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Illinois: End PJM Capacity Market?

Panelists speak at the Illinois Commerce Commission's hearing on PJM's capacity market Sept 20. | *Illinois Commerce Commission*

By Rory D. Sweeney

Illinois regulators have suggested that PJM consider ending its capacity market if it continues supporting policies that the state believes discount its generation preferences. [Editor's Note: An earlier version of this story incorrectly stated that regulators had threatened to leave the RTO.]

The Illinois Commerce Commission convened a Sept. 20 hearing on PJM's capacity market three weeks before a deadline to respond to a FERC order that rejected both of the RTO's proposals for revising its capacity market, which sparked a rush to develop alternatives. *(See FERC Orders PJM Capacity Market Revamp.)*

While several proposals emerged, including one supported by the Illinois Citizens Utility Board, PJM has maintained support for its own plan, which would pair an expanded minimum offer price rule (MOPR) with a two-stage auction that removes subsidized resources and reprices the results.

Already well aware of Illinois' grievances, PJM staff attending the hearing attempted to explain the RTO's position.

"We are really trying to make this work," PJM's Darlene Phillips said. "We recognize that Illinois and other states have the right to make decisions. We are not trying to fight against those decisions. We are trying to make sure that, at the end of the day, our markets work for the entire region. There are other states that aren't making those decisions ... [and their

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New England Senators Urge FERC to End Press Ban

By Rich Heidorn Jr.

Six New England senators urged FERC last week to end the New England Power Pool's ban on public and press attendance at stakeholder meetings.

U.S. Sens. Sheldon Whitehouse (D-R.I.), Jack Reed (D-R.I.), Ed Markey (D-Mass.), Elizabeth Warren (D-Mass.) and Jeanne Shaheen (D-N.H.) joined Sen. Richard Blumenthal (D-Conn.) in a letter urging FERC to reject NEPOOL's proposal to codify its longstanding closed-door policy (ER18-2208).

"Residents of New England pay some of the highest electricity rates across the country," the senators said. "Consumers deserve to be aware of the important decisions that are made that affect their household energy bills and the environment. Such decisions should be transparent and subject to public scrutiny."

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New NERC Chief Not 'Smartest Guy in the Room'

By Rich Heidorn Jr.

WASHINGTON — NERC CEO Jim Robb is a chemical engineer who learned the electric industry as a McKinsey consultant in California in the 1990s.

Jim Robb, NERC CEO | *© RTO Insider*

"So I learned the industry much more from a business and strategic angle than coming up through technology, operations and planning," he said Thursday during an hourlong press conference scheduled to mark six months on the job for Robb, who was previously CEO of the Western Electric Coordinating Council. *(See NERC Names WECC Chief to Top Post.)*

"I'm ... not an electrical engineer. ... I'm never

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NERC Chief Sees Need for Inverter, Fuel Assurance Standards (p. 3)

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In this week's issue

NERC Chief Sees Need for Inverter, Fuel Assurance Standards

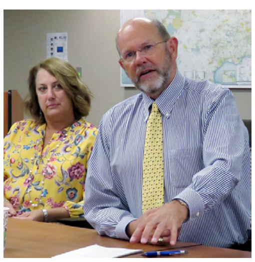
By Rich Heidorn Jr.

Flames from the August 2016 Blue Cut fire approach railroad tracks in Cajon Pass, San Bernadino County. | *California Department of Forestry and Fire Protection*

WASHINGTON — NERC CEO Jim Robb said Thursday he is pushing for new reliability standards to address fuel assurance concerns and ride-through settings for inverters on solar generation and storage.

"I think a standard will be called for" on inverters, Robb said during a press conference at NERC's D.C. office marking six months since he took the organization's helm. "I feel the same way about fuel assurance. But my eyes are wide open to the challenges in crafting those appropriate [requirements] and figuring out which entities should be accountable for them."

NERC has issued two *alerts* on inverters, one after the 2016 Blue Cut wildfire near Los Angeles caused transmission line faults and disconnected 1,200 MW of solar resources, and a second following a fire in spring 2018. Both were Level II alerts, which required registered entities to respond to NERC's recommendations and answer questions about solar generation in their footprints and how they plan for the loss of the resources.



NERC CEO Jim Robb with spokeswoman Kimberly Mielcarek | *© RTO Insider*

NERC is now finalizing a reliability guideline to ensure inverters are configured "so they play nicely with the rest of the system," Robb said. "An inverter can do almost anything you want it to do. You just have to tell it what to do."

Robb said the issue is a concern not only in California and the Southwest but also in North Carolina, Massachusetts and Texas, where solar penetration is rising. Battery storage also uses inverters and presents similar issues, he said.

"The issue around the standard that we're currently struggling with is that right now all of our standards … are technology-agnostic and fuel-agnostic," Robb said. "So, this would be the first that we would put in for a specific technology. And not everyone's embracing that notion, so we have some work to do." *(See Solar Inverter Problem Leads CAISO to Boost Reserves.)*

Fuel Assurance Standard

The shift from baseload coal and nuclear generation to variable resources and natural gas also justifies a reliability standard, Robb said.

"Loads are becoming much less certain than what we've had in the past. In fact, to be perfectly honest, we don't know what the load curve of California looks like anymore because so much of it is masked by the distributed solar panels on peoples' roofs," he said. "We have a lot of tools and a lot of rules … we use to operate and manage and plan the system that are all largely based on a 1950s view of the world [that's not] really true anymore."

One of the challenges is aligning the natural gas industry's infrastructure, scheduling policies and modeling to the real-time needs of the electric industry.

"Those [gas] power plant ramp rates are getting steeper and steeper" in the afternoons, when solar generation drops as loads peak, Robb said. "And effectively what we're seeing is power plants were sucking gas out of the distribution system faster than pipelines could pack it in."

Although pipelines can provide some storage by increasing pressure in their systems, "what we're seeing in areas like the Southwest … is some of the pipeline corridors are running 90 to 95% of capacity. So they don't have the same degree of flexibility they would have had five, 10 years ago."

In addition, because of the way gas is regulated, "there is really no [one] who can solve these problems with the stroke of a pen," Robb said.

Natural gas problems are most acute in New England and Florida, which have limited pipeline infrastructure, and California, which has lost most of Aliso Canyon's storage capacity. *(See related story, CAISO Seeks to Extend Aliso Canyon Rules.)*

Although NERC's current standards address planning for contingencies, they are "relatively vague as to how to think about fuel as a contingency," Robb said.

"So we're talking through getting a guideline in place that would make clear that any particular entity ought to look at a major pipeline disruption for example [or] a problem on the rail system … and start to factor that into their operating and shorter-term planning."

Still to be determined is which entities would be subject to a pipeline contingency rule. "The challenge in evaluating the gas system is you need to really look at it over a fairly wide area, probably a bigger footprint than a planning coordinator, certainly a bigger footprint than in individual utility. It might be something that might be best applicable to [a reliability coordinator] but the RCs aren't really set up to do that kind of planning," Robb said.

He acknowledged that the industry generally prefers guidelines over standards because the latter can result in enforcement actions. "I choose to think of them as providing great clarity around how things should be done, particularly around these very disparate resources around the system that can interact in ways that don't contribute to the community event that we call reliability. But it will take us a while to get there."

Robb also acknowledged that the issue has become politicized by the Trump administration's efforts to provide price supports for money-losing coal and nuclear generators. "My goal is to make sure that our work remains technically unimpeachable so it's there to inform people who are making important decisions around these issues but not get drawn into the political and ideological arguments around them." ■

New NERC Chief Not ‘Smartest Guy in the Room’

NERC Washington D.C. Office | *© RTO Insider*

Continued from page 1

going to present myself as the smartest guy in the room on any technical topic," he said. "I think the reason the NERC trustees chose me for this job was my ability to put the right set of people together to work on the right set of issues at the right time."

Robb, who was tapped to replace long-time CEO Gerry Cauley, met with the press at NERC's D.C. office, which houses about 30% of the organization's employees, including its legal, enforcement and communications staffs and the Electricity Information Sharing and Analysis Center (E-ISAC). Robb said he spends most of his time at NERC's Atlanta headquarters but visits D.C. about three or four times a month.

Robb said NERC has a good foundation, citing the long-term ***strategic plan*** developed over the last 18 months and its four-year effort to transition to a risk-based approach, the Reliability Assurance Initiative (RAI).

The RAI initiative moved NERC away from the "one size fits all, check the box" approach of the past, Robb said.

Instead of auditing all registered entities on a three-year cycle, NERC and its Regional Entities are focusing on the most critical standards. NERC also has identified about 20% of its requirements as candidates for retirement.

NERC is also narrowing its focus on the entities that present the biggest risks to the system, based on their scale, location and the neighbors with whom they are connected. The organization's staff now has power to change their audit scope on site if they encounter unexpected issues.

"It's much more tailored to the individual company, its risk posture and its historical performance," Robb said. "I think when we first rolled this out, industry thought, 'This is great. This is going to be much less [regulation].' And in fact, the experience has been all over the board. There's some entities that would say, 'Boy, we're seeing a lot more of you than we'd like.' And there are a few that we have had a much lighter touch on.

"We have to maintain rigor at all times. While we'll disproportionally focus our time on and attention on the key risks and issues of the moment, we can't lose sight of all the other stuff that goes on," he added, mentioning criticism the Federal Aviation Administration received over its inspection practices in April following a fatal Southwest Airlines ***engine failure*** caused by cracked fan blades. "I don't want to go through that," he said.

Among Robb's priorities are improving the consistency in how standards are implemented across regions, long a source of industry complaints, and improving the work of the ISAC.

The ISAC effort is being led by Bill Lawrence, a NERC veteran who led the GridEx IV exercise in 2017. Lawrence was ***appointed*** in August as chief security officer, replacing Marcus Sachs, who resigned last December. RTO Insider reported that Sachs was forced out because of concerns by industry officials on the Electricity Subsector Coordinating Council (ESCC) that he lacked the background to lead the ISAC's planned expansion. ***(See NERC Parts Ways with Chief Security Officer.)***

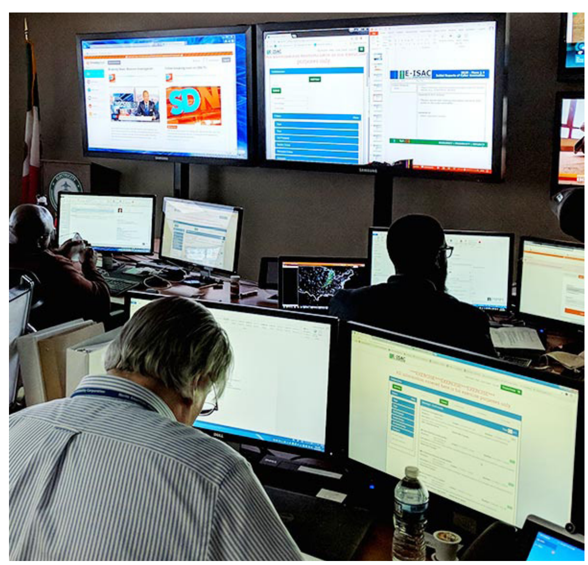
"The ISAC really has not performed up to expectations," Robb said. "Over the last couple years we, and the Electricity Subsector Coordinating Council's Member Executive Committee, worked with Bill and others to put real rigor around the strategic role of the ISAC. … The ISAC is really designed to [provide] a service function for the industry. It's not meant to be an idea lab."

Robb said the ISAC faced challenges in "sanitizing" confidential information it receives and converting it to actionable intelligence.

The ISAC will double its staffing to "build [a] very strong analytical capability" and create a 24/7 watch operation, Robb said. The ISAC is now staffed only during normal business hours, although there is a NERC officer on duty around the clock.

The Cybersecurity Risk Information Sharing Program ***(CRISP)***, which is funded by industry and the Department of Energy and managed by the ISAC, is now monitoring utilities representing about 75% of electric meters to identify hackers seeking to penetrate the companies.

"The risk of a major outage as a result of one of these [attacks] is very low — but not zero," Robb said. "And given the havoc that would result, we need to always be vigilant and staying way ahead of the curve, and I think we are. I think our system is designed with so much security built in, through the standards, through the isolation of operating systems from enterprise systems, that it would be very, very unlikely that a foreign entity or a malicious actor of any type would be able to create a catastrophic kind of cascading issue on the grid. Not zero, but very unlikely." ■



ISAC | *NERC*

CAISO NEWS

CAISO Seeks to Extend Aliso Canyon Rules

By Hudson Sangree

CAISO is seeking to extend for another year interim market measures designed to deal with gas supply restrictions at the damaged Aliso Canyon facility. | *California Governor's Office of Emergency Services*

CAISO is seeking to extend measures for another year that deal with the continuing threat to electrical reliability posed by limited operations at the Aliso Canyon natural gas storage facility, where a massive release of methane occurred in October 2015.

The ISO is seeking expedited approval from FERC to renew *the temporary tariff provisions*, which were first put in place in June 2016 and then subsequently refined and extended. *(See CAISO Board Aliso Canyon Rules Package.)*

"Our hope is to be able to keep these measures in place for another 12 months," Anna McKenna, an assistant general counsel for the ISO, said in a conference call with stakeholders last week.

The provisions include a measure allowing the ISO to enforce constraints on the maximum amount of natural gas that can be burned by gas-fired plants in the areas served by the Southern California Gas and San Diego Gas & Electric. The constraints would be based on limited supply anticipated by CAISO during specific hours.

The provisions also allow CAISO to suspend or limit the ability of scheduling coordinators to submit virtual bids if it's determined virtual bidding could undermine reliability or grid operations.

Similar provisions have been in place for the past two years to prevent blackouts or grid disruptions caused by the natural gas supply in Southern California being over-taxed.

The current proposal, called Phase 4, would extend the temporary provisions now in place for another year beyond Nov. 30 and Dec. 16, when they are set to expire.

CAISO planned to file its proposal with FERC by last Thursday and ask for a 60-day turnaround so the new restrictions are in place when the first set of rules expires at the end of November.

Before the 2015 blowout, Aliso Canyon was the state's largest natural gas reservoir, and its damaged status poses challenges to generators and regulators alike.

Despite objections from local residents and Los Angeles County officials, SoCalGas resumed injections into the facility in July 2017 to comply with a state directive to maintain sufficient gas inventories to support reliability on the region's gas and electric systems. *(See Aliso Canyon Resumes Injections.)* The California Public Utilities Commission this May authorized a temporary increase in the volume of injections to support summer grid operations but still maintains a policy of allowing withdrawals only as a last resort. *(See CPUC OKs Temporary Increase in Aliso Canyon Injections.)* ■

CAISO News

CAISO Finalizes Draft TAC Proposal

By Hudson Sangree

CAISO moved closer last week to updating its transmission access charge (TAC) structure to include new rules about how to measure transmission usage.

Stakeholders discussed *the final draft proposal* Sept. 24 at CAISO headquarters in Folsom, Calif., with participants also joining by telephone.

The proposed rules are intended to more accurately allocate transmission costs based on current grid conditions to achieve greater efficiency and cost-effectiveness, the ISO contends.

In particular, the rules would change the current volumetric TAC to a hybrid one that uses historic peak demand data instead of forecasted data.

"It's kind of a balance we're trying to strike here," Chris Devon, CAISO market and infrastructure policy developer, told stakeholders.

The volumetric-only approach is no longer appropriate because of a changing grid, most notably the rise of distributed generation and other distributed energy resources, the ISO and many stakeholders contend. The hybrid approach would help adjust for this new reality so that transmission owners can better recover the costs of building, maintaining and operating transmission facilities, proponents said.

"The proposed hybrid approach is an improvement over the current TAC structure," the ISO said in its presentation Monday. "[It] captures both volumetric and peak demand functions and reliability benefits provided by the system."

Planning for the revisions started in April 2017 and has included several stakeholder meetings. The initial straw proposal went through two revisions, with some of the more controversial proposals modified or rejected.

CAISO recently backed off a proposed provision that would have moved the point of measurement for transmission usage away from the end-use customer's meter to the interface between the transmission and distribution systems to better reflect increased customer reliance on resources directly connected to the distribution network, such as rooftop solar.

"The ISO is willing to revisit the point-of-measurement issue — for purposes of prospectively allocating the costs of future transmission facilities — if state policymakers and regulatory authorities, after careful consideration of the merits and implementation issues, support retail rate changes that provide a transmission cost credit (i.e., relief from retail rate charges for certain new transmission facilities) to load-serving entities that have procured distributed generation resources," the ISO wrote in the proposal.

