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

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Nine States Call for Rules to Boost ZEVs

By Jason Fordney

California and eight other states rolled out a plan Wednesday pushing for wider adoption of policies that would accelerate the use of zero-emission vehicles (ZEVs) and meet greenhouse gas-reduction goals.

The "Multi-State ZEV Action Plan" calls for increased adoption of ZEV purchase and infrastructure incentives, more consumer outreach and heavier emphasis on the technology at state utility commissions. The plan, which covers 2018 to 2021, comes out of a 2013 agreement signed by California, Connecticut, Maryland, Massachusetts, New York, Oregon, Rhode Island and Vermont, which represent almost 30% of new car sales in the U.S., they said.

"Transportation electrification is essential to deliver the deep reductions in emissions that are needed to meet state climate goals. The state ZEV programs, which require automakers to deliver increasing numbers of zero-emission vehicles between now and 2025, are a key strategy in state climate plans," the plan says.

It includes 80 recommendations for states, automakers, dealers, utilities and charging companies in order to bolster plug-in hybrid, battery electric and hydrogen fuel cell vehicles. The new effort follows a similar 2014 multistate plan the coalition said has increased ZEV incentive programs, new education campaigns and new commission initiatives in their states.

With hundreds of millions of fossil fuel-powered vehicles on American roadways,

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Lott, Breaux Join Push for Baker-Schultz CO2 Dividend Plan (p.38)

Western Reliability Margin Thin, WECC Says

By Jason Fordney

Planned additions of renewable generation and storage will not compensate for gas retirements in the Western Interconnection, and any major disruption to gas supply would push the system "to the limit," a new reliability assessment says.

Analysis by the Western Electricity Coordinating Council showed that reserve margins are projected to be tight through 2026, driven by coal and nuclear retirements and increases in power demand. The report forecasts 30% growth in natural gas demand across the interconnection. WECC retained Wood Mackenzie, Environmental Economics and Argonne National Laboratory to undertake the gas-electric interface

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MISO Players Probe Causes of Increasing Emergencies

By Amanda Durish Cook

INDIANAPOLIS — MISO is likely to face an increasing frequency of emergency conditions in the near future, and key officials participating in the RTO's Board Week sought to understand exactly what's behind the development.

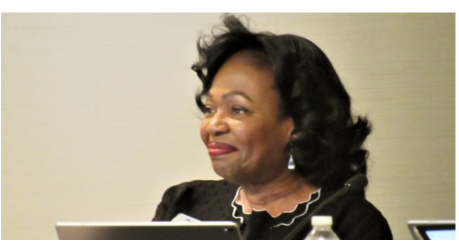
MISO executives, the Board of Directors and the Independent Market Monitor dissected contributing factors like erratic weather, demand response rules and the RTO's reserve margin. They also debated whether solutions could be found in the interconnection queue or capacity auction.

Directors were presented the results of the annual resource adequacy survey produced jointly by the RTO and Organization of MISO States, which predicts adequate reserves through 2019, but less certainty thereafter. Over the next five years, the footprint could see anything from a 7.5-GW surplus to a 4.5-GW shortfall. (See *OMS-MISO Survey Reveals Dimmer View of Future Supply*.)

MISO Executive Director of Resource Planning Patrick Brown said that despite

Continued on page 14

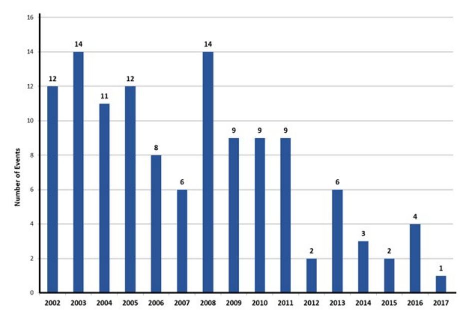
More from MISO Board Week



MISO's Board of Directors last week appointed as its new chair Director Phyllis Currie, the first African-American woman to serve in the position. See p.12. | *© RTO Insider*

- MISO Platform Replacement Risks Delay, Budget Overrun (p.12)
- Supply Sufficiency 'Hot Topic' (p.16)

NERC: Grid Resilience, Reliability Improved in 2017 (p.34)



Bulk power system transmission events resulting in loss of load. Load loss was lower in 2017 than in any year since 2002. | *NERC*

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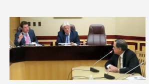

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IN THIS WEEK'S ISSUE

COUNTERFLOW
BY STEVE HUNTOON

Pigs are not Flying

As you may have read, the nuclear industry is promoting a new "study" by the consultancy ICF, purporting to show that failure to bail out nuclear plants would cause widespread blackouts in the Mid-Atlantic region of PJM.[1]

There are glaring fatal flaws. Let me offer just 10 (please email me with stuff I missed):

1. The Nuclear Energy Institute — not ICF — came up with the study assumptions, thus giving us the classic GIGO — garbage in, garbage out — problem. The study admits this: "NEI specified the scenarios for the analysis and the key assumptions for those scenarios" (page 1). So when you read below about all the unrealistic scenarios and assumptions, please keep in mind that they are the self-serving creations of the nuclear industry.

2. The study assumes that all the nuclear units (13 GW) in the PJM Mid-Atlantic region will retire if not bailed out (see App. A). No analysis supports this assumption. It is directly contradicted by PJM's Independent Market Monitor, which has demonstrated, using NEI's own cost data, that all these nuclear units except one cover their going-forward costs.[2] In other words, instead of 13 GW retiring, 1 GW retires.

3. The study assumes that retiring nuclear capacity is not fully replaced by other capacity resources, such that PJM overall suffers a capacity reduction of 10 GW (page 36, going from 152 GW to 142 GW). No analysis supports this assumption. It is directly contradicted by experience with PJM's capacity market, which is designed to, and does, replace retiring capacity with new, more reliable capacity. In the last capacity auction, 67 GW cleared in the PJM Mid-Atlantic region, and there were another 6 GW that offered but didn't clear — meaning they are available at a higher price if, for example, more nuclear units were to retire (which they won't, as discussed in #2 above).[3]

4. The study assumes two gas pipeline incidents happen to occur at the same time, happen to occur during the highest winter demands in history and happen to affect only gas-fired generation (no other pipeline customers), causing the sudden loss of 13 GW of generation, and the outage persists for 60 days. Please note how absurd this scenario is: (a) two incredibly rare incidents happen at the same time; (b) during the highest winter demands in history; (c) only gas-fired generation is curtailed (despite the study's premise that this curtailment is causing power blackouts); and (d) nothing is restored for 60 days (again, despite the study's premise that there are blackouts). There is no legitimate basis for these wild assumptions, or for cobbling them together.

5. The study assumes that all demand response resources fail to perform. No analysis supports this assumption. It is simply buried in a footnote (fn. 22) questioning whether DR would perform, despite enormous penalties for failure to do so.

6. The study assumes that no oil inventories at dual-fuel gas generators could be restocked over a 60-day period. There is a half-hearted effort to support this assumption with statements about how difficult it might be (page 33). Given enormous penalties for failure to perform, generators would move heaven and earth to resume gas delivery and to restock oil inventories. And, of course, if oil inventory levels are problematic, adding a few more oil tanks would be an infinitesimal cost relative to the subsidies demanded by the nuclear industry.

7. The study assumes no gas pipeline expansion projects are built, despite the many projects underway like Transco's Atlantic Sunrise project (1.7 Bcfd) and the PennEast Pipeline (1.1 Bcfd).[4] The study makes an argument that increased pipeline capacity somehow doesn't increase pipeline capacity (pages 34-35).

8. The study implicitly assumes zero capability to transmit electric generation from the western and southern regions of PJM into the Mid-Atlantic region. There are 4 GW of such capability in the summer, and more in the winter when circuit ratings are higher because of lower temperatures.

9. The study implicitly assumes PJM has no tools to mitigate a temporary generation shortfall other than customer outages. No analysis supports this assumption. In a potential emergency, PJM has tools like maximum emergency generation, load management, imports, voluntary conservation and voltage reduction.[5]

10. I saved the best for last. The nuclear industry is claiming that without a bailout there will be hundreds of hours of blackouts. You would think that if this claim had a shred of credibility that customers facing this prospect would be screaming for a nuclear bailout. Instead, *customers are diametrically opposed*.[6] Why? Maybe it's #1 through 9, above.

