution region operations.

McCellon-Allen spent 30 years with American Electric Power and its subsidiaries, which include SWEPCO. She had been SWEPCO's president since 2010. From 2010 through 2017, she also led the executive team at AEP Texas.

More: *American Electric Power*

MidAmerican to Start Building 2 More Wind Farms Next Month

MidAmerican Energy said May 1 it will begin constructing two wind farms with a total capacity of 550 MW in Adair County, Iowa, next month.

The Arbor Hill and Orient wind farms are part of MidAmerican's previously announced $3.6 billion Wind XI project, which is scheduled to be completed in December 2019.

MidAmerican expects renewable generation will comprise more than 90% of its customers' annual retail electricity usage by 2020.

More: *MidAmerican Energy*

Dominion Planning to Build At Least 8 Natural Gas Plants

Dominion Energy Virginia plans to build at least eight new natural gas-fired plants during the next 15 years, according to the integrated resource plan it filed May 1 with the Virginia State Corporation Commission and the North Carolina Utilities Commission.

Natural gas would grow from 38% of the company's capacity mix last year to as much as 59% by 2033, according to information that Dominion provided to the Associated Press. Coal would shrink from 21% to no more than 15%, and renewables would grow from 3% to as much as 9%.

Paul Koonce, president and CEO of Dominion Energy's power generation group, said the plan puts the company on an "environmentally responsible, sustainable path" for the long term.

More: *The Associated Press*

Duke: Renewable Portfolio Up 20% Last Year

Duke Energy added more than 1,000 MW of wind, solar and biomass energy last year, boosting its renewable energy portfolio by 20%, according to a sustainability report the company released April 30.

The addition put Duke closer to its goal of owning or having under contract 8,000 MW of wind, solar and biomass energy by 2020, according to the company.

More: *Citizen Times*

Marathon Agrees to Buy Andeavor for $23.3B

Marathon Petroleum has agreed to buy Andeavor for $23.3 billion in cash or stock, the companies said April 30.

The deal would be the biggest ever for an oil refiner and would create the largest independent fuel maker in the U.S.

It also would increase Marathon's natural gas processing capacity by about 20% to more than 10 Bcfd.

More: *Bloomberg Markets*

Sommers to Replace Gerard As API President, CEO

The American Petroleum Institute said May 2 that its board of directors has elected Mike Sommers president and CEO.

Sommers, who is president and CEO of the American Investment Council, will join API later this summer. He will succeed Jack Gerard, who said earlier this year that he would step down this summer after a decade with API and relocate to Salt Lake City.

Prior to joining the AIC in 2016, Sommers served as chief of staff to then-Speaker of the House John Boehner (R-Ohio).

More: *American Petroleum Institute*

ATC Cables in Straits of Mackinac Capped and Sealed

A team of investigators led by the Coast Guard on April 30 said crews have finished capping and sealing the American Transmission Co. cables that were severed by a suspected boat anchor strike in the waterway connecting Lake Huron and Lake Michigan. (See *Wisc. Tx Picks up Slack After Upper Peninsula Outage*.)

The cables were returned to the bottom of the Straits of Mackinac. ATC and the Michigan Department of Environmental Quality are working on a plan to remove them.

About 600 gallons of mineral oil insulation fluid leaked from the cables.

More: *The Associated Press*

FEDERAL BRIEFS

DOE to Provide $30M for Long-term Energy Storage Projects

The Department of Energy on May 1 said it will provide up to $30 million in funding for long-duration energy storage projects.

The funding opportunity is part of a new Advanced Research Projects Agency-Energy program called Duration Addition to electricitY Storage (DAYS).

The department said DAYS teams will develop energy storage systems that can be deployed almost anywhere and discharge electricity at a per-cycle cost much lower than systems available today.

More: *Department of Energy*

TVA's Q1 Net Income on Pace to Set Annual Record

The Tennessee Valley Authority said May 6 it had net income of $462 million on sales of $2.75 billion in the first quarter, which would put it on pace to top the record $1.2 billion in net income it posted in fiscal 2016.

The high figure was attributed to a cold January, which led TVA to set an all-time record for energy demand in a 24-hour period, 706 million kWh. TVA also racked up three of its top-12 winter peak demands during the month.

The high net income came despite a decrease in TVA's price of power, which fell to 6.8 cents/kWh in the first quarter of this year from 6.9 cents/kWh in the first quarter of last year. Rains that boosted hydropower production and cheap natural gas were behind the decrease.

