RTO Insider
Your Eyes and Ears on the Organized Electric Markets
CAISO ■ ERCOT ■ ISO-NE ■ MISO ■ NYISO ■ PJM ■ SPP

ISSN 2377-8016 : Volume 2017/Issue 50 December 19, 2017

CAISO Plan Extends Day-Ahead Market to EIM

By Jason Fordney

CAISO is floating a proposal that would extend many of the features of its day-ahead market into the footprint of the Western Energy Imbalance Market (EIM) while possibly averting some of the thorny governance issues related to regionalization of the ISO.

The proposal is part of a broader plan focused on improving CAISO's day-ahead market to better deal with emerging trends in resource procurement and planning, the ISO said. CAISO is including the plan in its Draft 2018 Policy Roadmap, which will guide the ISO's many ongoing initiatives over the next three years related to grid operations, markets, new resources and generator retirements.

But a proposed expansion of the ISO's day-ahead market could face competition from other corners. Reliability coordinator Peak Reliability and PJM announced last week they will explore the development of markets and other services in the West. (See *PJM Unit to Help Develop Western Markets*.) Farther inland, Mountain West Transmission Group is advancing on plans to integrate its member utilities into SPP.

California's efforts to regionalize CAISO's operations have twice stalled in the State Legislature in the last two years over concerns the state would cede too much oversight of its grid to other Western states less friendly to its ambitious environmental policies. Those states, in turn, have been wary of submitting control of their transmission systems to an entity controlled by their much larger neighbor.

Several utilities reportedly met in Phoenix this week to discuss the CAISO proposal, but

Continued on page 9

NARUC Calls for PURPA Reforms, Outlines Proposed Changes

By Rich Heidorn Jr.

State regulators on Monday called on FERC to change its interpretation of the Public Utility Regulatory Policies Act to "align" the 1978 law "with modern realities."

John "Jack" Betkoski III — vice chairman of the Connecticut Public Utilities Regulatory Authority and president of the National Association of Regulatory Utility Commissioners — wrote FERC commissioners a letter saying he was pleased that interim

Continued on page 45

NERC Report Urges Preserving Coal, Nuke 'Attributes'

By Rich Heidorn Jr.

NERC released its annual Long-Term Reliability Assessment on Thursday, calling for more efforts to preserve "essential reliability services" provided by coal and nuclear plants but saying it is agnostic as to how FERC and regional grid operators do so.

"FERC should consider the reliability and resilience attributes provided by coal and nuclear generation to ensure that the generation resource mix continues evolving in a manner that maintains a reliable and resilient" bulk power system (BPS), the 2017 report said.

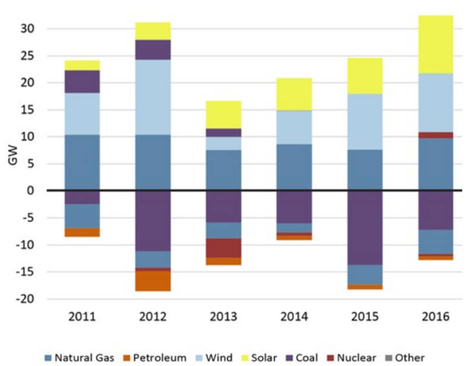
NERC's concerns that the increase in natural gas and renewable generation could endanger grid resilience puts it squarely in the middle of the debates over state nuclear subsidies and Energy Secretary Rick Perry's call for price supports for coal and nuclear plants in organized markets.

"The changing composition of the North American resource mix calls for more robust planning approaches to ensure adequate essential reliability services and fuel assurance," the report said, calling for new metrics to supplement reserve margins and requirements that all new generation provide voltage support and frequency response.

But NERC said it would limit its advice on the contentious issue, which is now before FERC. (See *McIntyre Takes FERC Chair; Wins Delay on NOPR*.)

"What would be a bad thing is if we bring on a lot more gas-fired generation but all that gas-fired generation ... can be interrupted, especially during winter peak times," John Moura, NERC's director of reliability assess-

Continued on page 43



NERC-wide generation additions and retirements (incremental nameplate) | *NERC*

Also in this issue:

RTO Insider

CAISO ERCOT ISO-NE MISO NYISO PJM SPP

Editorial

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

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

Production Editor
Michael Brooks 301-922-7687

Contributing Editor
Peter Key

CAISO/West Correspondent
Jason Fordney 571-224-8960

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

MISO Correspondent
Amanda Durish Cook 810-288-1847

PJM Correspondent
Rory D. Sweeney 717-679-1638

SPP/ERCOT Correspondent
Tom Kleckner 501-590-4077

Subscriptions and Advertising

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

Account Executive
Marge Gold 240-750-9423

Marketing Assistant
Ben Gardner

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

Subscription Rates:

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

See details and Subscriber Agreement at rtoinsider.com.

IN THIS WEEK'S ISSUE

COUNTERFLOW
BY STEVE HUNTOON

Where to Begin? Or End?

By Steve Huntoon


Huntoon

I'd like to thank Energy Secretary Rick Perry for granting, albeit ungraciously, new FERC Chair Kevin McIntyre's request for 30 days to clean up one of the biggest piles ever dumped on FERC's doorstep. As *The Economist* said last week: "In the fierce competition for the federal government's worst policy, this is a contender."[1]

Perry's letter came the same day coal magnate Bob Murray said two totally opposite things: One, he can sell all his coal to China no problem.[2] Two, "we must have" the Perry plan immediately.[3] Setting a new bar for cognitive dissonance.

Perry's letter included a lot of saber rattling. Like maybe he's going to do something before or even after FERC acts.

Perry's Legal Authority is Slim to None, and Slim Left Town

The saber rattling is interesting because those pesky lawyers already told Perry that Federal Power Act Section 202(c) can't support what he'd like to do on his lonesome to prove his fealty to Donald Trump and Trump acolytes like Murray.

Apparently, Perry is contemplating ignoring the lawyers after all, going ahead with destroying competitive markets and imposing a carbon tax on consumers.

Now you may be thinking: "Steve, the last thing the Trump administration would impose would be a carbon tax."

But, Kemosabe, this is not a tax *on* carbon; this is a tax *for* carbon. A new kind of carbon tax — *accelerating* climate change.

Of note, FPA Section 202(c) has three prerequisites: (1) emergencies, (2) shortages and (3) temporary situations.[4]

So Perry would need to prevaricate about all three.

It would be the energy equivalent of the Holy Roman Empire, which, as Voltaire quipped, wasn't holy, Roman or an empire.

FirstEnergy, the 2003 Blackout and the Davis-Besse Catastrophe

I have some space left and don't want to neglect the co-cheerleader for the Trump-Perry tax: FirstEnergy, the utility primarily responsible for the 2003 Northeast Blackout.

Yes, the same FirstEnergy that used the words "resilience," "resilient" and "resiliency" *2,031* times in its comments to FERC.

A prior column talked about how FirstEnergy's Sammis coal plant isn't baseload, nor retiring prematurely, no matter how many hundreds of times FirstEnergy abused the words "baseload" and "premature" in its FERC comments.

Today, let's talk about FirstEnergy's Davis-Besse nuclear plant. Another of the power plants that FirstEnergy wants bailed out yet again, after its plants first got billions in "stranded cost" payments and then got even more money to support FirstEnergy's credit rating.

Did you know Davis-Besse was down during the 2003 blackout that FirstEnergy caused? Yes it was.

And it was down for *two years*. So much for nuclear plant resiliency — 90 days fuel supply and all that poppycock.

Why was it down? Boric acid corrosion had eaten a cavity completely through a 6.63-inch-thick carbon steel reactor pressure vessel (RPV) head down to a 3/16-inch inner liner of stainless steel cladding, which miraculously held until the cavity was finally discovered. Had that last 3/16 of an inch been eaten away or collapsed before detection and shutdown, it could have been *really bad news*.


Davis-Besse corrosion | *NRC*

The corrosion had occurred over a number of years. As the Nuclear Regulatory Commission stated: "The licensee allowed accumulations of boric acid to remain on the RPV head even though Procedure NG-EN-00324 directed their removal."[5]

This became a poster child for nuclear negligence, and the basis for NRC fines of $5.5 million[6] and Securities and Exchange Commission fines of $28 million.[7]

Here's where things get relevant for today. Repairs and replacement power cost hundreds of millions of dollars. How much of that was "capitalized," i.e., added to Davis-Besse's rate base upon which FirstEnergy now wants a return? I ballpark that at $100 million based on the increase in total plant costs between the end of 2001 and end of 2004, relative to the increase for the Perry nuclear plant that didn't share the Davis-Besse experience.

This $100 million is the tip of the iceberg. More recently, FirstEnergy spent another $600 million on Davis-Besse.[8]

If that $600 million had turned out to be a good investment, FirstEnergy would have kept mum and kept the money. But it hasn't turned out so good, so FirstEnergy wants customers to bail it out. Yet again.

Heads I win, tails you lose. Hugely.

Wrapping Up

Remember the Wisconsin utility executive who famously said the utility business is the only one where you can make more money from redecorating your office?[9] If the Trump-Perry tax happens, we'll know a utility can make even more money from causing a near nuclear catastrophe, and making more bad investments after that.

Oh, and where to end? Roll Tide.

Steve Huntoon is a former president of the Energy Bar Association, with 35 years of experience advising and representing energy companies and institutions. He received a B.A. in economics and a J.D. from the University of Virginia. He is the principal in Energy Counsel, LLP, www.energy-counsel.com.

[1] https://www.economist.com/news/united-states/21732571-fierce-competition-federal-governments-worst-policy

[2] https://www.eenews.net/greenwire/stories/1060068535/

[3] http://www.washingtonexaminer.com/trump-ally-bob-murray-we-must-have-early-ferc-decision-on-coal-subsidies/article/2643005

[4] What the D.C. Circuit Court of Appeals has summarized as "temporary emergencies, epitomized by wartime disturbances." https://openjurist.org/574/f2d/610/richmond-power-light-of-city-of-richmond-indiana-v-federal-energy-regulatory-commission

[5] https://www.nrc.gov/reactors/operating/ops-experience/vessel-head-degradation/lessons-learned/lessons-learned-files/lltf-rpt-ml022760172.pdf (page 52)

[6] https://www.nrc.gov/docs/ML0511/ML051110336.pdf

[7] http://www.toledoblade.com/local/2006/01/21/FirstEnergy-to-pay-28-million-fine-for-lying-Davis-Besse-s-punishment-largest-in-nuclear-industry.html

[8] "The majority of the remaining capital investments over the next several years will be focused on projects to extend the life of our nuclear assets with new steam generators at Davis-Besse this year and new steam generators and a reactor head at Beaver Valley Unit 2 in 2017," http://www.cleveland.com/business/index.ssf/2014/02/firstenergy_spending_600_milli.html; http://investors.firstenergycorp.com/file/Index?KeyFile=21777558#gsc.tab=0.

[9] Oh yeah, he really said that: http://archive.fortune.com/magazines/fortune/fortune_archive/1995/11/13/207697/index.htm. And for a fine piece of investigative reporting on the regulated utility real world, check this out: https://www.postandcourier.com/news/power-failure-how-utilities-across-the-u-s-changed-the/article_434e8778-c880-11e7-9691-e7b11f5b3381.html.

STAKEHOLDER SOAPBOX

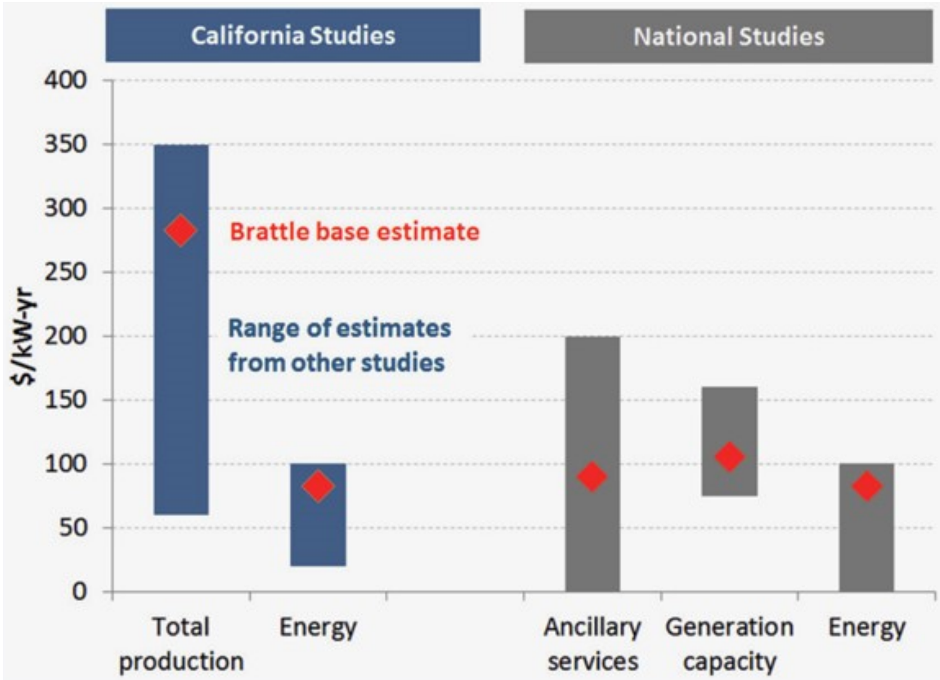
Nothing Worth Having Comes Easy: Capturing the Stacked Benefits of Battery Storage

By Ryan Hledik

THE Brattle GROUP

Batteries have the unique potential to provide a broad range of valuable services to the grid. If operators are able to control the battery in a way that simultaneously captures multiple value streams, the resulting "stacked benefits" can amount to significantly more revenue than pursuing any individual stream in isolation. In some cases, those benefits can justify battery investment at today's costs.

The potential for batteries to provide stacked benefits was challenged in a Dec. 5, 2017, *RTO Insider* editorial titled "Grid Batteries & Kool-Aid, Once More with Feeling," by Steve Huntoon. That article includes a critique of a report that I developed with colleagues at The Brattle Group, in which we quantify the multiple value streams that could be captured from batteries in California.[1]



Energy storage value estimates from recent studies | *The Brattle Group*

Huntoon's article makes four basic points when arguing against the feasibility of stacked benefits. However, there are nuanced conceptual problems with each of those four points.

Combined Energy and Capacity Value

First, the Huntoon article argues that energy price arbitrage value cannot be added to capacity value, because "a battery cycled daily for energy arbitrage is going to be partially or totally discharged most of the time" and therefore unavailable to provide capacity. This assumes that all reliability events occur instantaneously, with no warning. In fact, system operators commonly provide notice prior to a reliability event and can often anticipate events in advance by tracking and forecasting supply and demand. Such notification would allow the battery operator to charge the battery and fulfill its commitment. Further, in the event that the timing of battery dispatch for energy value is not coincident with reliability needs, the modeling behind our study has accounted for that impact.

Capacity Value

The Huntoon article suggests that batteries cannot provide capacity value because reliability events often last longer than four hours (which was the assumed battery capacity in our study). However, system operators typically establish a performance duration that resources must satisfy in order to qualify as a capacity resource. The required performance duration is only three hours for "peak ramping" and "super peak ramping" resources in CAISO's "flexibility capacity" products, for instance.

In fact, a battery with even less availability would still have capacity value. For example, the dispatch of two batteries each with two-hour capacity could be staggered in order to provide four hours of discharge. In the U.K., the government recently proposed a novel approach in which batteries are given capacity credit that is a function of their duration. Batteries with four-hour duration would receive the full allowed capacity credit. Batteries with less duration would receive a prorated credit.

To the extent that any individual day would have resource needs that are greater than four consecutive hours, that is accounted for in our study, and the capacity value of the battery was derated accordingly.

Energy Value

Huntoon's article questions the extent to which battery operators could predict the highest priced hours of each day and discharge the battery during those hours. It is certainly true that battery operators will not have perfect foresight into market prices. However, system operators will schedule batteries in energy markets to minimize system costs. Our modeling is based on a realistic assumption that this dispatch will align reasonably well with high priced hours. Additionally, self-scheduling resources could use day-ahead prices as a guide for bidding into the real-time energy market, and potentially benefit from the higher price volatility in that market.

Frequency Regulation

The Huntoon article points out that frequency regulation is a shallow market with limited need. This is true, and is explicitly acknowledged in our report.[2] At the same time, early movers in many markets have provided significant value by using fast-responding batteries to provide this service. Frequency regulation (and other ancillary services) could become increasingly important in the future as more intermittent renewable resources must be integrated

Continued on page 5

Stakeholder Soapbox

Nothing Worth Having Comes Easy: Capturing the Stacked Benefits of Battery Storage

Continued from page 4

into the power system.

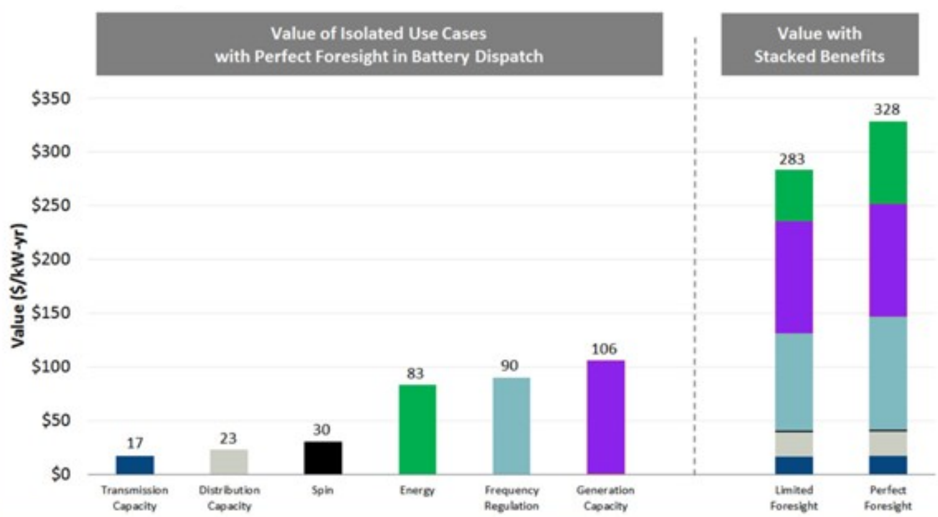
Additionally, in recognition of the current limited need for frequency regulation, we included a sensitivity case that assumed no incremental value from the frequency regulation market. In that case, the stacked value of the battery still exceeded $200/kW-year.

A point that is not raised in the Huntoon article, but which is important to consider when assessing the value of energy storage, is the impact that large quantities of energy storage deployment could have on energy and capacity market prices, thus impacting the incremental value of additional storage resources. Our California study was focused only on the incremental value of 1 MW of storage. However, a study by my Brattle colleagues in the ERCOT market included detailed modeling that accounts for the effect of these market impacts on the stacked value.[3] The study identified a significant amount of economic energy storage potential, as well as a number of barriers to achieving that potential.

Capturing the Potential

Our study in California was intended to illustrate the potential system value of stacked benefit streams from battery storage in the absence of existing barriers. There certainly will be challenges to capturing this potential. To fully tap into this value, market rules may need to change, regulatory constructs may need to be revised, retail rates may need to be redesigned and technical challenges will need to be addressed.

But to paraphrase Theodore Roosevelt, "Nothing worth having comes easy." In the power industry, initial skepticism about emerging technologies is regularly overcome through technological improvements and market and regulatory adjustments; just ask demand response providers, which have developed significant and valuable wholesale market resources over the past decade. In this case, the potential stacked value of battery storage is real and too significant to simply ignore.



| The Brattle Group

Ryan Hledik is a Principal in The Brattle Group's London office. He specializes in the economics of policies and technologies that are focused on the energy consumer. Mr. Hledik holds a Master's Degree in Management Science and Engineering from Stanford University, and a Bachelor's Degree in Applied Science from the University of Pennsylvania, with minors in Economics and Mathematics.

[1] Ryan Hledik, Roger Lueken, Colin McIntyre and Heidi Bishop, "Stacked Benefits: Comprehensively Valuing Battery Storage in California," prepared for Eos Energy Storage, August 2017. http://www.brattle.com/system/publications/pdfs/000/005/494/original/Stacked_Benefits_-_Final_Report.pdf.

[2] From page 11 of the report: "... it is important to note that the frequency regulation market is 'shallow' and can quickly saturate."

[3] Judy Chang, *et al.*, "The Value of Distributed Electricity Storage in Texas," prepared for Oncor by The Brattle Group, November 2014. http://www.brattle.com/system/news/pdfs/000/000/749/original/The_Value_of_Distributed_Electricity_Storage_in_Texas.pdf.

Huntoon Responds

I appreciate The Brattle Group responding to my column and would have these thoughts in reply:

1. Re. capacity value: Brattle says "system operators commonly provide notice prior to a reliability event." This is true regarding forecasted temperature extremes but not regarding unanticipated events, which are by nature unanticipated. The PJM Capacity Performance construct, for example, is based on a capacity resource being "on call" all the time.

2. Re. capacity duration: Brattle says a battery can have value even though its duration is constrained. The CP construct expects indefinite duration, and Brattle does not address the PJM spreadsheet in my column showing capacity emergencies longer than three to four hours. Brattle is of course correct that duration can be increased by "derating" the battery. So, for example, a three-hour 10-MW/30-MWh battery can be changed to a six-hour duration (incidentally the PJM expected performance duration) by derating it to 5 MW/30 MWh, but that would double the cost of the battery in terms of its capacity value ($/MW).

3. Re. energy arbitrage value: Brattle says "system operators will schedule batteries in energy markets to minimize system costs." But RTOs will not optimize dispatch of batteries to maximize revenue for the battery owner, certainly not in the eastern RTOs, and a colleague who knows CAISO well confirmed that the ISO won't do that either. The battery owner must decide in advance what hours to offer for charging and for discharging. A model that assumes the battery owner can know the lowest priced hours for charging and the highest priced hours for discharging is unrealistic.

4. Re. a market price reduction benefit: Brattle says I didn't raise that. Yes, because Brattle didn't raise that in its study. And Brattle was right the first time. In a market, no resource is entitled to compensation for a market price reduction it causes. A resource enters the market and is valued/compensated at the clearing price — not the clearing price plus the "value" to load of reducing the clearing price. Otherwise every resource would be entitled to the same deal, the clearing price would be bid down to almost nothing, everyone would go bankrupt and that would be the end of that. It's the same with subsidies for generation, such as subsidizing request for proposal winners to bid down the clearing price such that the market never clears at the cost of new entry, thus eliminating unsubsidized new entry. End of market.

— Steve Huntoon

CAISO News

CAISO Board OKs New Generator Rules, Budget

By Jason Fordney

FOLSOM, Calif. — CAISO's Board of Governors on Thursday approved new generator contingency modeling, rules extending time for generator interconnections and enhancements to the Western Energy Imbalance Market (EIM).

The board made several unanimous votes and also approved CAISO's 2018 budget of $197.2 million, which funds ISO operations and salaries based on fees collected from system users. The budget grew by less than 1% from last year. (See CAISO Seeks Bump in Spending, Revenue Requirement.)

CME Initiative Approved

The board approved a new tool that will allow dispatch of generation to return energy flows to normal levels within a required time frame following the loss of major infrastructure. The contingency modeling enhancements (CME) proposal took years to develop, said Keith Casey, CAISO vice president of infrastructure and market development.

"This was some four years in the making to bring this to you today," Casey told the board, which unanimously approved the measure with little discussion.

CAISO developed the CME initiative to address a Western Electricity Coordinating Council reliability provision requiring grid operators to return a critical transmission path to its system operating limit within 30 minutes of a destabilizing event, such as the loss of a generator or transmission line.

The ISO currently dispatches generation to ensure that output does not exceed system limits, but its market model does not consider how to dispatch in a way that returns a line to normal operating limits within the required time. CAISO has been relying on "minimum online commitment constraints" that dispatch generation to meet constraint requirements, but generators are not compensated for the capacity made available to meet contingencies, and exceptional — or out-of-market — dispatch is used to return the transmission system to normal.

The new modeling creates "corrective capacity" in the day-ahead and real-time markets, and resources would be paid for the locational corrective capacity they provide.

Southern California Edison and the Six Cities group of Southern California municipal utilities opposed the change, saying it has limited benefit. SCE said the measure also introduces complexity and makes market prices less transparent. Powerex supported the changes but said it should not be implemented until CAISO overhauls its congestion revenue rights policy. (See CAISO Finalizes Constraint Tool Proposal.)

During the stakeholder process, CAISO removed a provision that would have applied the methodology to lines not subject to the 30-minute restoration time frame, saying it would develop an additional policy in that regard if needed. The ISO also declined a stakeholder suggestion to allow bidding for "corrective capacity" intended to reduce flows across a line within 30 minutes of a contingency, saying the measure would be complex and difficult to mitigate for market power.

New Interconnection Rules

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

The board also approved a change to CAISO's generator interconnection policies that will extend the time projects can remain in the queue. The revision is designed to help renewable projects stay financially viable as utility-scale procurement of renewables declines.

"This change will provide additional time to validate and correct interconnection request submittals, which should further streamline the efficiency of the overall interconnection study process," Casey said in a memo to the board. The change requires approval by FERC.

Many load-serving entities require that generators complete the second phase of the ISO's interconnection process to qualify for procurement. There is typically about a four-month window between Phase II reports and a transmission deliverability allocation. While projects can currently sit in the queue for a year, there has been a sharp increase in the number of projects unable to secure power purchase agreements before being dropped from the queue.