The TAC plan still has a way to go before it could be implemented.

A final proposal will likely be submitted to the ISO Board of Governors in the first half of 2019, with board approval coming later next year.

It would then have to be submitted to FERC, with implementation occurring no sooner than 2021 or 2022, according to CAISO planners.

The grid operator previously developed a proposal to allocate transmission costs over an expanded balancing area if the ISO integrates new members from other areas of the West. *(See CAISO Floats Latest Cost Allocation Plan for Expanded Balancing Area.)* That proposal has been shelved until CAISO expands into other regions. ■

Power lines in Contra Costa County, California | *USDA*

ERCOT News

Technical Advisory Committee Briefs

Stakeholders Endorse DC Tie Operator as Market Participant

By Tom Kleckner

AUSTIN, Texas — ERCOT stakeholders last week granted Southern Cross Transmission's (SCT) request to create a new market participant category for DC tie operators after months of inaction.

The Technical Advisory Committee on Sept. 26 unanimously endorsed a Nodal Protocol revision request *(NPRR857)* and an accompanying change to the Nodal Operating Guide *(NOGRR177)*. Together, the changes create a "direct current tie operator" role that will clarify "obligations specific to those entities that operate DC ties" as distinct from those of transmission service providers (TSPs), who currently own all DC ties in ERCOT.

SCT was unable to qualify as a TSP because it will not own transmission facilities under the Texas Public Utility Commission's jurisdiction. Pattern Development is pushing the proposed HVDC transmission project in East Texas that would be capable of shipping more than 2 GW of energy between the Texas grid and Southeastern markets. *(See "Members Debate Southern Cross' Bid to be Merchant DC Tie Operator," ERCOT Technical Advisory Committee Briefs: Feb. 22, 2018.)*

The revision also requires any TSP that operates a DC tie to secure additional registration as a DC tie operator.

Before the change can be implemented, NPRR857 requires SCT to issue Oncor a notice to proceed with construction of the facilities and provide the financial security required to fund the interconnection facilities. SCT has already signed an interconnection agreement with Oncor.

Under a separate *memorandum of understanding* with ERCOT, SCT agreed to cover all Protocol revision costs and any system change costs necessary to implement NPRR857. Staff have estimated a budgetary impact of up to $700,000.

The NPRR had been tabled since May's TAC meeting, when SCT requested a delay in an attempt to increase the market's understanding of the revision. *(See "Staff Again Delays Vote on Amendment, Bylaw Revisions," ERCOT Technical Advisory Committee Briefs: May 24, 2018.)*

Cratylus Advisors' Mark Bruce, who represents Pattern Development before the TAC, said SCT was ready to move forward with the change requests, but it was waiting for ERCOT's determination of which market segment a DC tie operator should be placed in for governance purposes. That question is yet to be resolved.

Vice Chair Diana Coleman (Texas Office of Public Utility Counsel), Chair Bob Helton (ENGIE) and ERCOT COO Cheryl Mele follow the discussion. | © *RTO Insider*

Bruce said ERCOT comments *filed* Sept. 19 "address everything that was raised previously at TAC."

ERCOT built on NPRR857 to make it clear SCT will bear the cost of implementing the change and added the criteria necessary to begin its implementation. The grid operator will issue a market notice before beginning the project, and another before NPRR875's implementation.

The change addresses one of *14 directives* the PUC set for ERCOT before energizing the SCT project *(Project No. 46304).*

TAC Approves First PUC Directive Related to DC Ties

Stakeholders also approved the first ERCOT determination in response to the PUC's directives, but not before editing ISO staff's language.

In directive 10, the commission ordered ERCOT to decide whether pricing changes are necessary within the market during emergencies to avoid DC tie flows "adversely affecting price formation … or otherwise causing outcomes inconsistent with a properly functioning energy market."

TAC changed ERCOT's original determination ("No market changes are needed to address pricing issues.") to: "Although ERCOT staff recognizes potential price formation issues, ERCOT staff has identified no need for additional market changes at this time."

Members argued staff's original determination did not accurately reflect discussions within the Wholesale Market Subcommittee (WMS) and the Qualified Scheduling Entity Managers Working Group (QMWG). Both groups eventually endorsed ERCOT's determination, which noted that stakeholders had previously considered pricing issues.

WMS Chair David Kee of CPS Energy said a staff white paper approved by stakeholders did not capture the history of the issues.

Staff said it determined that actions related to DC ties could "adversely affect" price formation during both emergency and normal conditions. They noted stakeholders have considered these issues while developing NPRRs related to the *operating reserve demand curve's (ORDC)* price adder and the real-time online reliability deployment price adders.

Staff said there is no need to revise the NPRRs with another change request but said they will engage in stakeholder discussions should an NPRR be submitted or the PUC issues another directive.

ERCOT News

QMWG Chair Eric Goff of Citigroup Energy said a market participant he did not identify plans to file an NPRR making changes to price adders and the ORDC. Goff's abstention was the only vote the determination did not receive.

Staff's *white paper* explained its determination.

"That view may not jibe with the stakeholders' view, but we think it's important for the board to evaluate those opinions," ERCOT's Nathan Bigbee said. "We view this as an ERCOT staff artifact, but we want to give you a chance to see our input."

The white paper and determination will be presented for the Board of Directors' approval at its Oct. 9 meeting.

TAC Endorses $53.3M Economic Project in West Texas

The committee endorsed Wind Energy Transmission Texas' (WETT) Bearkat area transmission project in West Texas, which could become ERCOT's first economic project in three years.

The project, which will be up for board approval in October, addresses congestion on a 138-kV line near Odessa, which is burdened with 1.5 GW of operational and planned wind generation. It consists of two new 345-kV bays and a 27-mile, 345-kV single-circuit line on double-circuit-capable structures.

The Bearkat project had a $69.9 million price tag when WETT submitted it to the Regional Planning Group last year. ERCOT staff's independent review whittled the cost down to $53.3 million by recommending one of the least-cost 345-kV options, saying it provides a high transfer limit and "relatively good overall net societal benefits."

The review evaluated nine upgrade alternatives, all of which passed the grid operator's economic-planning criteria: Annual production cost savings must be equal to or greater than the project's first year annual revenue requirement, assumed to be 15% of the capital cost.

Bearkat has a savings-to-cost ratio of 60% and is projected to produce $400 million in 30-year net savings.

The review took into consideration Lubbock Power & Light's pending integration into ERCOT and the recently approved Far West Transmission Project. *(See ERCOT Board Approves West Texas Transmission Project.)*

TAC to Move 2019 Meetings to Wednesday

The TAC will likely move its 2019 meetings from Thursdays to Wednesdays to avoid conflicts with the PUC's open meetings. TAC Chair Bob Helton said the change will also allow committee members to devote more attention to several PUC dockets that will "create issues in the wholesale market."

Just Energy's Blakey Confirmed as RMS Chair

Committee members unanimously confirmed Just Energy's Eric Blakey as chair of the Retail Market Subcommittee, which serves as a forum to resolve retail market issues.

RMS Chair Eric Blakey | © *RTO Insider*

The committee's Reliability and Operations Subcommittee (ROS) will choose its new chair on Oct. 11. The ROS develops, reviews and maintains operating guides and planning criteria.

Other Approvals

The TAC also approved five NPRRs, two revisions to the Nodal Operating Guide (NOGRR), two Other Binding Document revision requests (OBDRR) and two changes to the Planning Guide (PGRRs):

- **NPRR845:** Incorporates numerous revisions to the reliability-must-run process, including standardizing the standby cost in terms of dollars per hour instead of dollars per megawatt; adjusting availability metrics used in settlements to the current operating plan rather than the availability plan; clarifying a resource's post-RMR status and requiring an entity to submit a resource-notification change no later than 60 days before an agreement's conclusion; allowing ERCOT to retain a mutually agreeable third party to help evaluate submitted RMR budgets; and modifying the RMR agreement to require detailed budgeted costs with or without capital expenditures.
- **NPRR869:** Requires generators over 1 MW within a private use network (PUN) to provide modeling information to ERCOT if they are not: registered with the PUC as a power generation company; part of a PUN with more than one connection to the ERCOT grid; or registered to provide ancillary services. The change includes a netting exemption for a qualifying facility that is a small power production facility and provides energy to a customer behind a single point of interconnection. It also deletes a reference to the now-expired System Benefit Fund.
- **NPRR880**: Requires ERCOT to publish shift factors for PUN settlement points for the real-time market, as is currently done in the day-ahead market.
- **NPRR883:** Removes the real-time reliability deployment price adder from the real-time settlement point price to avoid double payment when resources have received an ancillary services assignment.
- **NPRR888:** Clarifies the four-coincident-peak (4-CP) adjustment methodology that was implemented in conjunction with *NPRR830*.
- **NOGRR180:** Removes "governor deadband" and "governor droop settings" requirements for combined cycle steam turbines.
- **NOGRR181:** Ensures consistency between the ERCOT and *NERC* requirements regarding black start plans. Because ERCOT has to review each transmission owner's plan within 30 days of receipt, it must receive the plans for each year by Nov. 1 of the preceding year to complete its annual study.
- **OBDRR007:** Changes the ORDC methodology to account for the curtailment of solar PV resources. Solar generation had been excluded since the ORDC was implemented in 2014.
- **OBDR008:** Makes ERCOT's procedure for identifying resource nodes consistent with *NPRR890*, which aligns price-calculation formulas with ERCOT systems calculation of the real-time LMP at a logical resource node for an online combined cycle generation resource. NPRR890 has cleared the Protocol Revisions Subcommittee.
- **PGRR063**: Outlines the process for evaluating the reliability impact of transmission projects of 100-kV or above that are expected to be in service before the next Regional Transmission Plan's completion but that were not included in the current plan, a Regional Planning Group project submission, or a generation interconnection or change-request study.
- **PGRR064:** Requires resource entities to verify that dynamic devices used for reliability reflect their operating characteristics. ■

ERCOT News

Market Performed 'as Expected' During Summer Heat

Summer Peak Demands Records | *ERCOT*

By Tom Kleckner

ERCOT said an "exceptional" response by generators and a lack of extreme temperatures helped it meet record demand this summer without issuing alerts or calling for conservation measures.

The grid operator's summer performance review said the wholesale market "performed as expected," with generators responding to higher price signals and making their units available during peak demand periods. It noted the market "is designed to provide financial incentives to encourage market participants to respond appropriately" under tight operating conditions.

ERCOT, which manages 90% of the state's grid, set a new system demand peak of 73.3 GW on July 19, more than 2 GW higher than the previous record set in August 2016. The record high was one of 14 set during the lone period of extreme heat this summer (July 18-23).

It also set a new weekend peak demand of 71.4 GW on July 22.

The summer — which ends Sept. 30 for ERCOT — was the fifth hottest on record across Texas. However, high temperatures were "not as significant or as sustained" as they were during the 2011 record-setter, the ISO said. Temperatures averaged 86.7 degrees Fahrenheit during the summer, with Austin recording 90 days over 100 and Dallas 71 (including 40 consecutive).

Real-time systemwide wholesale prices ranged from $33 to $47/MWh between June and August, with a high of $3,125/MWh on June 5. The highest systemwide price for a single settlement interval during July's extreme weather came on July 18, when prices hit $2,169/MWh.

The highest systemwide day-ahead price was $2,062/MWh on July 23.

ERCOT had fewer reliability unit commitments in 2018 compared to last year because market participants made their units available during tight system conditions, according to the review.

Generation outages were also half of what was projected in ERCOT's final seasonal assessment in April, the grid operator said. *(See ERCOT Gains Additional Capacity to Meet Summer Demand.)* Outages and de-rates totaled slightly more than 2 GW during the July 19 peak.

ERCOT entered the summer with a planning reserve margin of 11%, almost half of that in previous years. The tightest operating conditions came on Aug. 18, when two large generators tripped, one just before the day's peak. ERCOT relied on operating reserves to meet demand "with no reliability concerns."

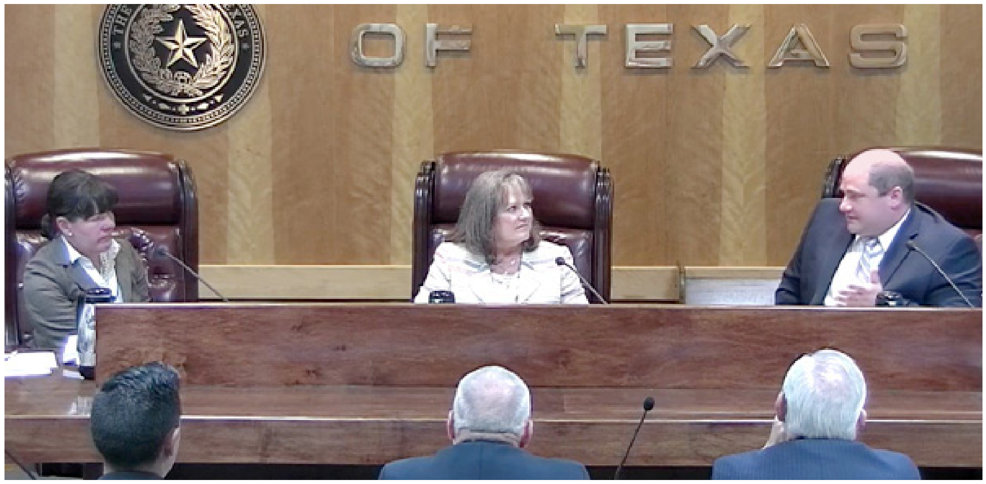
The grid operator filed the report and accompanying data Sept. 24 with the Texas Public Utility Commission, which has opened a docket on the summer's market performance (Project 48511).

ERCOT staff also shared their findings with stakeholders during the Technical Advisory Committee on Wednesday, and they will discuss them with the Board of Directors on Oct. 9. *(See related story, Technical Advisory Committee Briefs.)* ■

ERCOT News

PUCT Urges 2nd Look at Freeport Project Costs

By Tom Kleckner



(Left to right) Commissioners Shelly Botkin, Chair DeAnn Walker and Arthur D'Andrea confer on a case.

Texas regulators last week signaled their discomfort with the rising costs of CenterPoint Energy's planned 345-kV transmission line to serve load in the industrial Freeport area south of Houston.

The Public Utility Commission has asked ERCOT to provide further input on CenterPoint's project, which is part of the "Freeport Master Plan Project" addressing load growth around the Gulf Coast seaport.

"I'm not going to trust these huge shifts in costs without having ERCOT weigh in," Chair DeAnn Walker said during the commission's Sept. 27 open meeting.

CenterPoint's *application* for a certificate of convenience and necessity presented 30 alternative routes, ranging in length from 54 to 84 miles, and in estimated costs from $481.7 million to $695.2 million. The costs at the lower end are almost double ERCOT's estimate of $246.7 million when it approved the Freeport project in December. *(See "Board Approves $246.7M Freeport Transmission Project," ERCOT Board of Directors/Annual Meeting Briefs.)*

"Some of these numbers are approaching those of a nuclear plant," Commissioner Arthur D'Andrea said.

ERCOT's Warren Lasher (left) and Chad Seely

Warren Lasher, ERCOT's senior director of system planning, didn't argue that point. He explained that the grid operator made its recommendation based on "specific electrical reasons," but it has taken a second look after CenterPoint notified it of the cost increase.

"From our very preliminary analysis, neither the need nor the timing for the need for the project has changed," Lasher said. "When we looked at this project electrically, there were just not that many options to get to that part of the state and serve the increasing customer demand. I'm not sure we couldn't have found another option, but it's unlikely."

ERCOT has projected a 92% increase in the Freeport area's load to 1,979 MW by 2019, with a large chemical plant accounting for much of the growth. The region is expected to see an additional 300 MW of load by the end of 2022.

PUC staff agreed to prepare a preliminary order for the commission's Oct. 12 open meeting. The order would incorporate ERCOT's input on whether there are other alternatives for meeting the area's demand.

"I am going to need that," Walker said.

Rio Grande Electric, AEP Texas Reach Agreement

The commission canceled an Oct. 31 procedural hearing in the dispute between Rio Grande Electric Cooperative and AEP Texas over which utility will serve certain customers in a Uvalde subdivision after the companies said they had reached a settlement *(Docket 47186)*. *(See "Hearings Set for AEP Texas Legal Cases," PUCT Reduces Rates for AEP, Others on Income Tax Cut.)*

Rio Grande and AEP Texas told the commission they will resolve the dispute through requests for service area changes. They said they are finalizing maps and preparing the necessary documents to reflect "definitive boundary changes."

The PUC gave the parties until Oct. 22 to file an agreement or a status update.