Let me give you a realistic take on the PJM Mid-Atlantic region. Seventy-three gigawatts offered in the last capacity auction, and there is a conservative 4 GW of transfer capability from western and southern regions of PJM, for a total of 77 GW of resources. The PJM Monitor says 1 GW of nuclear is expected to retire, for 76 GW of resources. Now let's take the totally unrealistic scenario (see #4 above) of suddenly losing 13 GW of gas-fired generation at the worst possible time. That would leave us with 63 GW, 13 GW *more than* ICF's historic peak-hour demand of 50 GW depicted on Figure 6.4 of its study. And that's before considering pipeline expansion projects, PJM's emergency tools, etc.

There are plenty of things in this world to worry about. Blackouts from not bailing out nuclear plants? No, those pigs aren't flying.

[1] https://www.nei.org/CorporateSite/media/filefolder/resources/reports-and-briefs/icf-study-fuel-security-grid-resilience-201806.pdf.

[2] http://monitoringanalytics.com/reports/PJM_State_of_the_Market/2018/2018q1-som-pjm-sec7.pdf (page 324) (Please note that of the four plants shown as uneconomic, Oyster Creek is committed to retire and is no longer included as a potential resource, and the Davis-Besse and Perry plants are not in the PJM Mid-Atlantic region.)

[3] http://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2021-2022/2021-2022-base-residual-auction-report.ashx?la=en (page 15).

[4] A complete list of FERC-approved pipeline expansion projects is here, https://www.ferc.gov/industries/gas/indus-act/pipelines/approved-projects.asp.

[5] See PJM Manual 13, http://pjm.com/-/media/documents/manuals/m13.ashx.

[6] e.g., https://elcon.org/letter-congressman-greg-walden-seeking-oversight-hearing-doe-nopr-grid-resiliency-pricing/; https://states.aarp.org/dont-bamboozled-just-say-no-special-nuclear-subsidies-higher-electric-bills/; https://www.standunited.org/petition/no-nuclear-bailout-for-pennsylvania-nuclear-companies.

Mexican Infrastructure Still Wanting, Insiders Say

By Tom Kleckner

Al Garcia (left) and Alberto Rios chat with Customized Energy Solutions' Andrea Calo. | *© RTO Insider*

HOUSTON — Ordinarily, the power sector would eagerly welcome a coming wave of efficient combined cycle generation, especially when the government has set goals to increase the number of clean energy resources.

But that is not the case in Mexico, where the aging transmission infrastructure is having trouble handling the current generation, let alone what is coming.

"In Mexico, the closer you are to the U.S. border, the greater reliability you have," Al Garcia, an adviser to public and private sector energy companies in Mexico, said earlier this week during a meeting of the International Society for Mexico Energy (ISME).

Garcia said 10 GW of combined cycle generation is expected to come online through 2020, but he noted that is only part of the problem. He said Mexico's ISO, CENACE, which was created as part of the country's electric market restructuring, is still a work in progress.

"It takes more than the engineering side to become an ISO," he said. "You're going to see that in the next few years as the combined cycle units come online."

"The infrastructure is not robust enough in many places, so there are a lot of outages," said Acclaim Energy Advisors' Alberto Rios. "It's a physical obstacle."

Rios joined Garcia for a discussion before ISME, a nonprofit professional organization focused on Mexico's energy sectors. The two shared their insights on the nascent Mexican market with a bilingual audience eager to learn more.

"A new market gives you the ability to pick and choose what you're going to buy, and when," Rios pointed out. "Some generators in the market can sell to suppliers or on the spot market. Right now, the pricing in the spot market is more favorable. Generators are seeing very competitive pricing."

Competitive enough that qualified suppliers can find some contracts under the Federal Electricity Commission's (CFE) transmission retail rates, Rios said. The state-run utility's regulated rates dropped steadily to 6.4 cents/kWh in February, when a new transitory methodology was established. Rates have climbed 41% since to 9 cents/kWh.

"The effective rate methodology does not provide the guidance that the marginal cost of electricity will show up in that tariff," Rios said. "CFE is going to have to recover that cost."

CFE is known to keep its retail rates artificially low and to subsidize its residential consumers by charging the industrials more. To see rising prices in an election year is unusual, Rios said.

"Personally, I thought we would not have had that [increase] before an election," he said.

The market is somewhat leery of frontrunner Andres Manuel Lopez Obrador, a leftist populist who has advocated keeping the country's aging thermal plants online. Noting that 15 GW of new generation is expected to become available during the next president's single six-year term, Garcia said he doesn't expect to see any changes to the country's deregulation.

"I don't think that's going to happen under a left-wing government," he said. "What's going to save them is the influx of new generation. It's going to keep the prices down. They'll be able to say, 'Hey, look at our great policies!'"

Garcia believes Mexico will be long on generation in some regions because of the lack of infrastructure. The government has pushed for new generation, but it has also cited a need for $10 billion in transmission investment. It has two competitive projects out for bids, with more potentially to come. (See *Land Rights a Challenge to Mexico Tx Developers*.)

"Generation shouldn't have a problem in a few years. We'll start having healthier reserve margins once we get through the tough times we're seeing right now," he said. "But this is where [the Ministry of Energy] has to come out and be more proactive. Instead of talking about investment in new power generation, it should talk about challenges of going through private land ownership.

"That's what it should be doing to create sturdier infrastructure on the electric side," Garcia said. "Let the physical constraints work their way through system, and things should start looking better."

Mexico's July 1 election adds uncertainty to the electric market's reforms. | *© RTO Insider*

CAISO NEWS

Calif. Senate Committee Advances CAISO Regionalization Bill

By Jason Fordney

Assemblyman Chris Holden, second from right, discusses AB813 with committee Chairman Ben Hueso, second from left. | *© RTO Insider*

SACRAMENTO, Calif. — A State Senate committee advanced a bill last week that would allow CAISO to be transformed into an RTO, a major change in the electricity market that has been met with heavy opposition.

Sponsored by State Assemblyman Chris Holden (D), AB813 garnered the six necessary votes in the Senate Energy, Utility and Communications Committee to move on to the Judiciary Committee for review. The Assembly approved the bill on June 1, and with Gov. Jerry Brown a strong supporter of regionalization, the bill is likely to get his signature if approved on the Senate floor.

Proponents say the law would help the state export excess renewable energy and create a more efficient regional market, lowering costs.

"This is an opportunity for California to expand our good policies across state borders and to expand upon that," Holden told the committee. The recently amended bill was carried over from last year's session. (See *Calif. Energy Bills Move Forward, but Big Ones Stall*.)

The bill creates a Western States Committee with three representatives from each state with a participating transmission owner, which would provide input on RTO matters that affect more than one state. Left open is the question of whether state voting power would be weighted by electricity load. It also specifically prohibits the creation of a capacity market.

But memories of California's 2000/01 electricity crisis remain strong in the state, and many interests have expressed concerns about increased oversight of the market by the federal government. CAISO is already regulated by FERC, but some worry California would lose control of clean energy goals to the federal government and other states.

Committee member Robert Hertzberg (D) said that he "generally likes the notion of regionalization" but added that "I am very unhappy as to how this bill has proceeded." He said he had many concerns about repeating the mistakes of the electricity crisis and negatively affecting the economy by moving jobs out of the state.

"There is an underlying issue that is legitimate with respect to California jobs," Hertzberg said. "I am deeply concerned across the board."

The bill has a long list of opponents, including labor groups worried about exporting energy-related jobs to other states and environmental groups, such as Sierra Club and Earthjustice, who say the changes will make California subject to imports of fossil-sourced generation. More than 12 California cities, the Port of Oakland, Sacramento Municipal Utility District, the Utility Reform Network and other groups oppose regionalization.

Former FERC Chairman Jon Wellinghoff addressed the committee, attempting to ease fears about the commission's oversight. Wellinghoff said FERC acts independently, pointing out it recently dispensed with the Department of Energy's proposed Grid Resilience Pricing Rule.

"They are really going after PJM … where most of these coal plants reside," he said of the Trump administration's effort to bolster coal.

While the regionalization debate continues, CAISO has proposed bringing its day-ahead energy market to the Western Energy Imbalance Market. That measure would allow more energy trading across the region but does not create a new RTO with new multistate management as envisioned by AB813. (See *CAISO Day-ahead Could be Tailored for the West*.)

Sen. Henry Stern asks former FERC Chairman Jon Wellinghoff about federal jurisdiction over California. | *© RTO Insider*

CAISO Board Approves More CRR Auction Changes

By Jason Fordney

CAISO's Board of Governors on Thursday approved controversial revisions to the ISO's congestion revenue rights auction to address what some stakeholders contend are inequitable results and shortfalls for electricity consumers stemming from the CRR process.