The new rules extend by a year the "parking" period in the queue, and the ISO also intends to examine its transmission planning deliverability qualification criteria in 2018. (See CAISO Launches Generator Interconnection Effort.)

Governor David Olsen said the proposal is "a good faith effort by the ISO to accommodate the slowdown of project development, especially renewable resources, that we are facing." But he added "we are under no illusions that taking this step is going to do anything effectively to address the underlying problems behind the effective suspension of procurement."

That issue, according to Olsen, is rooted in the development of distributed resources and the loss of utility load, "which could very materially affect the ability to develop [utility-scale] renewable resources in the near future. Those are issues that are going to have to be addressed by others." Olsen said that all parties involved in California policies should ensure that clean energy development can proceed.

The board also approved a set of EIM enhancements that represent a pared-down version of a package proposed earlier this year. The EIM Governing Body in late November approved the package, which automates some manual processes, facili-

Continued on page 7

CAISO NEWS

CPUC Targets Wildfires, Multifamily Solar, RMRs

By Jason Fordney

California regulators have approved new measures aimed at wildfire prevention, as utilities face growing scrutiny over fires that have occurred in the state over the last decade.

At its meeting in San Francisco on Thursday, the California Public Utilities Commission also approved a solar incentives program targeting low-income residents, among other decisions. But the CPUC deferred a vote on the retirement of the Diablo Canyon nuclear plant, which has sparked disagreements around the recovery of shutdown costs. (See PG&E Disputes ALJ's Diablo Canyon Recommendation.)

Focus on Wildfires, Utilities

The CPUC approved more stringent wildfire protections for utilities, creating a "high fire-threat" district where correction of fire safety hazards will be prioritized.

"This is one of the areas where we are working hard to be at the forefront of utility safety programs" and represents "a major rewrite of the fire prevention rules for utility poles," CPUC President Michael Picker said.

"Most of the elements here are not specifically driven by climate change, but they accept and acknowledge that the scope of the problem is changing," Picker said, noting that high-hazard fire zones have grown to 44% of the state landscape. The decision requires new vegetation management and more stringent wire-to-wire clearances, among other measures.

Speaking during the public comment period, Southern California Edison President Ronald Nichols told the commission that the Thomas Fire in the Los Angeles area is threatening transmission lines and has caused some outages, but only about 500 customers have been affected. The company issued a press release Dec. 11 saying that state investigations "now include locations beyond those identified last week as the apparent origin of these fires. SCE believes the investigations now include the possible role of its facilities."

Recent fires in California, including the massive Thomas Fire, have been particularly destructive and increased the focus on utilities over their possible role. (See California Fires Spark CAISO Transmission Emergency.) The CPUC recently denied San Diego Gas & Electric's request to recover the costs of 2007 fires from ratepayers. (See Besieged CPUC Denies SDG&E Wildfire Recovery.) Pacific Gas and Electric is also facing investigation and lawsuits over the October fires in Northern California.

Low-income Solar Program

The CPUC passed a measure that implements the framework for a solar incentive program for multifamily housing, including goals, funding, administration and creating a new statewide program administrator. The program is to be financed by $100 million annually from PG&E, SDG&E, SCE, Liberty Utilities and PacifiCorp's greenhouse gas auction proceeds.

The measure implements Assembly Bill 693, passed in 2015, which creates the Multifamily Affordable Housing Solar Roofs Program. The incentive program will be run by the new administrator and subsidize the costs of solar generation on certain types of multifamily affordable housing. It will allocate net energy metering tariff credits associated with the system's generation to tenants and common areas of the property. The bill established the program for low-income households that would otherwise be unable to install on-site solar generation.

Picker expressed concerns over the long-term viability of the program because of tax proposals currently under consideration in Congress. Commissioner Martha Guzman Aceves was assigned the initiative.

Guzman Aceves cast the lone "no" vote against a proposed statewide marketing and outreach program for residential rate reform, which was assigned to Picker. The CPUC opened a rulemaking to examine investor-owned utilities' rate structures, the transition to time varying and dynamic rates, and other statutory obligations.

CPUC Resolutions on CCAs, RMRs

The decisions at the CPUC's regular meeting came in a week when the agency separately issued several new resolutions that received attention in the industry.

One resolution sets up a decision that community choice aggregators be subject to the same resource adequacy obligations as electric utilities. (See California Proposes Resource Adequacy Obligations for CCAs.)

Another resolution sets up a vote next month in response to controversial reliability-must-run agreements signed between CAISO and Calpine to keep the company's Yuba City and Feather River natural gas units online. The CAISO Board of Governors expressed reservations about the agreements, funded by ratepayers, when it approved them last month. (See Board Decisions Highlight CAISO Market Problems.) The increasing use of RMRs is drawing negative attention for keeping natural gas units operating when they would otherwise retire.

Finally, the CPUC on Friday issued a proposed resolution that would place a moratorium beginning Jan. 11, 2018, on new commercial and industrial customer gas connections in the Los Angeles County area that would rely on Southern California Gas' Aliso Canyon storage facility.

CAISO Board OKs New Generator Rules, Budget

Continued from page 6

tates bilateral settlements and improves the market's modeling accuracy. (See EIM Governing Body Approves 'Consolidated' Initiatives.)

In executive session, the board also promoted Jodi Ziemathis, the ISO's executive director of human resources, to vice president of human resources. Chief Financial Officer and Treasurer Ryan Seghesio was also named vice president, while retaining his current titles.

CAISO NEWS

Tight Supplies, Solar Ramps Drive CAISO Summer Spikes

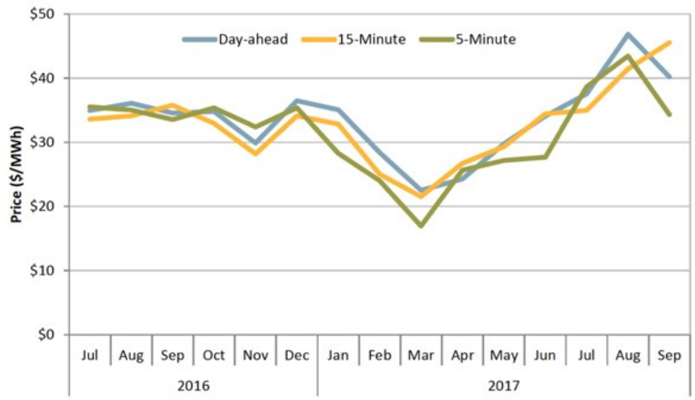
By Jason Fordney

CAISO day-ahead prices hit all-time highs for the second time this year during the third quarter, and the frequency of price spikes in the 15-minute and five-minute markets increased, the ISO's Department of Market Monitoring said in its quarterly market performance report.

High temperatures in California drove up demand at the beginning and end of August and into September, according to the report. Load peaked at 50,116 MW on Sept. 1, just short of the 50,270-MW peak record set in July 2006. Trading that day also saw day-ahead system marginal prices soar over $200/MWh during a four-hour period and hit $770/MWh in one interval.

"These outcomes were primarily driven by tight supply conditions as a result of a number of factors in combination with high demand while a significant amount of solar production is ramping down during sunset hours," the report said. Average 15-minute market prices increased during every month of the third quarter from about $34/MWh in June to more than $45/MWh in September because of higher temperatures and loads.

The Monitor also confirmed that software problems had caused day-ahead prices to hit record highs in the second quarter even after being mitigated. In its second-quarter report, the department had noted that prices should not rise after mitigation and said it was investigating the cause. (See Monitor: CAISO Q2 Prices Hit Record Despite Mitigation.) The third-quarter report said the error was fixed on July 22.

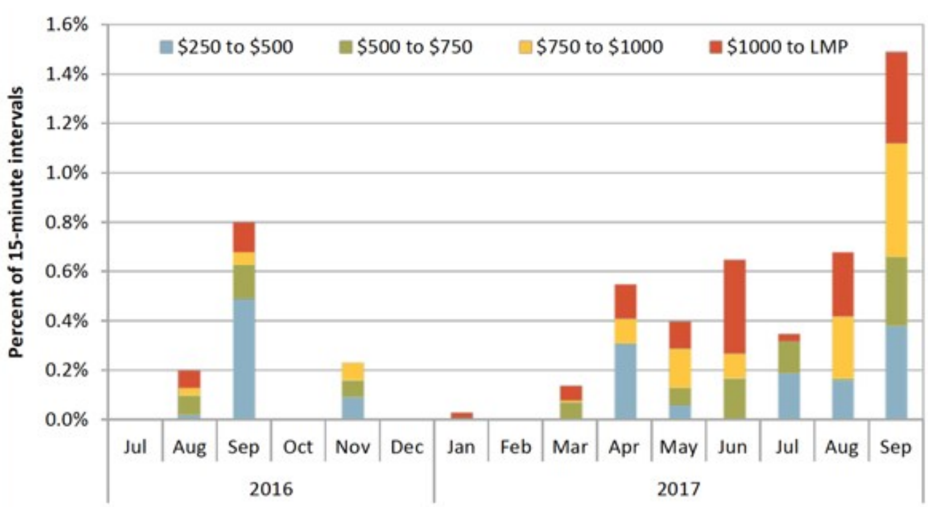


Average monthly prices (all hours) - system marginal energy price | *CAISO*

"The ISO has determined that a software error introduced in 2016 resulted in infeasible energy and ancillary service awards for resources in the market power mitigation run but not the binding market run in the day-ahead market," the Monitor said in the third-quarter report. "The software error resulted in an erroneous increase in supply available in the market power mitigation run, causing prices in that run to be lower than they would have been had all awarded schedules been feasible."

CAISO is "currently evaluating the impact of this error on the market power mitigation process on affected days," the report said.

Day-ahead prices appeared to be competitive in most hours, the Monitor said, and total year-to-date wholesale energy costs are close to 2016 totals, after the prices are adjusted for natural gas and greenhouse gas prices. Higher gas prices resulted in larger overall energy costs for 2017.



Frequency of high 15-minute prices by month | *CAISO*

Transmission congestion was low in the day-ahead market in the Pacific Gas and Electric and Southern California Edison service areas but caused prices to drop about 2% in San Diego Gas & Electric's area. Congestion in the 15-minute market pushed up prices in PG&E and SCE and decreased SDG&E prices. Frequent congestion on the Doublet Tap-Friars 138-kV constraint created an export-constrained area, undercutting prices in San Diego.

The Monitor said its analysis of natural gas price volatility shows a limited need for increased bidding flexibility created by raising commitment cost and default energy bid caps. CAISO followed the department's recommendation and reduced the Aliso Canyon real-time gas scalars to zero beginning Aug. 1, raising them again temporarily Aug. 4-7 because of hot conditions.

Congestion revenue rights auctions took in $9 million less than payments to entities purchasing those rights, increasing year-to-date ratepayer losses to $38 million and to more than $680 million since the market began in 2009. The Monitor for more than a year has been calling for CAISO to eliminate CRR auctions. (See CAISO Monitor Proposes End to Revenue Rights Auction.)

The Monitor will discuss the third-quarter report with market participants during a Dec. 20 conference call.

CAISO NEWS

CAISO Plan Extends Day-Ahead Market to EIM

Continued from page 1

neither ISO nor utility representatives would confirm that the meeting took place. Description of the meeting came from an industry source, who wished to remain anonymous because they were not authorized to speak publicly.

The ISO's proposal would create something like an "RTO-lite," allowing for each EIM balancing authority (BA) to retain its reliability responsibilities and assuring that states could maintain control over integrated resource planning. Under the plan, resource procurement would remain under the authority of local regulators that — along with BAs — would continue to direct transmission planning and investment decisions.

CAISO said its effort would target better load management, more integration of distributed resources and enhancements to the EIM. Primary among the challenges the ISO faces is a shift toward more renewable and distributed energy resources, and conflicts between resource planning and reliability planning that are driving an increased need for out-of-market reliability-must run contracts for natural gas plants. (See *Board Decisions Highlight CAISO Market Problems*.)

"Recent grid operations challenges [point] to [the] need for day-ahead market enhancements to better manage [the] net load curve in real time," the ISO said in a presentation prepared for a Dec. 14 call about the roadmap.

Extending the day-ahead market to the EIM would improve scheduling efficiency and integration of renewables, and allow EIM participants to take advantage of enhancements to the market, the ISO said. The ISO re-prioritized its initiatives to focus on the day-ahead market changes as well as deferring development of some other market products.

CAISO is proposing changes to the day-ahead market to "address net load curve and uncertainty previously left to [the] real-time market." These include 15-minute scheduling granularity and a "flexible reserve" product that pays resources for must-offer obligations in the real-time market to address load uncertainty. Also being contemplated is combining the integrated forward market and the residual unit commitment process.

Extending the day-ahead market to the EIM would require market members to align transmission access charge models, according to the ISO. It would also involve expanding congestion revenue rights across the expanded footprint and analyzing day-ahead resources so balancing areas don't "lean on" each other for capacity, flexibility or transmission.

The ISO is also planning collaborative programs with the California Public Utilities Commission to better align resource adequacy planning with reliability planning and the changing grid.

The policy initiatives catalog lists CAISO's many ongoing updates to market rules, the EIM, distributed resources, generation retirements and changing conditions on the grid. Part of the roadmap process is the February updating of the catalog.

The final roadmap is due to be posted on Jan. 10, and more stakeholder calls will be held prior to review by the CAISO Board of Governors on Feb. 15. The ISO will accept comments on the draft roadmap until Jan. 4.

ERCOT NEWS

Texas PUC Challenging SPP-Mountain West Intertie Costs

By Tom Kleckner

Walker

The costs of maintaining DC ties to allow SPP's merger with the Mountain West Transmission Group should be allocated based on benefits, Texas Public Utility Commission Chair DeAnn Walker said last week.

In brief comments during the PUC's Dec. 14 open meeting, Walker, who serves on SPP's Regional State Committee, updated Commissioners Brandy Marty Marquez and Arthur D'Andrea on the "very interesting debate" taking place as Mountain West pursues SPP membership. (See SPP, Mountain West Integration Work Goes Public.)

The benefits touted by the two entities come in part from using the four DC interties that separate them to schedule power as a part of the SPP market. The four ties have a combined transfer capability of 720 MW.

"I [told SPP] yesterday that Texas believes that whatever [maintenance] costs are related to those DC ties or future ones … be done on a cost-benefit ratio," Walker said.

Mountain West has proposed those and any future costs be allocated on a load-ratio share, as part of its recommendation for a Westside Transmission Owners Committee.

Hartburg-Sabine Delay

Walker also briefed the commissioners on the MISO Board of Directors' recent decision to postpone approval of the $130 million Hartburg-Sabine 500-kV market efficiency project in eastern Texas for two months because of a late cost-allocation change. (See "Texas Project Delay," MISO Board Approves $2.6B Transmission Spending Package.)

The Texas regulators last month asked MISO to create separate zones for it and Louisiana to allow more granular cost allocation. The Louisiana Public Service Commission filed a similar request with the RTO. (See "PUC to Ask MISO to Create Texas Local Resource Zone," PUCT Open Meeting Briefs: Nov. 17, 2017.)

"We have assurances [MISO] will come back after FERC rules on the cost issues," Walker said. "They've made statements they fully support the project."

With the delay, Walker will hand off her MISO liaison duties to D'Andrea. She had temporarily inherited the responsibilities when Ken Anderson stepped down from the commission in November.

Fending off FERC

Walker said she is continuing to work with the Texas governor's office and ERCOT on a "potential solution" addressing her concerns that transmission projects along the U.S. border with Mexico may threaten the ISO's electrical separation from the rest of the country and the PUC's exclusive jurisdiction over the Texas grid operator. (See Regulators Fear Cross-Border Tx Risks ERCOT's FERC Exemption.)

"I don't want to talk publicly at this point, because it is a litigation strategy," she said.

Walker did say ERCOT staff has told her they could develop protocol language that makes it clear the ISO has authority to deny an e-Tag "or go so far as disconnect [its] system" from HVDC connections. The protocol change could be ready in time for ERCOT's February Board of Directors meeting.

"Hopefully it's a protocol that won't have to be used," Walker said.

ERCOT has several synchronous (AC) and asynchronous (DC) ties with the Mexican grid. Texas regulators are concerned comingled electricity flows from border projects in California and Arizona could lead FERC to claim jurisdiction through the U.S. Constitution's Commerce Clause.

"These are drastic measures we're talking about," Marquez told Walker. "These are huge market disruptors, but they are a last line of defense, so I think it's important we do it. We'll continue to seek other solutions as well."

Texas PUC Commissioners (left to right) Brandy Marty Marquez, Chair DeAnn Walker and Arthur D'Andrea

ERCOT NEWS

Board of Directors Briefs

Board Approves $246.7M Freeport Transmission Project

AUSTIN, Texas — The ERCOT Board of Directors last week unanimously approved a $246.7 million transmission project to address growing energy needs along the Texas Gulf Coast.

The Freeport Master Plan Project was endorsed in November by the Technical Advisory Committee before coming to the board Dec. 12. (See *ERCOT Stakeholders OK $246.7M in Freeport Reliability Projects*.)

Freeport is a highly industrialized region with several large chemical facilities and a major seaport. ERCOT projects that by 2019, the Freeport area's load will increase 92% to 1,979 MW, with much of that growth coming from a large chemical plant. An additional 300 MW is expected by the end of 2022.

"We continue to see growing demand for electricity in the ERCOT region, especially in areas affected by industrial growth and oil and gas activity," said ERCOT Senior Manager of Transmission Planning Jeff Billo.

The ISO's independent review of the project confirmed its necessity. Staff analyzed five options and proposed the most cost-effective to support future electric needs in the area.

CenterPoint Energy, which services the area, suggested a two-phase approach to solve reliability criteria violations caused by the increased load. A $32.3 million first phase, or "bridge-the-gap upgrades," focuses on near-term reliability needs with a 345-kV loop and a series of reactors, autotransformers and capacitor banks at a key substation.

The $214.4 million second phase comprises a new 48-mile, 345-kV double-circuit line and circuit upgrades to another 345-kV line.

Any projects approved by ERCOT that cost $50 million or more are classified as Tier 1 initiatives and require board approval.

The project must also be approved by the Public Utility Commission of Texas. Work is expected to be completed by 2022.

NPRRs Clear Board, Despite Opposition

The board approved two nodal protocol revision requests (NPRRs) recently taken off the table by the TAC, but with varying degrees of opposition.

Brazos Electric Power Cooperative's Clifton Karnei, representing the cooperative segment, cast the lone dissenting vote against NPRR815. The change increases from 50% to 60% the limit on load resources providing responsive reserve service (RRS), with at least 1,150 MW coming from resources that can provide primary frequency response.

The Protocol Revisions Subcommittee said changing the constraint will allow additional resources to provide RRS at lower costs. However, the Lower Colorado River Authority's John Dumas, who opposed the measure when it passed the TAC last month, told the board that NPRR815 could harm reliability because of the reduction in generation resources that provide inertia and voltage support. (See "TAC 'Un-Tables,' Endorses NPRRs," *ERCOT Technical Advisory Committee Briefs*.)

"Our opposition has to do with concerns over reliability risk and commercial risk," Dumas said. "When you increase the amount of load in responsive reserves, you're decreasing the amount of potential generation on the grid to manage things like voltage, inertia and ramping capabilities. When you take generation off the grid, you're reducing reliability, you're not improving reliability."

Dumas said the commercial risk comes from a possible increase in RRS price spikes during high-wind, low-load situations.

"You can commit enough capacity to cover your energy position, but you cannot … when you suddenly have a wind variation or a unit trip," he said. "When you reduce the amount of supply from generation, you're reducing the offer curve."

Woody Rickerson, ERCOT's vice president of grid planning and operations, pushed back on the reliability concerns.

"[NPRR]815 in no way changes what we need for responsive reserves, only how we procure it," he said. "We've gone through probably six months of questions on it. We've studied it, and it in no way endangers reliability."

Rickerson pointed out ERCOT monitors inertia separately from responsive reserves, and that the ISO can always procure more services beyond the minimum amount.

NPRR825 also cleared the board, but with four votes in opposition from cooperative and consumer interests. The revision requires ERCOT to issue a DC tie curtailment notice before curtailing the tie's load, addressing the ISO's concerns about declaring an emergency condition before curtailing DC tie load for any reason, staff said.

Several directors were concerned about the NPRR's price tag — $200,000 to $300,000 in development costs as part of a larger software tool — but staff said the change would result in automated processes and

ERCOT's exiting board members gather with CEO Bill Magness and Board Chair Craven Crowell (left to right): Randy Jones, Magness, Donna Nelson, Crowell, Ken Anderson, Jack Durland and Wade Smith. | © RTO Insider

Continued on page 12

ERCOT NEWS

Board of Directors Briefs

Continued from page 11

system reports. Rickerson told directors that the day before, staff had to issue a watch to curtail 27 MW.

"It's increasing transparency in the marketplace," said unaffiliated director Karl Pfirrmann, speaking in favor of the NPRR. "That should make things more efficient and helps prepare us for emergency situations."

ERCOT Sees Favorable $8M Budget Variance

ERCOT CEO Bill Magness said the ISO is projecting to end the year nearly $8 million under budget following a warmer-than-normal October.

"Revenues go up, but so does congestion," he told the board.

A positive variance in October for ERCOT's system administration fee helped reduce an unfavorable year-end projection to about $100,000. Much of the overall positive variance stems from $4.1 million savings in interest expense because of project funding and minimal revolver usage, and interest income because of higher rates.

Magness said staff has completed their reliability-must-run studies of planned generator retirements and determined none of the units needs to be kept on for reliability needs. He also said the Texas grid is seeing higher-than-expected congestion in the day-ahead market, but that congestion revenue rights funding is not a concern.

IMM: Ancillary Services Market Growing in Importance

Beth Garza, director of the Independent Market Monitor, focused her board report on ancillary services, which have declined with the advent of the nodal market in 2011.

Garza said the services cost $1.03/MWh in 2016 and averaged 87 cents/MWh through Oct. 7, but that is likely to change with the pending retirement of more than 2 GW of aging generation (though those units only have provided 2.5% of regulation up and 6.4% of regulation down in 2017 through October). Regulation up and down have seen the biggest decrease since the zonal market was replaced, with dispatch now occurring every five minutes instead of 15.

"It's that efficiency of procuring on smaller time frames, and not over-procuring, that has brought the overall average down," Garza said. "These things we call ancillary will become more important in a future market that has more load to zero-cost variable resources. As the [ancillary services market] becomes more important and [resources] scarcer, as less units are around to provide those services, those prices are likely to become higher and more important going forward."

Asked if she was comfortable with ERCOT's ancillary market performance, Garza said the interaction between regulation and security-constrained economic dispatch "continues to be refined," but she noted total regulation has seen about a two-thirds reduction from the 1,800 MW in the zonal market.

"That balance seems pretty good," she said.

The Monitor is projecting ERCOT's real-time prices will be above last year's record low average of $24.62/MWh. Through the first 10 months of 2017, prices are up 17% to $28.97/MWh compared to the same period last year. Real-time prices settled at $24.

Gas prices averaged $2.44/MMBtu last year but were $3/MMBtu for the first 10 months of 2017.

CEO Bill Magness addresses ERCOT's annual Membership Meeting. | © RTO Insider

Membership Approves 5 New Directors

ERCOT's corporate members approved the election of Terry J. Bulger and the re-election of Peter Cramton to three-year terms during their annual membership meeting. Cramton's current term will expire on Aug. 1.

Bulger is a 35-year banking professional with ABN AMRO and Bank of Montreal, and has more than 25 years of experience in risk management. Cramton is an economics professor at the University of Maryland and the University of Cologne.

Members also approved four new segment directors, who were previously segment alternates, and their alternates, to serve in 2018. The directors are:

- Industrial consumers — Sam Harper, Chaparral Steel Midlothian
- Independent generators — Kevin Gresham, E.ON Climate & Renewables North America
- Independent retail electric providers — Rick Bluntzer, Just Energy Texas
- Investor-owned utilities — Kenneth Mercado, CenterPoint Energy

The new segment alternates are:

- Industrial consumers — Mark Schwirtz, Golden Spread Electric Cooperative
- Independent generators — Amanda Frazier, Luminant
- Independent retail electric providers — Mohsin Hassan, VEH
- Investor-owned utilities — Mark Carpenter, Oncor

Continued on page 13

ERCOT NEWS

Board of Directors Briefs

Continued from page 12

TAC Gets 6 New Members

The membership also approved six new members to the TAC, which makes recommendations to the board and is aided by five subcommittees:

- Independent generators — Ian Haley, Luminant
- Independent power marketers — Kevin Bunch, EDF Energy Services, and former ERCOT staffer Resmi Surendran, Shell Energy North America
- Independent retail electric providers — Sandra Morris, Direct Energy
- Investor-owned utilities — Walter Bartel, CenterPoint
- Municipals — John Bonnin, CPS Energy

Board Clears 4 NPRRs, Other Measures

The board unanimously approved revisions to the methodology for computing responsive reserves as a result of NPRR815's implementation and two changes to determining non-spinning reserves in 2018; accepted a clean system and organization control audit; and approved new key performance indicators.

The directors also unanimously approved NPRR846 by itself, and three other NPRRs on the consent agenda.