More: *Times Free Press*

Lobbyist Who Set up Pruitt's Morocco Trip Hired by Country

Lobbyist Richard Smotkin was hired by the government of Morocco as a foreign agent for $40,000 a month just months after he helped organize EPA Administrator Scott Pruitt's trip to the country last December, according to internal EPA communications related to Pruitt's schedule in Morocco.

Smotkin also took part in some of Pruitt's meetings in Morocco, according to people on the trip. Members of Congress had questioned whether Pruitt had a legitimate government reason to travel to Morocco, as well as the trip's cost.

Pruitt is the subject of at least 11 investigations concerning his first-class travel, pay raises given to his staff, money spent on security and office furnishings, and trips to his home in Oklahoma that were paid for by taxpayers.

More: *The New York Times*

Wind, Solar 94% of Capacity Installed in First Quarter

Wind and solar generation accounted for 94% of the capacity that was installed in the U.S. in the first quarter, according to the FERC Office of Energy Projects' Energy Infrastructure Update for March.

Sixteen wind projects with 1,793 MW of capacity and 92 solar projects with 1,356 MW of capacity came online during the quarter.

Despite that, wind still only makes up 7.7% of the country's installed capacity behind natural gas (43.4%), coal (23.1%), nuclear (9.1%) and hydro (8.5%). Solar (2.8%) trails all those plus oil (3.6%).

More: *FERC*

NRRI Hires FERC Economist Carl Pechman as Director

The National Regulatory Research Institute said April 30 it has hired Carl Pechman as director.

Pechman replaces Rajnish Barua, who recently was hired to be the Delaware Public Service Commission's executive director.

NRRI is the research arm for the National Association of Regulatory Utility Commissioners and the nation's public utility commissions. Pechman previously served as an economist/supervisory energy industry analyst for FERC and was assigned as a senior electricity advisor to the Department of Energy.

More: *NARUC*

NRC Launches Investigation Into Watts-Bar Plant

The Nuclear Regulatory Commission said April 30 it has launched an investigation into the circumstances surrounding voids in the residual heat removal system at the Tennessee Valley Authority's Watts-Bar power plant near Spring City, Tenn.

The residual heat removal system completes the plant's cooldown process at lower pressures and provides important functions during certain accident scenarios. The voids rendered it inoperable for a period of time on the plant's Unit 1 and Unit 2 reactors.

The commission expects the onsite portion of the investigation to take several days. It expects to issue a report documenting the results of the investigation within 45 days of concluding the investigation.

More: *Nuclear Regulatory Commission*

Hopi, Others File Suit to Force CAP to Buy Navajo Plant Power

The Hopi Tribe, the United Mine Workers of America and Peabody Western Coal on May 1 filed a lawsuit in U.S. District Court in Phoenix seeking to have the court declare that the Central Arizona Project (CAP) must buy power from the Navajo Generating Station as long as the coal-fired power plant remains open.

The generating station, which is on Navajo land, is scheduled to close next year. Its closure would force the closure of the Kayenta Mine, which is located about 80 miles away on Navajo and Hopi land.

CAP is the plant's biggest customer, using its power to pump water from the Colorado River to Phoenix and Tucson. CAP officials said last year that moving to natural gas-fired power could save money for water users in Maricopa, Pima and Pinal counties. The lawsuit maintains CAP must continue to buy power from the Navajo Generating Station if a buyer can be found for it.

More: *The Republic*

Supreme Court Lets Stand NY's Constitution Pipeline Permit Denial

The U.S. Supreme Court on April 30 declined to hear Constitution Pipeline's challenge to New York's refusal to issue a water quality certification for a natural gas pipeline it wants to build to the state from Pennsylvania.

The high court let stand an August 2017 ruling by the 2nd U.S. Circuit Court of Appeals in favor of the state.

FERC in January refused Constitution Pipeline's request to find that New York environmental regulators had failed to act in a timely manner on its water permit application. (See *FERC Upholds New York Denial of Constitution Pipeline*.)

More: *Reuters*

State Briefs

REGIONAL

Report: 37 States, DC Took Grid Modernization Actions in Q1

Thirty-seven states and D.C. took actions related to grid modernization during the first quarter, according to a report issued May 3 by the North Carolina Clean Energy Technology Center.