The five-member board unanimously approved a second round of changes to the CRR auction, long a subject of controversy over what the ISO's Department of Marking Monitoring has called out as consistently unfair outcomes to electricity ratepayers who have been require to foot about $100 million per year to make up for auction revenue shortfalls since the auctions began in 2012.

The new changes, known as "Track 1B," focus on the revenue adequacy issue. The board in March had approved the "1A" package of changes focused on auction efficiency, which are now under review at FERC. (See *CAISO Moves Ahead With Market Changes*.) CAISO wants to implement both proposals in time for the 2019 CRR auction in fall of that year.

CAISO CEO Steve Berberich noted that the board had called a special meeting to approve the changes, saying it "clearly shows the importance to all of us."

The 1B changes alter the current process in which all revenue inadequacy is allocated to measured demand, which includes electricity load and exports. That process does not consider the location of constraints on the system and creates an incentive to profit from differences between the CRR auction model and the day-ahead market model, according to Greg Cook, CAISO executive director of market and infrastructure policy, who presented the ISO's findings to the board.

Under the new partial funding model, revenue inadequacy will be allocated to CRR holders in proportion to their flow over each constraint. Holders will receive day-ahead market payments aligned with available transmission capacity, which should result in a more equitable allocation on a locational basis.

A second component of the changes reduces the amount of system capacity released in the annual process from 75% to 65%. This will provide greater assurance that CRRs obtained in the annual process will be feasible in the monthly process and will reduce the amount of payment reductions resulting from revenue inadequacy charges, CAISO Vice President of Market and Infrastructure Development Keith Casey said in a memo to the board.

The DMM, the publicly owned Six Cities utilities of Southern California and the California Public Utilities Commission support the changes. Other parties said they go too far and that the impact of previous changes should be considered first.

The ISO will provide information on the outcome of the changes in its market reports to help ensure transparency, Cook said. The changes had received resistance from financial traders who argue the current structure allows for legitimate hedging activity. (See *CAISO Developing New CRR Proposal*.)

CAISO NEWS

CPUC Denies Gas Pipeline, Inquires About Others

By Jason Fordney

The California Public Utilities Commission on Thursday denied a request to build a new natural gas pipeline after questioning Southern California Gas about why other major pipelines have been sitting out of service.

The commission rejected an application by San Diego Gas & Electric and SoCalGas to build a $639 million pipeline that would have stretched from Rainbow Station to Miramar, replacing the current Line 1600 built in 1949.

"The CPUC determined that the utilities' most recent natural gas supply forecast and the CPUC's reliability standard for gas planning do not demonstrate that there is a need for the proposed pipeline," the commission said as it approved its proposed decision.

The commission directed SDG&E and SoCalGas to pursue other supply options for smaller amounts and for shorter periods of time than would have been provided by the proposed pipeline near San Diego. It also directed the utilities to ensure the safe continuing operation of Line 1600.

The applicants had said the sole purpose of the line was not to meet any short-term supply deficits but for emergency situations such as unplanned outages on Line 3010 or at the Moreno substation. They had also proposed derating Line 1600 from transmission service to distribution service.

The commission last week asked SoCalGas why it had not restored to service two pipelines, Line 3000 and Line 235-2. Line 3000 went out of service on July 29, 2016, and Line 235-2 ruptured and exploded on Oct. 1, 2017.

"Though such outages are to be expected periodically, the significant volumes associated with these facilities and the fact they have been out for lengthy periods during peak demand periods — nearly two years for one and over eight months for another — are causes for concern," CPUC Energy Division Director Edward Randolph told SoCalGas President Bret Lane in a June 18 letter. Randolph questioned whether rates should be reduced if the lines are not providing benefits to ratepayers.

The Energy Division also issued a new report that cited the pipeline outages as a main reason it is recommending an increase in the allowed storage level at the Aliso Canyon facility from 24.6 Bcf to 34 Bcf. Comments on the proposal were due Monday.

Last month, the commission allowed SoCalGas to increase gas injections into Aliso Canyon but denied a request to increase the allowable capacity. (See *CPUC OKs Temporary Increase in Aliso Canyon Injections*.)

Montana PSC's Kavulla Named to EIM Body

The leadership of CAISO's Western Energy Imbalance Market on Thursday confirmed a new member and made other changes as Chairman Douglas Howe prepares to leave the body at the end of this month.

The EIM's Governing Body approved a nominating committee's selection of Montana Public Service Commission Vice Chairman Travis Kavulla to replace Howe as a member effective July 1, for a three-year term. The body named current member Valerie Fong as chair, and renominated current member Carl Linvill as vice chair, both effective for one year. Linvill was also approved for a second three-year term.

Kavulla is the first new member named to the body since the original members were selected in June 2016 to oversee the regional energy trading market. The other two members of the body are John Prescott and Kristine Schmidt, whose terms end in 2019 and 2020, respectively.

— Jason Fordney

CAISO NEWS

FERC Partially Approves CAISO Commitment Costs Enhancements

By Michael Brooks

The 3-MW New Hogan Dam in Calaveras County, Calif. Small hydro facilities such as Hogan are automatically classified by CAISO as use-limited resources. | *U.S. Army Corps of Engineers*

Use-limited resources will be allowed to attach opportunity cost adders to their bids in CAISO's energy market under a proposal approved by FERC on Thursday.

The change was the only significant part of a package of Tariff changes — proposed in March in phase 3 of CAISO's Commitment Costs Enhancements initiative — that the commission approved (ER18-1169). FERC rejected the ISO's proposals to alter the information generators are required to submit to its Master File (a database of all resources participating in its markets and their characteristics) and to remove all ramp rates as components of daily bids.

The initiative is separate from, but related to, CAISO's Commitment Costs and Default Energy Bid Enhancements; both involve better reflecting resources' costs in their offers, thus improving market efficiency.

Use-limited resources are those that have limits on the number of start-ups and runtime hours, or on energy output, over a certain period. Small hydro facilities, for example, are automatically classified as use-limited resources by CAISO, while other resources must submit a request that includes certain data to be classified.

But because the ISO's market optimization software makes unit commitment decisions only one day ahead, it cannot take into account that dispatching a use-limited resource may hinder its ability to run later. As a result, the resources' opportunity costs are not reflected in their offers.

CAISO said the changes are necessary because of the increase of variable energy resources on its system, making supply more unpredictable and use-limited resources necessary at any given time.

The opportunity cost adder that FERC approved "will capture the value of a use-limited resource's limited availability so that the use limitation is not reached until the end of the monthly or annual use limitation period and the resource may be dispatched when it is valued most," it said.

As part of the changes, effective Nov. 1, CAISO will all but eliminate one of the two methodologies under which use-limited resources are able to bid — the registered cost method. Under that approach, resources can elect to submit fixed commitment costs on a 30-day basis. CAISO told the commission that most use-limited resources use this method because it better reflects their opportunity costs and limitations, but because the costs are fixed, it cannot reflect variables such as the daily fluctuations of natural gas prices.

Use-limited resources will be required to use the proxy cost method, in which resources submit bids based on their start-up, minimum load and transition costs at a 125% cap. Resources less than a year old may still employ registered costs because, CAISO said, it needs a sufficient price history to calculate the adder.

"We find that the proposal is an improvement over the existing commitment cost recovery mechanism because the market optimization tool will be able to dispatch use-limited resources when they are most needed," FERC said.

However, FERC agreed with NRG Energy's protest of CAISO's method for calculating opportunity costs. The commission ordered CAISO to submit within 30 days more details on its calculations as part of its Tariff revisions; the ISO had proposed to include them in its business practice manual.

The Master File

FERC rejected CAISO's proposal to replace resources' listed physical characteristics in the Master File with "design capability values," information that reflects their capabilities when operating at maximum sustainable performance over a minimum run time. The ISO also proposed to allow scheduling coordinators to register "market values," such as maximum daily start-ups, maximum daily number of transitions, operational ramp rates, operating reserve ramp rates and regulation ramp rates. CAISO said this would allow the market to consider, for example, that "a resource may be designed to start up five times a day, but starting it up more than twice a day could dramatically increase wear and tear and increase the probability of catastrophic failure."

"We are concerned that, outside of exceptional dispatch, CAISO's proposal does not include a mechanism to ensure that market values cannot be used to undermine the market's economic resource dispatch when transmission constraints or other supply limitations create opportunities for the exercise of market power," FERC said.