- NPRR846: Allows previously committed emergency response service (ERS) resources to participate in must-run alternative agreements and modifies the methodology for evaluating the impact of ERS load performance during the first partial interval on calculating the alternate baseline. The change also defines acceptable parameters for an ERS generator's self-serve capacity, and sets the ERS test performance factor to significantly lower values, in some instances to zero for resources with three consecutive test failures within a 365-day period. The NPRR includes additional administrative changes and clarifications to existing ERS protocol language.
- NPRR834: Clarifies processes associated with ERCOT's repossession of congestion revenue rights following a payment breach or other default by a market participant. The change specifies data transparency requirements; documents the disposition of auction revenue funds above amounts owed to ERCOT; clarifies that the one-time auction bids must be positive; and allows the immediate transfer of CRR ownership to the winning bidder should an auction be necessary.
- NPRR839: Updates the protocols to clarify that, upon receiving meter data transactions from transmission or distribution service providers, ERCOT will forward the transactions to the designated competitive retailer.
- NPRR843: Addresses four reporting items in Section 3 of the Nodal Protocols (Management Activities) by:
  1. Changing the logic of short-term system adequacy reports for more consistent treatment of resource status; adding language to provide clarity to the reports' end users;
  2. Creating a new report that will show the portion of ancillary service offers at or above 50 times the fuel index price (FIP) when the market-clearing price for capacity of the service exceeds 50 times FIP;
  3. Adding elements to the "48-hour highest price [ancillary service] offer selected" report, including the highest-priced offer selected in a supplemental ancillary service market (SASM); and
  4. Creating a SASM disclosure report to provide transparency into ancillary service offers and awards for any SASMs executed within an operating day.

— Tom Kleckner

ERCOT NEWS

Sempra, Oncor Reach Deal with Texas Stakeholders

By Tom Kleckner

Sempra Energy's $9.45 billion bid for bankrupt Energy Future Holdings and its 80% interest in Oncor cleared a second major hurdle within a week after the California-based company reached a settlement agreement Thursday with several key Texas stakeholder groups.

The agreement represents a "significant step forward" and demonstrates "positive momentum" for Sempra's proposed acquisition of a majority stake in the Texas utility, both companies said. Under the settlement, the parties have agreed that the acquisition is in the public interest, meets Texas statutory standards and will bring substantial benefits.

On Dec. 11, FERC filed a boilerplate order approving the acquisition. (See "FERC OKs Sempra Acquisition of Oncor," *Company Briefs*.)

Parties to the settlement agreement include the Public Utility Commission of Texas staff, the Office of Public Utility Counsel, Steering Committee of Cities Served by Oncor and Texas Industrial Energy Consumers. They will ask the PUC to approve the acquisition, consistent with the governance, regulatory and operating commitments in the agreement, the companies said.

Sempra said the agreement includes regulatory commitments that preserve the existing Oncor ring-fence and the independence of the utility's board of directors. To protect Oncor, its customers and employees, the commitments also include extinguishing all debt currently held by EFH and Energy Future Intermediate Holding Co., the company said.

One consumer representative called the settlement a "good deal for customers," saying Sempra agreed to a more robust ring-fence than was in place earlier for EFH or Berkshire Hathaway Energy, which appeared to have a solid $9 million all-cash offer until Sempra stepped in. (See *Sempra Outmuscles Berkshire for Oncor*.)

Sempra CEO Debra Reed said she was pleased with the support from the groups. "We strongly believe that this transaction will benefit Oncor customers and the state of Texas, and we are working with the PUC to facilitate its comprehensive review of our proposal."

The PUC now holds the key to approval. The commission said in October it would complete its review within 180 days — by early April 2018. It has scheduled a Feb. 21-23 hearing on the acquisition in Austin. (See *Texas Regulators Seek More Details on Sempra Oncor Bid*.)

The PUC has seen a changeover among its commissioners since the unsuccessful attempts by Hunt Consolidated and NextEra Energy to acquire Oncor. Chair DeAnn Walker and Arthur D'Andrea have replaced Donna Nelson and Ken Anderson, respectively, with Brandy Marty Marquez the only holdover.

"Our partnership with Sempra Energy will result in a strong, well-capitalized Oncor that will help Texas continue to grow and invest in a safer, smarter, more reliable electric grid in the years to come," Oncor CEO Bob Shapard said. "This settlement agreement moves us one step closer to ending the EFH bankruptcy process."

Sempra announced the deal in August. It was approved by the U.S. Bankruptcy Court in Delaware in September but is still subject to a confirmation hearing by the court after PUC approval.

ISO-NE NEWS

Millstone Likely Profitable Through 2035, Conn. Consultant Says

By Rich Heidorn Jr.

Dominion Energy's bid to win state subsidies for its Millstone nuclear plant took a hit Thursday as consultants hired by Connecticut said the plant is likely to remain profitable through 2035 even under low natural gas prices.

Millstone nuclear plant | *NRC*

The report by Levitan & Associates concludes "there is no 'missing money' required to ensure Millstone's financial viability through the existing term of Millstone's Unit 2 operating license" in 2035.

The report projects that in 2022 the plant will earn after-tax net cash flow of $100 million under a low gas price/high operating cost scenario to more than $200 million under the reference case that assumes "business-as-usual" conditions.

"Under the reference case, the present value of Millstone's after-tax cash flows [through 2035] is about $2.4 billion. This number is reasonably representative of Millstone's enterprise value. Under the low gas price case, with all costs increased by 10%, the present value is $1.3 billion," the consultants wrote. "However improbable the array of market and operating assumptions underlying the low gas price case with all costs increased by 10% may be, the associated enterprise value of $1.3 billion represents a conceivable 'worst case' for testing Millstone's financial viability."

The consultants added a caveat to their analysis, saying that if Dominion were required to replace its existing system with cooling towers as part of its National Pollutant Discharge Elimination System permit renewal, "it is likely that cash flow from energy and capacity sales would be insufficient to rationalize the investment."

"We are still reviewing the report and don't have a comment at this time," Dominion spokesman Ken Holt said Thursday evening.

Connecticut Gov. Dannel Malloy ordered state regulators in July to assess the economic viability of the plant and determine whether the state should provide it financial support. Malloy's executive order also directed the state Department of Energy and Environmental Protection (DEEP) and the Public Utilities Regulatory Authority (PURA) to assess the role of large-scale hydropower, demand-reduction measures, energy storage and emissions-free renewable energy in helping Connecticut meet its ambitious targets to cut its carbon output. (See *CT Gov Orders Financial Analysis of Millstone Plant*.)

DEEP and PURA released the Levitan study Wednesday along with a draft report summarizing its conclusions and a request for comments on it, which are due Jan. 8. There will be a public hearing on the report today at Waterford High School.

PURA Chair Katie Dykes and DEEP Commissioner Robert Klee said during a press conference Thursday that the agencies will file a final report with their recommendations by Malloy's Feb. 1, 2018, deadline.

Dykes said the regulators' draft report contains no conclusion. "This report is laying out the dots," she said. "It's not necessarily connecting the dots."

The regulators' draft report noted "significant inherent difficulties" in evaluating the financial viability of a nuclear plant such as Millstone in a restructured market. "Merchant generators' financial goals may exceed the regulated rate of return earned by cost-of-service generators, given merchant generators' exposure to the risks of low energy prices, unplanned outages, and other costs that a regulated generator can recover from electric ratepayers," the regulators said.

"Such is the challenge in assessing the financial viability of Millstone, and the advisability of mechanisms that would shift some of the risk of energy price volatility to the ratepayers of Connecticut. Despite DEEP and PURA's specific data requests, Dominion only very recently provided a limited, two-page, high-level document with forward-looking financial projections. The document lacked the standard documentation supporting the projections concerning its actual financial condition. Thus, [Levitan] was limited to modeling Millstone's financial viability using the best publicly available information."

Levitan's conclusions were consistent with findings of a study funded by subsidy opponents, including Calpine and Dynegy, which Dominion rejected as "loaded with gross assumptions and preposterous claims, with no real data." Dominion, which purchased the 2,111-MW facility in 2001 for $1.28 billion, has said Millstone is more expensive to operate than other two-unit nuclear plants because its two units are of different designs. (See *Millstone No Dead Weight for Dominion, Says Opponents' Study*.)

Levitan said its report was based on simulations modeling the New England wholesale energy market under several scenarios covering natural gas prices, expanded clean energy deployment and generation entry and retirements.

The consultants said they constructed a worst-case scenario increasing their proxy operating costs by 10%.

Because Dominion indicated last March that the plant will compete in ISO-NE's Forward Capacity Auction next year, the company expects it to continue operations into at least 2022. Thus, the financial analysis considered only the period between 2022 and 2035, when the license for Millstone Unit 2 expires.

Malloy issued the executive order after Connecticut legislators failed to pass a bill sought by Dominion to boost the plant's revenues.

Some subsidy supporters have said the loss of the plant would jeopardize the state's ability to comply with the Global Warming Solutions Act of 2008, which mandates cutting greenhouse gas emissions to 10% below 1990 levels by 2020, and to 80% below 2001 levels by 2050.

Millstone supplies the equivalent of half of Connecticut's electricity, but Dykes said the state is "long generation."

New England Electricity Restructuring Roundtable

New England Panelists Talk 'Trust' in Power Project Siting

By Michael Kuser

BOSTON — Developing trust is vital for the project siting process, according to panelists speaking at Raab Associates' 156th New England Electricity Restructuring Roundtable last week.

"The thing that most undermines a project is when the proponent is seen as not presenting facts, not disclosing things, misrepresenting things," Conservation Law Foundation President **Bradley Campbell** told meeting participants. "And it happens more often than you might think."

Patrick Woodcock, assistant secretary of energy with the Massachusetts Executive Office of Energy and Environmental Affairs, highlighted the region's progress in reducing emissions over the past decade and his state's long list of project approvals in the past six months, including electrical transmission, LNG storage and natural gas pipelines.

But Woodcock, formerly Maine Gov. Paul LePage's principal energy adviser, also pointed out the "natural conflict" that occurs around permitting. "In Maine, the biggest issues were not with natural gas pipelines or transmission lines, but with wind permitting," he said.

Developers found that about 10% of the turbines represented about 90 to 95% of the controversy in Maine, he said.

"What that does is not only impede those projects that get a lot of media attention, but it creates a controversy for the entire industry, and I think there are parallels with what we see in Massachusetts," Woodcock said. "When you start to have bad actors, and we have had a few, that causes a public perception over the entire industry."

Compare and Contrast

Campbell said a developer's credibility issues are "the most potent weapon" CLF has when it opposes a project. He then compared two potential projects in New England: Northern Pass and the New England Clean Power Link.

Both projects were proposed in July in response to a Massachusetts solicitation for 9.45 TWh/year of hydro and Class I renewables (wind, solar or energy storage), with projects to be selected in January.

Eversource Energy partnered with Hydro-Quebec on Northern Pass, a 192-mile line that would bring 1,090 MW of Canadian hydropower into New England for 20 years starting in December 2020.

Transmission Developers Inc. partnered with Hydro-Quebec on the New England Clean Power Link, which would include a submarine cable under Lake Champlain and an overland section to transmit 1,000 MW of hydropower, solar and wind from Canada. (See <u>*Hydro-Quebec Dominates Mass. Clean Energy Bids*</u>.)

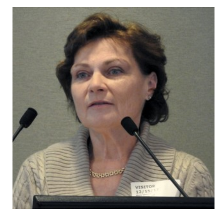
"There was inadequate public engagement on the Northern Pass side," Campbell said. "There were many, many points at which Eversource New Hampshire lost credibility with the public by not disclosing or by making representations that later turned out to be inaccurate, and the … process was entirely without significant stakeholder input. As a result of that you have an absolutely oppositional circumstance, which is going to affect the state of the project."

Even though Northern Pass received a presidential permit on the U.S. side, "that original sin of failing to engage with the public in a credible way stays with them," Campbell said. "Compare that with TDI, where you have 100% of the line being buried, as mitigation and minimization, as opposed to 30% [with Northern Pass]. Many fewer wetland impacts, many fewer vernal pool impacts. Down the line, a better engagement process and one that, in the case of our initial opposition, resulted in what we think is a robust mitigation package and a piece of transmission infrastructure that would serve the region well and also serve the environment and advance environmental objectives well."

Lawrence Susskind, director of the MIT-Harvard Public Negotiations Program, said there will always be winners and losers from projects — or people who see themselves that way. The difference between the two, he said, is that a million people in a city who stand to gain $100 from a project have no motivation either way, while just a few people, if they perceive themselves to be big losers, are motivated to oppose.

The key, Susskind said, is to influence the 30 to 40% in the middle who haven't yet made up their mind. The "guardians," as Susskind called them, want to be convinced of a project's merits and will support the opponents if they think that the process is unfair.

Building Trust



Building trust with stakeholders is key, said MU Connections President **Mary Usovicz**, who works with project developers on strategy.

"Ask, don't tell. Spend time listening," Usovicz said. "I recently did a project and the managers came in and said, 'What are our talking points, what are we going to say, how are we going to pitch this?' And I said, 'No, we're not doing any of that. We're going to go on a listening tour. We're going to go and listen to what people have to say. You're going to introduce yourselves and say, "And what do you think about this project? How would you do this?"'"

That client spent two months just meeting stakeholders and listening, and that leaves a sense of trust, she said.

"That's how you build trust," Usovicz said. "When you listen to what people say, acknowledge what they have to say and actually incorporate it. So they changed their entire campaign after they did this listening tour — that builds up trust. Also it allows you to know what are those gains that Professor Susskind spoke about."

When they go on such listening tours, developers can sometimes be shocked about what is important to people, she said.

"One lady said, 'I'll let you build that pipeline if, with all the trees you have to cut down, you stack them as firewood for me,'" Usovicz said. "That was her ask. I was like, 'Oh yeah, we'll stack it. I'll have my husband come and stack it.' It's amazing what is important to people, but if you don't listen and ask, you're going to jump to conclusions."

Continued on page 17

New England Electricity Restructuring Roundtable

New England Panelists Talk 'Trust' in Power Project Siting

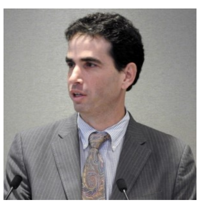
Continued from page 16

For one LNG project in Connecticut, Usovicz's polling and research determined that community members trusted first responders more than the developer, the utility and the mayor. Knowing that the project to expand an LNG facility would remove gas tanker trucks from the roads, she took that information to first responders, who wrote a letter in support of the project because of improved community safety.

"And then [first responders] became the point of reference for the project," Usovicz said.

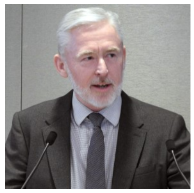
Energy Pricing and Fuel Supply

Participants also touched on other issues.



Andrew Weinstein, legal adviser to FERC Commissioner Cheryl LaFleur, spoke on behalf of his boss, who couldn't attend the meeting because of a family matter.

Weinstein read notes from LaFleur's speech highlighting issues of the coming years, such as "how energy pricing evolves in the face of so many new technologies and services. We've talked for years about non-volumetric energy pricing based on attributes provided, rather than just fuel burned, and it's closer than it's ever been."



ISO-NE CEO **Gordon van Welie** addressed what he said are the two most important issues facing the region: integrating markets and public policy, and fuel security issues, namely natural gas supply constraints in winter.

Van Welie pondered the issue of state support for renewable resources through contracting: "So the real philosophical challenge is how do you make a competitive market work if one set of resources in that market are going to get cost of service and the rest of the resources are merchant and have to live on the revenues in that wholesale market?"

If one stands back from the details, he said, the question is, "Should the market lean in the direction of creating certainty for the states in terms of the entry of their resources into the capacity market, or should we lean in the direction of ensuring price formation? And I think what you'll see is the ISO leans a little bit in the direction of price formation, knowing that we've got a big, three-decade transition ahead of us."

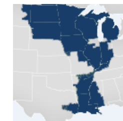
Van Welie also noted that the RTO has done a study on fuel security and will wait until issues are settled around the U.S. Energy Department's Notice of Proposed Rulemaking to subsidize uneconomic coal and nuclear before releasing the report. (See *ISO-NE Plans for Hybrid Grid, Flat Loads, More Gas*.)

"We've got more gas-fired capacity than we need in the winter, but we don't have enough fuel to supply it," he said.

"So the real philosophical challenge is how do you make a competitive market work if one set of resources in that market are going to get cost of service and the rest of the resources are merchant...?"

ISO-NE CEO Gordon van Welie

MISO NEWS



MISO Researching 30-Minute Reserves, Multiday Commitments

By Amanda Durish Cook

MISO Senior Market Engineer Chuck Hansen addresses the Market Subcommittee. | © RTO Insider

CARMEL, Ind. — MISO's market planners last week outlined a potential 30-minute reserve product to reduce uplift and multi-day generator commitments to cut production costs. Both concepts are in early planning stages, officials told the Dec. 14 Market Subcommittee meeting.

30-Minute Reserves

Oluwaseyi Akinbode | © RTO Insider

Engineer Oluwaseyi Akinbode said MISO currently addresses short-term capacity needs using offline resources with quick start-up times and economic generation already online. However, Akinbode said, the approach results in expensive uplift payments.

Akinbode said a short-term capacity reserve would be especially helpful in MISO South, which has less than 500 MW of offline capacity available within 30 minutes. Two southern load pockets — Amite South and the West of the Atchafalaya Basin (WOTAB) — have none and less than 100 MW, respectively.

"We are on track in 2017 to incur about $20 million [in uplift]. Last year, we incurred about $20 million … in day-ahead revenue sufficiency guarantee to manage load pockets," Akinbode said.

Making the price of the reliability service transparent may cause some generation owners to defer plant retirements and others to develop new fast-start resources, said Jeff Bladen, MISO executive director of market design.

"What we want to make sure is that generators have the best economic signal, and they judge for themselves," Bladen said.

Northern Indiana Public Service Co.'s Bill SeDoris said that with only some localized parts of the footprint needing the capacity product, he saw a possibility that only generation with access to certain load pockets would be able to benefit financially. "That may raise concerns," he said.

Bladen said that while MISO doesn't yet have systemwide need for the short-term product, conditions will change with the increased adoption of intermittent resources. He pointed out that MISO doesn't expect to have a short-term product ready for use until 2020, when the footprint's resource mix will have further shifted toward renewables.

"We expect this to be needed systemwide … and by the time we're fully utilizing it, we expect the need for a 30-minute product to be much more prevalent systemwide. We do see this as a need systemwide even though the short-term value proposition is localized," Bladen said.

MidAmerican Energy's Greg Schaefer asked under what conditions a 30-minute dispatch would be valuable.

Akinbode said the option would help eliminate out-of-market commitments that cause MISO to incur uplift payments.

Bladen said the product was needed because MISO's forecasting of anticipated wind supply is less accurate beyond 30 minutes from dispatch.

"It's a far less costly way to manage operations until we get to that 30-mintue window where we get a clearer picture of what to expect out of resources like wind," Bladen said.

SeDoris asked if MISO designers were thinking about creating penalties for units that commit to offer the short-term capacity but don't deliver.

"There are a lot of details we're going to have to work through," Akinbode agreed.

Werner Roth, an economist with the Public Utility Commission of Texas, thanked MISO for its work. "This is something we've been asking for a long time," he said.

Multiday Market

MISO also is considering the use of a screening tool to make recommendations for turning generators with long lead times on and off seven days in advance. The RTO estimates implementation sometime in 2019. (See *MISO Exploring Multiday Market*.)

"The savings of a multiday optimization window are substantial," Senior Market Engineer Chuck Hansen said.

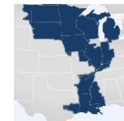
Hansen said MISO identified the best candidates for multiday commitments using three criteria: long lead times, high start-up costs and the ability to respond. The RTO then developed a screening tool that estimates potential cost reductions by examining units individually.

"Some units have high emissions upon start-up and sometimes they can only start once or twice per month to avoid going over their emissions" limits, Hansen said.

He said MISO began researching with a multiday candidate list of 85 generators and

Continued on page 19

MISO NEWS

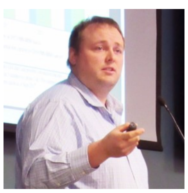


MISO to Fold Outage Forecasting into Larger Resource Effort

By Amanda Durish Cook

CARMEL, Ind. — MISO last week said it will defer any initiative to account for planned and maintenance outages in capacity planning until it kicks off a broader discussion on overall resource availability sometime next year.

The RTO floated the idea of the initiative last month after observing an increasing number of intentional outages that occurred during periods of peak demand. (See *MISO Seeks to Gauge Risk of Peak Season Planned Outages*.)



Ryan Westphal | © RTO Insider

But stakeholders are mixed in their support for accounting for the outages in forecasts for peak periods, MISO Resource Adequacy Coordinator Ryan Westphal said during a Dec. 13 Resource Adequacy Subcommittee meeting.

Instead of accounting for the outages in its mid-2018 capacity planning, MISO now hopes to implement the changes for the 2019/20 planning year. The RTO plans to roll the outage consideration into discussion about its seasonal capacity procurement proposal, which has been rebranded as "resource availability and need," as planners have increasingly begun to think the answer to capacity issues may not lie in seasonal procurements but in something more granular.

RASC liaison Shawn McFarlane said MISO is now assessing the "hour-by-hour" availability of capacity resources instead of relying on a season-by-season basis of availability. The RTO plans later this month to release a white paper on resource availability trends throughout the year.

"We want to make sure we understand when resources are available, especially in light of the increasing maximum generation events since the 2016/17 planning year," said MISO analyst Dustin Grethen.

Indianapolis Power and Light's Ted Leffler noted that MISO once had a Real-Time Sufficiency Task Force that worked on outage-related forecasting issues but ultimately did not come up with a new forecasting process that included planned outages.

"We worked on this for about a year and a half before we gave up," Leffler said. He urged MISO officials to review the old task force's documents, if any of them survived.

MISO stakeholders have likewise cooled on defining seasonal capacity procurement requirements.

At an October RASC meeting, some stakeholders questioned the need for seasonal limits, noting that MISO's emergency conditions in April and September were outside of the summer months, the result of poorly coordinated transmission outages.

NRG Energy's Tia Elliott suggested that MISO might not need a seasonal definition of capacity at all if it decided to pursue its own transmission project to link its Midwest and South regions. Elliott also expressed exasperation at "being down this dirt road before and ending up in a puddle," referring to MISO's two-season capacity market proposal in late 2015 that eventually devolved into the proposal being scrapped to allow the RTO to conduct more research. (See "Seasonal Aspect Back in Conceptual Stage," *MISO Postpones External Zones Until 2019 Auction*.)

MISO Researching 30-Minute Reserves, Multiday Commitments

Continued from page 18

later increased the number to 113 of the 1,200 units in the footprint after staff spoke with members and the Independent Market Monitor.

Using the 113 candidate generators, Hansen said MISO estimated that the multiday screening tool could reduce production costs by $157.3 million and output by 2,658 MW annually. Hansen said some of the savings were attributable to passing commitments to more nimble and economic units. But he cautioned that costs avoided using a multiday market won't likely be as dramatic as the study suggests because it couldn't account for unanticipated weather, unforeseen outages and increased renewable penetration. MISO estimates an achievable savings of between $29 million and $44 million per year, Hansen said.

"Some of this relies on [long-term] forecasts we don't yet have," he added.

Some stakeholders said that MISO estimating even a 10 to 15% share of the study's savings would overstate the benefits.

Customized Energy Solutions' Ted Kuhn said the multiday commitments could actually increase costs should MISO produce a wildly inaccurate seven-day forecast.

"With this, I just see more make-whole payments," added Kuhn's colleague David Sapper.

Bladen added that the screening tool merely suggests commitments to operators, and it's up to operators to decide whether to act on those. MISO and stakeholders have yet to decide if the tool's recommended commitment changes will come attached with make-whole payments and other market rules should operators decide to take its advice.

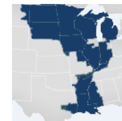
"What the tool is doing is simulating what the participant might change when they self-commit. The screening tool is not dispatch instructions. This is not a new kind of dispatch tool that we're trying out," Bladen said.

For financially binding commitments, MISO would have to create a multiday pricing forecast that the RTO would have confidence in, Hansen said.

When a generator decides to decommit, Hansen said, the lost generation will be replaced with new generation with the LMP at the hour, with the idea being to turn off more expensive generation and replace it with the system LMP.

In September, MISO Director Thomas Rainwater said that should MISO move to multiday financial commitments, "we have to make sure natural gas generation is in lockstep with pipeline commitments."

MISO NEWS



MISO Seeks FERC Reapproval to Keep Resource Adequacy Rules Intact

By Amanda Durish Cook

CARMEL, Ind. — MISO pre-emptively refiled its current resource adequacy construct for FERC approval Friday in an effort to dispel concerns that a future ruling could undo parts of the plan the commission itself had previously suggested.

MISO's concerns stem from a July D.C. Circuit Court of Appeals ruling that found FERC overstepped its authority under the Federal Power Act when it prescribed revisions to PJM's capacity market buyer mitigation rules in 2012 (15-1452).

That D.C. Circuit decision partially vacated FERC's approval of PJM's changes to its minimum offer price rule (MOPR) and remanded the case back to the commission for further action. As a result, the commission last week rejected the previously approved MOPR changes and required PJM to reinstate its previous design. (See *On Remand, FERC Rejects PJM MOPR Compromise*.)