Commission Accepts IOU Earnings Review; OKs Interventions

The commissioners accepted staff's *review* of the state's 14 investor-owned utilities' earnings reports. Staff said none of the IOUs "warrant[ed] a more detailed analysis" *(Project 48158)*.

Following a closed session, the PUC agreed to allow Walker, who represents the PUC on SPP's Regional State Committee, to work with outside counsel on FERC dockets involving SPP. The PUC also said it would intervene in two FERC dockets:

- The Louisiana Public Service Commission's complaint against Entergy Services and the corporation's five operating companies alleging they failed to include 100% of the costs of Entergy's transmission control centers in MISO's Attachment O formula rate *(EL18-201)*. The PSC said Entergy's failure to bill MISO for all of the costs would force "native load customers to cross-subsidize the use of the Entergy transmission system by third party wholesale customers."
- East Texas Electric Cooperative's complaint against American Electric Power subsidiaries Public Service Company of Oklahoma, Southwestern Electric Power Co., AEP Oklahoma Transmission and AEP Southwestern Transmission. The co-op alleges the 10.7% base return on common equity in the AEP West companies' formula transmission rates is unjust and should be reduced *(EL18-199)*. ■

ISO-NE News

Overheard at NECA 2018 Fuels Conference

NECA 2018 Fuels Conference Crowd | © *RTO Insider*

By Michael Kuser

MARLBOROUGH, MASS. — Fuel security public policy and the role of traditional and non-traditional fuels in New England highlighted discussions at the Northeast Energy and Commerce Association's 2018 Fuels Conference on Thursday.

Joseph Fagan | © *RTO Insider*

"Natural gas is as pertinent and important as ever, particularly in New England," Day Pitney attorney Joseph Fagan said.

"If it's not easy — in this region especially — to site pipeline or gas infrastructure, it only makes sense that we'll see virtual transportation become more important. It makes sense that LNG is going to become more of an issue," Fagan said. "How is [ISO-NE] going to address fuel security and reliability when we have the reality that we have no new pipelines coming into this state ... and we have a large plant [Mystic] that — unless things change — may be retired?"

In July, FERC tentatively accepted a cost-of-service agreement between ISO-NE and Exelon for Mystic Generating Station Units 8 and 9, ordering an expedited hearing process on unresolved issues related to cost justification *(ER18-1639)*. *(See "Fuel Security," Overheard at ISO-NE Consumer Liaison Group Meeting.)*

The goal to reduce greenhouse gas emissions is driving policy in the region, said Brian Jones, senior vice president of energy consultancy M.J. Bradley & Associates.

Brian Jones | © *RTO Insider*

"A lot of the resources that ISO New England manages today are a product of that and have to do with air quality and GHG," Jones said. "Fuel supply is an obvious one, and pipeline constraints into the region are another. We face a lot of challenges, with six states that have pretty aggressive policies on energy and environmental issues, and I don't think that's going to change."

Virtual Pipelines, LNG, RNG

Andrew Bradford | © *RTO Insider*

A big chunk of heating demand met by gas cannot be substituted with renewables or energy storage, and Elon Musk has not yet invented a battery-powered heater, said Andrew Bradford, CEO of energy consultancy BTU Analytics.

"What the latent natural gas demand is in New England is a good question," Bradford said. "We look at 0.75 Bcfd in winter, 1.5 Bcfd max, and 0.5 Bcfd on the peak price day and see there could be demand for around 2 Bcfd."

Given the constraint on pipeline supplies, "for natural gas end-users in New England, there is no silver bullet," he said.

There could be a large truck though. The lack of gas infrastructure has created a market for Xpress Natural Gas, a compressed natural gas distributor that now sends trailer trucks from its 40-Bcfd capacity terminal in Montrose, Pa., to inject into the Iroquois Pipeline at a terminal in New York.

Gary Ritter, XNG's vice president of sales, said the company serves customers from Prince Edward Island to the Mid-Atlantic states, both companies lacking pipeline access and "to facilities on the pipeline grid, bringing incremental supplies to capacity-constrained areas."

The Montrose terminal last winter loaded approximately 25 MMcfd filling some 60 trailers at an average capacity of 400 Mcf each.

Shaving of natural gas peak demand is the top use of LNG in New England, such as at National Grid's waterfront facility in Salem, which holds 12 million gallons of LNG, the equivalent of 1 Bcf of natural gas, said Jonathan Carroll, director of U.S. business development for Energir, formerly Gaz Metro, the largest gas distributor in Quebec.

"This facility or facilities like it are very common in New England," Carroll said. "As a matter of fact, there are close to 40 of these peak-shaving facilities in the region. Some actually have liquefaction and can produce their own fuel; others do not."

In addition, he said there are currently three LNG projects under development in the region: Granite Bridge, Northeast Energy Center and REV LNG.

McKenzie Schwartz, a National Grid gas analyst, said the market for renewable natural gas (RNG) is taking off because of support from state and federal policies, such as EPA's Renewable Fuel Standard.

RNG is derived from biomass and is fully interchangeable with natural gas.

"We believe this can help National Grid move our industry toward a lower-carbon future," Schwartz said.

National Grid pioneered technology in 1982 as the first utility to allow an RNG project to in-

ISO-NE News

terconnect. Its Staten Island Landfill project is still in operation, injecting 2,000 dekatherms/day into the distribution system.

Electrification: How Much?

Emily Lewis | © *RTO Insider*

Emily Lewis, senior policy analyst for Acadia Center, an environmental advocacy organization, said that if states push renewable energy policies, wind and solar energy could generate 45% of New England's electricity in 2030, versus 24% under current trends.

Rick Murphy | © *RTO Insider*

Lewis and Richard Murphy, energy markets director at the American Gas Association, debated how much electric heat pumps can reduce GHG emissions.

Repeating findings she shared earlier in the month at the ISO-NE Consumer Liaison Group meeting in Connecticut, Lewis said electrification of space heating, under current trends, would reduce GHG by 3% by 2030 and by as much as 16% under an accelerated policy scenario. *(See Overheard at ISO-NE Consumer Liaison Group Meeting.)*

Murphy countered with an AGA study that contends aggressive residential electrification of heating and cooling would reduce national GHG emissions by only 1 to 1.5% in 2035.

(See State Regulators Hear Challenges, Promise of Electrification.)

There are three common themes in efforts to achieve deep decarbonization of the energy sector, he said. One is to dramatically increase efforts around energy efficiency. The second is to advance policies that would require up to 100% of all the electricity generated in the U.S. to come from renewable resources. The third is to replace all end-use applications from natural gas or fuel oil to electric alternatives, he said.

"The region uses more than twice as much energy in peak winter months as in the summer, so what would the overall cost be of converting residences away from natural gas and to electrification?" Murphy said. "When we look at the data in the residential market, we really start to think about the impacts on consumers."

Approximately 60 million homes in the U.S. would have to be converted from natural gas heating to electricity, he said, which is a "massive undertaking" for such a modest environmental gain.

Oil Still Relevant

Oil comprises only 1% of New England's power generation on average. But the fuel remains relevant at times, such as a cold snap last winter when oil accounted for 37% of the region's electricity generation, said Kevin Grant, an oil trader at Sprague Energy.

Kevin Grant | © *RTO Insider*

The ability of oil to fill the fuel gap in winter is compromised by the cost of maintaining inventory, delivery logistics and the changed nature of the market, he said.

"Power generators, while still important, no longer drive the commercial oil market," Grant said. "A fuel supplier is going to gear their operations to the customer who comes in 300 times a year, not once a year. Logistics is also an issue, with a limited number of barges and trucks. Transportation companies have right-sized their assets in response to market demand the same as everyone else."

Stephen Leahy | © *RTO Insider*

Stephen Leahy, vice president of the Northeast Gas Association, said, "Natural gas is the last fossil fuel left standing for power generation, but oil is still the No. 1 fuel consumed overall in Massachusetts in terms of total Btus. It's mostly in the form of gasoline, but it's still oil."

How are we going to balance energy needs with environmental goals? asked Nancy Seidman, senior adviser to the Regulatory Assistance Project.

Nancy Seidman | © *RTO Insider*

"The first principle is to put energy efficiency first," Seidman said. "What it's done for New England has been huge. ... To have demand actually dropping is fabulous." ■

ISO-NE News

Continued from page 1

The senators dismissed NEPOOL's argument that allowing press access would hurt the ability of members to talk candidly, calling it "a claim that is neither supported nor justified. In New England and around the country, it is essential that the deliberation process be kept open to all who are affected by these decisions."

New England is the only one of the seven U.S. regions served by RTOs or ISOs where the press and public are prohibited from attending stakeholder meetings.

"Although NEPOOL does publicly release documents, including meeting minutes and official records, both in advance and after meetings take place, this cannot be considered a substitute for membership," the senators said.

They warned that approval of NEPOOL's proposal "could have significant impact on and set precedent for stakeholder participation in electricity market entities, and not only in New England. Formal exclusion of stakeholders from decision-making in NEPOOL would be in stark contrast to FERC Order 719, which sought to increase and not hinder responsiveness to stakeholders across all RTOs."

On Sept. 18, a dozen members of the House of Representatives also called on the commission to open the meetings.

FERC commissioners testifying before the Senate Energy and Natural Resources Committee in June. | © *RTO Insider*

Their letter was signed by Rep. Frank Pallone (D-N.J.), the ranking member of the House Energy and Commerce Committee; Rep. Fred Upton (R-Mich.), the chairman of the committee's Subcommittee on Energy; Rep. Bobby Rush (D-Ill.), the ranking member on the subcommittee; seven of nine members from Massachusetts' delegation; and one representative each from Rhode Island and Vermont.

Last week, NEPOOL filed a motion to dismiss RTO Insider's protest seeking to open the meetings, saying FERC lacks jurisdiction to force changes (EL18-196). Other intervenors supported RTO Insider's request that FERC either force a NEPOOL rule change or strip it of its role as ISO-NE's stakeholder body. *(See NEPOOL: FERC Can't Change Press, Public Ban.)* ■

ISO-NE News

FERC Approves New Hampshire Capacity Settlement

By Michael Kuser

A 4.5-MW biomass power generator in Claremont, N.H., will refund ISO-NE capacity payments it wrongly accepted for nine months following the plant's closure in September 2013 and pay a $250,000 civil penalty under a settlement approved by FERC on Friday *(IN18-10).*

The commission accepted a stipulation and consent agreement between its Office of Enforcement and Wheelabrator Technologies under which the company will disgorge $107,231.34 in capacity payments and interest.

Enforcement began its investigation in March 2015 following a referral from the RTO. "Claremont subsequently responded to data requests and requests for investigative testimony, and demonstrated cooperation during the investigation," the commission said.

Following the Claremont facility's closure, ISO-NE continued to issue monthly capacity payments for a year in exchange for Claremont's continuing obligation to supply capacity while the facility was inoperable. The RTO later clawed back the July to October 2014 payments through its Tariff-based reconciliation process.

Public Service New Hampshire (now part of Eversource Energy) previously purchased Claremont's generation and operated as its lead market participant and asset owner, managing Claremont's participation in the Forward Capacity Auctions (FCAs) and receiving the payments issued by ISO-NE. On Dec. 1, 2013, PSNH transferred Claremont's market participant status to Wheelabrator North Andover, which operates a generation facility in North Andover, Mass., and, as of that date, began receiving capacity payments on Claremont's behalf.

At the time, Wheelabrator management did not fully understand its obligation to shed its capacity supply obligations for FCA 4 (June 2013 to May 2014) and FCA 5 (June 2014 to May 2015) and continued to collect capacity payments for the closed Claremont facility, the commission said.

Claremont energy-from-waste facility | *Stuart B. Millner & Associates*

"Accordingly, Claremont did not successfully shed those obligations. Claremont did shed its obligation for FCA 9 through a non-price retirement request. Claremont's obligations in FCA 8 were eventually unwound by ISO-NE after it discovered Claremont's permanent closure," the commission said.

Wheelabrator's compliance measures were insufficient to identify the violation, the commission said. The company also agreed to submit annual reports for two years on the progress of its recently implemented compliance measures and any new incidents of noncompliance. ■

FERC OKs Discounted Tx for Maine Biomass Plants

By Michael Kuser

FERC on Thursday approved Emera Maine's proposal to provide discounted transmission service to two ReEnergy biomass plants in northern Maine *(ER18-2123, ER18-2124)*.

The commission's Sept. 27 order also found that a protest from Maine Gov. Paul LePage lay outside its jurisdiction. LePage alleged that Emera would recover the cost of the discounts from the state's retail customers, but FERC said retail rates are regulated by the Maine Public Utilities Commission. "Our findings here are limited to whether Emera Maine's proposed commission-jurisdictional wholesale rates are just and reasonable," FERC said.

ReEnergy owns a 39-MW biomass-fueled power plant in Ashland and a 37-MW biomass plant in Fort Fairfield. Both facilities have market-based rates and are allowed to sell their output into ISO-NE's energy, capacity and ancillary services markets.

ReEnergy employee leads tour of Fort Fairfield biomass generator. | *National Bioenergy Day*

Under the agreements, Emera will provide non-firm transmission service from the two ReEnergy facilities to ISO-NE for $0/MW-month for Oct. 1, 2018, through Dec. 31, 2019, and $1,132/MW-month for Jan. 1, 2020, through Dec. 31, 2020.

ReEnergy said the discounts were needed to remain in business because of the pancaked transmission charges they pay to move energy to the ISO-NE market.

Emera would provide service to the plants through the Maine Public District transmission system, which is not directly interconnected with any portion of the U.S. transmission grid. Entities interconnected with it can only access the New England grid over transmission facilities in New Brunswick, Canada, which NB Power owns and operates.

Emera said it agreed to the discounts because ReEnergy provides jobs in northern Maine. ■

MISO News

MISO Agrees to Create NOLA Cost Allocation Zone

RTO Defers Judgment on TOs' Interregional Allocation Plan

By Amanda Durish Cook

Jesse Moser | © *RTO Insider*

MISO said last week it will approve New Orleans' request to make the city a cost allocation zone but is deferring action on an interregional cost-sharing plan advanced by transmission owners.

In a *letter* signed by City Councilmember Helena Moreno, New Orleans asked MISO to create a standalone cost allocation zone for the city, pointing to FERC's policy that project costs be allocated "roughly commensurate" with estimated benefits and that non-beneficiaries not be required to pay for them.

"MISO's analysis has demonstrated that cost allocation on a more granular level within the state of Louisiana will improve the alignment of benefits and costs, consistent with MISO's objectives for cost allocation reforms," the city said.

The request involves creating an Entergy New Orleans transmission pricing zone. Director of Strategy Jesse Moser said the zone will not contain overlapping regulatory jurisdictions.

MISO conducted analyses to determine whether a New Orleans zone would contain enough generation and load to calculate benefits and result in better alignment of the costs and benefits for economic projects under the Transmission Expansion Plan.

"The short answer is 'yes,'" Moser said during a Sept. 27 Regional Expansion Criteria and Benefits Working Group meeting. He said example calculations show MISO can isolate benefits and costs for New Orleans.

"We do plan to make a filing some time in the middle of October … to effectuate this change," he said.

How Small?

Stakeholders asked MISO how small it's willing to make cost allocation zones, with some saying they thought the RTO favored larger cost allocation zones.

MISO hasn't established how small is too small, Moser responded.

"We could have something that's too small. I don't think we've put any definition around that yet," Moser said. "It's going to be incremental steps, and I think this [New Orleans] zone is a step in that direction."

The current 11 cost allocation zones, based on the historic grouping of transmission pricing zones by state jurisdiction, resemble the 10 local resource zones used in the annual capacity auction. MISO earlier this year separated its Texas territory into a distinct cost allocation zone at the request of regulators.

Moser said MISO's smallest cost allocation zone currently contains about 300 to 400 MW of generation. He added that while the RTO will not create any new cost allocation zones beyond New Orleans ahead of its planned cost allocation filing with FERC, it may revisit the possibility of creating new, smaller zones in the future.

"I think it's something we're going to come back to. I don't think we're done with this level of granularity," Moser said.

As part of its cost allocation overhaul, MISO said it would look into the possibility of more specific zones. The RTO has proposed eliminating a footprint-wide postage stamp rate and lowering its current threshold for market efficiency projects from 345 kV to 230 kV. It will also add new benefit metrics to judge a project's eligibility for cost allocation, including consideration for projects that defer or avoid other reliability transmission projects and a benefit for projects that reduce flows on the contract path on SPP transmission linking MISO's North and South regions. *(See MISO Recommends Cost-Sharing for Sub-345 kV Tx.)*

Speaking before the Board of Directors in September, MISO Vice President of System Planning Jennifer Curran said the RTO's cost allocation proposal had determined a good way to estimate regional benefits considering the "various interests of stakeholders."