Using the market values instead of the design capability values may reduce available capacity, the commission said. "Permitting market participants to make less capacity available to the market raises the potential for physical withholding, which can affect dispatch and increase energy and ancillary service prices that may benefit the market participants' affiliated resources. At times of tight supply conditions, it is more likely that withholding capacity could be a profitable action." FERC also noted that CAISO proposed no new market mitigation measures to address this concern, and that its existing measures would be insufficient to handle the change.

Because CAISO predicated its proposal to remove ramp rates from daily bids on the changes to the Master File, FERC summarily rejected this as well. "If we were to accept the ramp rate proposal and reject the Master File proposal, scheduling coordinators would lose the flexibility currently afforded to them by the existing daily bid-in ramp rate functionality," it said.

CAISO NEWS

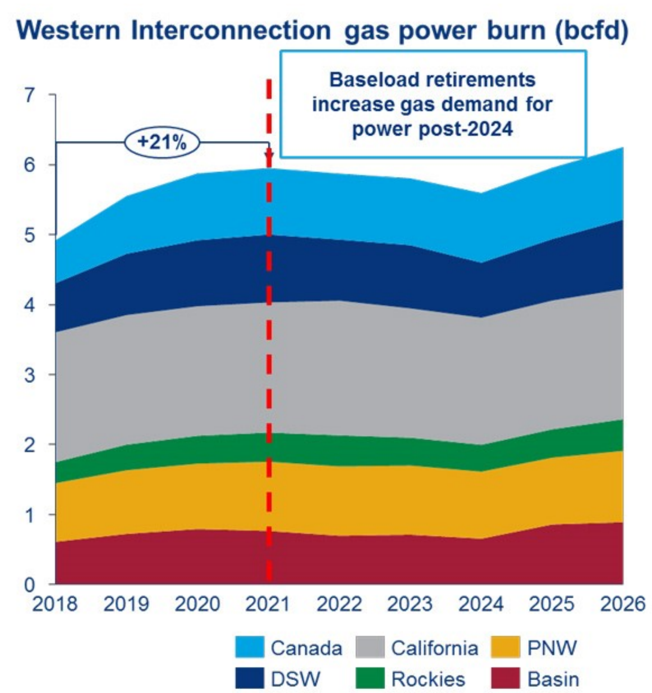
Western Reliability Margin Thin, WECC Says

Continued from page 1

study.

"We are now effectively in an N-1 scenario with any major disruptions in the gas transmission system or the Bulk Power System pushing the system to the limit," WECC said. The Salt Lake City-based organization is the NERC-certified Regional Entity for the West.

Restrictions at the Aliso Canyon gas field near Los Angeles — a facility that many want to shut down after a massive gas leak three years ago — have created a situation in which the failure of another large component on the grid could lead to reliability problems. The heavier penetration of renewables will increase reliance on natural gas for system peaks, and the amount of renewable generation needed to meet current state policy goals is not sufficient to entirely offset the loss of roughly 12,000 MW of baseload generation.



| WECC

The study assumes retirements of about 9 GW of coal and 2 GW of nuclear by 2026 across the West, including major baseload plants in California, the Pacific Northwest and the Desert Southwest, and 9 GW of wind additions to reach 29 GW of total wind. Solar capacity is projected to double to 36 GW, with 18 GW added in California. Total load in the interconnection is project to grow by 7% by 2026.

The report recommends improved regional coordination, including planning exercises, and more transparency around firm gas supply contracts and the power plants they serve. It also suggests designation of specific plants as critical to core reliability, and that there be more clarity around interstate gas curtailment protocols.

While historical natural gas resources have been sufficient, events over the past few years have tightened supply, including outages of Southern California Gas pipelines, a colder winter in 2018 and restrictions at Aliso Canyon. Other factors likely to drive up gas usage are the 2024 retirement of the Diablo Canyon nuclear plant and coal retirements in the Southwest and Northwest.

The CAISO Department of Market Monitoring recently said that tight gas supplies in Southern California drove up wholesale prices by 25% last year. SoCalGas recently told *RTO Insider* there is no timetable to bring back Line 235-2 in Southern California, which suffered a rupture last October, despite its status as a backbone facility and extreme price spikes of up to $12/MMBtu. (See *Gas Costs Drive Sharp Gain in CAISO 2017 Prices*.) CAISO has also warned of tight electric reserve margins because of gas supply constraints. (See *CAISO Board Approves Forecast Error Measures*.)

"Among other things, the report highlights a critical need to focus on better gas-electric coordination between the two sectors but also deploy a combination of solutions to ensure Western Interconnection system reliability," WECC Vice President of Reliability Planning Melanie Frye said in a written statement.

The report said the region must have "broader conversations" about ensuring that critical power plants have fuel, improving regional coordination around gas supply contingencies and better forecasting, as well as improved response by local distribution companies to curtailments.

FERC Grants SDG&E Financial Waiver on Storage Project

FERC on Thursday granted San Diego Gas & Electric a waiver allowing it to continue the CAISO interconnection study process for its proposed Top Gun Energy Storage project without having to post financial security to itself.

In its June 21 order (ER18-1360), the commission said it found that SDG&E acted in good faith, that the waiver request was of limited scope and addressed a concrete problem, and that granting it would have no undesirable consequences.

Because the utility is both the primary transmission owner (PTO) and the interconnection customer, the commission found it unnecessary for it to post financial security to protect itself from the risk of the project being abandoned after associated network upgrades have been undertaken.

For SDG&E to perform accounting entries to move money from one intracompany account to another intracompany account "in this case serves no useful purpose," the commission said.

— Michael Kuser

ERCOT News

Monitor Garza Offers Glimpse of ERCOT in 2018

By Tom Kleckner

HOUSTON — While sharing her organization's report on the state of the ERCOT market in 2017 last week, Potomac Economics' Beth Garza was naturally asked her forecast of this summer's energy prices.

Beth Garza | *© RTO Insider*

"My title is not market predictor. It's market monitor," Garza, director of ERCOT's Independent Market Monitor, reminded her audience June 21. "I get to watch and opine. I'm sorry to disappoint you."

Speaking to those gathered at the Gulf Coast Power Association's lunch in Houston, Garza shared highlights from the State of the Market report. Energy insiders listened attentively as she reviewed 2017 data — and even more so on the rare occasions Garza looked ahead to 2018.

Garza said reserve margins will be tighter this summer than last year, primarily because of the retirement of 4.2 GW of coal generation over the last 12 months. That dropped ERCOT's planning reserve margin from 18.9% to 9.3% — since increased to 11% — and raised fears of potential shortages during a long, hot summer. (See *ERCOT Gains Additional Capacity to Meet Summer Demand*.) On Friday, as the system flirted with June's demand record of 67.8 GW, the ISO still had more than 3.5 GW of operating reserves.

"We had an interesting test of the system in May," Garza said, referring to the multiple demand records ERCOT set for the month in the face of above-normal temperatures. "But as others have said, a hot May does not necessarily portend a hot summer."

Statewide temperatures have dropped since then, thanks to recent torrential rains. That has also dampened forward prices, which have settled at about $150/MWh after soaring above $250/MWh in May.

"Is that a reaction to the rain and the temperatures?" Garza asked. "We got through May, but the rest of June has not been severe."

Garza allowed herself some prognostication in addressing the forward prices.

"I can look at future prices and infer an estimate of how many hours of real-time prices at the 9,000/MWh cap we'll see," she said, noting ERCOT saw only 3.5 hours of prices above $1,000/MWh last year. Garza recalled a straw poll of attendees at the recent GCPA spring conference, with expectations of five to 10 hours at the $9,000/MWh cap this year.

"That's what the future pricing seems to indicate, but that's based on a $200 price. I haven't done the math on $150 prices," Garza said. "If we have 2 GW of wind generation on peak, it'll be a high-priced day. If we have 10 GW of wind generation on peak, it'll be a moderately priced day."

Garza also put in a plug for the addition of real-time co-optimization in the market, one of six recommendations the Monitor has made in each of its last few reports and one of several market improvements being considered by the Public Utility Commission of Texas. (See "Monitor Says Wholesale Market 'Performed Competitively' in 2017," *ERCOT Briefs*.)

"It's the key missing link in our market," she said. "Our market is dependent on pricing during significant scarcity intervals. My fear is that as we get to where we see tight reserve margins, the likelihood of scarcity events and high prices increase, because of the ineffective allocation of reserves. If they were allocated differently [through real-time co-optimization], we wouldn't see those high prices."

ISO-NE News

FERC Probes Salem Harbor for Cheating

By Michael Kuser

FERC last week ordered Footprint Power to refute a finding that the company violated ISO-NE Tariff rules and federal regulations by filing "false and misleading supply offers" for its Salem Harbor plant in June and July 2013.