Fearing that parts of its resource adequacy construct could be similarly vacated, MISO said it would refile Module E-1 of its Tariff on Dec. 15, putting language already approved by FERC before the commission once again.

"This filing will contain only our existing Tariff language and will not propose any changes," MISO corporate counsel Jacob Krouse told stakeholders at a Dec. 13 Resource Adequacy Subcommittee meeting.

Jacob Krouse | © *RTO Insider*

In 2011, FERC accepted MISO's current resource adequacy proposal, which replaced a monthly capacity auction framework with an annual auction and use of coincident peak demand forecasts to establish planning reserve requirements (ER11-4081). In that order, FERC directed MISO to remove its proposed MOPR provisions and instead use a peak load contribution methodology as its default methodology for assigning capacity obligations among other directives.

"We are giving FERC the opportunity to find our original filing just and reasonable … regardless of any procedural defects in the original order," Krouse said.

Manitoba Hydro's Audrey Penner asked why MISO's well-established resource adequacy construct must go before FERC again.

"What is outstanding that would require MISO to refile?" Penner asked.

Krouse called the reasons behind the filing "procedurally complex" and said MISO seeks to pre-empt the possibility that FERC will ask the RTO to refile a revised construct in the event that the commission also overstepped its authority when it approved the original filing six years ago.

"MISO is unsure how and when FERC will act," Krouse said.

The RTO is asking FERC to decide on the matter by March 1. If FERC doesn't act on the Section 205 filing before the requested effective date, the filing is automatically considered accepted, Krouse said, though he thinks it "unlikely" the commission won't address the filing.

Responding to a question from Indiana Utility Regulatory Commission staffer Dave Johnston, Krouse said the RTO will provide three pieces of staff testimony supporting the efficacy of the current resource adequacy construct. FERC liaison Chris Miller also said he expected MISO to quote at length the commission's 2011 acceptance of the construct.

Northern Indiana Public Service Co.'s Bill SeDoris asked how MISO would respond to a rejection by FERC.

"Where do we go from there?" SeDoris asked, pressing to know whether the RTO would begin operating under pre-2011 resource adequacy rules.

Krouse said his own recommendation would be that MISO continue with its existing construct until the commission acts on either MISO's refiling or the court's remand.

PJM has similarly said that restoring its old rules is "not a viable option" and continues to operate according to its filed rate while it awaits FERC action on the ruling.

Dynegy's Mark Volpe asked how MISO would respond if the commission issues an order on remand before it acts on the filing. Krouse said the RTO would reassess and adapt should that happen.

This fall, Krouse warned that the D.C. Circuit's ruling limiting FERC's ability to issue guidance on proposals might sway the commission in the future to issue more rulings that either accept or reject filings in their entirety.

MISO NEWS

MISO Designing Automatic Generation Control Program

CARMEL, Ind. — MISO is moving ahead with developing an automatic generation control (AGC) program designed to rapidly deploy 400 MW of fast-ramping resources by regulating either up or down in response to fluctuations in load.

Speaking during a Dec. 14 Market Subcommittee meeting, Pavan Addepalle of MISO's market engineering group said the RTO is moving from a conceptual design phase to detailed design with a vendor. MISO hopes to implement AGC by late 2019.

Addepalle said MISO will add new real-time market hourly offer parameters to accommodate the faster units but use the RTO's existing market and settlement rules to clear regulation. Resources must have a minimum 80-MW/minute ramp rate and a regulation limit of 1 MW or more to be eligible to participate in the program.

In response to a question from Northern Indiana Public Service Co.'s Bill SeDoris, MISO staff said resources under AGC will be cleared in the same market as other resources, but that fast- and slow-responding resources will be divided into pools waiting on separate dispatch signals.

"We're going to have a single energy market but realize that resources have different parameters and constraints … and design a market that is capable of using separate resources differently," said MISO Executive Director of Market Design Jeff Bladen, adding that the RTO will not follow in PJM's footsteps in creating a separate regulation market.

ITC Holdings' Ray Kershaw said the new designation, while amenable for pumped energy storage, is not an ideal use for batteries.

Addepalle said MISO did not approach the proposal with a specific type of generation in mind.

— Amanda Durish Cook

Pavan Addepalle | *© RTO Insider*

NYPSC Acts on CCAs, Demand Reduction

By Michael Kuser

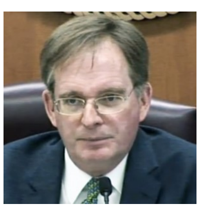
At its final meeting of the year, the New York Public Service Commission approved rules to implement community choice aggregation, a pilot program to reduce air conditioning loads and a waiver allowing an energy service company (ESCO) to market to low-income customers.

Utility Energy Registry

The PSC on Thursday approved fees, procedures and data privacy protection measures for the Utility Energy Registry, an online platform to provide information regarding customer energy use. The order requires utilities to file tariff amendments implementing CCA data fees effective Jan. 6, 2018 (14-M-0224).

Access to such information is vital to the success of the distributed energy resources market, the commission said; for CCA programs to function, municipalities and program administrators must be able to access both aggregated and individual customer data.

The order directs that customers pay one-half of the estimated cost to prepare queries to populate the registry, with the remainder recovered from fees for customer lists and customized aggregated data. The costs to be recovered via CCA fees will be based on an estimated request rate of 25% of eligible customers over five years.



Rhodes

"Through the creative bargaining power enabled by the community choice aggregation model, communities are enabled to work with their energy supplier to procure resources that better serve their citizens' local energy goals," PSC Chair John Rhodes said. "This order provides a fair and uniform approach to an essential point of enabling CCAs to go forward: an approach on data fees. It will accelerate the opportunity for communities who wish to establish a CCA."

The commission set a fee of 80 cents per account for all utilities, saying that obtaining the mailing list and the ability to engage in an opt-out program will help CCAs and ESCOs minimize customer acquisition costs.

Con Edison Smart A/C Trial

The commission also voted to approve a three-year, $7.5 million pilot program for Consolidated Edison to control its New York City customers' air conditioners to help shave peak demand in summer. Customers who allow the utility to install Wi-Fi-enabled 'smart plugs' on their A/C units will be eligible to earn $95 or more in rebates and rewards.

While some 21,000 electricity customers already participate in Con Ed's Smart AC program, the commission's order on the new pilot program, Connected Devices, expands the demand response measure to millions of people, including public housing tenants (17-E-0526).

New York City Housing Authority residents get their electricity from the New York Power Authority and do not pay the monthly adjustment clause (MAC) surcharge through which the programs' costs are recovered. Commissioner Diane Burman asked how expanding the measure to NYPA customers would affect the cost-recovery mechanisms approved by the commission.

"We anticipate the impact of any cost shifts from NYPA to Con Edison customers to be minimal while participation and penetration of these programs is low in the NYPA buildings," responded Robert Cully, a Department of Public Service staffer.

Con Ed estimates there are 450,000 residential units in the buildings supplied by NYPA, a significant source of untapped load relief. The utility could petition for additional cost recovery, "and Con Edison is not shy about requesting those sort of program modifications," Cully said.

ESCO Low-income Ban Waiver

The commission gave Utility Expense Reduction permission to serve low-income customers, ruling that the company had fulfilled the waiver requirements of its December 2016 order prohibiting ESCOs from enrolling customers who are participants in low-income assistance programs.

The PSC requires that ESCOs demonstrate an ability to calculate what the customer would have paid to the utility; an assurance that the customer will be paying no more than what they would have paid to the utility; and proper reporting and verification to ensure compliance. (See *New York PSC Adopts DER Rules, Sanctions ESCOs*.)

The order (12-M-0476) requires the ESCO to report semiannually on the participation of low-income customers in its Green Energy Price Cap Program. The company must report "the number of customers served, the monthly calculated amounts billed and the alternative amounts that the utility would have charged by customer, as well as the amount of any refunds issued to each customer to effectuate the price guarantee," the commission said.

Burman voted against the waiver. "I'm concerned about doing these individually in standalone petitions and would rather see a more collaborative process that gets to a more global solution in a more standardized way," she said.

Year-End Performance Wrap

Before adjourning, Rhodes took the opportunity to summarize the major actions by the commission and the Cuomo administration in 2017. Among the highlights: a Con Ed rate ruling intended to encourage energy efficiency and smart grid technologies; the announced closure of the Indian Point nuclear plant; a new compensation structure for valuing DERs; an order allowing large commercial batteries in New York City; an expansion of Con Ed's Brooklyn-Queens Demand Management project; and a solar project for low-income customers.

"So it has been a productive year," said Rhodes, the former CEO of the New York State Energy Research and Development Authority, who was appointed to the commission in June to replace Audrey Zibelman. (See *NYPSC Chair Promises 'Continuity' on State Energy Policies*.)

The commission ended the meeting by approving a resolution of appreciation to Tina Palmero, deputy director of the DPS' Office of Clean Energy, who is leaving the department. Rhodes said that Palmero joined the department as a transmission specialist in 1988 and that her work over the years, including on the state's Clean Energy Standard, has had "tremendous impact to the benefit of all New Yorkers."

NYISO NEWS

Business Issues Committee Briefs

Natural Gas Prices Rise 19% in November

RENSSELAER, N.Y. — NYISO year-to-date monthly energy prices averaged $34.72/MWh in November, a 5% increase from a year earlier, Senior Vice President for Market Structures Rana Mukerji told the ISO's Business Issues Committee (BIC) on Wednesday.

Locational-based marginal prices (LBMPs) averaged $30.60/MWh for the month, up 8% from October and up 16% from November 2016. The ISO's average daily sendout was 403 GWh/d, compared with 398 in October and a year earlier.

New York natural gas prices gained nearly 19% in November, averaging $2.92/MMBtu at the Transco Z6 hub. Prices were up 33.5% from a year ago.

Distillate prices gained 31% year on year, with Jet Kerosene Gulf Coast averaging $13.04/MMBtu, up from $12.30 in October. Ultra Low Sulfur No. 2 Diesel NY Harbor averaged $13.70/MMBtu, compared with $12.86 in October.

The ISO's local reliability share was 20 cents/MWh, up 6 cents/MWh from the previous month, while the statewide share dropped 10 cents/MWh from the previous month to -50 cents/MWh. Total uplift costs were lower than in October.

RTC and RTD Efficiency

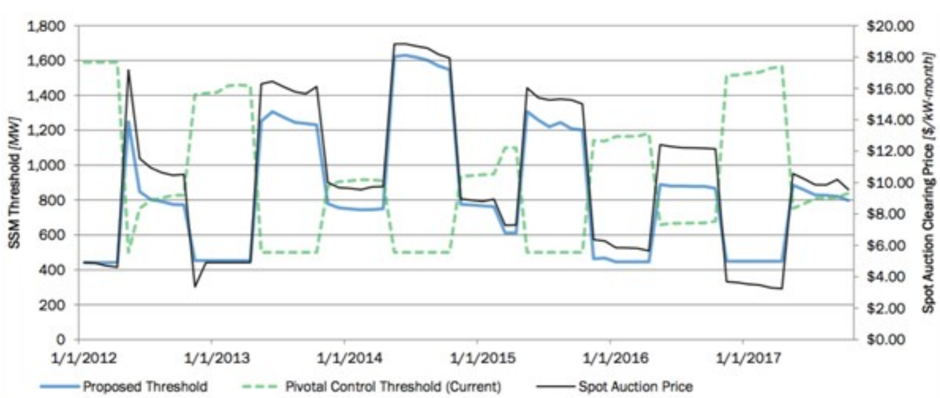
In reviewing NYISO's Broader Regional Markets report, Mukerji highlighted the ISO's effort to increase the consistency between real-time commitment (RTC) and real-time dispatch (RTD) modeling and identify improvements to look-ahead evaluations in order to improve scheduling and price convergence. The Market Issues Working Group reviewed staff analysis of the issue Dec. 5, and the ISO expects by the end of the year to release a whitepaper identifying efforts to further explore RTC-RTD convergence in 2018.

Mukerji also noted that PJM has asked NYISO to review the former's proposed *pro forma* pseudo-tie agreement that would apply to New York Control Area generators that sell all or a portion of their capacity to the RTO. PJM would provide commitment and dispatch instructions to pseudo-tied generators, which would be committed and dispatched to meet the RTO's — rather than NYISO's — needs.

NYISO has expressed concerns about using PJM's proposed pseudo-tie agreement but said it's prepared to work with the RTO to evaluate potential alternate solutions acceptable to both grid operators. FERC last month issued an order (ER17-1138) accepting many of PJM's proposed pseudo-tie rules. Rehearing requests on the order were due Dec. 15, and NYISO said it was still evaluating its options.

Mukerji said NYISO is also modifying the rules for documenting capacity imports across PJM AC ties. The ISO's proposal would require load-serving entities to submit evidence that an external resource with a capacity award has firm transmission service across the ties on the same day installed capacity (ICAP) results are posted. The Installed Capacity Working Group last month reviewed sample document types that would satisfy the requirement, which is slated to become effective May 1, 2018.

NYISO is additionally negotiating with PJM on cost sharing for the Ramapo 3500 phase angle regulator that was replaced by Consolidated Edison in September and plans to hold a joint NYISO/PJM stakeholder meeting on the issue in early 2018, Mukerji said.



Comparison of supply-side mitigation thresholds: New York City, January 2012 to present | *NYISO*

On/Off Ramp Rule Changes

The committee also reviewed a complete market design proposal for "on/off ramp" rules the ISO uses to decide whether to eliminate or create localities within its market. Randy Wyatt, senior market design specialist for the ISO, told the committee that the proposed methodology is based on reliability planning principles.

Wyatt said the project is designed to ensure that locality price signals allow developers to make informed and efficient investments that enhance grid reliability. The committee will take up the subject again in the first quarter of 2018.

Charter Update for IPPTF

NYISO Executive Vice President Rich Dewey presented a revised charter for the Integrating Public Policy Task Force (IPPTF), which he said incorporated "some, but not all" stakeholder comments received so far.

The charter states that the BIC will receive monthly progress reports from the task force and that "any potential changes to NYISO tariffs, agreements, manuals or any other guiding documents" will be subjected to the ISO's governance process.

NYISO and the New York Public Service Commission jointly formed the task force in October to create a forum for stakeholders to discuss pricing carbon into the wholesale electricity market. The task force held its first technical conference on Dec. 11. (See related story, *New York Hashes out Details of Carbon Policy*, p.24.)

Dewey acknowledged that there had been some confusion about why a new group was needed and explained that planners realized that integrating the state's policy on carbon into the power markets would require a high degree of coordination between the ISO and state agencies.

The IPPTF's next public hearing is scheduled for Jan. 8 in Albany.

— Michael Kuser

NYISO NEWS

New York Hashes out Details of Carbon Policy

By Michael Kuser

ALBANY, N.Y. — When pricing carbon into the wholesale electricity markets, remember to keep it simple.

Also: avoid unintentional emissions increases, mind the transmission needed, incent new renewable resources, abate emissions efficiently without hurting consumers, allocate revenues fairly, and leave the legal hassles for the due processes of regulators and NYISO.

Those were some of the stakeholder comments Dec. 11 at the first technical conference of the Integrating Public Policy Task Force (IPPTF), which was established in October by NYISO and the state's Public Service Commission to explore the carbon pricing issue as laid out in a Brattle Group report.

About 50 people attended the meeting, including PSC Chair John Rhodes. (See *New York Works to Frame Carbon Policy*.)

Leakage and More

Paul Hibbard of The Analysis Group facilitated two roundtable discussions, each with 23 stakeholders. The morning session addressed border adjustment mechanisms to prevent "carbon leakage," a parallel increase in emissions in regions neighboring New York.

"You don't have to have the absolute perfect solution to leakage to go forward," said Mark Reeder, an economist who represents the Alliance for Clean Energy New York at NYISO. "You just need to get most of the way there. Say if you can knock out 80 to 85% of the leakage problems at a $40 carbon price, you bring it down in essence to the latest we have now with a fairly small [Regional Greenhouse Gas Initiative] price and you've done the job."

In looking at leakage issues in RGGI states and California, Reeder said "the unit-specific approach and the resource shuffling is a real bad idea and does create a lot of problems. The example here is that a nuclear plant in Pennsylvania that's just selling spot-in in Pennsylvania could sign a contract to sell it to New York, and if New York declares that clean, we could work on that later, but it doesn't work."

Marco Padula, New York DPS; Paul Hibbard, Analysis Group; and Nicole Bouchez, NYISO. | © *RTO Insider*

Resource shuffling refers to the practice of utilities scheduling their lowest-emission generators to serve areas with emissions caps, while letting heavier polluters simultaneously serve customers in other regions.

"It's important to move forward with carbon pricing principles and not use leakage as a way to delay," said Gavin Donohue, president of the Independent Power Producers of New York. "We don't need to reinvent the wheel."

"You really get different answers depending on how you think about the question," said David Clarke of the Long Island Power Authority. "For example, if you have a uniform carbon tax on all sectors, you'd be thinking about offsets; you think about where are the places where folks can make the investments that have the largest carbon reduction at the lowest cost."

Baseline Leakage

"When you've got regions surrounding New York with such a wide range of marginal emissions rates, to start with a broad-brush approach, applying the New York rate to all of them will have pretty obvious unintended consequences," said Stephen Molodetz, vice president of Hydro-Quebec. "Quebec is zero or near zero and Ontario is close to that; then you've got PJM, which is a higher emitter than New York."

Don Tretheway, CAISO senior adviser for market design and regulatory policy, said some power producers outside the ISO have a resource portfolio with a significantly lower emissions profile than the default emissions rate for their region. In those cases, the ISO wants to give them the benefit of having cleaner resources.

"That's relatively straightforward to implement from a market standpoint," Tretheway said. "We can have each of the individual resources put their estimate of carbon compliance costs into their energy bids and we can dispatch away and everything works."

Tretheway noted how the roll-out of the Western Energy Imbalance Market (EIM) further complicated CAISO's treatment of greenhouse gas costs.

"The complexity CAISO introduced with the Energy Imbalance Market is that, not only did we need to solve to meet load in California that has a [greenhouse gas] program, but we had to actually solve to meet load in other states that don't, and that's where we had to separate those greenhouse gas costs into separate bids," Tretheway said.

Mark Younger of Hudson Energy Economics said "what California is doing now is probably a mistake. [New York] should have a very high bar on resource-specific carbon pricing. Just because you can contract with what is nominally a clean resource, doesn't mean that you in any way affected what the emissions were in the neighboring area other than by the fact that there was a bigger import to New York, regardless of resource."

Allocating Carbon Revenue

The afternoon roundtable discussed how — and whether — New York would allocate revenues collected from a carbon pricing scheme.

NYISO Executive Vice President Rich Dewey said, "We're conflating a couple issues here. First and foremost, we need to decide if there's going to be a fund. When I think about how the NYISO settlements process works today, that revenue amount only exists for the microsecond it takes to do the calculation in the settlement itself, so there is no actual fund.

"At NYISO we're not setting the policy, we're administering the market," he

Continued on page 25

NYISO NEWS

New Builds to Cover Indian Point Closure, NYISO Finds

By Michael Kuser

New gas-fired and dual-fuel generation coming online in the next few years will be enough to maintain reliability after the 2,311-MW Indian Point nuclear plant shuts down completely in 2021, NYISO said Wednesday.

An ISO report assessing the reliability needs arising from the staggered closure of Indian Point Units 2 and 3 cited three major projects totaling 1,818 MW now under construction: the 120-MW Bayonne Energy Center II uprate in NYISO Zone J, and the 678-MW CPV Valley and 1,020-MW Cricket Valley plants in Zone G.

NYISO had been reluctant to perform a reliability needs assessment prior to formal notice of deactivation from Indian Point owner Entergy, which it received in November. However, in March 2017 both the Public Service Commission and the ISO predicted that the plant's closure would present no problems for the state's bulk power system. (See *NYISO, PSC: No Worries on Replacing Indian Point Capacity*.)

The report also analyzed a scenario without the three new projects. The Lower Hudson Valley (Zones G-J) would need other solutions to maintain reliability, "including generation, transmission, energy efficiency and demand response measures." Transmission constraints into the valley from upstate (Zones A-F) and Long Island (Zone K) would make additional resources in any other zone unable to effectively resolve a deficiency, the report said.

While a generic addition of at least 200 MW by 2023 anywhere within Zones G-J would resolve the deficiency over a five-year horizon, a deficiency through 2027 would require additional resources ranging from 400 to 600 MW, depending on type and location of the resources within the valley, the ISO found.

The ISO determined the new capacity needed to compensate for the loss of Indian Point under the scenario by adding generic "perfect capacity" resources to zones in 100-MW blocks. "Perfect capacity" represents a hypothetical resource not subject to derates and not tested for transmission security or interface impacts.

New York City and Westchester County depend on Indian Point for 25% of their electricity, and the village of Buchanan and surrounding area rely on it for jobs and taxes. Gov. Andrew Cuomo in February formed the Indian Point Closure Task Force to explore ways to mitigate local tax and workforce impacts. The group next meets today in Cortland.

Entergy agreed to deactivate Units 2 and 3 by April 30, 2021, under a deal reached with Cuomo in January. The agreement would allow the plants to operate for two additional two-year increments — with final closure slated for 2025 — if an emergency affected reliability in the New York City area. Unit 1 at the plant was shut down in 1974.

Cuomo had long sought the total closure of the plant, saying it was inherently unsafe to risk having a nuclear accident occur just 40 miles north of midtown Manhattan. (See *Entergy to Shut Down Indian Point by 2021*.)

New York Hashes out Details of Carbon Policy

Continued from page 24

continued. "Be that as it may, you may have the desire, for the greater good, to create a fund in some capacity. Then we have to decide where is that fund."

Miles Farmer of the Natural Resources Defense Council said that if the PSC determines what load-serving entities must do with carbon revenues, "that's bounded under the legal constraints of PSC ratemaking, and you can't have just general slush funds of money the way that it happens with RGGI."

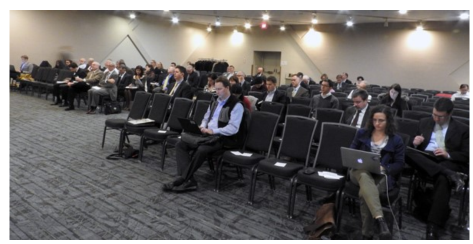
NYISO Senior Manager for Market Design Michael DeSocio said that when considering a carbon revenue fund, "we haven't actually talked about what does the rate look like. And there are components of the rate that go into various funds already — a congestion rent fund, there's a loss fund — all of that money is already allocated in some way based on various other markets. We want to do this in a way that doesn't unnecessarily increase the cost to customers."

Kelli Joseph, NRG Energy's director of market and regulatory affairs, said that making carbon pricing sustainable requires considering how RGGI moneys have been used for energy efficiency and incenting renewables in to help reduce greenhouse gases.

"The [Brattle] report assumes a certain marginal emissions rate that may not be true over time," Joseph said. "Over time, those marginal emission rates are going to decrease and there's probably not going to be anything left to refund because there's not going to be a lot of carbon-emitting resources on the system."

Scott Weiner | *© RTO Insider*

Scott Weiner, Department of Public Service deputy for markets and innovation, cautioned roundtable participants about getting caught up in the legal details so early in the planning process.

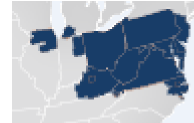


About 50 people attended the first technical conference of the Integrating Public Policy Task Force in Albany. | *© RTO Insider*

"It's going to be a collaborative effort and will be vetted legally," Weiner said. "We will subject everything to the governance processes of NYISO, so there are a lot of legal issues, and in the absence of specific facts ... I urge you to leave the legal discussion to another day."

Task force co-chair Nicole Bouchez, a NYISO market design economist, said they had decided to cancel the Dec. 18 task force meeting and will next meet on Jan. 8, 2018.

PJM NEWS



AMP Presses AEP, PSE&G on Transmission Projects

By Rory D. Sweeney

VALLEY FORGE, Pa. — American Municipal Power last week continued its criticism of PJM's grid spending, grilling utility officials during a marathon Transmission Expansion Advisory Committee meeting.

Scheduled for four hours, Thursday's meeting lasted closer to five as Ryan Dolan, AMP's director of transmission planning, asked technical questions about nearly every project presented and at one point accused American Electric Power of attempting to increase its revenue by overbuilding.

"The reason I was hired at AMP was to control their transmission costs," said Ed Tatum, AMP's vice president of transmission, who joined the company two years ago from Old Dominion Electric Cooperative. In September, he hired Dolan — from AEP — to aid his effort.

"AMP has put in place the human and transmission modeling resources to enable us to review and assess PJM and the Transmission Owners' plans and ask the necessary technical questions to support the need for a project," Tatum said.

'Minimum' Information Required

The TEAC session followed a Planning Committee meeting at which AMP presented templates illustrating the "minimum" information it needs to evaluate projects.

Tatum said he did not "try to orchestrate" the long meeting or "filibuster" to make his point. Without the information requested, he said, "we're not going to have any choice but to ask those questions" and "we're probably going to be here until 6 o'clock" next month as well, he said. "The meetings could be done in a couple hours if the information on the examples we provided was available sufficiently in advance."