"This is a very thorny issue here. You're talking about money," Director Mark Johnson said. "The entire MISO team needs to be commended for this effort."

Alternate Interregional Proposal

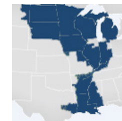
However, most members of MISO's Transmission Owners sector are seeking an alternative to the RTO's plans for interregional project cost allocation.

A majority of TOs, including those with Section 205 filing rights, have formally requested that MISO consider their alternative *approach* for projects developed jointly with SPP and PJM.

The proposal stipulates that for interregional projects located in both RTOs through tie lines — or wholly within MISO — MISO would allocate costs to each RTO based on adjusted production cost benefits outlined in joint operating agreements. To allocate interregional costs within MISO, benefiting cost allocation zones would share costs for projects 230 kV and above, and the transmission pricing zone where the project is located would take on costs of projects below 230 kV down to 100 kV.

For interregional projects located wholly outside of MISO in either SPP or PJM, RTO costs

MISO NEWS



would be divvied up according to adjusted production cost, with MISO's allocation spread across benefiting cost allocation zones for projects 230 kV and above. However, for 100- to 229-kV projects, costs would be divided based on a line outage distribution factor (LODF) to determine the local transmission prizing zone beneficiaries. A LODF measures the change in flow on a facility stemming from the outage of a new project facility.

The RTO has said it wants consistency in project requirements along its seams with SPP and PJM, citing that reason in June when it proposed cost sharing 100-kV and above interregional projects along both the PJM and SPP seams. At the time, more than 20 MISO TOs said they opposed the 100-kV cost sharing threshold on SPP interregional projects because the MISO-SPP seam is lengthier with sparser load density than PJM. They also argued the seam is a better fit for higher-voltage projects, which can carry electricity farther. *(See MISO to Lower SPP Interregional Project Thresholds.)*

Moser said MISO is not yet taking a stance on the TOs' proposal, waiting until it can work out numerical examples for hypothetical projects under the proposal. He said the RTO might not take an official position until early November.

"We appreciate the work of the owners," Moser said. "It's not everyone in the TO community, but it does represent a [Section] 205 filing majority, notwithstanding other filing rights that could be exercised in that community."

Speaking for the TOs, attorney Wendy Reed thanked MISO for considering their proposal and said members hope they can negotiate with the RTO to avoid filing a competing cost allocation proposal with FERC.

Stakeholders at the meeting appeared divided on the proposal. LS Power's Pat Hayes and Northern Indiana Public Service Co.'s Clark Gloyeske said they still supported MISO cost sharing down to 100 kV on interregional projects, though Mississippi Public Service Commission Counsel David Carr expressed support for the TO proposal. MISO asked for written stakeholder feedback on the proposal through Oct. 16. ■

FERC OKs New MISO Retirement Process

By Amanda Durish Cook

FERC last week approved MISO's plan to replace its retirement notification process with a more general three-year generation suspension period.

MISO's proposal places all generation owners submitting an Attachment Y retirement notice into a catch-all three-year suspension period, with suspended units maintaining interconnection rights for the full three years unless they formally decide to retire *(ER18-1636)*. Units that do not return to service after three years are presumed retired and their interconnection rights dissolved. The changes became effective July 16, 2018.

After FERC issued a July deficiency letter on the proposal, MISO said the new suspension process would still allow it to designate resources seeking suspension as system support resources needed to keep operating for reliability reasons. *(See FERC Seeks Details on Proposed MISO Retirement Rules.)* The RTO also explained its old suspension process wasn't working as intended, saying that out of 77 suspensions over the last five years, only eight generators returned to service at the end of the originally designated suspension period.

For modeling purposes, MISO will treat approved suspensions as unavailable resources with no specified date of return service.

The RTO also said its proposal requires no notice from a generation owner should it want to change its suspension status into a permanent retirement any time during the three years.

FERC said MISO's proposal that modeling not anticipate suspended units will return to service "better reflects the inherent uncertainty of planning."

"We agree with MISO that its current requirement to provide a return-to-service date in Attachment Y notices to suspend may at times create an illusion of certainty that does not actually exist," the commission said. ■

MISO News

MISO Utilities Float New Load Forecasting Approach

MISO Planning Advisory Committee in June | © *RTO Insider*

By Amanda Durish Cook

A new stakeholder-led proposal would require MISO load-serving entities to develop a 20-year base load forecast that includes monthly predictions for energy and non-coincident peaks.

The Coalition of Utilities with an Obligation to Serve in MISO (CUOS), an ad hoc group of MISO utilities and regulators, advanced the plan after the RTO earlier this month requested stakeholder ideas for improving load forecasting.

LSEs must currently provide just two years of monthly forecast data to MISO, but WPPI Energy economist Valy Goepfrich said long-term forecasts the RTO obtains from the Purdue University State Utility Forecasting Group — which are compared against LSE projections — so far "have confirmed the validity of the LSE base load forecasts."

Under the CUOS plant, the LSEs' base load forecasts would be applied to MISO's base case Transmission Expansion Plan (MTEP) future, the "limited fleet change" future. The other futures include a continued fleet change future, an accelerated fleet change future and a future in which distributed and emerging technologies become more widely used in the MISO footprint.

"The CUOS proposal is leveraging the forecasts that LSEs already develop," Goepfrich explained during a Sept. 26 Planning Advisory Committee meeting. She said the proposal is more cost-effective than continuing to pay Purdue for independent load forecasting.

The CUOS proposal would also direct LSEs to provide data on transmission losses, as well as demand served by energy efficiency planning resources, demand resources and behind-the-meter planning resources. LSEs would not be required to provide numbers on demand served by energy efficiency programs and other resources not classified as planning resources. Goepfrich said MISO can continue to use consulting firm Applied Energy Group for distributed resource data predictions in the three other MTEP futures.

The Parable of the Ox

Goepfrich referenced an address at this year's MISO Market Symposium in which RTO Director Trip Doggett cited "The Parable of the Ox," a story included in James Surowiecki's book "The Wisdom of Crowds." The story recounts how in 1906, statistician Francis Galton studied a competition to guess the weight of an ox at a country fair, observing the average guess was accurate to within 1% of the actual weight of the 1,200-pound animal. Doggett used the story to illustrate that MISO's large stakeholder community is needed to lend their ideas about what shape the future grid should take.

Trip Doggett at the MISO Market Symposium in August | © *RTO Insider*

Goepfrich said the story also applies to load forecasting. An average of many forecasts, she said, will be more helpful than a forecast designed by a few individuals.

"It doesn't make sense to have a forecast that is divorced from the LSEs' forecasts," Goepfrich said. She added that MISO should be more transparent about the "behind the scenes" analyses that might lead it to prefer an independent load forecast over one originated by LSEs.

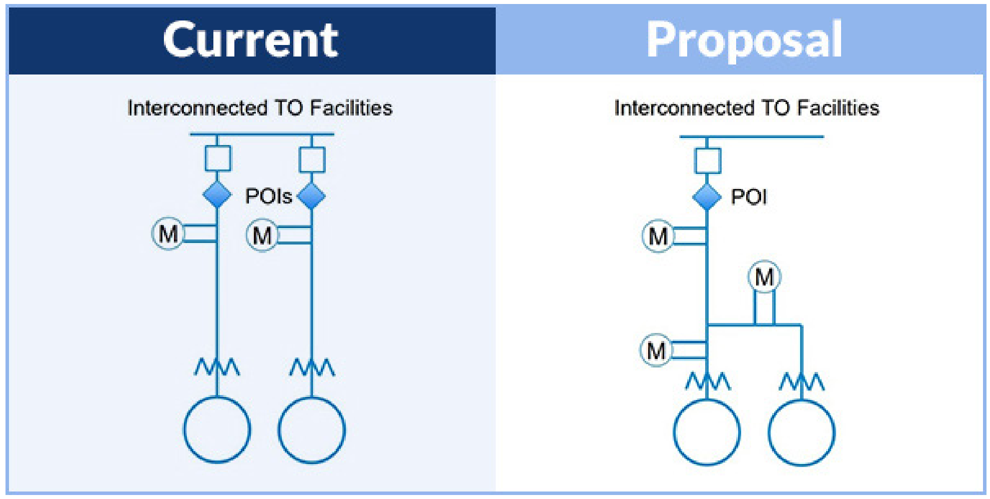
MISO Director of Planning Jeff Webb said the RTO will evaluate and respond to the load forecast proposal. MISO committed to soliciting stakeholder opinions on load forecasting after taking a break this summer from ordering more independent load forecasts from Purdue. *(See MISO Looks to Members for Load Forecasting Ideas.)*

In the face of widespread stakeholder disapproval, MISO in June abandoned a proposal to have its 140-plus LSEs annually assemble four distinct 20-year load forecasts with hourly load shapes to align with each of the four futures in the annual MTEP. *(See MISO Nixes LSE Load Forecast Plan.)* ■

MISO News

MISO Queues up Interconnection Options

By Amanda Durish Cook



2 projects 1 POI | *MISO*

MISO last week announced plans to update its interconnection queue procedures to allow multiple projects to interconnect at one point on the system. It also said it will study ways to bring hybrid projects into the process.

At the same time, the RTO is receiving stakeholder pushback on previous proposals to increase the queue's milestone fees and merge its Interconnection Process Task Force (IPTF) with the Planning Subcommittee.

Speaking at a Sept. 25 IPTF meeting, MISO engineer Tim Kopp said the RTO now thinks multiple projects can share a single interconnection point, but it wants a shared-use agreement struck early in the process and separate metering for each interconnecting facility. He said MISO plans to make Tariff *changes* that will go before the Planning Advisory Committee.

MISO's current policy allows only one project per point of interconnection, but market participants have contended they can decrease costs by sharing a single point of interconnection.

The RTO's plan would require interconnection customers to signal their intention of a multiparty arrangement when they submit applications to join the queue. Before entering the queue, the customers, transmission owner and MISO itself would sign an agreement that would be referenced in the projects' generator interconnection agreement. Kopp said the agreement is needed to prevent customers from changing use arrangements while advancing through the queue.

"We don't want to introduce delays with this process because we're waiting on interconnection customers to negotiate" use agreements, Kopp said.

MISO expects joint requests to increase in the future as smaller projects that only use a small amount of interconnection service proliferate on the grid, he said.

Hybrids in the Queue

MISO staff said minimal revisions to the Business Practices Manuals are required to accommodate hybrid interconnection configurations within the queue study process.

The RTO expects it will most commonly study storage alongside wind and solar generation, as well as wind and combined cycle configurations and wind and solar configurations. Wind and solar have somewhat complementary roles in the MISO footprint; wind tends not to kick up full-force during the sunniest periods of the day.

MISO also said it would consider other configurations at stakeholder request.

Neil Shah | © *RTO Insider*

"We're open to review on what stakeholders are going to address," said Neil Shah, MISO manager of resource interconnection.

Draft *rules* show MISO would largely use its existing BPM language for other resource types, though it said it will evaluate hybrid fuel dispatch predictions, used in its five-year-out power flow analysis, on a case-by-case basis in ad hoc meetings.

During a Sept. 24 Energy Storage Task Force meeting, Xcel Energy and NextEra Energy proposed that MISO phase in hybrid formats involving storage over time, with hybrid market rules created in the short term. In the longer term, the RTO should devise plans for optimizing charging, which would be handled either by the RTO or market participants, the companies said. Beyond that, MISO would create a flexible participation model where hybrid unit owners can toggle among which ancillary and energy services they provide.

NextEra's Holly Carias said MISO and stakeholders would have to establish how to best optimize intermittent resource hybrids like wind and solar so they charge and discharge at the most economic times. MISO's compliance with Order 841 will not involve storage optimization. *(See "No Optimization Yet," MISO Closing in on Storage Participation Plan.)*

Energy Storage Task Force Chair John Fernandes said the issue could be ripe for a white paper. MISO's Steering Committee this month recommended the task force focus on creating white papers for technical storage issues. *(See New Direction for MISO's Energy Storage Task Force.)*

MISO to File Queue Changes

Stakeholders are skeptical about MISO's final milestone modifications aimed at speeding up the slow-moving, 90-GW interconnection queue. While the RTO's proposal for more stringent site control appears unchallenged, its plan to revise the milestone fee structure is drawing ire. *(See MISO to Tweak Queue Rules on Site Control, Project Fees.)*

The latest version of the plan calls for the last of three milestone payments in the queue to be reduced to 10% of network upgrades, down from an earlier proposal of 20%. However, MISO plans to raise its first milestone payment from $4,000/MW to $10,000/MW, and some stakeholders say the increase is too steep. They question the RTO's reasoning for more than doubling the rate.

MISO News

Tradewind Energy's Derek Sunderman said MISO was unnecessarily focusing on the milestone fee structure when it should be working to expedite its own study process.

"I would argue that MISO really needs to focus on its study process because this is getting ridiculous. … I don't think MISO is listening to stakeholders," Sunderman said.

MISO Resource Utilization Director Vikram Godbole said the current low milestone fees don't do enough to deter interconnection customers from entering speculative projects that could harm the economic viability of ready projects.

"Our record does not indicate good progress," Godbole said of the 90-GW queue, arguing for the milestone change.

Other stakeholders said that the active queue will likely slow down after production tax credits for new wind generation expire in 2020.

But Rhonda Peters of Clean Grid Alliance (formerly Wind on the Wires) said the 35 GW of prospective solar generation currently in the queue suggests that solar will become the new resource that keeps the queue busy.

Shah asked for stakeholder feedback on the revised plan by Oct. 9. He said MISO expects to have a final version of the plan in time for review at the Oct. 17 PAC meeting.

In-house Model Development

Shah added that, contrary to some opinions, MISO is focusing on speeding up its study process.

One example: MISO will start building queue study models in-house, according to principal engineer Cody Doll, who noted the RTO currently hires third-party consultants to build the models used in the definitive planning phase of the queue.

"Currently, there seems like there are a ton of delays in our model building," Doll said. "We're doing this to gain control of the process."

Doll said the new process will help MISO maintain better records of the queue process and should cut down on errors made when entering information. It should also shorten MISO's current 30-day model review period, which can stretch into months depending on whether the RTO uncovers modeling errors.

"We'll still have the review period, but we're hoping it'll be a week or so," Doll said.

End of IPTF?

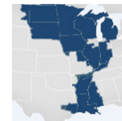
Meanwhile, MISO is proposing to end the IPTF and fold its discussions and duties into the Planning Subcommittee. The task force has largely completed its queue revisions, but some stakeholders say more work remains and pointed out that stakeholders attending the IPTF have voted to transform it into a working group. In MISO's stakeholder structure, working groups are more permanent than task forces, which have an expected sunset date.

Several stakeholders said MISO didn't provide enough warning to stakeholders before bringing the idea forward at the Sept. 26 PAC meeting, with some suggesting the RTO was trying to subvert the stakeholder process by not posting the discussion as an agenda item. WEC Energy Group's Chris Plante said he did not have time to introduce the idea to the Transmission-Dependent Utilities sector ahead of the meeting and said he was "disappointed in MISO's process."

MISO Executive Director of Resource Planning Patrick Brown said moving the IPTF into the permanent Planning Subcommittee will cut down on identical presentations at the two groups and will result in more comprehensive discussion because interconnection topics will take place alongside transmission planning discussions. It will "enable a more holistic approach to planning," Brown said.

"We'll have a broad range of stakeholders involved in the conversation," he added.

MISO staff promised more discussion in October on how to merge the IPTF's charter into that of the PSC. ■



MISO Contemplates Storage as Tx Reliability Asset

By Amanda Durish Cook

MISO last week floated a relatively simple straw proposal for treating storage as a reliability asset in its annual transmission plan.

The *proposal* involves no interconnection queue entry, asset registration and day-ahead scheduling notices.

Jeff Webb | © *RTO Insider*

Speaking during a Sept. 26 Planning Advisory Committee meeting, Director of Planning Jeff Webb said the RTO hopes to get a final proposal in place in time for the 2019 MISO Transmission Expansion Plan cycle.

Webb said stakeholders have asked how storage projects providing reliability transmission services will be able to enter the MTEP.

"Well how does any other transmission project get in? It's proposed as a solution in the planning process," he said.