Footprint has 30 days from the June 18 order to show why it should not forfeit $2,049,571 in capacity supply obligation (CSO) payments for a period in which FERC's Office of Enforcement staff found that Unit 4 at the plant could not provide capacity. The company must also demonstrate why it should not be assessed $4.2 million in civil penalties.

Enforcement staff allege Footprint submitted supply offers that Unit 4 could not satisfy because Salem Harbor lacked usable fuel. Staff found the company not only failed to report the lack of fuel to the RTO but also "omitted material information from and/or misrepresented the fuel status of Salem Harbor and related operational status of Unit 4."

Background

Footprint bought Salem Harbor, a 748-MW coal- and oil-fired plant with four units, from Dominion Resources Services in 2012. Two units at the plant had been retired in 2011, while Units 3 and 4 were operational at the time of purchase. Both units had a CSO for ISO-NE's Forward Capacity Auction 3 (capacity commitment period June 2012 through May 2013) and FCA 4 (June 2013 through May 2014).

However, Units 3 and 4 were scheduled to retire effective June 1, 2014, coincident with the start of the FCA 5 capacity commitment period. Unit 3 was primarily a coal-fired unit and Unit 4 was a 437-MW oil-fired unit.

The units have since been demolished, and Footprint is now converting the plant to a 674-MW gas-fired, quick-start, combined cycle generator, which is expected to go into service by the end of the year. (See "Future Locational Reserve Needs," *ISO-NE Planning Advisory Committee Briefs: June 13, 2018*.)

The RTO had rejected earlier delist bids to retire Unit 4 during FCAs 3 and 4, citing reliability needs. In exchange for keeping the unit online and available, "Dominion was not paid the prorated capacity auction clearing floor prices in FCAs 3 and 4, but instead received the unit's cost of service — which was approximately double the amount received by other ISO-NE capacity resources," the commission noted.

Footprint subsequently collected CSO payments in the same amount awarded to Salem Harbor when Dominion owned the plant, which totaled about $4.4 million from June to July 2013.

At the time, Salem Harbor had only one fuel storage tank that could hold roughly 200,000 barrels (bbl) of oil used to supply Unit 4. However, Footprint had also sold most of Salem Harbor's fuel inventory back to Dominion, leaving only 40,000 bbl on site by December 2012, an amount the plant staff believed was less than two days' worth of fuel.

Enforcement staff alleged that because Unit 4 burned between 14,000 and 16,000 bbl of fuel per day when operating, the plant's managers were aware the remaining 40,000 bbl would not last longer than two days because only 29,000 bbl could be physically accessed from the tank.

'Feasible' Defense

ISO-NE's internal Market Monitor alerted the commission to Salem Harbor Unit 4's repeated inability to meet its CSO, also alleging "that false or misleading day-ahead supply offers and verbal communications were made to ISO-NE regarding Unit 4's availability."

In 2015, FERC staff and Footprint counsel discussed staff's preliminary findings and Footprint's claim that staff relied on assumptions rather than data to calculate Salem Harbor's usable fuel inventory. Footprint claimed staff used the wrong data in its investigation, but "even after staff used the data source proffered by Footprint, use of that data source did not materially impact staff's calculations," the commission said.

In response, Footprint claimed Unit 4's offers were "feasible" because it did not have to operate in accordance with its CSO because of certain environmental limitations on nitrogen oxide emissions.

In February 2018, after Footprint and staff had the opportunity to discuss the settlement, staff issued a letter providing notice of staff's intent to recommend the commission initiate a public proceeding against the company.

Footprint submitted its response on March 12, 2018. "Although staff narrowed the set of violations pursued in light of the additional information it received ... staff still concluded that the majority of Footprint's arguments were not supported by the evidence and did not alter staff's views that violations occurred," the commission said.

MISO NEWS

MISO Board Selects Currie as New Chair

By Amanda Durish Cook

INDIANAPOLIS — MISO's Board of Directors last week appointed Director Phyllis Currie to serve as its chair, replacing current Chairman Michael Curran.

Phyllis Currie | © RTO Insider

The board voted unanimously to appoint Currie at its June 21 meeting after discussing her credentials and nomination in closed session a day earlier. As a rule, MISO considers all personnel-related matters to be confidential.

Currie is the second woman and first African-American woman to chair MISO's board since it was established in 1998.

Former Director Judy Walsh was the first woman to chair the board during her tenure from January 2016 to December 2017.

"I hope that I will perform in a manner that will bring continued pride in the MISO community," Currie said upon accepting the position during a June 21 board meeting.

"I will be immediately instructing you on the Philadelphia sense of humor, and you can have my watch," Curran joked.

Currie is one of three directors whose three-year term concludes at the end of this year. Along with Mark Johnson, she will be up for re-election for a second term. Curran will reach MISO's three, three-year term limit at the end of 2018 and is not able to seek re-election.

Director Baljit Dail reported that the RTO's Nominating Committee will begin vetting and interviewing candidates for the board starting in August.

MISO Expects Year-end Budget Overrun

MISO expects to end the year about 1% over its operating budget, the board heard. Chief Financial Officer Melissa Brown said the RTO is forecasting $267 million in spending this year, about $2 million more than its total budget.

Brown said the overrun would stem from spending on computer maintenance and reclassifying some outlays from its capital budget to its operating budget. MISO also expects to spend just $25.6 million of its $29.6 million capital budget by the end of 2018.

Year to date, MISO has spent $108 million of its $109 million operating budget and $11.4 million of its $15 million capital expense budget. Brown attributed the underspending mainly to delayed investment timing in the operating budget and delayed and decreased technology spending in the capital budget.

MISO Platform Replacement Risks Delay, Budget Overrun

By Amanda Durish Cook

INDIANAPOLIS — MISO's multiyear effort to replace its market platform will likely come in slightly over budget and is at risk of delay because of project snags with vendor General Electric, the RTO's Board of Directors learned this week.

MISO now expects it will fully migrate to the new modular market platform by 2024, about a year later than it initially projected in 2017. The project's cost is predicted to increase from $130 million to just under $134 million. (See *MISO Makes Case for $130M Market Platform Upgrade*.)

The platform replacement was discussed in multiple committee meetings during MISO Board Week.

Todd Ramey, MISO vice president of market system enhancements, said current platform vendor General Electric reported a "significant increase in the work requirement" in early May. Kevin Caringer, executive director of MISO's IT team, said the RTO recently determined that GE was "too optimistic" in its original timeline, especially concerning estimates on the complex software needed to clear the day-ahead market. He acknowledged that GE got off to a "slow start" in recruiting and hiring staff for the project in 2017 and estimated the company is about five or six months behind schedule.

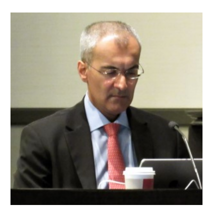
"We did express our disappointment" in response to GE's proposed timeline, Caringer said, adding that MISO is working with PJM and ISO-NE to consider a counterproposal to GE's timeline. The modular platform's design is being jointly developed with those RTOs, which also use GE-designed platforms. (See *MISO Sets Target for Market Platform Upgrade Decision*.)

Although MISO executives said the RTO will likely have to adjust timelines for the remainder of the project, they maintain the overall replacement effort remains "generally on target."

Sunk Costs

A separate third-party vendor was this year expected to deliver a development and testing platform to evaluate new components from GE. MISO now says that plan "is at risk of minor delays beyond July 31 due to vendor negotiations and lead time needed."

Caringer said he thought MISO could meet its self-imposed 2018 deadline on the testing platform, but he added the RTO "used up a lot of [its timeline] flexibility in negotiations" with the third-party vendor.



Baljit Dail | © RTO Insider

Director Baljit Dail pointed out that MISO's original $130 million budget provides for an additional 20% in contingency funds for unforeseen expenses.

"In the event that things happen — like they're happening now — we have that buffer," Dail said.

Director Theresa Wise asked how much in sunk costs MISO would risk if it decided to switch vendors at this point. Executives estimated the RTO has so far spent $2 million to $3 million with GE on developing

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MISO Platform Replacement Risks Delay, Budget Overrun

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the platform.

Soon after the question, MISO lawyers said that any discussion on alternative plans should be saved for closed session. Multiple directors responded that they would reserve more specific questions about vendor performance for a closed meeting.

Dail later reported that the board had a robust, nonpublic discussion on GE's performance.

"General Electric's woes are being well publicized; they've recently dropped out of the Dow Jones. We need to send a strong message to GE and its management because they are critical in this path. … I think we're all very concerned, and I think we need to send a strong message that they need to step up their game," Dail said during a June 21 board meeting.