The TEAC meeting was surprising for its length, but not its content. Dolan and Tatum have led a customer pushback on the more than $1 billion in transmission projects that get discussed at monthly TEAC meetings before being authorized for construction by PJM's board through the Regional Transmission Expansion Plan. Their frustration is also on display at meetings of the Transmission Replacement Processes Senior Task Force, where they argue for increased engagement with TOs on when to determine that transmission infrastructure needs to be replaced and how to do it. (See *New Wave of PJM Transmission Upgrades Rankles AMP*.)

TOs argue that their networks are theirs to maintain as they see fit, but AMP, ODEC and other customers contend that as the ones paying the bills, they should have a say.

Tatum had proposed presenting the project information templates at the TEAC, but PJM moved it to the PC because that is where all discussions on the planning procedure take place. Tatum hopes the move indicates that PJM will organize a discussion on the topic.

"At this point, I'd like to see how that discussion goes," Tatum said after the meeting. "We would hope that we be able to get more transparency."

PJM appeared amenable to discussing AMP's information demands. Staff agreed to add the issue to next month's PC agenda.

"Clearly what we're doing now is not sustainable," said Paul McGlynn, PJM's administrator of the TEAC.

Confidentiality

TOs have previously raised legal concerns with discussing confidential details of transmission projects in open meetings and did so again on Thursday. Alex Stern of Public Service Electric and Gas said that because issues involving PJM and TO compliance with FERC Order 890 are awaiting a FERC decision, there is a limit on how much TOs can discuss. (See *Load Blocks TO Effort to Extend Hiatus of PJM Transmission-Replacement Talks*.)

"All of this raises some legal issues as well, so before we go back to the PC, you might want to confer with" PJM's legal team, he said.

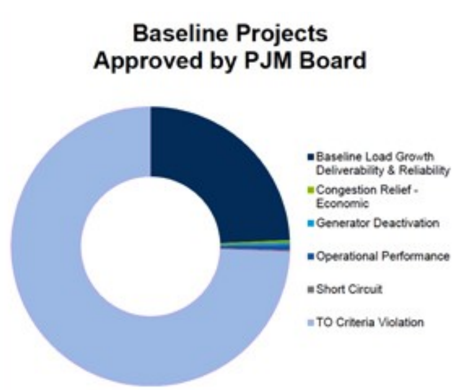
Dolan and Tatum said they understand confidentiality and security concerns and suggested that when there are multiple projects with Critical Energy Energy/Electric Infrastructure Information (CEII) information, PJM could hold meetings restricted to stakeholders with CEII clearance so that the information can be discussed.

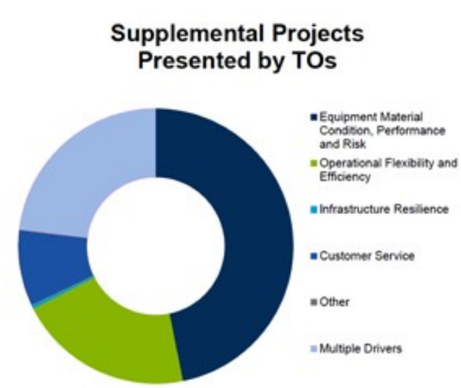
Layering Impacts

The pair said several AEP and PSE&G projects discussed at the TEAC highlight their concerns.

AEP is planning to replace its Tidd 345/138-kV transformer on the Ohio-West Virginia border, about 45 miles west of Pittsburgh. The 150-MVA unit, which was manufactured in 1957, was taken out of service in March. The new unit will be increased to 450 MVA and include a series reactor on the low side to mirror a parallel transformer, at a cost of $7.8 million.

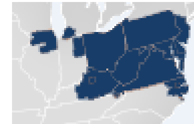
Dolan said the project description failed to explain whether the proposal sizes the reactor appropriately for future short-circuit changes. "Are we going to see an issue in five years? Four years? Two years?" he asked. Tatum later questioned whether AEP





| PJM

Continued on page 27



AMP Presses AEP, PSE&G on Supplemental Projects

Continued from page 26

planned ahead when it replaced the facility's breakers to account for a second breaker.

AMP argues that TOs' supplemental projects — which are based on their internal criteria and don't require PJM authorization — can create reliability issues that necessitate baseline projects, which are directed by the RTO's criteria and do require board authorization. The lack of information makes it impossible to evaluate how a supplemental project impacts individual equipment on the system because stakeholders are only made aware after a piece of equipment is overloaded, AMP said. (See *Report Decries Rising PJM Tx Costs; Seeks Project Transparency*.)

"The lack of this information concerns us because by putting in a bunch of supplemental projects, the transmission owners can be bringing the system up to a point where the [NERC criteria] would soon require baseline reliability upgrades," Tatum said.

PJM has said its abiding principle in planning for increased grid resiliency is "do no harm."

"What do you consider 'do no harm'?" Dolan asked. "The only organizations that are aware of the impacts, power-flow-wise, of these supplemental projects are the TOs that are submitting them and PJM.

"Stakeholders are not getting an opportunity to review the impact of these projects. The only time that there is any sort of review done is if those projects actually create overloads," he said. "What we are interested in is to understand the incremental [system power flow changes associated with these projects]. … We have concerns about the layering of projects … which change system impedances and responses that drive [future baseline] overloads."

Selective Criteria

At the Broadford station in southwestern Virginia, AEP is planning to spend $102 million installing six new breakers and replacing seven breakers, a reactor and two transformers that are showing signs of imminent failure. Dolan argued the additional breakers were unnecessary and will protect nothing that isn't already protected by the existing breakers.

Damage to the Branchburg-Pleasant Valley line | *PJM*

AEP has similar situations at its Kenzie Creek, Cloverdale and Desoto stations, he said, but chose not to increase protection there. Kenzie Creek is in Michigan about 20 miles north of South Bend, Ind., Cloverdale is in Virginia and Desoto is northeast of Muncie, Ind.

"You're willing to spend money when you're able to get away with it," Dolan said to AEP representatives who called into the meeting. They denied the accusation and said they use discretion when applying their criteria.

"Even though the projects involve circuit breakers' replacement, the optimal solution for each is unique," AEP's Kamran Ali said in an email to *RTO Insider*.

The difference, he said, is that nearly all the 138-kV breakers need to be replaced at Broadford, so it makes sense — from a cost, reliability and outage perspective — to build a new 138-kV yard. Adding the "separation of protection zones" at that time is both cost effective and efficient, whereas the other projects only require individual equipment replacements that make separation of protection zones "neither prudent nor cost effective," Ali said.

Dolan wasn't satisfied.

"They are not being consistent, and they are not being consistent about information they do not provide to the public," Dolan said. "I'm starting to notice that this is unique to certain states."

Dolan said AEP is planning similarly excessive breaker installs at the Axton station, also in Virginia.

"It is most cost-effective to tailor the asset replacement solution to the scope of the project and the specific site conditions. This is not the result of inconsistent approaches, but a commitment to deliver solutions that address the need in the most cost-effective manner for our customers," Ali said in his email. "Applying a rigid approach that does not recognize the differing situations could lead to higher costs, lower reliability, and less efficient projects for our customers."

Maintenance Questioned

Other stakeholders joined Dolan in questioning PSE&G's $546-million rebuild of its 53-mile Roseland–Branchburg–Pleasant Valley corridor. David Mabry, who represents the PJM Industrial Customer Coalition, noted that two of the photos of degraded equipment included in PSE&G's documentation were date-stamped September 2013. Stakeholders questioned why PSE&G waited four years to present the violation of its FERC Form 715 criteria, which allow TOs to determine what factors indicate when its facilities should be replaced.

Dolan argued it might be because the shortened repair timeline designates the project as "immediate need," which ensures PSE&G will be able to replace the infrastructure itself and the project won't be eligible for competitive bidding.

"One of two things is happening: We've either chosen not to address it back then and customers could have been put at risk [of service interruptions], or we waited until we could make the determination that it is immediate need," Dolan said. "By driving everything to immediate need ... you're pre-

Continued on page 28

PJM NEWS

AMP Presses AEP, PSE&G on Supplemental Projects

Continued from page 27

venting opportunities for competition. … When we have a lack of competition, we have an excessive amount of costs."

Stern and PSE&G colleague Esam Khadr disagreed with the "immediate need" characterization, saying it went through a condition assessment as outlined in Form 715 procedures, including independent analysis by an outside consultant.

"These particular pictures may have been from 2013, but the line continued to be maintained and provide service while condition assessments per the FERC Form 715 procedures were only recently completed," Stern explained.

Dolan said this is a pattern with PSE&G projects.

"I have yet to see a [Form 715] project come forward that is not immediate need when they bring it forward," he said.

In an email to *RTO Insider*, Stern responded that "AMP can't have it both ways."

"They can't profess to want TOs to maintain facilities for as long as viable, performing assessments and maintenance for as long as possible and then when condition assessments indicate that that is no longer viable, assert that the project should have been brought sooner. The Roseland-Branchburg-Pleasant Valley line is one of the original lines dating back to the formation of PJM 90 years ago. It has been maintained for decades and provided steady, reliable service on behalf of customers through that entire time. It has certainly done its job. However, condition assessment clearly reveals that it is in need of replacement, and replacement under these circumstances is the correct and cost-effective approach for customers."

Stakeholder Support

Sharon Segner of LS Power also questioned the timing of the proposal, saying the project should be opened for competitive bidding under FERC Order 1000.

"It very well may be the solution," she said. "What I'm questioning is the process."

Stern later noted that "FERC Form 715-driven projects are exempt from competitive bidding processes pursuant to FERC orders."

AMP's proposed project information templates received endorsement from Greg Poulos, the executive director of the Consumer Advocates of the PJM States (CAPS).

"The consumer advocate offices are well aligned with AMP," Poulos said.

PJM Response

PJM staff attempted to divert project questions to its newly formed online Planning Community, providing a refresher on the group's purpose.

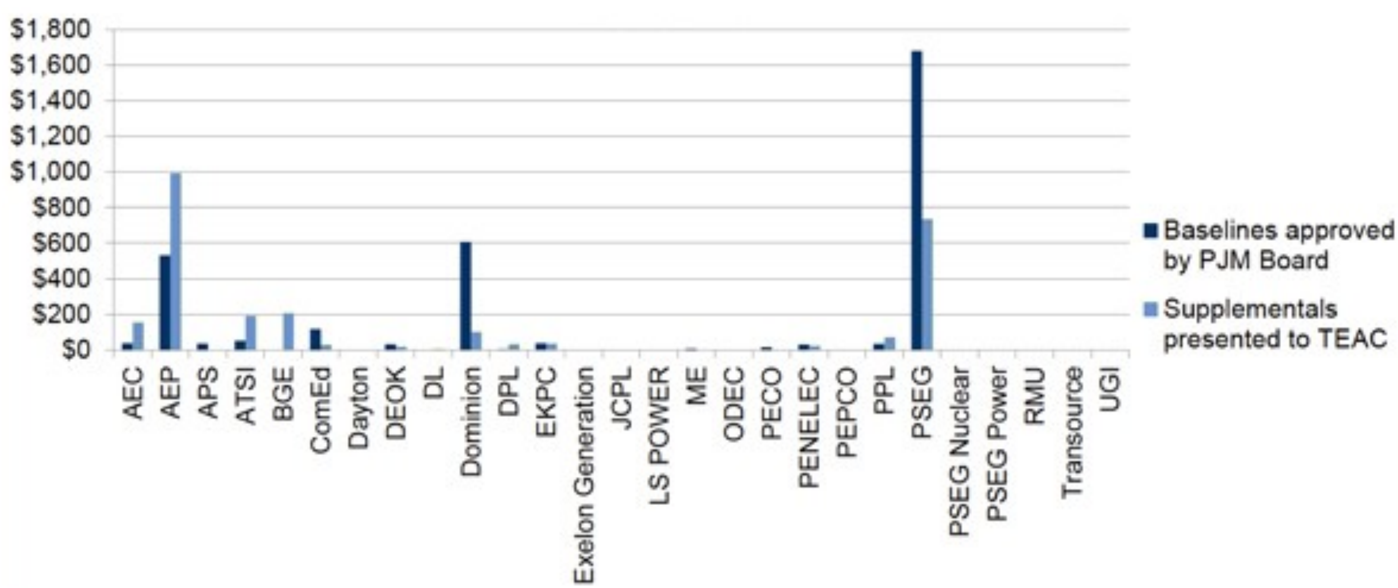
"It's not a dead letter office," PJM's Fran Barrett said.

But Dolan disagreed, complaining that he hasn't received responses in that forum.

"I've submitted a whole slew of questions [to both the planning community and directly to PJM], and just writing them down doesn't get them answered. My question is: Even if we write them down are they going to get answered?" he said. "I have not received a response to everything [asked], and in fact, we've been told we're not getting an answer" to some questions.

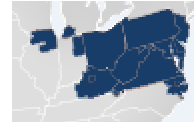
PJM presented several charts documenting transmission projects including one (below) that showed AEP, Dominion Energy and PSE&G proposing many supplemental projects, which are not competitively bid.

"I understand the visuals here, but I don't think this is enough information to draw conclusions about individual transmission owners and their [Form] 715 criteria," PJM's Sue Glatz said.



| PJM

PJM NEWS



Nuke Bailout Bill Introduced in NJ Senate

By Rory D. Sweeney

Public Service Enterprise Group and Exelon would receive hundreds of millions in subsidies to maintain the profitability of three in-state nuclear plants under legislation introduced in the New Jersey Senate on Friday (S3560).

Two of the sponsors, Sens. Stephen Sweeney and Jeff Van Drew, represent the area of southern New Jersey where the units are located. The third, Sen. Bob Smith, is chair of the Senate Environment and Energy Committee. PSEG has three nuclear reactors between the Salem and Hope Creek facilities; Exelon owns 43% of the Salem units.

Under the bill, the plants could be compensated through the issue of "nuclear diversity certificates" (NDCs) representing the "environmental and fuel diversity attributes" of 1 MWh produced by an eligible nuclear unit. All utilities in the state would be required to purchase NDCs from the nuclear plants monthly.

Funding for the program would come from a 0.4-cent/kWh charge on all New Jersey retail customers' bills. The state Board of Public Utilities would have discretion to reduce the charge as it deems appropriate.

Several groups, including PJM's Independent Market Monitor, New Jersey's Division of Rate Counsel and coalitions of in-state citizen advocates and non-nuclear power generators oppose the plan and have pointed out that PSEG's plants remain profitable. (See *Opponents Assemble as PSEG Seeks NJ Nuke Subsidy*.)

The three nuclear units provide about 40% of the state's power. PSEG has estimated the subsidies could cost $240 million a year, about $31 for an average residential ratepayer. The Division of Rate Counsel put the cost at $320 million, or $41 per customer.

Eligibility Process

Plants would become eligible for NDCs by providing, within 30 days of the law's enactment, certified three-year forward-looking cost projections that include operations and maintenance, fuel, non-fuel capital, and a valuation of operational and market risks that would be avoided if the plant shut down. The plants also could provide "any other information, financial or otherwise, to demonstrate that the nuclear power plant's fuel diversity and air quality attributes are at risk of loss because the nuclear power plant is cash negative on an annual basis, or alternatively is not covering its costs including its cost of capital on an annual basis."

Salem and Hope Creek nuclear plants | *Green Delaware*

Exelon and PSEG would also have to provide "certification that the nuclear power plant will cease operations within three years unless the nuclear power plant experiences a material financial change, and the certification shall specify the necessary steps required to be completed to cease the nuclear power plant's operations."

All information could be supplied confidentially.

The BPU would then have another three months to develop an application process for the plants to receive payment for their NDCs, and the plants would have another month to apply. A plant would have to satisfy five inquiries concerning why it deserves to be in the program and pay an undetermined application fee that could reach $250,000.

Justification

The bill references New Jersey's plan to secure 70% of its energy needs from "clean energy sources by 2050," calling nuclear a "critical source of zero-emissions energy."

If the plants close, the void will be filled with natural gas plants, the bill says, and that "capacity challenges on existing natural gas pipelines combined with the difficulty in siting and constructing new natural gas pipelines, along with competing uses for natural gas, such as building heating, have created supply constraints in the past, and those constraints could impact system reliability."

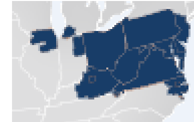
Part of the bill's justification is that "recent severe weather events have demonstrated the need to improve the resilience of the electric power delivery system" and that "the mix of generation resources serving New Jersey residents must be capable of handling high-impact, low probability weather events."

However, selected plants could be excused from performance in the event of natural disasters or other catastrophic events, such as labor disputes, or if the plant would need more than $40 million in capital expenditures. Plants that stop operating for a reason that isn't covered would need to pay back all the payments it received since its last eligibility determination.

"Gov. [Chris] Christie is attempting one last robbery of the people and environment of New Jersey before he leaves office in January," Jeff Tittel, director of the New Jersey Sierra Club, wrote in an op-ed about the bill Monday.

"The bill would give PSEG subsidies for their nuclear plants in New Jersey and simultaneously tie Governor-elect [Phil] Murphy's hands when it comes to promoting renewable energy. Cheap natural gas combined with nuclear subsidies means renewable energy gets pushed out. Christie is trying to dictate New Jersey's energy policy for the next 40 years, despite the fact that the people want renewable energy, and this bill undermines that."

PJM NEWS



PJM Monitor Battles Exelon on MOPR-Ex Proposal

By Rory D. Sweeney

"We don't understand the rationale of" Illinois' zero-emission credit program. "The definition of 'renewable' is not all that complicated."

Jeffrey Mayes, Monitoring Analytics

VALLEY FORGE, Pa. — PJM's Independent Market Monitor faced a barrage of questions last week at the final stakeholder evaluation of its capacity market proposal ahead of a vote at Thursday's Markets and Reliability Committee meeting.

Monitor Joe Bowring was absent for the first half of the meeting, leaving his chief counsel, Jeffrey Mayes, to answer whatever he could. Many were technical, however, and had to await Bowring's arrival.

PJM offered stakeholders no assistance, making it clear from the start that its facilitation of the meeting did not indicate its support of the proposal. The Monitor's MOPR-Ex proposal was the only one among 10 debated at the Capacity Construct/Public Policy Senior Task Force (CCPPSTF) to receive the task force's endorsement and automatic consideration at the MRC.

After a year of meetings at the CCPPSTF, many stakeholders decided they preferred the current capacity design to any of the proposals, but they feared PJM would file its own two-stage repricing proposal in the absence of a clear endorsement by stakeholders. They believed that the RTO's repricing proposal, which isolated subsidized generation offers from competitive ones by administratively reorganizing auction results, was such a drastic change that it could not be undone once implemented, while the Monitor's proposal, which would extend the minimum offer price rule (MOPR), was as close to the status quo as possible.

The MOPR-Ex proposal would allow exemptions for many unique circumstances, including public power facilities and generators subsidized through states' renewable portfolio standards, but it would not include Illinois' zero-emission credit (ZEC) program. That doesn't sit well with Exelon, which stands to benefit the most from the ZECs and whose own repricing proposal was rejected by the task force.

Exelon's Jason Barker peppered the Monitor with questions about revisions to the RPS exemption that were inserted after the CCPPSTF endorsed it. Those revisions will be proposed at the MRC as an alternative to the endorsed version.

He asked Mayes if ZEC programs, designed to curb air emissions like other states' renewable energy programs, qualify as "renewable" under the proposal. Mayes said no.

"We don't understand the rationale of that program," Mayes said. "The definition of 'renewable' is not all that complicated."

The reason for the revisions, he said, was that programs that incented one type of renewable energy, such as wind or solar, are acceptable, but being preferential to a certain type of technology to harness that energy, such as offshore wind or rooftop solar, was not.

"It's ironic that we're trying to protect against states picking winners and losers and drafting tariff language that picks winners and losers," Barker said. "They'd have the same effect on the marketplace, but one would be mitigated and one would not."

The exemption calls for the inclusion of some programs based on the date of their implementation.

"It's ironic that we're trying to protect against states picking winners and losers and drafting tariff language that picks winners and losers."

Jason Barker, Exelon

"It's called 'grandfathering.' You've never heard of it?" asked Ruth Ann Price, who represents Delaware's Division of the Public Advocate. "What Jason is trying to do is he's trying to show some discrimination. I get it."

Barker and his colleague Sharon Midgley also questioned revisions that prohibited supply from affiliates but allowed public power to overbuild facilities and then have the excess capacity exempted from the MOPR floor price.

Bowring acknowledged some of the concerns and said he would consider ways to address them in a revised final proposal.

The situation is complicated by a ruling from FERC that struck down the MOPR that PJM has been using since 2013 and on which the Monitor based its proposal. (See *On Remand, FERC Rejects PJM MOPR Compromise*.) The previous iteration of the rule was limited to gas-fired units and included fewer exemptions, and PJM has indicated it's planning to allow that version to largely go back into effect with enhancements to calculation methods that have been developed since it was implemented.

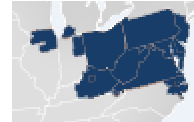
Bowring, however, was unconcerned.

"I think the MOPR-Ex aligns explicitly with the order," he said.

"They seemed to pretty emphatic that extending the mitigation period would be more costly," Barker said, referring to FERC's denial of an extension of the MOPR mitigation from one year to three years.

Bowring said the mistake was in using a floor price that was designed for a new unit for the subsequent years after the initial mitigation. Had the floor been switched to being based on the units' net avoidable cost rate, it would have been consistent, he said.

PJM NEWS



NJ Merchant Tx Operators Win Relief on Upgrade Costs

By Rich Heidorn Jr.

Linden VFT facility | *Joseph Jingoli & Son*

PJM must amend interconnection service agreements (ISAs) to allow two merchant transmission facilities to convert from firm to non-firm service, FERC ruled Friday, the latest reverberation resulting from the cancellation of the Con Ed-PSEG "wheel."

The commission's orders could relieve Hudson Transmission Partners (HTP) (EL17-84) and Linden VFT (EL17-90) from hundreds of millions in cost allocations under PJM's Regional Transmission Expansion Plan.

The commission said the companies' ISAs, signed with PJM and transmission owner Public Service Electric and Gas, were unjust and unreasonable because they did not allow the merchants to convert firm transmission withdrawal rights (TWRs) to non-firm TWRs that are subject to curtailment.

HTP owns a 660-MW, 345-kV underwater HVDC line that connects PJM in northern New Jersey and NYISO in New York City. FERC issued a show cause order after PSE&G rejected its request to convert 320 MW of firm TWRs to non-firm. (See *Rejecting PJM 'Wheel'-related Requests, FERC Sets Inquiry*.)

Linden VFT, which operates three 105-MW variable frequency transformers between the PSE&G system and Consolidated Edison, filed a complaint after PSE&G rejected its request to convert 330 MW of firm TWRs to non-firm.

The two merchant projects were part of a decades-old service agreement between PSE&G and Con Ed that the latter terminated in April. The service "wheeled" 1,000 MW from Upstate New York through PSE&G's facilities in northern New Jersey and into New York City.

Following termination of the wheel, PJM asked FERC to reassign $533 million in costs related to the Bergen-Linden Corridor project to HTP, which the commission approved on April 25.

Under PJM's Tariff, merchant transmission facilities are assigned the costs of the network upgrades that would not have been incurred "but for" their interconnection request. Merchant facilities also are responsible to pay annually for the costs of any post-interconnection network upgrades needed to support the merchant's firm TWRs.

"We see no reasonable basis for barring HTP from converting from higher quality firm TWRs to lower quality non-firm TWRs by amending the existing ISA," FERC said. "HTP already has satisfied the interconnection requirements, and we find that requiring it to maintain such firm TWRs for the life of the merchant transmission facility is unjust and unreasonable in the absence of any operational or reliability basis for doing so."

The commission dismissed PSE&G's allegation that reducing the service level would harm reliability.

"Under the existing ISA and PJM's Tariff, PJM must guarantee that its transmission system is robust enough to permit HTP to use its firm TWRs to export 320 MW of power from its source in PJM across the river to New York at all times. Converting those firm TWRs to non-firm TWRs imposes no additional obligation on PJM and, in fact, is less burdensome in that PJM will no longer have to guarantee that its transmission system can support such use," the commission said. "In any case, HTP's line is fully controllable by PJM so that PJM can shut off flows if those flows jeopardize reliability or cause operational problems in New Jersey or elsewhere on the PJM system."

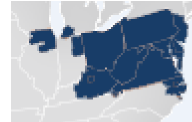
FERC also rejected PSE&G's contention that allowing the change would undermine the interconnection process. The commission said PSE&G's argument that it relied upon the long-term duration of the existing ISAs was "unpersuasive," noting that the merchants had unilateral rights to terminate the ISAs at any time.

The commission rejected as beyond the scope of the cases a request by PJM's Independent Market Monitor to change Schedule 12 of the Tariff. The Monitor said the changes were needed to address what it called a discrepancy in the cost responsibility assignments for RTEP projects for merchant transmission providers that hold firm point-to-point transmission service and those that hold firm TWRs.

"Those general concerns with Schedule 12 do not address whether [the merchants] should be permitted to convert" their firm TWRs, FERC said.

The commission ordered PJM to file the revised ISAs in seven days from the Dec. 15 orders. Chairman Kevin McIntyre, who was sworn in Dec. 7, did not participate in the order.

PJM NEWS



Operating Committee Briefs

Gas Generators Block PJM Pipeline Plan

VALLEY FORGE, Pa. — PJM's plan to add several gas pipeline emergency procedures to its manuals was derailed by stakeholders at last week's Operating Committee meeting.