Webb explained the projects would be proposed in MTEP as either a baseline reliability project driven by NERC criteria and allocated to local pricing zones, or as an "other" reliability project not eligible for regional cost allocation. If the storage project solves the issue at the lowest cost, it will be included in the annual plan.

He stressed that MISO's plan only serves to treat storage comparably to other transmission assets, clarifying that storage projects would not necessarily take priority over traditional wires projects because "storage has a lot of hurdles and costs" to overcome.

"There will be opportunities, I think, to use" storage, Webb added.

'To Queue or not to Queue'

Webb said storage as transmission would not be required to enter the interconnection queue as long as the project will not participate in the energy and ancillary services markets. If a storage asset is planned for both reliability transmission services and market services, the asset must first respond to reliability needs in the transmission market. If MISO doesn't need the asset for reliability transmission purposes, it would be free to participate in the energy market pursuant to MISO's future Order 841 compliance plan, provided it has completed the interconnection queue.

The queue is required "if for no other reason than comparability with other resources that the project would be competing with in the energy market," Webb said.

"There's a lot of controversy; to queue or not to queue," he said of stakeholder reactions. He also said opportunities for market participation by storage projects intended for transmission use will vary according to location, noting that, for example, storage located in rural Iowa with few generation options nearby will have different market opportunities than storage added in a large metropolitan area where generation is already abundant.

"So maybe the answer comes down to significance factors: Where and how big?" Webb mused.

Reliability storage projects will be required to complete asset registration to allow MISO to control the asset when it's required to maintain system reliability. The asset will receive notice of need in the day-ahead schedule and be recalled as needed during the operations day. Like other transmission assets, the storage assets will be price-takers when under RTO instructions.

Webb said MISO hasn't proposed rules to credit a storage asset's market revenue against its transmission asset cost recovery. Some stakeholders have said that allowing the two revenue streams would incentivize dual-use storage to the point that transmission reliability is diminished.

Webb said he expects MISO and stakeholders to discuss storage as reliability transmission services through the first half of next year. He noted that MISO could possibly schedule a workshop on the topic in response to stakeholder requests. ■

MISO Plan to Reduce Queue Studies Gets FERC Nod

By Amanda Durish Cook

FERC last week approved MISO's plan to cut some duplicate analyses from the first phase of its generation interconnection queue.

The approval means MISO can remove its dynamic stability, short-circuit and affected-system analyses from the first phase of the queue's definitive planning phase (DPP) *(ER18-2049)*. The RTO said the procedures are currently repeated once a project hits the second phase of the DPP.

MISO staff have said the changes would help speed along the overbooked, 90-GW interconnection queue, a sentiment shared by the RTO's Transmission Owners sector in comments on the filing. *(See "Studies Reduction," MISO Proposal Aims to Speed Up Queue Process.)*

FERC agreed with that assessment: "We find that MISO's proposed Tariff revisions will streamline DPP Phase I and likely reduce the duration of delays experienced by interconnection customers in MISO's interconnection queue."

The commission also noted some stakeholders' position at an April technical conference that an affected-system analysis in each of the three DPP phases is a contributing factor to queue delays. *(See Renewable Gens Face Off with RTOs at Seams Tech Conference.)* MISO has also said that results of its first affected-system studies are often subject to change later, given the uncertainty of the early information.

Early last week, MISO's Neil Shah said if FERC didn't approve the changes, the RTO would continue using its current study process that includes the redundant studies. ■

NYISO News

Appeals Court Upholds NY Nuclear Subsidies

EPSA Seeks Rehearing of Ill. Ruling

By Rich Heidorn Jr.

The 2nd U.S. Circuit Court of Appeals on Thursday upheld New York's zero-emission credits (ZEC) for nuclear generation, rejecting claims they intrude on FERC jurisdiction *(17-2654-cv).*

"We conclude that the ZEC program is not field pre-empted, because plaintiffs have failed to identify an impermissible 'tether' under Hughes v. Talen Energy Marketing between the ZEC program and wholesale market participation; that the ZEC program is not conflict pre-empted, because plaintiffs have failed to identify any clear damage to federal goals; and that plaintiffs lack Article III standing as to the dormant Commerce Clause claim."

Nine Mile Point Nuclear Plant | *Constellation Energy Nuclear Group*

In upholding a district court's dismissal of the complaint by the Electric Power Supply Association and others, the appellate court said its finding was "consistent" with the 7th Circuit's Sept. 13 ruling upholding Illinois' own ZEC program. *(See 7th Circuit Upholds Ill. ZEC Program.)*

EPSA on Thursday *asked* the 7th Circuit to rehear its ruling, alleging the court had made legal and factual errors. "The panel overlooked or misapprehended three key legal arguments under which appellants would prevail," EPSA said.

Threading the Needle

The New York Public Service Commission created the ZEC program in August 2016 as part of its Clean Energy Standard (CES), which set a goal of reducing greenhouse gas emissions by 40% by 2030. The PSC said it crafted the program to avoid the issues behind the Supreme Court's April 2016 ruling in Hughes v. Talen, which voided Maryland regulators' contract with a natural gas plant as an intrusion into federal jurisdiction over wholesale power markets. *(See NY Attempts to Thread Legal Needle with Clean Energy Standard, Nuke Incentives.)*

The court said that ZECs, like renewable energy credits (RECs), are certifications of an energy attribute separate from the purchase or sale of wholesale energy. Although the ZEC program "exerts downward pressure on wholesale electricity rates, that incidental effect is insufficient to state a claim for field pre-emption under the [Federal Power Act]," the court said.

The court said the PSC avoided the defects of the Maryland contract for differences, which required the generator to participate in PJM's capacity market.

"Plaintiffs point to nothing in the CES order that requires the ZEC plants to participate in the wholesale market," the court said. "As the district court concluded, a generator's decision to sell power into the wholesale markets is a business decision that does not give rise to preemption concerns.

"Until 2019, the ZEC price cannot vary from the social cost of carbon, as determined by a federal interagency workgroup. After 2019, the ZEC price is fixed for two-year periods, and does not fluctuate during those periods to match the wholesale clearing price," the court said.

The court also said the ZEC program was permissible under the dual federal/state regulatory system over electricity because it "does not cause clear damage to federal goals."

The PSC approved the program to prevent the premature retirements of three New York nuclear power plants, Exelon's FitzPatrick, Ginna and Nine Mile Point.

EPSA and the other plaintiffs — the Coalition for Competitive Electricity, Dynegy, Eastern Generation, NRG Energy, Roseton Generating and Selkirk Cogen Partners — claimed they were harmed because the ZEC program allows "favored New York power plants to prevail in interstate competition against" their generation by underbidding them in the wholesale electricity markets.

"If the PSC awarded ZECs in a non-discriminatory manner to out-of-state nuclear plants (as it may do in the future under the terms of the CES order), there would be no abatement in the injury plaintiffs claim to suffer from the general market-distorting effects of the ZEC program. In short, plaintiffs' injuries 'would continue to exist even if the [legislation] were cured' of the alleged discrimination," the court said. "Because plaintiffs' asserted injuries are not traceable to the alleged discrimination against ou-of-state entities, but (rather) arise from their production of energy using fuels that New York disfavors, they lack Article III standing to challenge the ZEC program."

Win for RECs?

"The decision is a win for both ongoing state efforts to preserve existing nuclear plants — New Jersey regulators expect to finalize a ZEC program by the end of the year — and long-standing renewable energy policies," said Ari Peskoe, director of the Electricity Law Initiative at Harvard Law School. "The panel held that renewable energy credits (RECs), instruments that are used for compliance with renewable portfolio standards, are legally indistinguishable from ZECs. Today's decision thus implicitly concludes that RECs are not pre-empted under the FPA, an issue which no court has ever squarely addressed." ■

NYISO News

'Negative Leakage' from NY Carbon Charge, Study Shows

By Michael Kuser

RENSSELAER, N.Y. — An independent study suggests New York's effort to price carbon into its electricity market could result in reduced CO_2 emissions from generators in neighboring areas, rather than an uptick due to "carbon leakage," the state's Integrating Public Policy Task Force (IPPTF) learned last week.

That so-called "negative leakage" in other parts of the Eastern Interconnection would be the result of electricity price changes that very slightly favor natural gas over coal generation, analysis by the nonprofit Resources for the Future (RFF) found.

At the IPPTF's Sept. 24 meeting, RFF's Dan Shawhan presented the study, which modeled the impact of carbon pricing on emissions and prices in New York and neighboring regions based on expectations for 2025. The group used its own Engineering, Economic and Environmental Electricity Simulation Tool (E4ST) to project effects in New York and throughout the interconnection.

In terms of 2025 dollars, the study estimates an environmental benefit of $288 million per year, mostly from a slight reduction in emissions outside New York, and a net total benefit of $279 million per year.

Because New York will have no coal-fired capacity in 2025, less than a quarter of the estimated environmental benefit is from NO_x and SO_2 emission reductions, Shawhan said. Estimated SO_2 damage actually increases slightly because a carbon charge would shift some emissions to locations that cause larger estimated health damage per pound emitted.

Excluding the positive environmental benefits, collective end-user costs in New York come in at $562 million per year, equivalent to $3.60/MWh, with a "somewhat smaller profit gain" for New York generators.

The study estimates a 0.9% reduction in generator CO_2 emissions in the state and a 0.2% increase in in-state generation. RFF attributes a 1.1% reduction in New York power sector CO_2 emission intensity primarily to equalizing the CO_2 emission price applied to in-state fossil fuel generators both exempt from and subject to the Regional Greenhouse Gas Initiative. A carbon charge would reduce damage from New York generator emissions by $17.4 million per year. With the RPS still binding in 2025, the study finds no change in the state's volume of renewable generation due to carbon pricing.

The study estimates an LBMP price increase of approximately $20/MWh in zones A-E, $22/MWh in zones F-I, and $23/MWh in zones J and K, while the renewable energy credit price would drop from $45.88/MWh to $27.28/MWh, and the zero-emission credit (ZEC) price would plummet from $13.64/MWh to zero.

Upstate nuclear unit revenue would climb under the model from $65/MWh to $67/MWh, while the RGGI price would rise slightly, from $11.28 to $11.90 per ton CO_2.

Couch White attorney Michael Mager, who represents Multiple Intervenors, a coalition of large industrial, commercial and institutional energy customers, said: "If one were to rely on your study results to decide whether New York should do this or not, it would be tough to make that decision on a single-year snapshot, so I'm trying to get a feeling for whether your model is likely to produce consistent results over time."

"I think of this as an approximation of the average effect over the multiyear period ... however, it is not exactly the same as what we would get if we simulated each of those years," Shawhan replied.

Zonal Allocation

The Brattle Group's Sam Newell presented analysis on carbon revenue allocation — the process of crediting carbon prices back to electricity consumers. The analysis shows the implications of four alternative allocation approaches that NYISO had proposed and provides a spectrum of options along two competing allocation objectives: to align LBMPs with the marginal cost of serving load while avoiding major cost shifts among customers.

"As soon as you get into debating how best to allocate money, that's a very difficult discussion," Newell said.

Newell said transmission constraints into New York City represent one of the key challenges related to allocation.

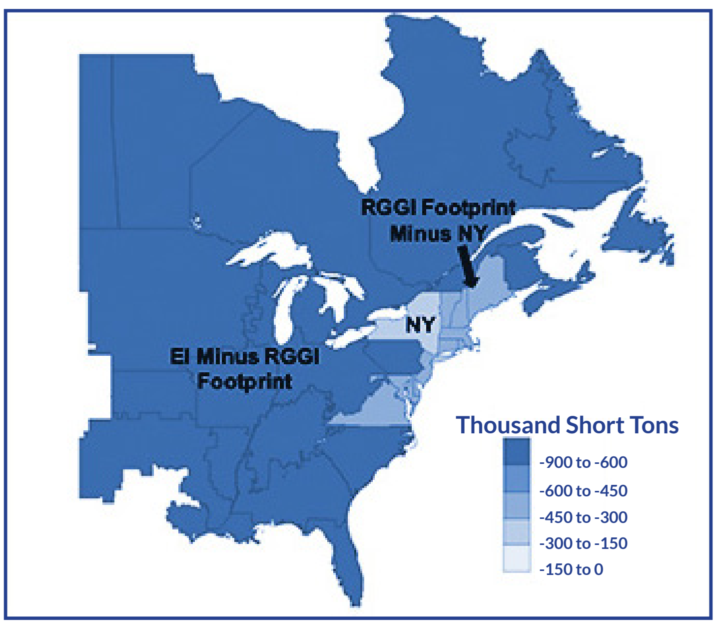
"So if you add a carbon charge, you'd have a greater increase in LBMPs there than elsewhere, and that's one of the things we need to account for... and how that can possibly be offset by different allocation approaches," he said.

All the individual zone results in the study's appendix reflect nodal modeling, he said. To the extent there are transmission constraints going into Zone J (New York City), the model tries to capture them.

But the model found the biggest constraint "by far" is really across NYISO's Central-East Interface, "much more than it is going into southeast New York," Newell said.

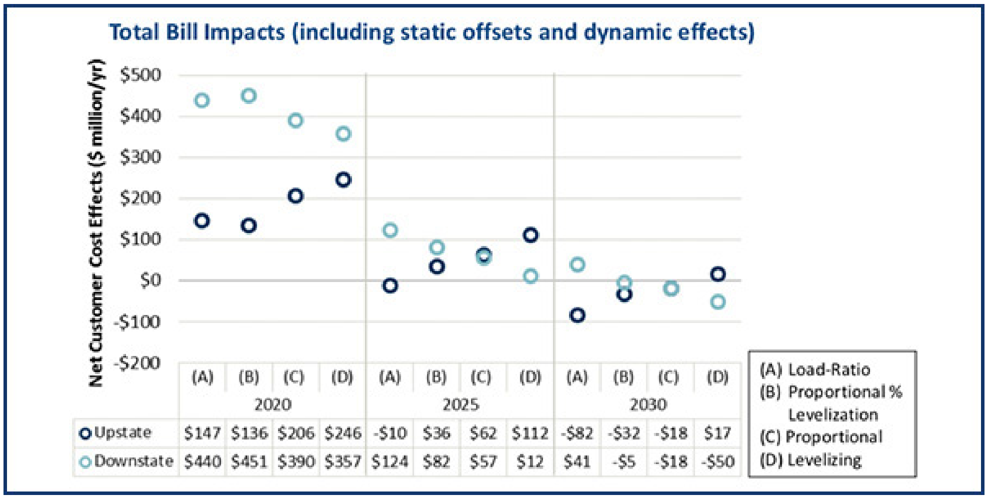
"We did the math, and not surprisingly, with the load-share approach, everybody in every zone, whether upstate or downstate or any part of those, gets about $10/MWh" in allocations, Newell said.

To levelize the net effect (what an LSE pays for the carbon component of the LBMP minus the allocated residuals), downstate zones would



New York's carbon policy could produce "negative leakage," reducing emissions not only in New York but in the rest of RGGI and the non-RGGI parts of the Eastern Interconnection. | *Resources for the Future*

NYISO News



NYISO recommends "levelizing allocation" because it prioritizes avoiding major cost shifts across zones, despite eliminating an efficient price signal that internalizes the costs of CO_2 emissions. | *The Brattle Group*

need to receive about $4/MWh more in allocated residuals than upstate zones, he said.

IPPTF Chair Nicole Bouchez, the ISO's principal economist, said, "When we would go to do the allocations, there are only two things we can observe: one is the carbon component of the LBMP, and the other is how much money we collected from generators."

The ISO cannot observe whether a carbon scheme attracted more investment downstate than upstate and thereby lowered capacity prices downstate, lower than the non-carbon component of LBMPs downstate, Newell said.

A carbon charge opens up a bigger gap between the upstate price and the downstate price, and the markets will tend to levelize the impacts somewhat as suppliers respond to and partially undo the price stimulus, he said.

"What are dynamic effects?" Newell said.

"That's the market responding to price signals."

Seams and MER

Newell also presented analysis on seams, reiterating a presentation he made in April on applying carbon charge border adjustments to the ISO's external transactions.

Newell backs the ISO in proposing to levy import charges and export credits in such a way that makes the effects of carbon pricing invisible to external transactions, with external resources competing on a "status quo" basis. However, if NYISO were to consider an alternative approach, levying charges based on the emissions associated with transactions, several key concepts would have to be addressed, Newell said.

"What is the relevant rate?" Newell asked. "Is it the average rate of their fleet? No, it is the marginal emissions consequences of taking a transaction from there. That's how spot pricing is supposed to work — to create efficient marginal incentives in the operating timeframe. So they're not average emissions; it's the marginal emissions rate."