The first-quarter edition of "The 50 States of Grid Modernization" said 259 grid modernization actions were taken, up from 196 in the fourth quarter of 2017 and 148 in the first quarter of 2017. New York, California and Massachusetts took the greatest number of actions during the quarter, followed by Hawaii, New Jersey and Minnesota.

The report said the greatest number of actions related to advanced metering infrastructure rules, energy storage deployment, grid modernization investigations and utility business model reforms.

More: *North Carolina Clean Energy Technology Center*

IOWA

Bill Reducing Energy Efficiency Funding Sent to Governor

The Senate on April 30 passed a bill that would reduce the amount that utilities charge their customers for energy-efficiency projects by $100 million.

The bill, which also requires utilities to pass their tax savings from the Tax Cut and Jobs Act on to their customers, had previously passed the House of Representatives and now goes to Republican Gov. Kim Reynolds.

The Senate approved the bill on a party-line vote. Republicans contend it will save residents money. Democrats say it will lead to higher energy costs and threaten the jobs of 20,000 residents who work on energy-efficiency projects.

More: *Des Moines Register*

NEW MEXICO

Solar Developer Funding Campaigns Of Regulators After Favorable Vote

Two of the three Public Regulation Commissioners who ignored a hearing examiner's recommendation and voted to allow Public Service Company of New Mexico (PNM) to purchase five solar farms to be built for it by Affordable Solar are largely having their re-election campaigns funded by the solar developer, according to campaign finance reports filed with the secretary of state's office.

PRC Chairman Sandy Jones and Commissioner Lynda Lovejoy voted in favor of the purchase even though the hearing examiner, Carolyn Glick, said PNM had failed to show the deal was the most cost-effective way for the company to procure solar power. Other PRC staff also opposed approving the purchase.

New Energy Economy Executive Director Mariel Nanasi said the votes by Lovejoy and Jones — and the campaign donations they have received from Affordable Solar and related parties — have created an appearance of impropriety. New Energy Economy is appealing the PRC's approval of the deal to the Supreme Court.

More: *Santa Fe New Mexican*

NEW YORK

NYSERDA Makes $15 Million Available for Fuel Cell Systems

The New York State Energy Research and Development Authority said May 3 that it will make available $15 million to install and run fuel-cell systems to support critical infrastructure, such as hospitals, police and fire stations and supermarkets.

NYSERDA said the amount of funding it will give to a system depends on how it will be used, but no system will receive more than $1 million. Each fuel cell module must be greater than 25 kW, it added.

Funds for the systems will be available through Dec. 31, 2019.

More: *NYSERDA*

OKLAHOMA

Landowners Told to Allow Wind Catcher Surveys

Residents with land in the path of the proposed Wind Catcher Energy Connection project on April 30 received letters threatening to have an injunction filed against them if they don't allow environmental surveys of their properties.

The letters were sent by the Taylor Foster law firm on behalf of Public Service Company of Oklahoma, which is a partner in the $4.5 billion project with its sister company, Southwestern Electric Power Co.

One of the recipients said the letters say that if they don't allow the surveys, an injunction would be filed against them in Garfield County District Court.

More: *Enid News & Eagle*

PENNSYLVANIA

PUC Allows Sunoco to Resume Operating Mariner East

The Public Utility Commission on May 3 issued an order allowing Sunoco Pipeline to reinstate operations of the Mariner East 1 Pipeline, which were suspended after an emergency order it issued March 7.

The commission said the order follows an extensive investigation into safety concerns raised by its independent Bureau of Investigation and Enforcement and comes in response to a petition filed by Sunoco.

The PUC ordered the pipeline shut down after sinkholes opened up near it in the Philadelphia suburb of West Whiteland Township. Sunoco is building two other pipelines along Mariner East 1's route, and the sinkholes were near a construction site for them. The three Mariner pipelines are meant to carry natural gas liquids from the Marcellus Shale to a port south of Philadelphia on the Delaware River.

More: *Pennsylvania Public Utility Commission*

TEXAS

Xcel Files $65M Upgrade Plan with PUC

Xcel Energy said April 30 it has filed a plan with the Public Utility Commission to perform $65 million in upgrades to its grid in Bailey and Lamb counties.

The company said the upgrades are meant to relieve overloaded lines and accommodate future expansion in the region.

The upgrades are part of Xcel's Power for the Plains initiative for enhancing the company's infrastructure in its service area. The company hopes to have them completed within four years.

More: *Lubbock Avalanche-Journal*