Staff had included the pipeline contingency plans in revisions to Manuals 3: Transmission Operations Updates and 13: Emergency Operations, two of five manual revisions set for endorsement votes at the meeting. All five were endorsed by acclamation, but not before the pipeline contingencies were stripped out.

The revisions would have added procedures for assessing the impacts of gas contingencies on the grid, including system conditions triggering the assessment; determining applicable gas infrastructure contingencies; and coordination with generation owners and gas pipelines.

PJM is attempting to get rules for a responding to emergencies on the pipeline system documented before the winter season, but stakeholders fear a repeat of the polar vortex conditions in 2014, when gas prices soared past offer caps and generators were left with no mechanism to recoup costs in the aftermath.

Gas generator representatives convened before and during the meeting to orchestrate moving an informational item on system resilience — scheduled for the tail end of the meeting — to the top of the agenda ahead of the votes. During that discussion, Panda Power Funds' Bob O'Connell proposed adding a waiver to the manuals that would allow gas generators to recoup all expenses incurred if PJM directed them to operate outside of their dispatch schedule during an emergency.

PJM balked at the proposal. Chris O'Hara, PJM's deputy general counsel, questioned whether stakeholders could vote to require the RTO to include in its Tariff a waiver of its own rules. O'Hara's input made other stakeholders, including Dave Mabry of the PJM Industrial Customers Coalition and Exelon's Sharon Midgley, hesitant to support the waiver until they could vet the motion with their organizations. Both expressed willingness to discuss the matter further at the Markets and Reliability Committee.

The meeting took a short break to discuss the situation. When it reconvened, O'Connell withdrew his waiver proposal and instead moved to vote on the manual revisions without the pipeline-contingency sections. The votes passed, and PJM's Ken Seiler, who chairs the committee, said that a solution would be developed to present to the Dec. 21 MRC meeting.

Owner Transfer Rules Revision

PJM is planning to revise its rules for alerting it to changes in generator owners. The revisions would require notification at least 60 days prior to the date requested for the generation transfer — time for the RTO to review the information and ensure that all required documentation is submitted.

The request would need to be accompanied by 22 pieces of information, including contact information, a fuel-cost policy for applicable units and reactive credits. The fuel-cost policy would need to be submitted within 45 days of the requested effective date. PJM plans to develop a user guide to provide step-by-step directions on how to fill out the necessary information.

— Rory D. Sweeney

FERC Seeks Info on Ohio Generator's Reactive Power Claim

FERC last week set hearing and settlement proceedings for a new Ohio merchant plant, saying it had not provided sufficient backing for its reactive power revenue requirement (ER18-92, EL18-32).

The 747-MW Carroll County Energy combined cycle plant, expected to go in service this month, is seeking compensation for its generator, associated exciter equipment, step-up transformers and other equipment under allocation factors representing their contribution to both reactive service and real power.

The commission said the plant's owners had not demonstrated that its proposed revenue requirement was just and reasonable. "CCE's filing has no underlying support for the costs claimed for this new generation facility, and the balance of plant investment allocator and the accessory electrical equipment allocator may be excessive. We further note that the components of the accessory electrical equipment are not provided," the commission wrote.

FERC said that, if no settlement is reached, it expects to issue a decision within eight months of the filing of briefs opposing exceptions to the initial decision by an administrative law judge. "If the presiding judge were to issue an initial decision by July 31, 2018, we expect that, if the proceeding does not settle, we would be able to render a decision by May 31, 2019."

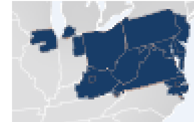
Carroll County Energy plant | *Power Technology*

The plant's owners include TIAA, Chubu Electric Power, Ullico, Prudential Financial and Advanced Power, a Boston-based development company that oversaw construction and will manage the start of commercial operations.

Chairman Kevin McIntyre did not participate in the decision.

— Rich Heidorn Jr.

PJM NEWS



MIC Briefs

FTR Changes in the Works

VALLEY FORGE, Pa. — PJM is moving to implement three changes to its financial transmission rights market, developed through its FTR Modeling, Performance and Surplus Funds special sessions. All three received endorsement at last week's Market Implementation Committee meeting.

The first involves changes in long-term FTR modeling to account for future transmission system upgrades, which can impact congestion revenue. PJM is concerned that long-term FTR clearing prices don't reflect "true future system capability." FTRs entitle holders to credits based on locational price differences in the day-ahead energy market when the transmission grid is congested. They can be purchased or converted from auction revenue rights, which are allocated to network and firm point-to-point customers.

PJM's annual ARR/FTR network model includes transmission upgrades that will be in place by the following June 30, and staff proposed expanding that methodology to the long-term FTR network model so that it also looks forward one year. The model would be filtered to only include upgrades that fit a "low-frequency, high-impact" threshold.

That threshold would be defined as the upgrade being a constraint itself or impacting by +/-10% constraints that have contributed at least $5 million to congestion over the past year or any future constraint. For new facilities, the analysis would be based on the line outage distribution factor (LODF), a measure determining how the change in a line's status affects flows elsewhere in the system. The FTR group would work with PJM's planning staff to determine which upgrades should be included in the model. PJM included in its presentation an example of how that process would have worked for 2016 and found that three out of 21 upgrades would have been modeled.

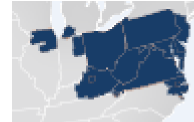
PJM would also develop a new long-term residual ARR market to ensure holders maintain priority rights to any incremental capability created by upgrades still to be modeled.

The second set of changes would improve PJM's ability to finalize and publish FTR auction results on time. Impetus for the solution came after PJM delivered its March auction results late and blamed it on having to simultaneously finish the results for several overlapping FTR auction periods. (See "FTR Lateness Blamed on High-Volume Period," *PJM Market Implementation Committee Briefs*.)

PJM proposes to resolve the issue by eliminating some auction periods. PJM's Brian Chmielewski said the proposal, if endorsed on its current timeline, would be

Continued on page 34

PJM News



MIC Briefs

Continued from page 33

filed with FERC in February to be effective for the June overlapping period.

The third set of changes would allocate any surplus from FTR auctions and day-ahead congestion to ARR holders after FTRs are fully paid to their target allocations. The issue developed after FERC required PJM to revise its methods for allocating ARRs and balancing congestion. (See FERC Accepts PJM's FTR Plan, Rejects Rehearing Requests.)

MIC members had to vote on two proposals: one developed by a coalition of ARR holders that allocated all surplus to holders, and a second developed by financial traders that allocated FTR surpluses to ARR holders up to their target credits and all day-ahead congestion surpluses to FTR holders.

The MIC endorsed the ARR holder proposal, with 90% in favor, and rejected the financial traders' proposal with 34% in favor.

EnerNOC DR Aggregation Solution Questioned, Approved

Stakeholders endorsed by acclamation a problem statement and issue charge to examine the aggregation rules for seasonal demand response, but not before thoroughly questioning the proposal's sponsor, EnerNOC. (See "Seasonal DR Aggregation Registration Rules," PJM Market Implementation Committee Briefs: Nov. 8, 2017.)

"We don't think this is a problem," Independent Market Monitor Joe Bowring said, adding that "it seems to be presupposing the solution."

Other stakeholders reiterated previous complaints that PJM's stakeholder meeting schedule is already overbooked and that examining the issue doesn't provide enough relative benefits to justify adding to the load.

"If we take issues up where there's not really a problem, we create extra work for ourselves. I don't think you can blame PJM for that. We have to blame ourselves," Calpine's David "Scarp" Scarpignato said.

EnerNOC argues that the current registration process is inefficient and provides a Capacity Performance value that fails to reflect the full reduction that the aggregated resources could achieve. PJM did not update its customer-registration rules when DR rules were revised to comply with CP requirements, nor did it seek stakeholder endorsement prior to unilaterally filing for approval last year of its seasonal aggregation plan. (See FERC Staff OKs PJM Aggregation DR Rules; Refunds Possible.)

> *"I hope this doesn't take 20 meetings, but I think it's worth working on."*
>
> **Brian Kauffman, NRG**

EnerNOC's Katie Guerry said the issue is worth examining because it could lead to more efficiency for both DR aggregators and PJM dispatch operations.

"If status quo comes out [as the result], we're ok with that as well," she said.

Other DR stakeholders supported her.

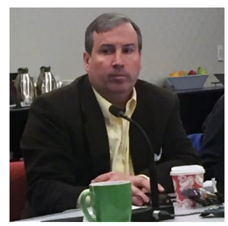
"I hope this doesn't take 20 meetings, but I think it's worth working on," NRG Energy's Brian Kauffman said.

Monitor, Financial Marketers Propose Different Paths

Unable to work out their differences on how to regulate the market path of energy sales coming into PJM, the Monitor and financial marketers are asking the MIC to resolve the issue. They are presenting three different proposals on the issue.

The Monitor's proposal would develop a list of "prohibited paths" that could be subject to resettlement. The Monitor would develop a monthly report of activity on those paths and share it with PJM so that either entity could refer use of those paths to FERC for enforcement.

Pierce Atwood partners Ruta Skucas and Jared des Rosiers presented a proposal developed by American Electric Power and the Financial Marketers Coalition. It would entail a change in PJM's Tariff for the initial list of banned paths and require FERC, PJM and Monitor approval for any additions. It would also develop a "query" where users could seek a preliminary evaluation from PJM on whether a potential path would risk resettlement.

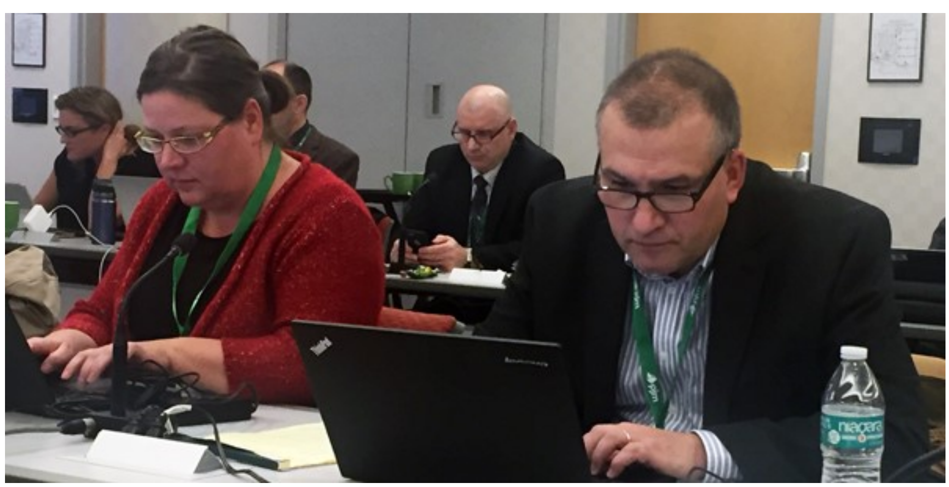


Stephen Kelly | © RTO Insider

Stephen Kelly of Brookfield Renewable presented another proposal that would allow market participants the opportunity to establish with PJM and the Monitor that a potentially problematic transaction is "legitimate" before it is automatically settled.

The proposals also differed on what level the activity should be evaluated. The Monitor proposed considering it from the level of the parent corporation, but the others called for analysis on the level of individual companies.

— Rory D. Sweeney



Pierce Atwood partners Ruta Skucas and Jared des Rosiers | © RTO Insider

PJM NEWS

PC/TEAC Briefs

Vote Postponed on Market Efficiency Proposal

VALLEY FORGE, Pa. — Recognizing stakeholder concerns, PJM postponed a planned vote at last week's Planning Committee meeting on its proposal to adjust the analysis process for market efficiency transmission projects. (See "PJM Seeks Changes to Market Efficiency Process," *PJM Planning and Transmission Expansion Advisory Committee Briefs: Nov. 9, 2017*.)

PJM's Asanga Perera acknowledged questions about the proposed problem statement and issue charge, which would reconsider the timing of market efficiency windows, how projects are selected, modeling and benefit calculation and how rejected projects are reevaluated.

During the meeting, stakeholders posed questions related to their specific interests.

Greg Poulos, executive director of the Consumer Advocates of the PJM States (CAPS), asked whether resiliency would be factored into project evaluation.

"Any project that we would put into the [Regional Transmission Expansion Plan], we would look at it for resilience as well," PJM's Paul McGlynn assured him.

LS Power's Sharon Segner asked how cost-containment would factor into evaluations. PJM's Sue Glatz said it's being discussed.

Ryan Dolan with American Municipal Power asked about treatment of supplemental transmission projects.

"All we're trying to do is point to issues we're concerned about," he said.

The special interest inquiries drove PJM's Steve Herling to discuss level setting.

"We have to keep some of these things separate in the problem statement," he said.

Cost-containment in Proposals

PJM unveiled proposed revisions to its Operating Agreement and Manual 14 to include cost-containment provisions and redaction requirements discussed at recent special sessions of the committee. (See *PJM Stakeholders Battle over Cost Cap Rules*.)

Terms and conditions relative to a cost cap commitment will be public information, though specific supporting information may be eligible for confidential treatment with appropriate explanation. PJM said it plans to limit cost cap evaluation to construction costs because they are the largest and most enforceable component of the overall cost.

Segner noted that other grid operators allow other cost-containment factors, such as annual revenue requirements and return on equity, and asked Poulos what the process would be to propose that PJM evaluate their inclusion in any evaluation.

"As you know, competition is something the [state consumer] advocates have wanted in this process — and even more competition," Poulos said.

Other market issues requiring attention are piling up quickly, he said, so there has been nothing but discussions among advocates on the idea.

> ***"As you know, competition is something the [state consumer] advocates have wanted in this process — and even more competition."***
>
> **Greg Poulos, CAPS**

"The ratemaking process is where we feel is the appropriate place to take any additional challenges," Glatz said, effectively punting the issue to FERC.

Alex Stern with Public Service Electric and Gas praised PJM for keeping conversation on the issue constructive.

"A number of [transmission owners] were concerned about the entire process as it went, but PJM ensured it remained … a challenging but collaborative process," he said. It produced a "negotiated resolution, which I think is a fair direction for how to handle this at this juncture."

Segner said she wouldn't "necessarily agree on" Stern's characterization because the result is a "significant deviation from what every other organized market in the country is doing relative to cost containment."

One stakeholder chimed in from the phone to ask that because "cost containment is voluntary to start with, why would we put a limit on … that if they offer it?"

Glatz reiterated that PJM's role doesn't involve ratemaking and that construction costs are a "firm number," while "the financing and ratemaking tends to have a lesser impact overall."

Resilience in Planning

PJM's Mark Sims told stakeholders to anticipate proposed rule changes in January to address planning for resiliency. Stakeholders requested that the topic be split off into a separate task force to facilitate additional discussion. PJM acknowledged the request. (See "Resilience in Planning," *PJM Planning/TEAC Briefs Oct. 12, 2017*.)

Competitive Proposal Fees

The past two years have produced a deficit of $58,119 on evaluating Order 1000 competitive projects, PJM's Michael Herman said. The numbers aren't final, he said, but they represent a very good estimate.

Given that the evaluations cost $1.688 million and PJM collected $1.63 million, Herman said, "We think we did a pretty good job estimating the amount of money we would need to perform these analyses."

With only two years of data to consider, PJM staff see refining the process as a "moving target."

"Based on that, we feel it isn't appropriate to make any changes to the process at this point," Herman said.

The analysis showed this year's deficit was offset by surplus collections last year. The costs include internal hours spent on evaluations, along with external costs for consulting on constructability and other analyses.

Herman said he'd have to follow up on Segner's request for a breakdown of internal versus external spending. "While we do have some level of detail as to what variation on what was analyzed … I think it's a little premature to jump to conclusions about trends," Glatz said.

Herling acknowledged that "anything that's outside of our wheelhouse gets expensive" and that "as a general matter, some of the external consultants are the bigger dollar" expenses.

PJM plans to return next year with addition-

Continued on page 36

PJM NEWS

Stakeholders Seek Load Discussion in PJM DR Task Force

By Rory D. Sweeney

VALLEY FORGE, Pa. — Despite being out of scope for potential rule changes, representatives of state interests last week asked for education sessions on load-related analyses during the first meeting of PJM's new Summer-Only Demand Response Senior Task Force (SODRSTF).

The task force's issue charge specifically prohibits proposed changes to loss-of-load expectation (LOLE) studies or business rules, but stakeholders still asked if they can learn about LOLE issues.

"I don't think the out-of-scope items precludes us from doing any education," said Greg Carmean, the executive director of the Organization of PJM States Inc. (OPSI), which represents state utility regulators within the RTO's footprint.

Greg Poulos, executive director of the Consumer Advocates of the PJM States (CAPS), and EnerNOC's Katie Guerry supported the request.

PJM staff agreed to education but warned that contemplating any changes based on that education would require seeking a charter amendment from the Markets and Reliability Committee.

James Wilson of Wilson Energy Economics, who consults for several consumer advocates within the PJM footprint, asked about the RTO's seasonal capacity filing being out of scope for discussion, calling it "the elephant that's not invited in the room." Foregoing stakeholder endorsement, PJM last year unilaterally filed for FERC approval of its proposal to aggregate seasonal resources so they can qualify for the year-round rules of PJM's Capacity Performance capacity construct. The proposal was accepted under delegated authority during FERC's eight months without a quorum, but Wilson noted that the commissioners could review and reject it at any time.

PJM has far more summer-only seasonal resources than winter, so the aggregation rules left thousands of megawatts of summer-only resources without capacity commitments. In the aggregation filing, PJM agreed to address what to do with them since, as it acknowledged in the task force's problem statement, "these resources have made investments, and in some instances commitments to state regulators, that will result in their continued operation (primarily as peak shaving resources)."

Calpine's David "Scarp" Scarpignato asked the group to investigate what operational flexibility DR can provide beyond simply reducing load.

The task force's next meeting is Jan. 29, when PJM will provide an overview of how it develops its LOLE study including winter resource adequacy, load forecast and installed reserve margin.

PC/TEAC Briefs

Continued from page 35

al data and draw more conclusions. If a change is needed, the plan would be to file it with FERC in early 2019.

Segner and Dolan expressed concern about supplemental projects being submitted by TOs that compete with projects submitted through competitive bidding.

"There's no question that the supplemental projects as they're submitted the way it works right now is problematic," Segner said.

"People lob in a supplemental project at the 11th hour," Dolan said. "Something is wrong with the process." He also asked why a proposal fee shouldn't also be required for supplemental projects.

2018 Preliminary Load Forecast

The RTO's preliminary forecast for 2018 is more optimistic about demand than in previous years, PJM's John Reynolds explained.

The forecast compares predictions for 2021 and 2023 with last year's forecast. Summer demand during those years decreased slightly from last year's forecast, but winter demand held steady or increased. The forecast for summer 2021 fell 0.7%, but the forecast for summer 2023 was down 0.1%.

Demand in winter 2020-21 was the same as last year's forecast but increased 0.4% for 2022-23. Increases in the equipment index, which measures demand for heating, cooling and other uses, was the biggest factor.

Reynolds said that non-retail behind-the-meter generation transitioning to demand response was expected to be a major factor in the forecasts but ended up causing "very small changes" after some generators backed out after learning what would be required to make the transition and others learned they were already treated as DR.

Renewables Can Increase CIRs Through Hybrid

A PJM study found that renewable resources can increase their capacity factors upward of 33% by combining wind and solar into a hybrid generator.

The analysis provides a pathway for increasing capacity injection rights (CIRs), which indicate the threshold at which the RTO can curtail renewable resources injecting power onto the grid. By increasing their CIRs, renewable generators can essentially ensure they can produce more power more often.

PJM's Jerry Bell said the analysis found that the generating capabilities of wind and solar units are often underutilized because they are operating at different times. Combining them creates a higher capacity factor.

The analysis focused on a 2.5-MW wind turbine combined with a 1-MW solar array, and Bell noted the 2017 results might be higher than normal because it was an above-average wind year.

"It's feasible that we could … get a reasonably better capacity factor for the hybrid product," he said.

The hybrid may be more attractive for PJM's Reliability Pricing Model because it's "less volatile" than the resources individually.

Gabel Associates' Travis Stewart asked about studies combining renewables and storage. Bell said some proposals exist.

"I think it comes down to the metering and what's going on," Bell said.

— Rory D. Sweeney

PJM NEWS

MRC Preview

Below is a summary of the issues scheduled to be brought to a vote at the PJM Markets and Reliability Committee this Thursday. Each item is listed by agenda number, description and projected time of discussion, followed by a summary of the issue and links to prior coverage in *RTO Insider*.

RTO Insider will be in Wilmington, Del., covering the discussions and votes. See next Tuesday's newsletter for a full report.

2. PJM Manuals (9:10-9:40)

Members will be asked to endorse the following proposed manual changes:

A. Manual 1: Control Center and Data Exchange Requirements. Revisions developed to update NERC references and procedures related to outages and system-restoration planning. PJM members will be required to send the RTO data on transmission megawatt and MVAR flows and bus voltages at greater than or equal to 100 kV, down from 345 kV.

B. Manual 10: Pre-Scheduling Operations. Revisions developed to comply with NERC standards as part of a periodic review of the manual. Generators will be required to notify PJM of operating conditions that could result in a single contingency causing an outage of multiple generators.

C. Manual 14D: Generator Operational Requirements. Revisions developed as part of a periodic review. Generators will need to be modeled in eDART consistent with the PJM energy management system model.

3. Manuals 3 and 13 Revisions and Gas Pipeline Contingencies (9:40-10:10)

A. Members will be asked to endorse proposed changes to Manual 3: Transmission Operations and Manual 13: Emergency Operations, which include processes for addressing gas pipeline disruptions that affect generator reliability.

B. Members will also be asked to endorse manual revisions proposed by gas-fired generators to document compensation mechanisms for generators directed by PJM to take action related to a pipeline contingency. (See related story, "Gas Generators Block PJM Pipeline Plan," *Operating Committee Briefs*, p.32.)

4. FTR Modeling, Performance & Surplus (FTRMPS) (10:10-10:40)

Members will be asked to endorse revisions to the Tariff, Manual 28: Operating Agreement Accounting and Manual 6: Financial Transmission Rights resulting from special sessions on FTR issues. The revisions will address changes to long-term FTR modeling for future transmission expansion, streamlining management of overlapping FTR auctions and allocating any surplus funds from day-ahead congestion and FTR auction revenue. (See related story, "FTR Changes in the Works," *MIC Briefs*, p.33.)

5. New Service Request Study Methods (10:40-11:00)

Members will be asked to endorse changes to the procedures for the study of transmission service requests and upgrade requests in the new services queue process. (See "Interconnection Study Process to be Rearranged," *PJM Planning/TEAC Briefs Oct. 12, 2017*.)

6. Energy Market Price Formation Problem Statement & Issue Charge (11:00-12:00)

Members will be asked to endorse PJM's proposed problem statement and issue charge to changes price formation in the energy market. The RTO has proposed revisions that would allow inflexible units to set LMPs. The Independent Market Monitor has proposed an alternative problem statement and issue charge that would take up to two years to examine all components of energy market price formation and determine if changes are needed. (See "Questions Remain as PJM Continues Push for Price Formation Revisions," *PJM Markets and Reliability/Members Committees Briefs: Dec. 7, 2017*.)

7. Capacity Construct/Public Policy Senior Task Force (CCPPSTF) (12:45-1:45)

Members will be asked to endorse Tariff revisions associated with the Monitor's "MOPR-Ex" proposal to change the minimum offer price rule. The Monitor is proposing to amend the version endorsed by the Capacity Construct/Public Policy Senior Task Force to revise exemptions for state renewable portfolio standards. (See related story, *Monitor Battles Exelon on MOPR-Ex Proposal*, p.30.)

8. Incremental Auction Senior Task Force (IASTF) (1:45-2:00)

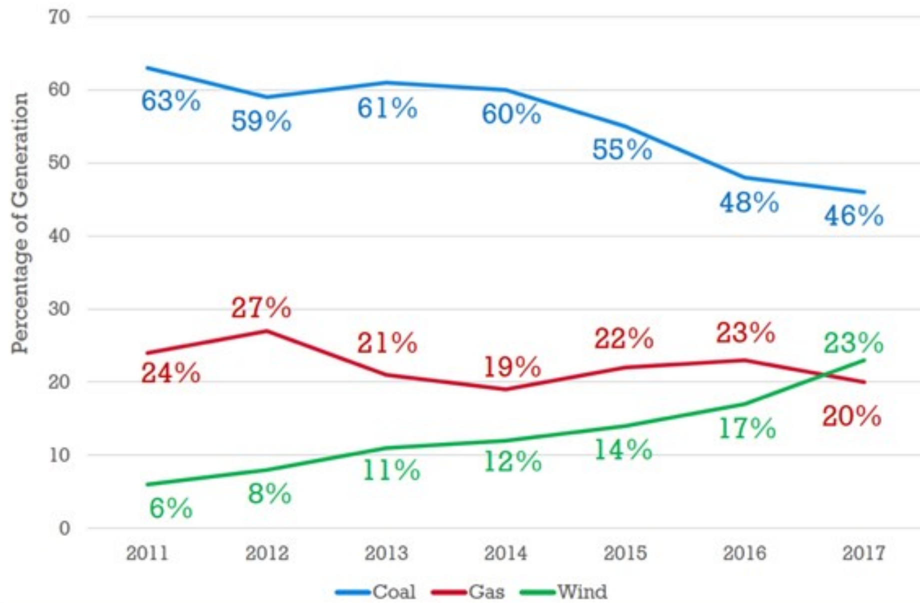
Members will be asked to endorse a proposal developed by the Incremental Auction Senior Task Force to address concerns of excess capacity and low clearing prices. Although Proposal A" did not receive enough support at the IASTF to be automatically considered at the MRC, stakeholders moved for an endorsement vote. (See "Stakeholders Move Incremental Auction Proposal," *PJM Markets and Reliability/Members Committees Briefs: Dec. 7, 2017*.)