One stakeholder questioned the study's hypothetical resource shuffling that might result from a "status quo" approach to carbon pricing, saying the ISO has import limits and it's probably impossible for all of the nuclear generation in PJM to flow in while all the fossil generation in New York state flows out.

"Yes, it can happen," Bouchez said. "When you look at imports and exports today, in any one hour, it's almost unheard of to see transactions only going in one direction ... physically there are people importing and exporting at the same time on the same interface. What matters are the net flows, which we calculate as the net of the imports and exports."

Tariq Niazi, ISO senior manager and Consumer Interest Liaison, presented a study summarizing the Brattle report, finding that a carbon charge would reduce CO2 emissions approximately 3% by 2030, causing only limited fuel switching, and that most emission reductions would result from dynamic effects such as renewable shifts, nuclear retention and price-responsive load.

Speaking of the need to reconcile various reports and their differing cost estimates, Niazi said, "Our focus is to get this NYISO analysis done between now and mid-October, when we plan to come back."

Brattle will present the final version of its customer impact analysis at the next IPPTF meeting on Oct. 15 at NYISO headquarters, with an additional task force meeting possible in the interim. ■

NYISO News

Management Committee Briefs

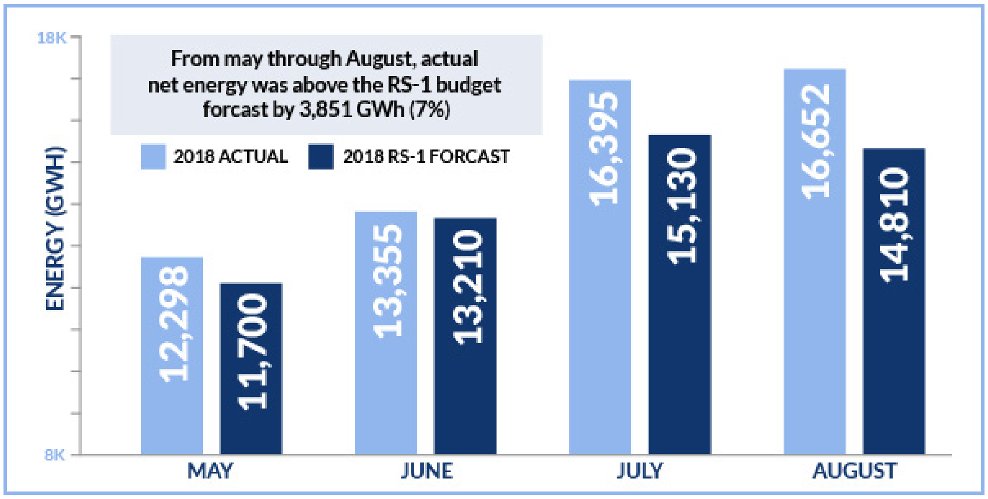
Summer Peak Loads Top 31,000 MW on Six Days

By Michael Kuser

RENSSELAER, N.Y. — NYISO experienced six days with peak loads of more than 31,000 MW this summer, compared with last summer's actual peak of 29,677 MW, the ISO's Management Committee learned last week.

New York ambient temperatures were above the 20-year average in May, July and August, and near average in June. Albany registered 19 days over 90 degrees Fahrenheit this summer, which has occurred only 10 times since 1874, Wes Yeomans, vice president of operations, said as he delivered the Summer 2018 Hot Weather Operations report.

"Fuel supplies for electric generation worked very well this summer," he said. *(See "Adequate Summer Capacity Forecast," NYISO Management Committee Briefs: June 12, 2018.)*



Total load (GWh) was above 50/50 projections this summer, while peak load was below the 50/50 projection for the fifth consecutive summer. | *NYISO*

Total New York Control Area load was above 50/50 projections this summer, while peak load was below the 50/50 projection for the fifth consecutive summer. The summer 2018 50/50 forecast was 32,904 MW, while actual peak load hit 31,861 MW on Aug. 29. The all-time peak of 33,956 MW occurred on July 19, 2013.

NYISO on Aug. 29 activated 481 MW of demand response for Zone J to support New York City transmission security from noon to 6 p.m., while utilities in the state also activated their DR programs. The ISO will report scarcity pricing outcomes at the Market Issues Working Group meeting in October.

Pallas LeeVanSchaick of Potomac Economics, the ISO's Market Monitoring Unit, said the ISO called DR in Zone J for the two largest contingencies, not just the single largest.

"So, these DR resources are needed to meet the reserve requirements for Zone J — which is a real reliability requirement, but it's not reflected in the market," LeeVanSchaick said. "It's really a failure of the market to procure reserves for this requirement, not an operational issue of activating excessive demand response."

Yeomans replied that the ISO is engaged in a project to review reliability criteria.

Significant summer transmission outages were the 345-kV Hudson-Farragut B and C Lines, the 230-kV St Lawrence-Moses L33P and the 345-kV Dunwoodie-Mott Haven 71, which was forced out on July 1 in New York City near the beginning of a six-day heatwave and remains out of service.

Many more outages occurred, but the ISO only reports those that were out for a long time and impacted power availability during a heatwave, Yeomans said.

NYISO's behind-the-meter solar installations have increased six-fold since 2013, with total registered nameplate capacity around 1,200 MW, Yeomans said. "But you'd need all of the panels aimed south and working in full sun to achieve that."

Yeomans said pop-up showers on a hot day can reduce load by around 500 MW, prompting Mark Younger of Hudson Energy Economics to suggest that the weather normalization program at the ISO should try to account for this effect on net load.

Weather normalization refers to smoothing chaotic weather data from several years in order to provide a useful model for load forecasting.

AC Transmission Project on Hold

NYISO CEO Brad Jones informed the MC about why the ISO's Board of Directors had not yet voted on the AC Public Policy Transmission Project approved by the committee in June.

"The board has looked at this and asked for additional data," Jones said. "We hope to get as much as we can to them for the October board meeting but are not sure we'll have all of it." *(See NYISO MC Supports AC Transmission Projects.)*

The MC in June approved joint proposals by North America Transmission and the New York Power Authority to build two 345-kV transmission projects that could cost $900 million to $1.1 billion.

NYISO Proposes 8.5% Budget Increase

The ISO's draft 2019 budget totals $168.2 million, including an 8.03% increase in revenue requirement from this year's budget and a 0.45% decrease in projected megawatt-hours, for an overall Rate Schedule 1 increase of 8.51%.

Alan Ackerman of Customized Energy Solutions, chair of the Budget and Priorities Working Group, presented the review of a budget allocated across a forecast of 157.1 million MWh, for a Rate Schedule 1 charge/MWh of $1.071, compared to $155.7 million allocated across 157.81 million MWh for a Rate Schedule 1 charge/MWh of 98.7 cents this year.

The ISO has held the budget to an approximately 1% average increase in revenue requirement for the past four years, "but this trend is not sustainable for the 2019 budget," Ackerman said.

One big factor driving up spending is repayment of a $30 million loan to finance an Energy

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Topline (formerly Econometric), Baseline and Adjusted Summer Peak Forecast

Annual MW	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
2018 Topline* Forecast	33,763	34,099	34,367	34,554	34,727	34,946	35,132	35,442	35,750	35,982	36,154
2018 Gold Book Baseline**	32,904	32,857	32,629	32,451	32,339	32,284	32,276	32,299	32,343	32,403	32,469
+ 2018 Solar PV	440	566	689	774	843	889	928	963	989	1,017	1,038
2018 RNA RA Base Case***	33,344	33,423	33,318	33,225	33,182	33,173	33,204	33,262	33,332	33,420	33,507

Comparison of Base Case Peak Forecasts - 2016 & 2018 RNA (MW)

Annual MW	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
2016 RNA RA Base Case***	33,618	33,726	33,825	33,948	34,019	34,120	34,256	34,393	34,515	34,646	34,803		
2018 RNA RA Base Case***			33,344	33,423	33,318	33,225	33,182	33,173	33,204	33,262	33,332	33,420	33,507
Change from 2016 RNA			-481	-525	-701	-895	-1,074	-1,220	-1,311	-1,384	-1,471	NA	NA

The 2018 RNA is based on information from the Gold Book 2018, the annual transmission planning and evaluation report (Form 715) filed with FERC, historical data and market participant data. | *NYISO*

Management System/Business Management System upgrade project, Ackerman said. Other factors include debt service, new software needs, professional consultant fees, and salaries and benefits. The ISO plans to add 15 new positions over the coming year.

The board will review the draft budget Oct. 15, the MC will vote on a new budget Oct. 31, and the board will consider the final proposal on Nov. 13, 2018.

MC Approves 2018 Reliability Needs Assessment

The committee approved the ISO's 2018 Reliability Needs *Assessment* (RNA), which identified no reliability needs on the state's bulk power system over the coming decade. The board will consider the RNA in October.

Resource Planning Manager Laura Popa reported that the 2018 RNA is based on information from the 2018 *Gold Book* (the annual transmission planning and evaluation report filed with FERC), historical data and market participant data.

For transmission security, planners evaluated Year 1 (2019), Year 5 (2023) and Year 10 (2028) for summer peak baseline power flow cases, and found no reliability needs for Years 1 and 5. However, for Year 10 they identified one preliminary reliability need: a 3-MW deficiency in Eastern Long Island.

The deficiency would stem from a 1% overload on the 138-kV Brookhaven-Edwards Avenue line (Line 864), the contingency being the loss of the 138-kV Wildwood-Riverhead line (Line 890) and returning the system to normal criteria. PSEG Long Island presented an updated and firm long-range transmission plan at the June 28 Electric System Planning Working Group/Transmission Planning Advisory Subcommittee that involved scheduling terminal upgrades at the Brookhaven 138-kV substation to be in service in June 2019. With these upgrades the overload is resolved, according to NYISO.

LeeVanSchaick elaborated on MMU *comments* filed with the ISO that markets are generally well designed, noting an inconsistency between the assumed value of certain resources needed for reliability transmission planning purposes and how NYISO's capacity market compensates those resources.

The MMU recommends the ISO periodically reassess the assumed relief from land-based wind generators and special case resources (SCRs) in transmission security planning assessments to ensure levels are commensurate with their expected performance and availability. It also asked the ISO consider using different assumptions for offshore wind generators than for land-based wind units, and possibly further discount the capacity ascribed to wind generators and SCRs, which represent load capable of being interrupted upon demand or a distributed generator rated 100 kW or higher.

Failure to maintain consistency between planning reliability criteria and capacity market requirements may increase the need for regulated transmission solutions and reliability-must-run contracts to satisfy reliability needs, which becomes particularly important as more wind generation is built in import-constrained areas over the coming decade, the MMU said.

"It's important to think about this as the resource mix is turning over," LeeVanSchaick said.

ISO Customers Mostly Satisfied with Query Response

Customers and market participants continue to be pleased with how NYISO interacts with them and are nearly 100% satisfied with how the ISO answers their questions, according to a biannual customer satisfaction *survey* conducted by the Siena College Research Institute (SRI).

SRI Director Don Levy told the MC his group recorded a 98% "customer inquiry satisfaction" score on the survey, which combined a market participant satisfaction score (89.9%) with assessment of performance (76.8%) for an overall approval rating of 84.7%.

Levy said the surveys identified several areas for improvement, including tariff, legal and regulatory webpages; ISO manuals, technical bulletins and user's guides; market mitigation and analysis interactions; transparency of operations; and increasing the consideration of stakeholder input.

MC Approves Revisions to OATT Attachment L

The MC approved *revisions* to Attachment L of NYISO's Open Access Transmission Tariff updating terms regarding transmission congestion contracts (TCCs).

Gregory R. Williams, manager of TCC market operations, said the updates to Section 18.1.1 (Table 1A) of Attachment L followed an annual review. Among the changes were revising contract expiration dates from Dec. 31, 2017, to Dec. 31, 2027, for two specified agreements.

If authorized by the board at its meeting in October, the ISO will file the revisions with FERC.

MC Approves Change to Unsecured Credit Scoring Model

The MC approved *changes* to the ISO's unsecured credit scoring model following its first review of the methodology since 2009.

John Jucha, senior credit analyst for corporate credit, said that under the new model, the 12.7% weighting for revenue/market capitalization in predicting a default will be replaced with a measure of total assets. The review found that asset size variables were not represented in the model despite their "strong predictive power."

Rating all market participants — including corporations, financial institutions and government entities — on the same scorecard may mask differences between them, the analysis found.

If authorized by the board in October, the ISO will file the revisions to Attachment K of the Market Administration and Control Area Services Tariff with FERC. ■

PJM News

Illinois: End PJM Capacity Market?

Continued from page 1

generators] don't have the luxury of getting an out-of-market payment."

Another Way?

PJM's assurances didn't sway either the ICC commissioners or the other panelists, largely made up of either environmental advocates or representatives of Exelon, which has two nuclear facilities in Illinois benefiting from a 2016 state law that subsidizes the units with state-funded zero-emission credits. The 7th U.S. Circuit Court of Appeals recently upheld the state's right to provide the funding.

"What if we throw this capacity market out?" ICC Commissioner John Rosales asked, noting that FERC had already ruled the market unjust. "There's some rationale we can do it another way."

He pointed to ERCOT, which doesn't have a capacity market.

"Is that an option? ... Is there something else that we can do? Because the amount of money is uneconomical," he said. "That's a lot of money that's invested in a reserve market that doesn't seem to be needed most of the periods throughout the year," Rosales continued. "Understand, there's times that we're going to need some help, but you get that [help] from others."

Jen Tribulski, a PJM attorney, suggested that FERC didn't intend to do away with PJM's "capacity market as a whole," but sought to improve how the market deals with out-of-market payments.

The disagreement came over what is considered a subsidy. Phillips said that "we have to draw a line somewhere. This is not easy."

However, opponents argued PJM has larger market distortions to address.

"Regulated utilities have the ability to subsidize all of their generation with ratepayer funding, so if you're going to talk about a market without subsidies, you've got to really relook at the whole market. It's the single biggest market distortion that there is," said Rob Kelter of the Environmental Law & Policy Center. "When you consider the cost of energy and you don't consider the cost of environmental externalities, you are creating the biggest distortion

Panelists speak at the Illinois Commerce Commission's hearing on PJM's capacity market Sept 20. | *Illinois Commerce Commission*

you could possibly create. Coal and natural gas pollute."

"Right now, the proposal on the table is to artificially raise the prices that consumers would be paying to preserve the supremacy of the capacity market," said Andrew Barbeau of The Accelerate Group. "There's a certain fealty to the capacity market that we've seen in recent years ... to use the capacity market to start serving other purposes. It's always been there to serve as this insurance product. Consumers are paying more and we're getting less for it, and it's kind of violating what residents of the state have been pretty consistently demanding, which is that the power be cheaper and cleaner."

'Fundamental Disconnect'

Phillips said the market "is doing what it was meant to do when it was put in place" to produce "reliability at the least cost," but that it didn't contemplate environmental concerns. She added that she was "not saying there's not room for improvement."

"That's something that states can get together and have a discussion about" in creating a market-based proposal, she said. "You're getting reliability. You're getting assurances, not insurance, [but] assurances that three years from our market, three years forward, that we have enough capacity online to make sure the energy needs during that period are met."

ICC Chairman Brian Sheahan said there is a "fundamental disconnect in PJM's conception of what 'accommodate' is and what 'mitigate' is."

PJM says its proposal accommodates states' policy decisions, but states argue it instead mitigates their efforts to sponsor preferred technologies.

"You can't just start doing this kind of line drawing," he said. "And the end result, I predict, will be if they don't accommodate, then the states are going to find alternatives. ... Legislatures and governors in states that care about climate change and care about environmental policy are not going to bow to how [PJM thinks] they should work."

ICC Manager Randy Rismiller suggested moving away from capacity markets altogether.

"Energy and ancillary services markets historically have worked quite well. They haven't been as contentious as capacity markets. This sort of gradual gravitation away from capacity might be a way out of these constant conundrums," he said.

CUB's Kristin Munsch urged PJM to "stop trying to separate us, but integrate our preferences into the market."

"I think PJM in recent years has begun to adjust the construct, a market that we thought was working well, to one that's no longer reflecting what I think consumers are looking for," she said. ■

PJM NEWS

PJM Price Formation Group Talks Reserves

By Rory D. Sweeney

Catherine Tyler, IMM | © *RTO Insider*

VALLEY FORGE, Pa. — PJM's initiative to revise how its energy market is constructed continued down the rabbit hole last week with a complex discussion about the timing of procuring reserves.