"Could you convey at least one director's disappointment … in the primary vendor?" Director Thomas Rainwater asked MISO executives during the same meeting.

Board Chairman Michael Curran said the situation was not unlike the adjustments made while developing transmission projects.

"You think you can understand what that vendor can do, you think you have a plan, but once you break ground, shifts may occur. They're a natural part of the process, and we look forward to you managing it well," Curran told executives at the end of the week.

MISO reported it is ahead of schedule on at least one aspect of the platform replacement: the hiring of extra staff for the project is occurring earlier than expected.

Caringer explained that the board previously expressed concern that skill shortages might cause delays in hiring technical talent. "While this risk is real, MISO has been able to attract the right skills so far, although this will continue to be a challenge."

Limited Improvements for Old Platform

MISO reported again that its existing platform and new FERC directives are restricting which market improvements it can undertake.

Thomas Rainwater (left) and Michael Curran | © RTO Insider

Executive Director of Market Development Jeff Bladen said about a third of projects under the RTO's Market Roadmap cannot be implemented because the existing market platform cannot manage the complexity required for the improvements.

However, MISO said it would complete at least two projects on its legacy computer system: 1) the creation of a short capacity reserve market by early 2020 that can deliver reserves within 30 minutes (a Market Roadmap item); and 2) compulsory compliance with FERC Order 841 to create a participation model for energy storage by late 2019.

MISO said other market system-dependent changes on the Market Roadmap will be deferred until the new platform can accommodate them. The deferral includes the plan to create a more sophisticated model that can mimic different combinations of combined cycle units and their dependencies. The project had previously been planned for implementation on the legacy system.

Bladen also explained MISO is not currently planning to implement an integration model for distributed energy resources on the legacy system. He said staff have been in contact with FERC since an April technical conference to explain that the RTO's footprint doesn't contain enough growth in DERs to warrant a significant rule change just yet. MISO will be able to transition technology platforms before the need for DER rules emerges, he said.

Dail thanked MISO for the analysis. "This is a very, very complex needle that we're trying to thread," he said of undertaking improvements as the platform replacement unfolds.

"It's almost like there's a new criteria [for market projects]: impacts to the legacy platform," Curran said.

MISO President Clair Moeller agreed that it is a balancing act to select market design improvements while not "distracting from the market system enhancement."

Meeting with Members' CIOs

MISO has also begun holding biannual nonpublic meetings with member companies' chief information officers to discuss cybersecurity, NERC critical infrastructure protection and adaptation to the new platform, among other technology issues.

MISO Chief Information Officer Keri Glitch said CIOs and chief information security officers from nine member companies attended a second meeting in St. Paul, Minn., in mid-May.

Glitch said MISO will hold another meeting of the group, now called the CIO/CISO Technology and Security Advisory Council, in St. Louis sometime in November.

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MISO Players Probe Causes of Increasing Emergencies

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flat load growth, resource retirements and increased forced outages continue to drive up the planning reserve margin, which increased year over year from 15.8% to 17.1%.

Forced outages in MISO South are nearing 14%, compared with about 8% at the time Entergy was integrated in 2013. Brown said the outages will eventually abate as new capacity resources replace retiring generation.

"However, this new capacity will require time and transmission," Brown said during a June 12 conference call of the board's System Planning Committee ahead of the quarterly Board Week.

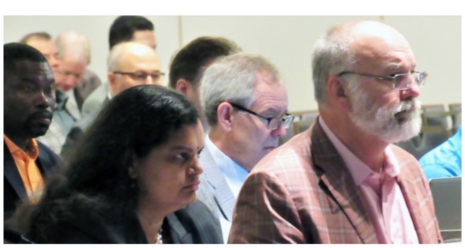
At a June 19 meeting of the board's Markets Committee, Director Baljit Dail asked if MISO could simply discount the planning reserve margin to shave the probability of emergencies.

RTO President Clair Moeller responded that MISO is currently reconsidering its planning reserve margin altogether as emergencies become more likely in shoulder months.

"The question we're trying to ask is, 'How do we evaluate risk every hour of the year instead of those four to five days across summer peak?'" Moeller said. MISO has said its analysis shows that peaks will soon occur during any hour of the year, rather than simply during an annual predicted system peak period.

Queue to the Rescue?

New generation could boost MISO's resource adequacy, with the RTO possibly seeing as much as 11.4 GW of new generation come online by 2023. Wind generation interconnection requests should taper off as production tax credits expire in 2020, but solar requests should rise as the cost of panels come down, according to Brown.


Renuka Chatterjee (left) and Clair Moeller | © RTO Insider


| © RTO Insider

But a record interconnection queue could impede development of new generation. And while stakeholders typically blame MISO's lengthy study process for queue delays, Brown said the "true bottleneck" can be found in the physical limitations of the RTO's transmission system.

Brown said MISO requires billions of dollars in transmission upgrades to support the 93 GW of generation currently in its queue, something particularly true of the nearly 200 proposed projects in MISO's West region (including the Dakotas, Minnesota, Iowa and part of Wisconsin), where proposed projects can become uneconomic when the costs of new transmission to support them are factored in.

MISO Vice President of System Planning Jennifer Curran said the RTO is also evaluating expanded use of bidirectional HVDC technology to manage the changing fleet and make the grid more interconnected with other RTOs.

Monitor: PRA Should Take Share of Blame

However, Monitor David Patton said he partly blames the increasingly tighter operating conditions on the annual Planning Resource Auction, which he thinks is discouraging construction of new generation. He called the recent $10/MW-day clearing price "near zero." (See *MISO Clears at $10/MW-day in 2018/19 Capacity Auction*.)

"Our markets are telling us not to build anything," Patton said. "This is why our competitive suppliers are doing whatever they can to export to PJM." He again urged MISO to adopt a sloped demand curve in its capacity auction.

"This is the first I'm hearing that the market is not sending the right price signal," Director Michael Curran joked, feigning shock to a roomful of laughter. "The price signal is the price signal, but there's more than 90 GW sitting in the queue," he added.

Patton said he remains unconvinced that all the proposed generation in the queue will come online.

"It's very expensive to let lower-cost generation retire and be replaced with more expensive new generation," he added.

Patton also said new natural gas generation set to come online in MISO South won't really benefit MISO Midwest because it will be trapped behind the transfer constraint along SPP's transmission link between the regions.

He also predicted that the larger amounts of DR cleared in this year's auction will lead the RTO to call emergency alerts earlier and then possibly cancel them, as occurred during a mid-May near emergency. He also remains concerned that states won't take sufficient measures to guarantee resource adequacy.

Dail, asked if the situation was really that dire.

"If it's harder for you to sleep at night, then my mission is accomplished," Patton responded.

Volatile Spring

MISO's average load was 72.2 GW this spring, compared with 69 GW a year earlier, and staff attributed the uptick to volatile conditions that saw April temperatures well below normal and May well above. The RTO hit a 111.6-GW systemwide peak on May 29, compared to last spring's 92-GW

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spring peak on May 16.

"April was much colder than normal, and we flipped a switch in May to much hotter than normal. ... We skipped over spring," said MISO Executive Director of Market Operations Shawn McFarlane. Compared to the last spring, average load increased about 5% for the quarter, and peak load increased a "pretty incredible 20%, with a few other days approaching similar levels," McFarlane said.

"This quarter was bizarre," agreed Patton. "On May 29, temperatures in Minneapolis hit 100 degrees."

Patton said high temperatures that day forced the RTO to derate transmission and contributed to a local transmission emergency in the central portion of MISO Midwest. He praised RTO operators for successfully managing the transmission emergency.

"We had 15 straight days of heat in May. That will impact day-to-day operations," said MISO Executive Director of System Operations Renuka Chatterjee.

However, energy prices were down about 3% from last spring, averaging $29/MWh. MISO credited the lower prices to fewer instances of congestion and lower natural gas costs compared to last spring. The RTO also set a 15.6-GW wind peak on March 31, breaking the previous Jan. 17 wind output record of 15 GW. Spring maintenance season brought 29 GW in outages, in line with usual seasonal trends, it said.

The unusually warm May (the hottest in MISO's history) yielded an emergency alert declaration on May 11 (a Friday) for conditions projected for May 14 (a Monday). The RTO ultimately retracted the warning on May 13 as forecasts changed and later asked stakeholders if they preferred the earlier warning. (See [MISO Mulls Additional Emergency Communication](#).)

McFarlane said MISO issued the alert "out of an abundance of caution."