— Rory D. Sweeney

SPP News

Overheard at the Great Plains Institute SPP Workshop

AUSTIN, Texas — The Great Plains Institute last week convened state officials and other stakeholders from across the Midwest for a one-day workshop exploring trends in SPP's footprint. The workshop, which was streamed on the Internet, featured multiple perspectives on ongoing challenges and included panels on wind development and SPP's proposed expansion with the Mountain West Transmission Group.



| SPP

SPP Continues to Manage Growing Wind Resources

Lanny Nickell, SPP's vice president of engineering, recalled a time less than 10 years ago when the RTO thought if it ever exceeded 25% wind penetration, "it'd be a miracle."

It's the miracle that keeps on giving. SPP, the first North American RTO to exceed wind penetration levels of greater than 50%, saw that level reach 56.25% on Dec. 4, when wind resources accounted for a record 14,150 MW of energy.

"We've exceeded [25%] by far, because of our large geographical footprint," Nickell said. The RTO added the Integrated System in 2015 and is now working with Mountain West to add its entities to its membership rolls.

SPP has added almost 12.5 GW of wind capacity since 2010, giving it 17.75 GW of installed wind. With the addition of another 5.3 GW that have interconnection agreements but are not yet in service, the RTO's wind capacity will exceed its minimum load of just more than 20 GW. Another 35 GW of wind capacity is under various stages of review in SPP's generator interconnection queue.

	Denmark	Kansas
Peak Days Compared		
Date	July 9, 2015	April 24, 2017
Wind penetration	116%	106%
Load	3,236 MW	3,507 MW
Wind Generation	3,768 MW	3,712 MW
Other non-wind generation	498 MW	1,518 MW
Exports	1,030 MW	1,723 MW
System Summary		
Peak Demand	6,100 MW	9,290 MW
Total non-wind generation	6,300 MW	10,783 MW
Total wind generation	6,000 MW	4,731 MW
Interties	With 3 Counties	With 5 States

| SPP

The RTO has approved $7 billion in transmission infrastructure since 2005 to accommodate the growth in wind energy, with another $3 billion planned. Half of the build are 345-kV facilities; the rest are primarily 100- to 300-kV infrastructure.

"We don't add transmission because we like transmission. We do so because it's beneficial and helps keep the lights on," said Nickell, who hinted at the need for 765-kV infrastructure in the future. "In order to reliably deliver the amount of wind that's been requested, we're probably going to need something more than just 345-kV."

Nickell compared one of SPP's windiest states, Kansas, with Denmark as an example of the RTO's operational capabilities. He said Denmark had 116% wind penetration in 2015 and noted, "You can't do that unless you're exporting wind." But when Kansas hit a wind penetration level of 106% on April 24, it wasn't exporting wind out of the RTO.

"It's because we have a regional transmission organization," Nickell said. "We can facilitate [those wind levels] and still keep the lights on."

Continued on page 39

SPP News

Overheard at the Great Plains Institute SPP Workshop

Continued from page 38

As more wind energy comes online, Nickell said, wind developers must face the question of what to do when energy exceeds load. "Exporting it does make sense, unless wind developers want to have their wind curtailed," he said.

Landowner Opposition Formidable Obstacle to Tx Projects

Several speakers discussed the opposition Clean Line Energy Partners has faced from landowners and regulators in its plans to connect renewable resources with urban centers via long HVDC transmission lines.

"You're going right back to the not-in-my-backyard thing," said Ted Thomas, chair of the Arkansas Public Service Commission. "That's causing intense pushback. 'My granddaddy had this land. This is our family property. I don't want this big, honking thing coming through here. You don't understand, this property is not for sale.'"

"Siting is difficult," agreed Missouri Public Service Commissioner **Steve Stoll**. "Anytime you're dealing with private rights and eminent domain, it's difficult. You can say you're helping our area by giving us the ability to sell our homes and attract business, but [the landowners] don't see much value in it."

"But even if [interregional] projects are built, it doesn't draw down that massive supply of wind in the Oklahoma Panhandle," Thomas said.

Nickell said another impediment to selling wind outside SPP is the cost of the transmission facilities themselves.

"It boils down to the question of who pays," Nickell said. "Should the customer who wants to buy that energy pay for the upgrades to deliver it, as well as the cost of renting the transmission facilities? Or should there be a recognition of benefits to others that helps fund these projects?"

"SPP will have to grapple with what's a fair cost to move wind out of the SPP footprint, and how that should work," Stoll said. "It's the biggest challenge since national electrification."

Wind's Economic Benefits Cross Party Lines

Xcel Energy's **Steve Beuning**, one of the leaders of the Mountain West's proposed membership in SPP, thanked the RTO for working with the Rocky Mountain entities and helping them increase their access to renewable resources.

"There's an operational benefit that comes from the pooling of resources," said Beuning, Xcel's director of market operations. "That expansion of balancing diversity into a broader footprint is different. It didn't exist when other RTOs were formed."

"Any RTO can put a market together. I don't know that we do a market any better than PJM, or any better than MISO, or any better than CAISO," Nickell said. "From what we've been told, it's how we do what we do that was important to the Mountain West group. They appreciate our stakeholder-driven culture. They appreciate our collaborative nature, the relationship-based culture."

At some point, the Colorado Public Utilities Commission will be asked to give its regulatory approved to the merger. PUC Chair **Jeff Ackermann** said he is viewing the expansion in three parts.

"There's the part about reliability, the part about transmission and the market," Ackermann said. "It comes through really clear … that the culture and how SPP chooses to operate spills into the governance subject. I've heard a lot of good stuff about that pursuit of consensus, but the world we live in doesn't lead to consensus. As you add more parties to things, and they haven't had experience with discord, how is that done? How do you deal with discord? How do you factor in whatever is the next iteration, and how does that fit into the market?"

"Bringing those distant resources to urban centers is why we value those regional organizations," said the National Resources Defense Council's **John Moore**, director of the Sustainable FERC Project. "With all of the discussion around this integration, you ask, 'Is this good for the customer?' We hope so. We don't want to see the balkanization that you see in the east, with interregional barriers … the last thing we want to see in the west is three or more RTOs developed."

Speaking on a panel on wind power, **Vanessa Tutos**, director of government affairs for EDP Renewables, said the economic benefits of renewables are clear, "irrespective of your political persuasion." She cited a two-thirds drop since 2009 in the cost of wind energy, $128 billion of private investment and more than 20,000 wind industry jobs.

"Job opportunities are coming back to these rural areas," Tutos said. "When you have a wind farm, you maintain the agricultural capabilities. The wind turbines, though they alter the landscape, allow [farmers] to maintain that form of life."

But while the wind industry provides economic benefits, it doesn't do it alone, Tutos said.

"Transmission planning is very important. I love the idea of a 765-kV overlay. I know reliability organizations don't work that fast … but what wind generation is trying to do is ensure [that] the maximum amount of wind can be integrated in a reliable and efficient way. SPP has a huge opportunity to help implement policies to help reach a 21st century economy."

"If you don't have adequate transmission, things will grind to a halt," said the Wind Coalition's Steve Gaw. "If building transmission results in a lower cost of power, you're doing your consumers a disservice by not

Continued on page 40

SPP NEWS

Overheard at the Great Plains Institute SPP Workshop

Continued from page 39

examining [those options]. We have not gotten close to what low-cost energy would do to the [SPP] footprint. It's not just transmission capacity; it's also the scheduling of power across interfaces, and how much you have to pay for energy in pancake rates."

Alternatives to DOE NOPR

Several speakers suggested there are better alternatives to the Department of Energy's Notice of Proposed Rulemaking to provide price supports to coal and nuclear generation. (See *McIntyre Takes FERC Chair; Wins Delay on NOPR*.)

Rob Gramlich, a consultant who served as an adviser to former FERC Chairman Pat Wood III, said he expects the discussion in D.C. to become focused on price formation and market-based approaches.

"Obviously, the proposed resiliency rule is a major focus," he said. "But since 90% of [the rule's] eligible generators are in PJM, and PJM is more committed to markets than anyone else, it's hard to imagine PJM doing anything to upend those markets. I'm not sure what we get from resiliency that we didn't get from other new rules."

"If it was me running the whole thing and giving them advice, it would be 180 degrees from what [the Trump administration is] doing," Thomas said. "They ought to be embracing the fact that markets serve consumers. Markets serve consumers, and the administration should not squander opportunities to make that point.

"We should let the NERC engineers tell us when we have problems. We always say we might have a crisis in 30 days. Well, we had a crisis. It was the polar vortex, and it got to the edge of reliability problems. The next year, we had a weather event that came close to the polar vortex, but it didn't cause a problem. Why? Because we had engineers study the problem and come up with solutions. Let the markets serve consumers, and let engineers tell us what the problems are."

Stoll suggested another potential solution to the reliability issue: small (50-MW) modular nuclear reactors (SMRs) that are brought onsite already assembled. Taking great pains to say he was not shilling for the technology, he offered up SMRs as a source of baseload power.

"I wouldn't want to put all our eggs in the natural gas basket. We don't know what's going to happen with natural gas," Stoll said. Referencing the Utah Associated Municipal Power Systems' work with SMRs, he said, "They rely on coal, but they're going to put the first [SMRs] in their footprint. If everything goes right, they plan to replace their coal plants with SMRs. It's a very interesting technology, and a technology the rest of the world is working on."

Thomas agreed, saying the SMR market will likely be ready by the mid-2020s.

"We don't need to be focused on subsidizing nuclear energy. We probably have a window with gas that will take us to that," he said.

— Tom Kleckner

FERC & Federal News

Analyst: FERC Likely to Modify DOE NOPR

By Tom Kleckner

With a permanent chairman and full complement of commissioners now in place, FERC will likely modify "and keep moving" the Department of Energy's controversial proposal to offer price supports to coal and nuclear plants, according to one industry analyst.

Christine Tezak, managing director of research for ClearView Energy Partners, said Wednesday her firm expects the commission to acknowledge the administration's concerns and to take some action on the department's Notice of Proposed Rulemaking (RM18-1).

Chairman Kevin McIntyre, who was sworn in Dec. 7, requested a 30-day delay for FERC to address the NOPR, which was granted by Energy Secretary Rick Perry. The commission now has until Jan. 10 to take action. (See McIntyre Takes FERC Chair; Wins Delay on NOPR.)

"The NOPR DOE sent over articulates a pretty straightforward concern that closing [baseload] power plants is bad," Tezak said during a Texas Renewable Energy Industries Alliance webinar on the proposal. "It couches that concern by saying there could come a day under extreme circumstances where we would be really sorry not to have those plants around."

Given broad opposition to the NOPR, Tezak thinks Commissioners Cheryl LaFleur, Robert Powelson and Richard Glick would all like to set aside the directive. She said LaFleur and Powelson reportedly prefer to close the docket and issue a Notice of Inquiry to RTOs with a 90-day timeline. Glick is also thought to be amenable to that option, Tezak said.

"I'm not sure that's going to control the day," she said. "The chairman does set the agenda. We think a variety of unusual circumstances are likely driving the commission to keep moving on the proceeding and to be responsive to the DOE's concerns."

It's "feasible" FERC could issue an Advanced Notice of Proposed Rulemaking or a revised NOPR and keep the docket open if McIntyre can persuade two commissioners that action is required, Tezak said. "A revised rulemaking is not a final rule."

Base on comments filed, Tezak said FERC has several other options to consider besides adopting the NOPR as written — unlikely, she said, given its lack of support and criticism for being vague:

- To "go even bigger" and offer 15-year cost-of-service contracts to all coal- and nuclear-fired generators;
- Adopt cost-of-service payments now and devise a permanent fix later;
- Revise or refine the NOPR, define "resiliency" and procure it starting in 2019;
- Study first, and act later; and
- Just say "no" and close the docket.

While serving as interim chairman before McIntyre's arrival, Commissioner Neil Chatterjee proposed a "show cause" order requiring grid operators to compensate resources that may provide resilience benefits and are at risk of retirement as an interim measure while the commission conducts a longer-term rulemaking.

"With apologies to Lynyrd Skynyrd, we called the variant Neil Chatterjee seemed to endorse 'Gimme Two Steps,'" Tezak said. "[The NOPR] is a very, very broad proceeding, notwithstanding the criticism. It's not a popularity contest or an election. Expert opinions matter, and there is a lot of different evidence in the docket. Looking ahead, that's important to consider even if [many parties] would like to see FERC shelve the whole mess and move on."

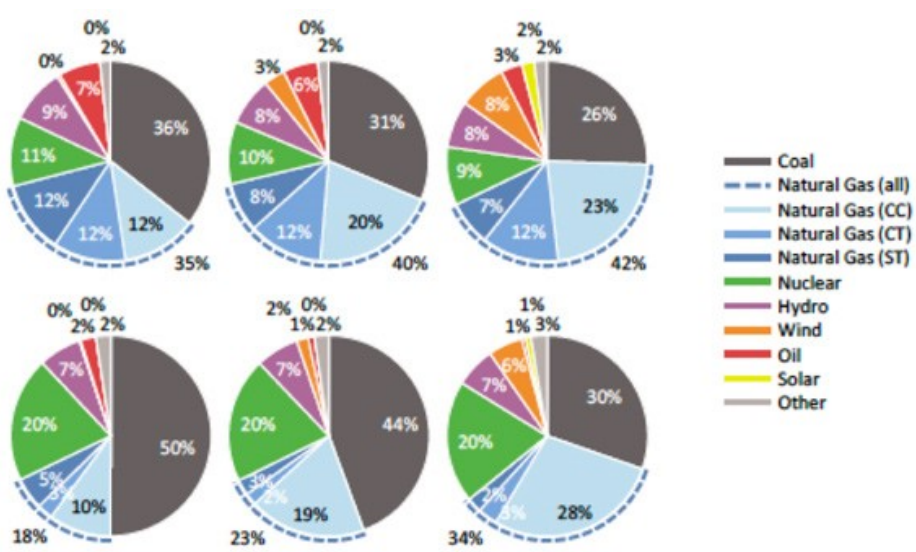
Industry consultant Alison Silverstein, who — "through a bizarre chain of events" — helped organize and write the DOE's "Staff Report on Grid Reliability and Markets," referred to the NOPR's "premature" retirements of baseload plants as "road kill."

"The DOE staff said there was no such thing as premature retirements," Silverstein said during the webinar. "If you believe in markets, then those things retired when they were no longer needed. Almost all of them retired because they were no longer economic."

The root causes — low natural gas prices and the growth of renewables — were so obvious, the DOE report did not address them, Silverstein said.

She defined grid resiliency as the system's ability to absorb, restore and quickly recover from major adverse events. Reliability has short-term (withstanding sudden disturbances) and long-term (resource adequacy) dimensions, Silverstein said.

"It's important to articulate the problem we're trying to solve here," she said. "Resiliency and reliability is very different for a power plant than the grid as a whole. For my money, we can buy a lot of transmission and distribution improvements and provide economic support for coal miners for the billions of dollars it would cost to subsidize uneconomic coal and nuclear plants."



Changes in U.S. capacity (top) and generation (bottom): 2002, 2009 and 2016 | *DOE*

FERC & FEDERAL NEWS

NRC Officials, Industry Favor Plant Self-Assessments; Others Skeptical

By Michael Kuser

A Nuclear Regulatory Commission official said last week that a team of the federal agency's reactor safety engineers would likely recommend that the commission continue working on replacing a portion of its inspections with a self-assessment regime for operators of commercial nuclear power plants.

Tony Gody, NRC director of reactor safety in Region II (Southeast), said Dec. 12 that "the working group agrees that self-assessment, if implemented properly, can be very effective in finding latent conditions" and probably will be recommending further exploration of how to get there via a pilot program.

Gody made his remarks at the end of the agency's second public hearing in two months on the use of licensee self-assessments in the NRC engineering inspection program and other changes in the reactor oversight process.

The Director of the Office of Nuclear Reactor Regulation formed the working group in February 2017 to review the commission's engineering inspections that verify the adequacy of facility design, operations and testing, and make recommendations on improving both their effectiveness and efficiency. The commission has a webpage with related documents, including public comment.

The Good and the Bad

"We need to collectively as an industry own our own licensing design basis and regulatory performance," said Greg Halnon, vice president for regulatory affairs at FirstEnergy, which owns two nuclear power plants in Ohio and one in Pennsylvania. The plants are the Davis-Besse plant in Oak Harbor, Ohio, the Perry plant in Perry, Ohio, and the two-unit Beaver Valley plant in Shippingport, Pa., which collectively generate 4,000 MW.

"We're not abdicating our responsibility; we're maintaining and owning that licensing basis," Halnon said.

Dave Lochbaum, director of the Nuclear Safety Project for the Union of Concerned Scientists, said the 17 years of the reactor oversight process "have resulted in safety improvements, there's no doubt about that, but achieving success loses value if backsliding occurs. ... Our concern is, some of the measures being contemplated are banking on that success at risk of undermining it."

NRC inspectors conduct seismic walkdowns at the Kewaunee nuclear plant. | *NRC*

Gody said that if whoever is doing an inspection or a self-assessment applies scientific principles, "it's going to be a good inspection or self-assessment. And the fact that your own folks are already so familiar with your procedures, and the fact that your own folks already have computer accounts, already know the processes at the facility, already know the licensing basis, is a good thing and a bad thing."

The good thing is they'll be more efficient, he said.

"The bad thing is they may have preconceived conclusions," Gody said. "It's critical that when that checklist is developed that critical thinking is considered. If you accomplish that one thing, you potentially eliminate the human factor disposition to not challenge your own conclusions."

Lochbaum said he wanted to push back on the "fanciful notion that there aren't any more legacy, latent issues out there. There seem to be plenty of latent issues from long ago that we still haven't found. Fort Calhoun [in Nebraska] is a perfect example, which shut down in 2011 and didn't restart for 30 months. During that time, they submitted something like 18 LERs [licensee event reports], with the youngest of those being 15 years earlier, so they were at least 15 years old. Several of those involved engineering issues."

Getting to the point of metrics, Lochbaum said "we recommended before and recommend again that the NRC should have looked at those LERs to see if the expectations were that the engineering inspections should have or may have identified those before they were found during an extended plant shutdown."

NEI Supports

The Nuclear Energy Institute supports self-assessments, saying plant operators already do their own inspections in advance of NRC visits. "We believe that licensee self-assessments could be an important part of a modernized approach to engineering inspections. Such a solution would be rooted in our cultural value of self-identifying issues," Greg Cameron, NEI's senior project manager for regulatory affairs, wrote the commission in July. "We hold ourselves accountable to identify conditions at our stations early and to resolve them in a timely fashion commensurate with their safety significance; the NRC verifies that accountability through regular resident inspector interactions and the biennial Problem Identification and Resolution inspection. Transitioning from direct inspection to oversight of self-assessment activities, where appropriate, strengthens this accountability."

Concerns in Mass.

But the self-assessment concept is unpopular with some neighbors of Entergy's Pilgrim nuclear plant in Massachusetts, one of three plants in the country classified in Column 4 — the worst performers in NRC's grading system.

A citizens group, Pilgrim Watch, cited an email written by the leader of a federal inspection team, who wrote that "the plant seems overwhelmed just trying to run the station." The internal email became public mistakenly.

"Pilgrim provides the perfect example why NRC nuclear safety inspections are necessary and why industry self-assessments would be dangerous," the group wrote NRC. "Pilgrim cannot be counted on to conduct any complete or accurate self-assessment. The NRC's own records prove that Pilgrim has regularly and consistently failed to follow established procedures, to report problems, or to take corrective actions even when the NRC tells it to do so."

NERC Report Urges Preserving Coal, Nuke 'Attributes'

Continued from page 1

| NERC

ment and system analysis, said during a media briefing on the report. "We replaced coal and nuclear that has some resilience to extreme weather and they're going to be there, with resources that don't have that. That's our responsibility to look at and call out but … we do not have the authority or really the view as to how the market should address that."

Recommendations

The report said:

- FERC should support new products and revised market rules to ensure "essential reliability services" including frequency response and ramping.
- State, federal and provincial regulators must recognize the long lead times for generation, transmission and natural gas infrastructure and the difference between regulated areas with long-term integrated resource plans and organized markets that can lose a generator with as little as 60 days' notice.
- State and federal policymakers, including the Department of Energy and FERC, should consider the impact of natural gas disruptions on the BPS when evaluating infrastructure requirements. Transmission planners and operators should identify reliability concerns resulting when a large share of gas generators rely on interruptible fuel contracts.
- System operators and planners should gather more data on the "aggregate technical specifications" of distributed energy resources on local distribution grids to ensure accurate planning models, coordination of system protection and real-time situational awareness. Moura said the aggregate amount of behind-the-meter resources "is generally well known," but that bus locations and technical specifications such as protection settings and voltage operating ranges are not.

In addition, NERC said it would conduct a "comprehensive evaluation" of its reliability standards to ensure their compatibility with nonsynchronous and distributed resources.

"A lot of our standards were written largely for conventional generation, and words like 'tripping' or 'spinning' that are … well known when we're talking about conventional generation don't completely translate when we're talking about asynchronous machines and inverters," Moura said. "And so, we really need to look at our standards to make sure we're not missing anything when we have more nonsynchronous machines on the system."

NERC also said it will monitor reserve margins, citing projected shortfalls in ERCOT and the SERC Reliability region. The reserve margin in SERC-E, which comprises utilities in the Carolinas that aren't part of PJM, is expected to fall below the reference margin level beginning in 2020 because of the canceled expansion of the V.C. Summer nuclear power plant. The announcement of 4,600 MW of coal and gas retirements this fall means ERCOT reserve margins will fall below targets by summer 2018.

Higher Reserve Margins, Additional Metrics Needed

"As we see the resource mix change, we're really making a call to action to industry and regulators to increase the robustness of the planning approaches," Moura said.

In the past, he said, planners assumed fuel would be available and that there would be generators with sufficient inertia to control frequency response. Neither is a given, he said, as the mix changes to more gas and renewable generation.

The report said increasing variable generation may require more planning reserves to maintain the one-day-in-10-years loss-of-load-expectation, boosting target reference margin levels to 17% from 15%.

Since 2008, all but one of nine regions increased their reserve margins by about 2 percentage points. The exception was SPP, which has seen its reserve margin drop from 13% to about 12% over 10 years. ERCOT and Quebec are currently below 15%, although they have increased over the last decade.

Essential Reliability Services

Moura acknowledged that NERC has made the recommendation for preserving reliability services before. "But we wanted to reiterate it here: that all new resources, no matter the fuel, need to have the capability to support voltage and frequency response."

He said FERC's November 2016 rulemaking proposing changes to its *pro forma* generator interconnection agreements seeks to address the frequency response issue but said it's up to states to implement the interconnection requirements. And even that, he said, is not sufficient. (See FERC Has More Questions on Frequency Response NOPR.)

Interconnection requirements don't "guarantee any performance," he said. "It requires them to have the capability and the [ability] to provide it, but in market areas, if they're not bidding in and being incentivized to provide that frequency response, they don't.

"We're not in trouble right yet with frequency response," he added. "But we see it on the horizon."

Similarly, he said ERCOT's establishment of

Continued on page 44

FERC & FEDERAL NEWS

Penalty Review Denied, DTE Faces Friendlier EPA

By Amanda Durish Cook

The U.S. Supreme Court last week denied DTE Energy's petition to review an environmental penalty against one of its Michigan coal plants over increased emissions, but the new tone set by the head of EPA will likely diminish the court's action.

The court last week declined to hear the Michigan-based utility's defense of upgrades it performed on its coal-fired Monroe power plant, clearing the way for EPA enforcement action. (See *DTE Initiates Last-Ditch Effort in Clean Air Act Case*.)

However, the agency has performed an about-face under in the intervening months since DTE filed a writ of certiorari with the court. Administrator Scott Pruitt earlier this month released a policy memo specifically citing DTE's case and adopting some of its arguments against having to pay penalties for excessive air pollution, making it unlikely the agency will pursue penalties.

EPA and the Sierra Club have pursued enforcement against DTE since 2010, when the company started a $65 million upgrade to Unit 2 of the 46-year-old Monroe coal plant without installing additional pollution controls. They contended the upgrade violated the Clean Air Act's New Source Review (NSR) program because DTE ignored its own projections that the renovation would cause emissions to increase by thousands of tons per year. EPA called the project a major overhaul that should have included new pollution controls and sought civil penalties of up to $37,500 per day.


Monroe power plant | *Port of Monroe*

DTE maintained that the higher emissions from the Monroe plant were a product of demand growth and not caused by the improvements. By 2014, DTE had installed four selective catalytic reduction units and four flue gas desulfurization units at the plant at a cost of about $2 billion.