At Wednesday's meeting of the Energy Price Formation Senior Task Force, the Independent Market Monitor's Catherine Tyler suggested revising the operating reserve demand curve (ORDC) to compare the value of purchasing reserves now to fill potential shortages later versus purchasing them later during the peak hours of the day.

Tyler explained that this level of *analysis* could determine the value of reducing the probability of a reserve. Hung-po Chao, PJM's chief economist, agreed the idea merits consideration and that "the PJM team has been struggling with that" idea.

FirstEnergy's Jim Benchek questioned the Monitor's assumption that the relationship between the price for reserves now and the price for reserves later would be linear.

"That seems like a pretty big leap of faith," he said.

PJM's Patricio Rocha-Garrido explained the RTO's justification for its *recommendation* of a 30-minute reserve product, which he said would account for all the time necessary to dispatch a resource and have it be ready to operate if necessary. Security-constrained economic dispatch (SCED) cases are solved 10 minutes prior to being implemented, and units that are assigned reserves have 10 minutes after a case is implemented to be online, so that accounts for 20 minutes, Rocha-Garrido said. The additional 10 minutes would cover SCED cases that are completed up to 14 minutes ahead and the additional output assigned units could provide past their assignments, if not for their ramping constraints.

The justification didn't satisfy Tyler.

"It kind of sounds like fudging the numbers more than it's based on anything," she said. "You are increasing the looking forward time span such that there is more forecast uncertainty, increasing the probability of a shortage and therefore the price."

"Obviously, I wouldn't describe it in those terms," Rocha-Garrido said. "We're trying to capture the mathematical value … and not dismiss it completely."

PJM's Anthony Giacomoni provided market *simulations* using the RTO's proposed revisions, which would consolidate Tier 1 and Tier 2 synchronized reserves and implement a downward-sloping ORDC. The simulations found that a net annual increase of $250 million to $800 million in load costs would be shifted from other areas, such as uplift, into the energy market, creating a $1 billion annual increase in energy market revenues. ■

PJM News

FERC Upholds PJM TOs' Policies on Supplemental Projects

By Rich Heidorn Jr.

FERC on Wednesday rejected a rehearing request over PJM transmission owners' revised processes for planning supplemental projects, ruling it in compliance with Order 890.

The commission denied a request by American Municipal Power, Old Dominion Electric Cooperative and others seeking rehearing of the commission's Feb. 15, 2018, ruling that the TOs' processes for developing supplemental projects fell short of Order 890's transparency and coordination requirements. FERC also approved PJM's and the TOs' compliance filing in response to the February ruling (ER17-179, EL16-71-002).

PJM stakeholders have long complained about the rules involving supplemental projects — transmission expansions or enhancements not required for compliance with RTO system reliability, operational performance or economic criteria. TOs can develop, build and seek reimbursement for such projects without the approval of PJM, which only reviews them to ensure they don't harm reliability.

The Feb. 15 order approved a proposal to move the TOs' process for planning supplemental projects from the Operating Agreement to Attachment M-3 of the Tariff but required PJM and the TOs to make changes to the attachment and the OA. (See FERC Orders New Rules for Supplemental Tx Projects in PJM.)

The commission said the rehearing request "largely repeats arguments" made earlier in the docket. "We are not persuaded that the commission erred in the Feb. 15 order, which we believe appropriately responds to these concerns."

AMP, ODEC and others argued the commission erred in permitting Attachment M-3 because it circumvented the division of filing rights in PJM, including the supermajority vote of the Members Committee required for changes to the Operating Agreement. They also said the commission should have required the TOs to respond to stakeholder comments under the supplemental process.

PJM's Transmission Replacement Processes Senior Task Force meets earlier this year. | © *RTO Insider*

"Order No. 890 requires that stakeholders be afforded the opportunity to provide meaningful input, and that public utility transmission providers 'craft a process that allows for a reasonable and meaningful opportunity to meet or otherwise interact meaningfully,'" the commission said. "Its requirements are not so prescriptive as to dictate whether and how the PJM transmission owners must respond to that input. While we encourage the PJM transmission owners to be as responsive as possible to stakeholder comments, we also realize that not all comments may require answer."

In addition to AMP and ODEC, those seeking rehearing and challenging the March 19 compliance filing were the Delaware Division of the Public Advocate, PJM Industrial Customer Coalition, Illinois Citizens Utility Board, the D.C. Office of the People's Counsel and Public Power Association of New Jersey, which FERC named the "Load Group."

"The Load Group's requests for various additional provisions go beyond what the commission required in, and constitute requests for rehearing of, the Feb. 15 order," the commission said. "We therefore find these requests to be outside the scope of the compliance proceeding, and were we to consider them as requests for rehearing, would deny them." ■

PJM Members Vote to End FTR Liquidations

By Michael Brooks

VALLEY FORGE, Pa. — The PJM Markets and Reliability and Members committees on Thursday approved Operating Agreement revisions that would eliminate the requirement that the RTO liquidate a member's financial transmission rights when it falls into default.

The proposed changes are in response to the June default of GreenHat Energy, which could cost other members more than $145 million. (See Doubling Down — with Other People's Money.)

PJM presented stakeholders with four packages of revisions at the MRC. Two of those had received a majority sector-weighted vote out of 24 proposals at a special committee session Sept. 18. Option B, Thursday's winner, received 3.8 out of 5 in support, while Option J1 — which would have liquidated all of a defaulting member's long-term positions except those remaining in the 2018/19 planning year, allowing them to go to settlement — received 3.3.

After the special meeting, Macquarie Energy, with support from Apogee Energy Trading and Vitol, offered two more proposals: B' and J1' (read as "B prime" and "J1 prime"), identical to B and J1 except that they would only apply to GreenHat's portfolio. Macquarie said these proposals would allow for continued discussion of PJM's liquidation process after dealing with GreenHat.

All four proposals included two identical provisions. One would ensure that the maximum $10,000 default allocation assessment is charged only once for a default that spans multiple years, rather than each year.

The other would allow those who sold FTRs to the defaulting member in a bilateral trade to take them back if their most recent auction clearing prices were less than the purchase prices.

Brian Wilkie of Rockland Electric Co. moved for considering B without the bilateral provision, which Exelon's Jason Barker seconded. This proposal was dubbed B'' ("B double prime").

Dean Bickerstaff of Hartree Partners moved, with CPower's Bruce Campbell

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seconding, that the MRC also consider Option K1B, which had only received 1.99 in support at the special meeting. K1B would have also allowed the 2018/19 positions to go to settlement, but it would have canceled all defaulting long-term FTRs. It also would have forced counterparties to the defaulters' bilateral trades to reassume those positions.

Only B received the 3.34 sector-weighted supermajority support necessary to move on to the MC, with 3.73 in favor. B'' received 1.88, B' and J1 each received 1.8, J1' got 1.44 and K1B 0.44.

At the MC later Thursday, Bob O'Connell of Panda Power Funds moved that the committee vote to accept the MRC's vote as its own, but he withdrew the motion when DC Energy's Bruce Bleweis called for a sector-weighted vote on it. Committee Chair Michael Borgatti, of Gabel Associates, called for a sector-weighted vote on B anyway, and the proposal passed with 4.01 in favor.

CFO Suzanne Daugherty explained that PJM will submit B as three separate "prongs" to FERC, with the $10,000 maximum and bilateral provisions in their own filings.

PJM CFO Suzanne Daugherty explains the "Option B" proposal to revise the RTO's financial transmission rights liquidation process. | © *RTO Insider*

Daugherty said this was done so that if the commission ends up rejecting one provision, it would not be forced to reject the entire package.

Members also reaffirmed their opposition to the status quo, with only 0.5 in support. If FERC rejects the proposal to eliminate the liquidation requirement, the RTO will ask in an amendment to a pending filing that the commission allow all of GreenHat's positions to go to settlement until the end of February to allow for additional stakeholder discussion of alternatives to the status quo. PJM has asked the commission to allow the positions to go to settlement through Nov. 30, but FERC has not acted on the filing, nor on the RTO's waiver request seeking permission to only liquidate prompt month FTRs. ■

MRC/MC Briefs

PJM, Monitor Come to Agreement on Opportunity Cost Calculator

By Michael Brooks

VALLEY FORGE, Pa. — Stu Bresler, PJM senior vice president of operations and markets, announced at the Members Committee that he and Independent Market Monitor Joe Bowring had signed an *agreement* regarding the use of the Monitor's opportunity cost calculator.

Under the agreement, Monitoring Analytics will continue to use its calculator to calculate the opportunity costs for market participants and will explain its inputs and logic to PJM to demonstrate that the unit-specific opportunity costs are compliant with the OA.

In return, PJM acknowledged that the calculator is the Monitor's intellectual property, that the agreement is not a license for PJM to use the calculator and that the RTO will not attempt to reverse engineer it.

In response to stakeholder questions, Bresler said he was not sure how long it would take for PJM to get the Monitor's data, but he estimated it would take two weeks.

The agreement is the culmination of a yearlong dispute between PJM and the Monitor over opportunity cost calculations, which came to a head in August when the Markets and Reliability Committee approved Tariff revisions, proposed by Bob O'Connell of Panda Power Funds, allowing participants to use the Monitor's calculator. The RTO said it would be willing to allow its use but needed to understand the details of how it worked, something at which the Monitor balked. *(See PJM Monitor Holding Firm on Opportunity Cost Calculator.)*

The Monitor has repeatedly criticized PJM's calculator as inaccurate and the RTO's process for verifying inputs as flawed.

Calpine's David "Scarp" Scarpignato asked

PJM General Counsel Vince Duane introduces the new web-based governing documents to the MRC. | © *RTO Insider*

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what would happen to a generator if the calculators gave different results, and the generator used the one that gave it a higher price. Bowring answered: "It is still our responsibility to calculate opportunity costs, and if you propose to use an opportunity cost that is too high, we will let you know and refer you to FERC as necessary."

O'Connell, who had originally been scheduled to speak before Bresler on the topic and had deferred, moved to postpone the vote on his proposed revisions to the next meeting to give PJM and the Monitor time to put the new process in effect. The motion was approved by acclimation with no objections or abstentions.

Quadrennial Review

The MRC voted on four *packages* of revisions as part of PJM's quadrennial review of the variable resource requirement (VRR) curve, but none of the proposals received majority support.

The committee's sector-weighted votes were advisory to the Board of Managers, which has ultimate approval of what is filed with FERC.

The MRC voted on proposals by PJM, the Monitor, Calpine and the D.C. Office of the People's Counsel. Several stakeholders noted that their support hinged on the reference unit used in the calculations. PJM and the Monitor have proposed changing it from General Electric's 7FA combustion turbine to the new 7HA, while the OPC proposed using an F- and H-class combined cycle. Calpine's proposal maintains use of the 7FA.

Exelon's Jason Barker said his company was against the HA being used, noting that GE has had trouble with its newest turbine class.

Reports of problems with the H-class began coming in last year, and Exelon recently had to *shut down* two power plants in Texas after GE identified a flaw in the design.

PJM's proposal came in first with 2.32 in favor, followed by Calpine's with 2.14, the Monitor's with 1.96 and the OPC's with 1.42.

At the MC, Carl Johnson, representing the PJM Public Power Coalition, moved to adopt the MRC's votes for the sake of efficiency. This was quickly approved by acclimation, with only one objection.

VOM Proposal Rejected by MC

A revised *proposal* by PJM to include certain variable operations and maintenance (VOM) costs in cost-based energy offers failed to win supermajority endorsement from the MC, garnering only 2.92 of a sector-weighted vote.

At last week's MRC, PJM's Melissa Pilong *presented* several revisions to an RTO proposal that had been rejected, along with four others, by the MRC in July. *(See PJM Ponders Advancing VOM Effort over Objections.)* The changes included removing the ability for resources that did not clear the capacity auction to recover their fixed costs in their energy offers.

Originally, the proposal included only changes in Manual 15, which would only require MC endorsement and approval by the Board of Managers. As part of the new proposal, PJM would also add clarifying language to the Tariff and OA, meaning it would have to be approved by FERC.

Greg Poulos, executive director of the Consumer Advocates of the PJM States, said that while he appreciated the additional FERC provision, he was frustrated that the VOM proposal kept coming up with little change. In a sector-weighted vote motioned for by Poulos, the MRC advanced PJM's new proposal, with 3.4 in favor.

Later at the MC, Poulos motioned to delay a vote on the proposal, which Chairman Borgatti set for a sector-weighted vote. Before members voted on whether to vote, however, Bresler noted that because of the Oct. 12 deadline for filing changes stemming from the quadrennial review, PJM had set both matters for that day. CEO Andy Ott also urged members to vote, saying "it would be helpful to the board if you resolved this today."

PJM's proposal would allow major maintenance costs to be included in the VOM costs in energy offers. That would mean that they would be not included in the cost of new entry, which is set as part of the quadrennial review. Without the vote, Deputy General Counsel Chris O'Hara said that it would be difficult for PJM to justify the quadrennial review. "We would have to tell FERC we lack sufficient information to ensure the quadrennial review is just and reasonable," he said.

With only a simple majority needed, members resolved to vote that day, with 3.1 in favor, before the actual proposal failed in a subsequent vote. Bresler later told RTO Insider that PJM will discuss with the board whether it should file the proposal under Federal Power Act Section 206, which is done when a proposal lacks member support. The RTO would have to show that its existing OA language regarding VOM costs is unjust and unreasonable, rather than just show that its proposal is just and reasonable.

Liaison Committee Meeting to be Closed to Nonmembers

Near the end of the MC meeting, a *motion* by Poulos for a temporary waiver to the Liaison Committee's charter to allow some nonmembers to attend its upcoming Oct. 3 meeting as listening-only participants failed in a sector-weighted vote, with only 2.43 in favor.

According to PJM's Dave Anders, it has been accepted practice to allow nonmembers — such as state regulators and their staff, FERC staff, PJM management and staff, and the Monitor — to attend since an LC meeting in D.C. one year coincided with a meeting of the National Association of Utility Regulatory Commissioners several years ago. State regu-

| © RTO Insider

PJM News

lators and FERC staff had asked to be allowed to attend the LC, and "how could we say 'no' to that?" Anders said.

In an email to RTO Insider after the meeting, Poulos said his motion was prompted by a member's request to enforce the charter during a "prep call" for the upcoming meeting. Poulos declined to name the individual who made the request.

"It was not the first time I've heard this request, but this time the request was gathering support from the others on the call," he said. "I thought the decision was important enough to be heard by the entire stakeholder body."

At Thursday's meeting, Barker said he was disappointed that PJM had been lax in its enforcement of the charter. "This is our private discussion with the board," he said. "This is our one opportunity."

Alex Stern of Public Service Electric and Gas, who participated in the formation of the Liaison Committee and its charter several years ago, echoed the statements of other stakeholders. He said the charter should be respected and that it had been thoroughly developed to allow members direct and unfettered access to the board.

Before voting on Poulos' motion, O'Connell moved to keep individual members' votes private, only allowing the board to view them. This passed with 3.42 in favor.

Adam Keech, PJM executive director of market operations, addresses stakeholders. | © *RTO Insider*

Ott said PJM would notify members of the charter's stricter enforcement going forward.

"Member actions at PJM's September Members Committee reduced transparency in PJM governance," said Illinois Commerce Commissioner John Rosales, president of the Organization of PJM States Inc., in a statement provided to RTO Insider. "This is an issue which needs examination going forward."

PJM Debuts Web-based Governing Documents

PJM has converted its *OA*, *Tariff* and *Reliability Assurance Agreement* into user-friendly webpages.

On the left side of each page is a sidebar with links to each section in a document, and each page contains hyperlinks to referenced sections and attachments. Every term on a page has a clickable pop-up containing its definition.

There's even a search bar.

The web versions are technically unofficial versions, as PJM changed the formatting and removed redundancies from the official, FERC-approved PDFs to make them more readable.

PJM staff presenting the new pages at the MRC were enthusiastic, and stakeholders expressed gratitude.

The Tariff PDF is a 3,554-page, 58-MB file. Its Table of Contents alone runs for 29 pages.

The PDFs for the OA and RAA are a bit more manageable at 630 and 251 pages, respectively. ■

Company Briefs

PJM: No Reliability Issues from Retiring FES Plants

The retirement of several FirstEnergy Solutions plants will not threaten reliability because of planned upgrades to the transmission system, PJM said Oct. 1.