Curran asked if load-modifying resources (LMRs) were equipped to respond in that instance.

The LMRs reported they could have furnished about 750 MW had an actual emergency been declared, said Rob Benbow, MISO senior director of systemwide operations. McFarlane reminded the board that LMRs are only required to respond to summer emergencies. May's near emergency would have fallen outside the required months.

In response to the high spring temperatures, McFarlane said MISO is now exploring the possibility of revising its seasonal forecast model from one that switches over based solely on the calendar to one that also considers weather forecasts one to two weeks out.

MISO predicts above-normal temperatures will continue into summer, especially for MISO South, leading to a higher peak load. The RTO now predicts a 121.7-GW peak load, about 1 GW above last summer's peak. It also forecasts an 80% chance of deploying emergency resources this summer. (See [MISO: Summer Reserves Adequate, but Emergency Likely](#).)

But calling up DR resources takes careful planning, RTO officials said.

"Many of them have an eight-hour lead time, so you have to see the emergency yesterday," Moeller said.

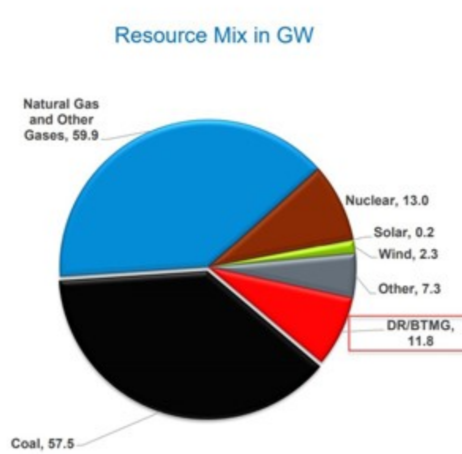
Staff have signaled that the RTO will possibly seek rule changes for DR participation, part of a larger effort to address changing resource availability and need times.

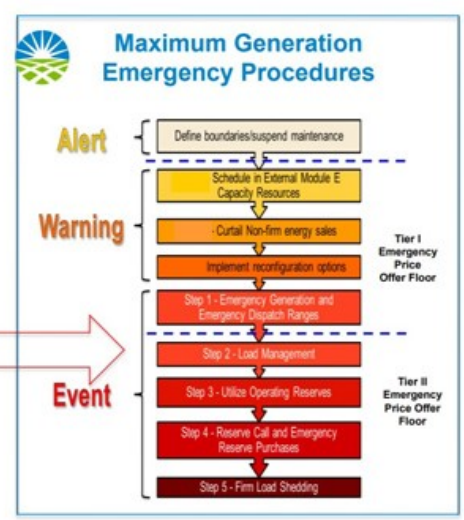
"For about eight years, we've been recommending that load-modifying resources be moved up in the stack," said Patton, who noted he has recommended repeatedly that MISO allow itself to call up LMRs at the earliest stage of its emergency process, giving those resources adequate time to generate by the time emergency conditions materialize.

Director Thomas Rainwater suggested that MISO consider separating its emergency resources into those that can be ready in four hours or less and those that require a longer lead time. He added he was "encouraged" by the idea that some non-traditional generation in the queue could function as more nimble reserves.

Ted Thomas, OMS president and chair of the Arkansas Public Service Commission, said Patton's concerns about DR were overblown. He said all MISO states except Illinois have a legal obligation to ensure resource adequacy, and he expected the footprint to persevere despite the possible shortfall reported in the OMS-MISO survey.

"While we had some red in some areas of the chart, we're not going to cruise along for the next five years until we hit a wall," Thomas said at a June 21 board meeting. "I will be resting just fine, waking up early to work through these issues."





| MISO

MISO NEWS

Supply Sufficiency 'Hot Topic' at MISO Board Week

By Amanda Durish Cook

| © RTO Insider

INDIANAPOLIS — MISO could ensure sufficient energy supply by improving demand response rules, devising a storage participation model and better coordinating outages, among other efforts, Advisory Committee members said last week during a "hot topic" discussion on resource adequacy at the RTO's Board Week.

The RTO has declared 12 maximum generation events since June 2016 — nine of which occurred in winter and shoulder-season months. That represents a sharp increase from the past pattern of one event "about every two years or once a year," said MISO Chief Customer Officer Todd Hillman, who moderated the discussion during a June 20 Advisory Committee meeting.

Hillman said the RTO is looking to abandon the standard that it has adequate resources on hand if it can reliably serve load during the one summertime peak hour of the year "when air conditioners run hard."

Vistra Energy's Mark Volpe, of the Independent Power Producers sector, said he wasn't certain how much of MISO's 12 GW of DR will respond to dispatch signals during maximum generation events. A MISO report last month showed that load-modifying resources underperformed during a mid-January emergency, and the RTO has signaled it will reconsider its rules for LMR participation. (See "LMR Performance in January," MISO Mulls Additional Emergency Communication.) In 2017, 9% of the capacity load-serving entities committed to the forecasted summer peak consisted of emergency-only resources, MISO has said.

"I think we agree that LMRs have value, and a lot of these processes were designed before MISO was in existence," said WEC Energy Group's Chris Plante, representative of the Transmission-Dependent Utilities sector. "Right now, we have an annual resource adequacy construct. … Do we need to look at a more granular resource adequacy construct to respect the temporal nature of LMRs?" he asked.

Representing MISO's End-User Customers sector, Kevin Murray of the Coalition of Midwest Transmission Customers said the RTO should switch from negative to positive reinforcement for DR performance.

"If MISO is getting to the point where it thinks its current Tariff structure is not blending well with operational needs, well, it needs to look at positive rewards," Murray said.

MISO could employ a practice where resources agree to voluntarily remove load from the system when prices reach a certain level. He also said the RTO could improve its communication with state commissioners on resource adequacy efforts.

"You're not going to change behavior until MISO communicates what it needs," Murray said of LMR performance.

Madison Gas and Electric's Megan Wisersky said LMRs were originally designed to address capacity emergencies but are now being called on to solve transmission emergencies.

"You have LMRs that have to be available at 2 a.m. on a Sunday now," Wisersky said. "You're asking them to do something they weren't designed to do."

She also criticized the MISO Communications System — where LMRs report their emergency availability — for being "hard to use" and inflexible.

Hillman asked where distributed energy resources fit into efforts to manage load in tight capacity conditions.

Murray said he saw a place for DERs in controlling load. "How many Nest thermostats does it take to offset a 1,000-MW gas unit?" Murray asked rhetorically. "It's a crop that's ready to harvest. It just needs the pickers."

Great Plains Institute Policy Associate Matt Prorok, the Environmental sector representative, said he agreed DERs could unlock value by "shaving loads, shifting loads and shimmying loads."

More Outage Control?

Hillman pivoted the discussion.

"OK, increasing outages," he said. "What do we do?"

Multiple committee members said MISO should discount outages from capacity performance.

"Don't we do that already?" Hillman asked, referencing the three years of generation data MISO uses to produce unit-specific forced outage rates.

Plante suggested MISO include in the rate planned and maintenance outages, in addition to unplanned outages.

Stakeholders also repeated a longstanding suggestion that MISO give itself a stronger

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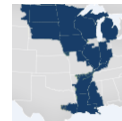

Supply Sufficiency 'Hot Topic' at MISO Board Week

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role in outage coordination, perhaps with the authority to approve outages.

But Michigan Public Service Commission Chairman Sally Talberg said the Organization of MISO States does not support the RTO having authority over outage scheduling.

MISO Director Phyllis Currie asked if generation and transmission owners were communicating enough about the conditions of their resources to the RTO so it can better predict when and where outages will occur.

"Generation doesn't take outages because they want to be out. They take outages because they want to be on," Murray said. PJM provides more forward-looking information about resource need than MISO, he said, noting that during the previous week, the Mid-Atlantic grid operator issued a hot-weather alert for its footprint with a request that asset owners wrap up outages early, if feasible.

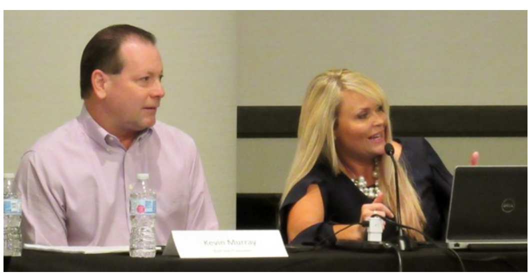
"We didn't see a similar hot-weather notice" in MISO until two days later, Murray said. He added the notice was another example of the positive reinforcement he advocates: Generation owners could reap higher prices if they come online in a hot-weather, high-demand situation.