"It is pretty simple. DTE chose to overhaul their dirty coal plant and not install modern pollution control technology at that time even though their own projection showed that pollution would increase after the overhaul," said Regina Strong, director of the Sierra Club's Beyond Coal Campaign in Michigan.

DTE contended that enforcement action could not proceed until after an actual pollution increase occurred, an argument that the 6th U.S. Circuit Court of Appeals twice rejected (14-2274, 14-2275).

However, Pruitt's memo aligns with DTE's arguments, saying that EPA will no longer bring NSR enforcement against generators until they've had the chance to increase pollution, contradicting the preventative nature of the NSR that the 6th Circuit recognized.

Pruitt wrote that EPA does not "presently intend to initiate enforcement … unless post-project actual emissions data indicate that a significant emissions increase … did in fact occur."

According to the Sierra Club, EPA will now "no longer seek to challenge even obviously faulty or fraudulent projections by a utility that a proposed modification to a coal plant will purportedly not lead to a New Source Review-triggering emissions increase so long as such projection was procedurally done properly."

"The new Pruitt approach appears to be little more than an attempt to give coal utilities a sense of empowerment to ignore the critical public health protections of the Clean Air Act New Source Review program," Shannon Fisk, managing attorney with environmental law firm Earthjustice, said in a statement. "Such [an] approach should not stand as it is contrary to law, public health and common sense."

"We are disappointed that the U.S. Supreme Court will not be taking our case," a DTE spokeswoman said. "We are in full compliance with all New Source Review requirements, as the Monroe Power Plant is one of the cleanest power plants in the country."

NERC Report Urges Preserving Coal, Nuke 'Attributes'

Continued from page 43

a "critical inertia" level of 100 GW/s is "a really good approach to manage this. But a long-term mechanism will be needed as even more … wind will be coming on to their system."

Gas Supply

The report notes that on-peak natural gas capacity has increased from 280 GW in 2009 to 442 GW today, with another 32 GW of gas capacity planned for the next 10 years. It projects the Florida Reliability Coordinating Council assessment area will rely on gas for 78% of its power by 2022.

"Areas can have and can rely on large amounts of natural gas as long as they have fuel assurance mechanisms, and Florida does that very well," Moura said. "They have dual-fuel requirements as well as firm transportation … and the pipeline was really built for the natural gas generation in that area."

Moura also said PJM's Capacity Performance requirements and ISO-NE's Pay-for-Performance program is "exactly what we're looking for."

"But the jury's still out as to whether or not those penalties for nonperformance will compel generators to get dual fuel. … At least in New England, states have been very clear that new natural gas pipelines aren't wanted."

The report also pointed out that the 0.61% (summer) and 0.6% (winter) 10-year annual demand growth rate for North America is the lowest on record. Despite flat loads, it noted grid operators added more transmission during 2006-2015 compared to 1991-2005.

FERC & FEDERAL NEWS

NARUC Calls for PURPA Reforms, Outlines Proposed Changes

Continued from page 1

Chairman Neil Chatterjee had pledged that the commission would be pursuing PURPA reform.

"As the primary point of responsibility for PURPA's on-the-ground implementation, the states have a strong interest in the reform of PURPA's associated federal administrative regulations, and we hope this reform will continue to be a priority under the leadership of Chairman [Kevin] McIntyre," Betkoski wrote.

PURPA is a persistent source of annoyance to state regulators, who sounded off at a July 2016 technical conference (AD16-16). (See FERC Conference Debates PURPA Costs, Purchase Obligations.) It also was the subject of a Congressional hearing in September. (See Witnesses Offer Alternate Realities on Need for PURPA Reform.)

Betkoski cited four changes since PURPA's enactment in 1978 that he said required a new look from FERC. "These four changes — the rise of wholesale markets, the place of [qualifying facility] technologies as a commonplace source of power, the open-access regulation of the transmission system and the use of competitive methods to select projects throughout the states — suggest that PURPA's administrative regulations should be aligned to these developments, instead of obstructing them. Despite these changes, many states incur significant transaction costs administering PURPA pursuant to the law's arcane, 20th century mandates," Betkoski wrote.

He quoted Montana Public Service Commissioner, and former NARUC president, Travis Kavulla, who told the technical conference that PURPA issues consume more than one-quarter of his commission's time on electric utility regulation. (See Montana PURPA Solar Saga Continues in State Court.)

NARUC proposed three changes, "each of [which] allows FERC to work within existing law to make meaningful changes to PURPA, while remaining committed to the law's underlying goals of competition and encouragement of QF technologies," Betkoski said.

NARUC proposed that:

- FERC adopt regulations that move away from the use of administratively determined avoided costs to their measurement through competitive solicitations or market clearing prices. "We propose that in certain circumstances, such as when a QF has both nondiscriminatory access under an [Open Access Transmission Tariff] and exists in a region where public utilities routinely use competitive solicitation processes, such a construct would qualify as wholesale markets under 18 CFR 292.309(a)(3). Making this determination would allow FERC to erase the false dichotomy between RTO/ISOs regions, and those regions without such an RTO/ISO but where each public utility nevertheless has an OATT and where states oversee utility procurement and require the use of competitive solicitations."
- Lower or eliminate the 20-MW threshold for the rebuttable presumption that QFs with a capacity at or below that size do not have nondiscriminatory access to the markets. "In keeping with the goal that FERC should better align PURPA implementation with modern realities, this threshold should be lowered to whatever the minimum capacity requirement is for a resource to participate in an RTO/ISO."
- Making changes to the 1-mile rule and changes to discourage gaming. "There are a number of well-documented incidents where projects have forgone economies of scale to qualify themselves as individual QFs and evade other regulations; for instance, state commissions requirements for competitive solicitations. The commission should not encourage this form of regulatory arbitrage." NARUC recommended Idaho Public Utilities Commissioner Paul Kjellander's suggested criteria for determining whether a single project has been disaggregated in order to create multiple QFs under the generation size limit.

COMPANY BRIEFS

Invenergy Completes Financing For Illinois Wind Farm

Invenergy said Thursday it has completed construction financing for the 132-MW Bishop Hill III Wind Energy Center, which it is building in Henry County, Ill.

The wind farm is scheduled to be in operation by the middle of next year. WPPI Energy has agreed to buy power from the facility through the middle of 2040.

More: Invenergy

Santee Cooper Chairman Sues to Challenge His Firing


Lord

Santee Cooper Chairman Leighton Lord filed a lawsuit Wednesday in Richland County Circuit Court challenging South Carolina Gov. Henry McMaster's authority to remove him from the state-owned utility's board of directors.

McMaster fired Lord on Dec. 8, saying in a letter that he wasn't cooperating with legislative committees investigating the failed attempt by Santee Cooper and SCANA to build two additional nuclear reactors at the V.C. Summer Nuclear Station.

Lord, chairman of the law firm Nexsen Pruet, disputes that and the allegation by McMaster that he withheld information about the Summer project from the governor's office.

More: The Post and Courier

SCE Says Investigators Examining Equipment's Role in Fires

Southern California Edison said last week that state investigators are looking into whether its equipment played a role in sparking the fires that have ravaged Southern California this month.

The company said last week that its equipment likely didn't ignite the fires, based on where they were believed to have begun. But last week, the utility said state investigators are examining other possible starting points for the fires — places where its equipment could have played a role in touching them off.

More: San Francisco Chronicle

ATC to File with Wisconsin PSC for $140M Project

American Transmission Co. said it plans to file an application with the Wisconsin Public Service Commission in February for a $140 million project to provide power to the manufacturing complex that Foxconn Technology Group intends to build in Racine County.

The project consists of a second 345-kV transmission circuit along 12 miles of existing lines, 1.2 miles of new transmission lines, a new substation and an underground line from the substation to Foxconn's factory.

ATC said it will ask the PSC to rule on the project by August.

More: Milwaukee Journal Sentinel

Alliant Names John Larsen President


Larsen

Alliant Energy has named John Larsen president, effective Jan. 1.

Patricia Kampling, who had been president, will continue to lead Alliant as chairwoman and CEO.

Larsen has been Alliant's senior vice president since 2014 and president of its Wisconsin Power and Light subsidiary since 2010. He joined Alliant in 1987.

More: Wisconsin State Journal

Oregon PUC Acknowledges PacifiCorp Wind Power Plan

The Oregon Public Utility Commission voted 2-1 last week to acknowledge PacifiCorp's "Energy Vision 2020" proposal to spend $3.5 billion on wind power and transmission in Oregon, Wyoming and other states.

The acknowledgement doesn't guarantee PacifiCorp will be able to recover the costs of the Oregon projects detailed in the proposal from its ratepayers but does increase the likelihood that it will.

The commissioners didn't appear convinced the projects are necessary, but they acknowledged the plan to give PacifiCorp what the company said was the opportunity to cash in on vanishing federal tax incentives and add the renewable energy that its customers want.

More: Portland Business Journal

SCANA Says Rate Rollback Could Force Bankruptcy

An attorney representing SCANA told the South Carolina Public Service Commission last week that the company would be forced into bankruptcy if it were prohibited from charging its customers $37 million a month for the abandoned project at the V.C. Summer Nuclear Station.

The commission is considering rolling back a series of rate hikes meant to pay for the construction of two reactors, which SCANA and state-owned Santee Cooper stopped trying to build in the summer after spending more than a decade and $9 billion on them.

SCANA's attorney said that if the company goes bankrupt, it may not be able to provide power to its 700,000 customers.

More: The Post and Courier

Eversource Serves EDF with Cease-and-Desist Letter

Eversource Energy has served the Environmental Defense Fund with a cease-and-desist letter over a study that said Eversource and Avangrid habitually bought natural gas pipeline capacity they didn't use, costing New England electric customers an extra $3.6 billion between 2013 and 2016.

The letter demands that EDF refrain from any further defamation of Eversource, remove all versions of the study from its website and advise everyone to whom it has given the study to take it down from their websites too.

An EDF spokesman said the organization stands by the study and rejects Eversource's "attempt to intimidate and chill legitimate public inquiry."

More: New Hampshire Public Radio; Eversource

Continued on page 47

COMPANY BRIEFS

Continued from page 46

Settlement Filed with NM PRC on Xcel Wind Project

New Mexico Attorney General Hector Balderas, consumer advocates and others have reached a settlement with Xcel Energy over the utility's plan to build wind farms in New Mexico and Texas that would serve customers in both states.

The settlement was filed last week with the New Mexico Public Regulation Commission.

The Public Utility Commission of Texas also must approve Xcel's plans for the 520-MW Sagamore Wind Project, which would be the largest wind farm in New Mexico, and a nearly 480-MW wind farm in Hale County, Texas.

More: The Associated Press

Santee Cooper Board Approves Reduced Budget

The Santee Cooper Board of Directors last week approved an operating budget of $2.1 billion for next year, nearly 35% less than its current budget.

The utility, which is owned by the state of South Carolina, said it needs to conserve cash, pay off debt and hold down electricity bills after its failed effort to expand the V.C. Summer Nuclear Station.

Most of the spending cuts come from halting the expansion. But Santee Cooper is also planning to slim its overhead to avoid raising rates while hundreds of millions in borrowing comes due.

More: The Post and Courier

FEDERAL BRIEFS

PTC, ITC Largely Spared in Tax Bill

The tax bill that emerged from the House-Senate conference committee will preserve most of the value of the production and investment tax credits for wind and solar projects.

Some had feared the Base Erosion Anti-Abuse Tax (BEAT) provision in the bill passed by the Senate earlier this month, which is intended to prevent multinational corporations from moving profits and jobs out of the U.S., would reduce the value of the credits. ClearView Energy Partners said the bill will shelter up to 80% of wind and solar tax equity from the base erosion tax.

"It's a fix that I think everybody in the end can live with, and will allow the credits that have been used to finance these projects to continue to be used to finance these projects," Sen. John Thune (R-S.D.) told Bloomberg. "We were going to make sure the wind industry, for example, wasn't adversely impacted."

The conference bill also preserves a $7,500 tax credit for first-time buyers of electric vehicles but excludes an extension of a tax credit for new nuclear production approved by the House of Representatives. The current 2021 deadline would threaten its use by Southern Co.'s delayed Vogtle project in Georgia.

More: Bloomberg; Washington Examiner; Reuters; Greentech Media

Q3 Solar Installation Down 51% from Year Ago

The U.S. solar energy installed 2,031 MW of capacity in the third quarter, down 51% from the same period a year ago, according to the latest U.S. Solar Market Insight report from GTM Research and the Solar Energy Industries Association.

The capacity addition was the lowest for a quarter in two years. Despite the drop-off, solar still accounted for 25% of the total capacity added to the grid in the first three quarters, second only to natural gas.

More: Greentech Media

NERC Hires Firm To Search for CEO

NERC said Thursday it has hired Russell Reynolds Associates to conduct a search for a new president and CEO.

The organization said referrals to potential candidates should be submitted to Jennifer Rockwood at Russell Reynolds no later than Jan. 2.

General Counsel Charles Berardesco has been serving as acting CEO since Gerry Cauley resigned Nov. 20 following his arrest for domestic abuse. (See Cauley Resigns; NERC Launches Search for Replacement.)

More: NERC

DOE Providing $18.5M to Offshore Wind Consortium

Energy Secretary Rick Perry said last week that the Department of Energy will provide $18.5 million in new funding to a consortium that will do research and development aimed at reducing the cost of offshore wind in the U.S.

The consortium will include members of the offshore wind industry, who will contribute funds to it and use its research to further advance offshore wind technologies.

The department will select an administrator to coordinate the consortium's activities and allocate an additional $2 million to research and development at its national laboratories to support the effort.

More: Department of Energy

GAO: Admin Broke Law by Not Spending on ARPA-E

The Government Accountability Office said last week that the Trump administration violated the Impoundment Control Act by failing to spend $91 million budgeted for the Energy Department's Advanced Research Projects -Agency-Energy (ARPA-E), which supports the research and development of novel energy technologies.

GAO said the administration has since released the funds, which were part of the fiscal 2017 budget, but Democrats fear the

Continued on page 48

FEDERAL BRIEFS

Continued from page 47

administration could fail to spend money already allocated by Congress for other programs it doesn't like.

The Impoundment Control Act was adopted in 1974 because Congress feared then-President Richard Nixon was abusing his power by withholding funding for programs that he opposed but that Congress had adopted.

More: *The Washington Post*

Report: DOD not Preparing For Climate Change Abroad

The Government Accountability Office released a report Wednesday saying that although the Defense Department frequently voices concern about how rising sea levels and atmospheric temperatures could affect military activity abroad, it is not doing enough to prepare for climate change at its foreign facilities.

Although the department in 2014 began surveying officers running military installations to see how climate change could affect their bases, GAO found the effort was "incomplete and not comprehensive" because dozens of overseas sites were exempt from completing the vulnerability assessment — and because the Pentagon didn't consistently track the estimated cost of climate impact.

GAO also found only a third of the plans it reviewed for projects at the bases — such as construction or renovation of piers, hangars and other infrastructure — properly addressed flooding, drought, winds, wildfires and other climate-linked effects that the bases' commanders had identified in the department's survey.

More: *The Washington Post*

Group Unveils Plan to Rebuild Puerto Rico Grid

A group of electricity experts last week unveiled its plan to rebuild Puerto Rico's grid after it was devastated by Hurricane Maria in September.

The Puerto Rico Energy Resiliency Working Group — a collaboration between the New York Power Authority, U.S. Department of Energy, electric trade organizations and the Puerto Rico Electric Power Authority, among others — released a 63-page report detailing $17.6 billion in upgrades that would strengthen the grid against any future Category 4 hurricane. These include using sturdier construction materials, undergrounding transmission lines and investing in distributed energy resources.

The group, which includes Consolidated Edison and the Long Island Power Authority, used many of the lessons learned in the aftermath of Superstorm Sandy.

More: *Greentech Media*

STATE BRIEFS

ARIZONA

Salt River Project to Issue Renewables RFP

Salt River Project said Thursday it will issue a request for proposals for 100 MW of renewable energy early next year.

The utility said the RFP will enable it to expand the number of green energy programs it can offer big commercial and industrial customers.

SRP is seeking proposals for projects that can be in operation by the end of 2020.

More: *Phoenix Business Journal*

Supreme Court Agrees to Hear Rooftop Solar Case

Arizona Supreme Court

The state Supreme Court last week agreed to review lower courts' rulings that the state can't require companies leasing rooftop solar systems to homeowners to pay property tax on the systems.

The Court of Appeals last May upheld a trial judge's ruling that the Department of Revenue was wrong when it determined in 2013 that leased rooftop solar systems should be subject to property tax as electricity generating systems.

The trial judge's ruling came in a case initiated by leasing companies SolarCity and SunRun, which sued the department.

More: *The Associated Press*

IOWA

GHG Emissions down, Driven By Shift from Coal to Wind

Greenhouse gas emissions in the state fell 2% last year from 2015, their second consecutive decline, according to a report issued by the Department of Natural Resources.

Emissions from power plants fell 14%, offsetting emissions from other sources, which rose about 5%.

Power plant emissions have declined 40% from their 2010 peak, reflecting the shift in the state's generation mix. Coal plants now provide 47% of the state's power, down from 78% in 2005, while wind provides 37% of the state's power, up from 4%.

More: *Radio Iowa*

MAINE

PUC Opens Inquiry into Storm Restoration Efforts

The Public Utilities Commission voted last week to open an inquiry into the efforts by Central Maine Power and Emera Maine to restore power after an October storm that caused the largest outage in state history.

The PUC asked the companies to file reports detailing their responses and lessons learned in 30 days. It also said it wanted to know how the state's electric utilities and regulated phone companies worked together after the storm and

Continued on page 49

STATE BRIEFS

Continued from page 48

whether their coordination efforts need to be changed.

The 30-day deadline — a tight time frame for data gathering, especially during the holiday season — was a signal that regulators see the issue as a priority, said Barry Hobbins, the state's public advocate.

More: Portland Press Herald

MICHIGAN

Study: Wealthier Ratepayers Benefit more from EE Programs

A study by the University of Michigan's Urban Energy Justice Lab found that energy efficiency programs at the state's two largest utilities disproportionately benefit wealthier ratepayers.

The study found that although 35% of Michigan utility customers qualify as low-income, only 17% of DTE Energy's and only 12% of Consumers Energy's EE investments went to programs that targeted low-income households.

Additionally, the study found, for every kilowatt-hour that the programs saved for low-income customers, they saved up to 22 kWh for higher-income customers.

More: Midwest Energy News

MINNESOTA

State OSHA Investigating Death at Biomass Plant

The state Occupational Safety and Health Administration said last week it is investigating the death of a man who fell into a hopper at the Benson Power biomass plant.

The agency has investigated the plant, which is also known as Fibrominn, twice since 2012 and fined it both times.

The 55-MW plant burns turkey manure mixed with wood chips to produce power for Xcel Energy. State regulators on Nov. 30 approved Xcel's plan to close Benson and two other biomass plants. Xcel does not own the plant, but plans to buy it before closing it.

More: Star Tribune

MISSOURI

Legislation Would Cap Average Rate Increases to 3% a Year


Berry

State Rep. T.J. Berry (R) has pre-filed legislation that would cap average electric rate increases to 3% every year.

Berry said the legislation would give energy consumers rate certainty for probably five years.

Ameren said it was "continuing to work with all parties, including consumer groups, toward a solution."

More: KSPR

NEW YORK

NYPA Opens Integrated Smart Operations Center

Gov. Andrew Cuomo last week announced the opening of a digitized power asset monitoring and diagnostic center at the New York Power Authority's headquarters in White Plains.

The Integrated Smart Operations Center uses GE Digital's predictive analytics software to monitor NYPA's 16 power plants and more than 1,400 circuit miles of transmission lines to spot issues that could cause equipment failures and significant outages so they can be dealt with before they do.

More: Gov. Andrew Cuomo

OKLAHOMA

ALJ Recommends Lower Rate Increase for PSO

A Corporation Commission administrative law judge issued an order last week recommending that Public Service Company of Oklahoma be granted a rate increase of $81.2 million, less than half the $169.7 million it sought.

Stan Whiteford, a spokesman for the utility, said it's disappointed the judge didn't give it a higher return on equity or compensation for retiring an old coal-fired plant that was well past its prime.

Whiteford said the company is reviewing the recommendation and will file a response with the commission.

More: The Oklahoman

PENNSYLVANIA

Supreme Court to Hear Appeal of Polar Vortex Fine

The state Supreme Court has agreed to hear electric retail supplier HIKO Energy's appeal of the Public Utility Commission's decision to fine it more than $1.8 million for gouging customers during the winter of 2013-14.

HIKO claims the fine, issued along with other penalties for actions it took during the polar vortex, violated the excessive fines clauses of the state and U.S. constitutions.

In addition to paying the fine, the PUC required HIKO to issue $2 million in customer refunds, give $25,000 to electric distribution companies' Hardship Fund and modify its marketing practices. (See "HIKO Energy Fined for Deceptive Practices," State Briefs.)

More: PennLive

TEXAS

PUC Approves SWEPCO Rate Hike, Punts on Amount

The Public Utility Commission has approved Southwestern Electric Power Co.'s request for a rate increase but hasn't set the amount of the increase. The subsidiary of American Electric Power had asked for a 12.7% increase.

PUC spokesman Terry Hadley said staff will have to recalculate some figures as a result of memos that Chairwoman DeAnn Walker issued before the PUC's vote. In the memos, Walker called for making changes to the rate increase that were proposed by the Office of Administrative Hearings.

More: Longview News-Journal

Continued on page 50

Montana PURPA Solar Saga Continues in State Court

By Amanda Durish Cook

Three solar advocates last week filed a joint challenge to the Montana Public Service Commission's decision to alter the contract terms available to small generators under the Public Utility Regulatory Policies Act.

In a state district court complaint filed Dec. 13, Vote Solar, the Montana Environmental Information Center and solar developer Cypress Creek Renewables argue that Montana regulators "drastically and unreasonably" reduced the standard contract length and energy rate available to small renewable energy projects under PURPA. The commission last month reduced the contract length from 25 years to 15 years and cut the rates utilities must pay renewable projects up to 3 MW from $66/MWh to $31/MWh.

The PSC defended the decision as protecting ratepayers from overpaying for electricity produced by independent generators. NorthWestern Energy initially asked the commission for PURPA rate relief in May 2016.

The complaint characterizes the PSC's decision as a "death knell for small solar development in Montana at a time when demand for renewable energy is growing, the cost of producing renewable energy is at an all-time low and NorthWestern has claimed a significant need for electric capacity that solar and wind developers are well-positioned to supply."

The solar advocates say the decision resulted in dozens of solar projects across the state being put on hold. They argue it's doubtful Montana will see solar expansion "in the foreseeable future" if the commission's order is stands. Cypress said it has delayed four prospective solar projects in Cascade County, where the challenge was filed.

"As a result, the state will lose hundreds of millions of dollars of economic investment, hundreds of construction jobs, affordable clean electricity and significant tax revenues for local governments," the three organizations said in a statement. They asked the court to find the PSC's order unreasonable and unlawful.

In June, Montana Commissioner Bob Lake was heard on a microphone appearing to confirm that state regulators put the rules in place knowing that they would stifle development of small solar projects. (See *'Hot Mic' Reveals Montana Move Against Solar QFs*.) FERC earlier this year declined to enforce PURPA action against the Montana PSC.

| *Cypress Creek Renewables*

PURPA requires utilities to pay qualifying facilities the cost a utility would incur for supplying the power itself or by obtaining supplies from another source. The law leaves it to each state's utility commission to formulate those rates and set contract terms, depending on project size.

Adam Browning, executive director of Vote Solar, said competitive rates and longer contract lengths are needed to avoid utility monopolies.

"Now that solar is cost-competitive, fossil fuel interests in Montana and across the country are attempting to change the rules of the game. Fair treatment for solar opportunity will benefit Montana's families, economy and environment," Browning said.

Cypress Director of Market Development Casey May said the complaint is an attempt for a fair chance at competition for independent power producers. "Plainly put, we want to do business in Montana," May said. "We want to increase Montanans' access to clean energy, create jobs and increase the tax base of state and local governments, but this decision prevents that. … It's a bad deal for Montanans and economic development across the state."

TransAlta Scraps Wind Farm After PSC Ruling

In a related development, TransAlta said it won't build the New Colony Wind Project because of a Dec. 12 PSC ruling that said NorthWestern should pay the wind farm $23.20/MWh over 15 years on a PURPA contract.

TransAlta had asked to be paid $43.63/MWh over 25 years. Northwestern had proposed paying $13.96/MWh.

Peter Key contributed to this article.

STATE BRIEFS

Continued from page 49

WISCONSIN

Conservatives Launch Organization To Promote Renewable Energy

A group of conservatives has launched an organization chaired by former Gov. Tommy Thompson to promote cheap, reliable and cost-effective energy, including renewable power, in the state.

The Wisconsin Conservative Energy Forum is affiliated with the Conservative Energy Network, which began in Michigan in 2013 and now has affiliates in 19 states. It also has ties to the Capitol Group, a Madison lobbying firm.

The group's executive director, Scott Coenen, said the organization would not just lobby for bills but also work to make Republicans aware of the potential benefits of wind and solar power. Coenen said the group supports an "all of the above" energy production strategy that includes natural gas and nuclear power in addition to renewables.

More: Milwaukee Journal Sentinel