Bruce Mansfield plant

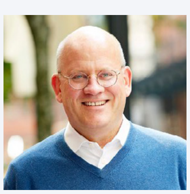
FES said in late August that it would retire its W.H. Sammis and Eastlake plants in Ohio and Bruce Mansfield plant in Pennsylvania by June 2022. That timeline "provides sufficient time for upgrades to be completed," PJM said in announcing that it had completed a 30-day reliability study for the plants. The retirements amount to about 4 GW, and the units are coal-fired, except for a diesel unit at Sammis.

FirstEnergy has been seeking a bailout from the Trump administration for its merchant coal and nuclear plants, contending the impending retirements constitute an emergency. PJM, however, said its system "has adequate power supplies and healthy reserves in operation today, and resources are more diverse than they have ever been."

GE Takes $23B Write-down on Power Biz, Fires CEO

General Electric on Oct. 1 announced it would take a $23 billion non-cash charge on its Power business, causing it to miss its earning expectations for 2018.

"While GE's businesses other than Power are generally performing consistently with previous guidance, due to weaker performance in the GE Power business, the company will fall short of previously indicated guidance for free cash flow and [earnings per share] for 2018," the company said.



Flannery

The company also said it had fired CEO John Flannery after only a year on the job and replaced him with H. Lawrence Culp, a member of the board of directors and former CEO of Danaher. The move is unusual for GE, which is known for the longer-than-average tenures of its CEOs, who have always been hired from within the company.

More: The Washington Post; General Electric

SC Agency: Limit SCE&G Cost Recovery for VC Summer

South Carolina Electric and Gas customers shouldn't have to pay any of the costs the utility incurred after March 12, 2015, in the failed attempt to expand the V.C. Summer Nuclear Station, the South Carolina Office of Regulatory Staff (ORS) argued in testimony it filed with the state's Public Service Commission.

From that date onward, the ORS said, SCE&G knew construction of the two reactors that were to be added to the plant "was delayed by years and would cost billions more than it was telling the Public Service Commission."

In its Sept. 24 filing, the agency said SCE&G's efforts to recover the cost of the failed expansion through its rates should be "permanently ended," and all money it has collected to recover the costs of the expansion since construction on it was halted on July 31, 2017, should be returned to customers.

More: The State

Exelon Removes Last Fuel Rods from Oyster Creek Reactor

Exelon told the Nuclear Regulatory Commission on Sept. 26 that it has removed the last fuel rods from the reactor at its Oyster Creek Generating Station, which it closed on Sept. 17.

| Exelon

The company placed the fuel rods in a pool for spent fuel on the grounds of the Lacey Township, N.J., power plant, where they will cool down for at least two years.

The fuel rods eventually will be placed into sealed concrete casks on the power plant grounds for longer-term storage.

More: The Associated Press

Musk Settles with SEC, Remains Tesla CEO

Tesla CEO Elon Musk on Sept. 29 agreed to pay the U.S. Securities and Exchange Commission a $20 million fine and step down as chairman of the company after he was sued for fraud over a tweet about potentially taking the company public.

The commission had sought to ban Musk from serving as CEO from any publicly traded company, but as part of a settlement reached with regulators, he will remain CEO of Tesla. The company will also separately pay another $20 million and add two new independent members to its board of directors.

Musk and Tesla were not required to admit to any wrongdoing as part of the settlement.

More: The Washington Post

Companies Agree to Continue Plant Vogtle Nuclear Expansion

The four companies with stakes in the Plant Vogtle expansion agreed on Sept. 26 to continue the project, which would add two nuclear reactors to the power plant near Waynesboro, Ga.

The companies — Georgia Power, Oglethorpe Power, the Municipal Electric Authority of Georgia and Dalton Utilities — were required to take a vote on continuing the project after Georgia Power disclosed last month that the cost of the expansion had gone up by another $2.3 billion, bringing its total cost to at least $25 billion, about double what was originally expected.

The companies said they have reached agreements that will limit their financial exposure, but a 8-K filing by Georgia Power indicates that if additional cost overruns on the project exceed $800 million, the company will bear a share of them that is bigger than its ownership share of the project.

More: WABE

Iberdrola to Expand US Renewable Capacity by 50%, CEO Says

Iberdrola CEO Ignacio Galan said Sept. 24 that the Spanish electric utility plans to expand its renewable capacity in the U.S. by about 50% over four years as part of its global plan to reduce carbon emissions.

Galan said Iberdrola expects to spend about $15 billion on its U.S. transmission and distribution system and increase its renewable generation to around 10,000 MW by the end of 2022.

Through its majority-owned Avangrid subsidiary, Iberdrola has more than 6,500 MW of renewable generating capacity in the U.S.

More: Reuters

Dominion Agrees to Sell Merchant Assets for $1.32B

Dominion Energy said Sept. 24 it has agreed to sell two merchant power plants and a stake in a third for $1.32 billion in cash.

Dominion agreed to sell the Fairless Power Station, a 1,240-MW combined-cycle gas turbine in Fairless Hills, Pa., and the Manchester Street Power Station, a 468-MW combined cycle gas turbine in Providence, R.I., to an affiliate of Starwood Energy for $1.23 billion.

The company also agreed to sell its 25% interest in the Catalyst Old River Hydroelectric Limited Partnership, which owns a 192-MW hydroelectric generating station in Louisiana, for $90 million.

More: Dominion Energy ■

Federal Briefs

Energy-related CO2 Emissions Fell 0.9% Last Year

Energy-related CO_2 emissions in the U.S. fell 0.9% last year to 5,142 million metric tons (MMmt) from 5,189 MMmt in 2016, the Energy Information Administration said in a report issued Sept. 25.

The fall came even though the country's real gross domestic product grew 2.3% in 2017, EIA said. The agency attributed the drop to declines in the carbon intensity of the country's energy supply, energy intensity and the economy's overall carbon intensity.

EIA said energy-related CO_2 emissions have fallen in the U.S. in seven out of the past 10 years and were 849 MMmt, or 14%, below 2005 levels in 2017.

More: Energy Information Administration

NYT: EPA to Dissolve Science Advisor Office

EPA plans to dissolve its Office of the Science Advisor, according to a person familiar with its plans who spoke anonymously to The New York Times because the plans haven't been made public.

The science advisor works across EPA to ensure that the highest quality science is integrated into its policies and decisions, according to the agency's website.

In a prepared statement, Science Advisor Jennifer Orme-Zavaleta said dissolving the office would "combine offices with similar functions" and "eliminate redundancies."

More: The New York Times

Dominion: No Delay to Pipeline Work from Court Order

Dominion Energy said Sept. 25 it doesn't expect construction on the Atlantic Coast Pipeline will be delayed by a Sept. 24 order from the 4th U.S. Circuit Court of Appeals that stayed the implementation of a Forest Service permit for the pipeline.

Dominion said the Forest Service permit affects only 20 miles of the pipeline, which will carry natural gas 600 miles from West Virginia to North Carolina, and work on other areas of the pipeline will continue.

The Southern Environmental Law Center asked FERC on Sept. 25 to stop work on the entire pipeline because of the court ruling.

More: Reuters

DOE Releases $5.8M FOA to Improve Grid Resilience, Reliability

The Department of Energy on Sept. 25 released a $5.8 million funding opportunity announcement to support the research and development of advanced tools and controls to improve grid resilience and reliability.

Under the FOA, the department said its Office of Electricity Transmission Reliability Program will seek applications exploring the use of big data, artificial intelligence and machine learning technology and tools to get more out of the sensor data already being collected and used to monitor grid health and support system operations.

DOE said the projects funded will shape the development and application of faster grid analytics and modeling; better grid asset management; and sub-second automatic control actions that will help system operators avoid grid outages, improve operations and cut costs.

More: Department of Energy

Hopi Ask Government to Explore Other Options for Plant

Hopi tribal officials are calling on the federal government to explore other options for the Navajo Generating Station, after two affiliated companies that were considering buying the coal-fired power plant near Page, Ariz., decided it faced too many challenges to purchase.

Without the sale, the 2,250-MW plant could

close at the end of 2019, which would be a huge economic blow to the economies of the Hopi and Navajo tribes. Coal revenue provides about 85% of the Hopi's budget and about 20% of the Navajo's budget.

Hopi Vice Chairman Clark Tenakhongva said the federal government must either continue to buy power from the plant or provide his tribe with the support it needs to avoid an economic catastrophe.

More: The Associated Press

6th Circuit Reverses Coal Ash Clean-up Order to TVA

In a 2-1 decision, a 6th U.S. Circuit Court of Appeals panel on Sept. 24 overturned an order that would have required the Tennessee Valley Authority to dig up and move almost 14 million cubic yards of coal ash at its Gallatin Fossil Plant.

The court said leaks from unlined coal ash pits through groundwater into the Cumberland River are a "major environmental problem" at the power plant, but the Clean Water Act isn't the "proper legal tool of correction" to address it.

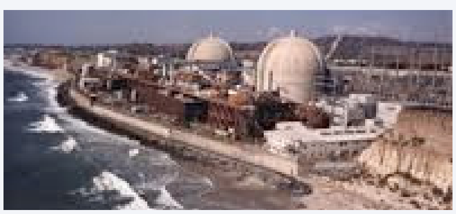
In a dissent, Judge Eric Clay said the ruling lets polluters escape Clean Water Act liability by moving their drainage pipes a few feet from the riverbank and noted two other circuit courts have made opposite rulings.

More: The Associated Press ■

State Briefs

SDG&E Customers to See Savings from SONGS Settlement

San Diego Gas & Electric customers' bills next month will contain a refund and rate reduction because of the settlement reached earlier this year that altered the financial terms surrounding the closing of the San Onofre Nuclear Generating Station.



The company said its typical residential customers will receive an estimated one-time refund of $13.80 and see their monthly charges reduced by about $1.32 on an ongoing basis.

SDG&E owns about 20% of the mothballed power plant.

More: The San Diego Union-Tribune

ILLINOIS

Commerce Commission Issues NOI for EVs' Effect on Grid

The Commerce Commission on Sept. 24 approved a Notice of Inquiry to solicit information and opinions from stakeholders on the roles that electric vehicles can play in grid resilience and energy efficiency.

The commission said the NOI is a follow-up to policy sessions on transportation electrification it held in April and September. Although the NOI is not a rulemaking and is non-decisional in nature, the commission said it may use information gathered through the NOI to initiate a rulemaking.

More: Illinois Commerce Commission

KANSAS

KCC Approves Cutting Westar's Rates, Imposing Demand Charges

The Corporation Commission on Sept. 27 approved a settlement that lowers the bills of average residential Westar Energy customers by about $3.80 per month but also imposes demand charges that could cost residential solar customers $27 to $36 a month.

The settlement, which is between Westar, commission staff, the Citizens' Utility Ratepayer Board and several commercial interests, turned Westar's request for a $17 million rate increase into a $66 million rate reduction. Part of the rate cut stems from an agreement that Westar made to get permission to merge with Kansas City Power & Light to form Evergy.

The Sierra Club, Vote Solar and the Climate and Energy Project continued to fight the settlement after other consumer interests agreed to it, arguing that it discriminates against home solar users.

More: The Wichita Eagle

MASSACHUSETTS

DPU Issues Order Implementing New Solar Payment Program

The Department of Public Utilities on Sept. 26 issued an order approving compensation for owners of new solar projects under the Solar Massachusetts Renewable Target (SMART) program.

The DPU order came a few days after a coalition of solar groups wrote state energy officials, urging them to implement the program, which was supposed to be launched in summer, as soon as possible.

Under the program, investor-owned utilities pay a flat tariff to owners of solar arrays smaller than 5 MW. SMART also offers additional incentives to projects that meet certain policy goals.

More: The Republican

MONTANA

PSC Grants NorthWestern Renewable Purchase Obligation Waiver

The Public Service Commission on Sept. 26 granted NorthWestern Energy's petition for a waiver from its Community Renewable Energy Project (CREP) purchase obligations for two years.

"NorthWestern took all reasonable steps to procure CREP resources in 2015 and 2016, yet documented factors beyond its control prevented NorthWestern from achieving full compliance," the commission said in its order.

Commission Vice Chairman Travis Kavulla and Commissioner Roger Koopman both dissented from the decision, citing NorthWestern's request for proposals process as evidence that it had not taken all reasonable steps to achieve compliance with state law.

More: Public Service Commission

NEVADA

NV Energy: Neutral on Renewable Power Ballot Measure

NV Energy said it is neutral on a ballot measure that would require electric producers to buy or generate 50% of their power from renewable energy by 2030.

The measure, which faces little organized opposition, is expected to pass, but would have to pass again in 2020 to become law, and NV Energy won't say whether it would oppose the measure then.

Supporters of another ballot measure that would end NV Energy's monopoly and allow state residents to pick their own power provider by 2023 predict that if that initiative fails, the utility will spend millions to defeat the renewable measure in 2020.

More: Reno Gazette Journal

NEW JERSEY

PSE&G Proposes 6-Year, $4.1 Billion Clean Energy Program

Public Service Electric and Gas on Sept. 27 filed a proposal with the Board of Public Utilities to spend $4.1 billion over six years on projects and programs that it says would reduce energy consumption and carbon emissions.

The company said its six-year Clean Energy Future program, which includes money for electric vehicle infrastructure, energy storage and smart meters, would increase the monthly bill of a typical residential customer by amounts starting at 50 cents next year and reaching $7 by 2024. Despite that, PSE&G said the program would save its customers $7.4 billion in "lifetime energy costs" by enabling them to reduce their power consumption.

Rate Counsel Director Stefanie Brand and the New Jersey Large Energy Users Coalition were skeptical of the program, saying it would generate hefty guaranteed returns for shareholders while financing programs that best could be provided in the competitive market.

More: The Philadelphia Inquirer

NEW YORK

NYSERDA, Denmark Sign MOU to Share OSW Dev Strategy

The New York State Energy Research and Development Authority and the Danish Ministry of Energy, Utilities and Climate said Sept. 27 they have signed a memorandum of understanding to cooperate in sharing strategies for developing offshore wind energy.

NYSERDA said the MOU recognizes the shared interest the state and Denmark have in developing offshore wind and reflects its commitment to learn from Europe.

NYSERDA said the partnership will build on the foundation of the state's Offshore Wind Master Plan, which was released earlier this year by Gov. Andrew Cuomo, to guide the state's efforts to develop offshore wind.

More: New York State Energy Research And Development Authority

NORTH CAROLINA

Cypress Creek Drops Plans for Solar Farm

Cypress Creek Renewables said Sept. 25 it has dropped its plans to build an 80-MW solar farm in Cool Springs.

The company said it has decided not to take legal action challenging the Iredell County Zoning Board of Adjustment's rejection of its plans for the 400-acre facility in January. A spokesman said the company may consider building a solar farm elsewhere in the county.

More: Statesville Record & Landmark

OHIO

AEP Ohio Files Settlement Detailing Use of Tax Savings

AEP Ohio said Sept. 27 it has filed a settlement with the Public Utilities Commission that outlines what it will do with its $607 million in savings from the Tax Cuts and Jobs Act.

The company said it has passed on $66 million of its savings to its customers through bill reductions since January and will pass on another $263 million through bill reductions over the next six years following PUCO's approval of the settlement.

AEP Ohio said the remaining $278 million will be credited over the next 20 years to the Distribution Investment Rider, which funds improvements to its distribution system.

More: AEP Ohio

OKLAHOMA

PSO Seeks $88 Million Rate Increase, Performance-based Rates

In a Sept. 26 filing, Public Service Company of Oklahoma asked the Corporation Commission to grant it an $88 million rate increase and let it move to performance-based regulation.

The company said the increase, which would amount to $7/month for its typical residential customer, would allow it to recover increased costs related to aging infrastructure, storms, taxes and other necessary business expenses.

PSO said the new rate structure would tie its financial condition to its ability to meet a set of customer-focused performance standards.

More: Public Service Company of Oklahoma

WASHINGTON

Avista-Hydro One Sale Agreement Protects Customers, Expert Says

The agreement governing Avista's proposed sale to Hydro One has safeguards to protect local customers from Canadian government interference and rate hikes if Hydro One experiences financial difficulties, according to written testimony filed with the Utilities and Transportation Commission.

John Reed, an energy and utility consultant hired by Avista and Hydro One to scrutinize their sale agreement, called the safeguards in it "very robust and well in excess of industry norms." Reed said the structure of the board that would run Avista after the sale ensures that the company's decision-making would remain in the Pacific Northwest rather than move to Toronto.

Reed compared provisions in the Avista-Hydro One sale agreement to provisions in agreements from 40 other sales or mergers of U.S. utilities, including 10 that involved Canadian companies.

More: The Spokesman-Review ■

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