Wisersky agreed that MISO should communicate when it most needs equipment to return online.

Energy Storage

OMS President and Arkansas Public Service Commission Chair Ted Thomas said storage can help address resource availability issues.

"Storage is crazy flexible. It's the most flexible thing I've seen," Thomas said.



Kevin Murray and Advisory Committee Vice Chair Tia Elliott | *© RTO Insider*

However, he thinks MISO and regulators should create rules to ensure storage has a monetary value in the market.

"FERC can't do it all in wholesale, and we can't do it all in retail," Thomas said of creating compensation rules. "Who is going to do the aggregation? These questions are really complex."

LS Power's Pat Hayes, of the Competitive Transmission Developers sector, said a storage asset in MISO cannot currently generate enough revenue as a standalone resource. He said it should find ways to value storage resources as both a transmission facility and generation asset.

MISO is currently examining how storage resources can function as reliability transmission projects in its annual Transmission Expansion Plan. It is also considering permitting storage resources to bypass the interconnection queue when the resources will be used exclusively as a transmission asset.

'One Thing'

"If there's one thing MISO could be working on, what would it be?" Hillman asked, pointing at Advisory Committee members around the panel.

"Creating flexibility for the future — getting all resources on a level playing field. I can't minimize how difficult that is, but clearly the evolving future requires it," said Alcoa's DeWayne Todd.

"Challenge MISO's current planning assumptions to see if they reflect reality," Exelon's David Bloom responded.

"We need to take a hard look at policy associated with resource adequacy," Plante said.

"Enabling competition among all resources," Prorok added.

FERC OKs Cut in Great River Revenue Requirements

FERC last week accepted Great River Energy's slimmed-down annual revenue requirement for reactive supply and voltage control at eight of its generating stations.

The cooperative's revenue requirement is reduced by a little more than $1 million per year with the June 21 order (EL18-45).

Great River settled for the lower amount after FERC opened an investigation in early January into whether the rates were just and reasonable. The company had originally proposed an approximately $5.2 million requirement for the eight plants but lowered it to $3.9 million after settlement proceedings. The individual requirements for the plants now range from $8,371 to $1.7 million per year, lowered from the original range of $24,908 to $2.3 million.

The co-op had claimed the $5.2 million figure was based on previous requirements accepted by FERC in 2010, with adjustments made to reflect the 2017 retirement of the 189-MW coal-fired Stanton Station in Stanton, N.D., and the addition of three generating facilities since 2010: the 170-MW natural gas-fired Cambridge Station and the 19-MW Maple Lake and 23-MW Rock Lake oil-burning stations, all in Minnesota.

But FERC questioned the figure, saying Great River did not adequately support its revised reactive power revenue requirements, including "development of multiple fixed charge rates, its accessory electrical equipment allocator and its generator/exciter investment portion of the turbogenerator." The commission also said it did not provide complete information on the reactive service capability of its units, including MISO test reports.

— Amanda Durish Cook

MISO NEWS

FERC OKs MISO Revision of Queue Termination Rules

By Amanda Durish Cook

FERC ruled last week that inconsistencies between the termination provisions in MISO's generator interconnection procedures (GIP) and *pro forma* generator interconnection agreement were unreasonable, but it simultaneously accepted the RTO's proposed Tariff changes to remedy the discrepancy (EL18-17).

In an October 2017 order, FERC found that an interconnection customer's ability to extend the commercial operation date (COD) of a project by up to three years without MISO seeking termination under its *pro forma* GIA conflicted with a provision in the RTO's GIP stating that any extension required a material modification of the interconnection request, or the project risked removal from the queue.

FERC originally took issue with the differences in 2012, and MISO at the time contended that the two provisions did not conflict because its GIP applied before the execution of a GIA, with the GIA provisions taking precedence after an agreement is executed.

But the discrepancy arose again after MISO successfully sought to terminate a GIA with EDF Renewable Energy's 150-MW Merricourt wind project in North Dakota. (See FERC Upholds MISO Cancellation of GIA.) While FERC sided with the RTO in the termination, it instituted an investigation over the inconsistency in late 2017.


| © RTO Insider

As part of a paper hearing in the proceeding, MISO late last year submitted a proposal to clarify within the GIP section of its Tariff that the COD for a project that completes the definitive planning phase of the interconnection queue will be spelled out in a GIA.

"MISO states these proposed revisions also remove any ambiguity as to which Tariff provision determines the COD and any permissible extension beyond the COD, thereby providing greater certainty," the commission noted.

FERC said that MISO's approach addressed its concerns.

"We also agree with MISO that the GIP and *pro forma* GIA are intended to work together, and although the *pro forma* GIA 'memorializes the arrangements reached in the GIP,' the GIP does continue to apply even after execution of a GIA; therefore, specifically referring to the correct section of the GIP in the *pro forma* GIA is preferable to separating the two documents entirely in these circumstances," the commission wrote.

FERC also directed MISO to make a further Tariff filing to make it more clear that an interconnection customer can extend its COD by up to three consecutive years before risking withdrawal from the queue.

MISO NEWS

FERC Broadens Challenge to TOs' Tax Calculations

By Amanda Durish Cook

FERC on Thursday identified 13 additional transmission owners it said should change accounting practices that could inflate rates by underestimating tax credits.

The commission ordered a Section 206 proceeding investigating the companies' use of a double averaging formula to calculate accumulated deferred income taxes (ADIT) (EL18-155, *et al.*). The utilities include two Ameren subsidiaries, American Transmission Co., GridLiance West Transco, ITC Midwest, Northern States Power, Public Service Company of Colorado, Southern California Edison, TransCanyon DCR, Southwestern Public Service and Virginia Electric and Power Co.

In April, FERC opened a similar investigation of five MISO TOs after rejecting proposed formula rate template revisions that would have applied the two-step averaging methodology in annual true-up calculations of ADIT balances.

The commission signaled it would probe whether the practice makes deferred income tax credits appear lower than they should be, possibly raising rates (ER18-224, EL18-138). The filers were ALLETE, Montana-Dakota Utilities, Northern Indiana Public Service Co., Otter Tail Power and Southern Indiana Gas and Electric Co.

The commission said that the TOs' practice of averaging the prorated ADIT value for the year with the beginning-of-year ADIT balance "produces a result that is disproportionately skewed towards the beginning-of-year balance."

"Because most companies tend to continuously make investments in plant[s], which in turn generates ADIT, plant and ADIT balances typically increase throughout the year," the commission said.

MISO TOs Offer New Formula

On June 4, the five MISO TOs submitted revisions to remove the proposed double averaging and instead apply the IRS' proration methodology in calculating the annual transmission formula rate true-up.

In last week's order, FERC suggested that the 13 newly identified utilities would need to similarly revise their rates.

"Upon initial review, the concerns we identify might be addressed by revising respondents' transmission formula rates to eliminate the use of the two-step averaging methodology to determine ADIT balances," FERC said. "In particular, respondents could modify their transmission formula rates to apply the first step of the two-step averaging methodology to generate a prorated ADIT value for the year, without taking the second step of averaging the prorated value for the year with the beginning-of-year balance."

Change of Heart

FERC noted that, in previous proceedings, it had allowed TOs to use the two-step methodology "based on the understanding that this methodology was necessary to comply" with the IRS' normalization rules, an accounting system the Department of Treasury uses for regulated public utilities to reconcile accelerated depreciation of their public utility assets or investment tax credits with regulatory treatment.

However, FERC said in April that its opinion on the matter has since changed, guided by private letter rulings from the IRS. FERC said it now interprets updated IRS rules to "not require that any averaging convention applied to other elements of rate base also apply to taxpayer's prorated [ADIT] balance."

"We conclude that if the IRS' proration methodology is applied to calculate ADIT balances in forward-looking formula rates — such as the Attachment O formula rate templates of certain MISO TOs — then the additional averaging step need not also be applied in order to comply," FERC said.

PJM: MISO Monitor Lacks Standing in Pseudo-tie Complaint

By Amanda Durish Cook

PJM has again moved to dismiss Potomac Economics' complaint against its pseudo-tie construct, citing a recent court ruling that describes a limited role of RTO/ISO market monitors in legal proceedings.

MISO's Independent Market Monitor filed a Section 206 complaint in April 2017 asking FERC to eliminate PJM's existing pseudo-tie definition, claiming that the increasing use of pseudo-ties degrades reliability, hampers efficient dispatch and raises costs. (See *Pseudo-Tie Feud Rises as Patton, NYISO Protest PJM Proposal*.)

PJM is pointing to a June 15 D.C. Circuit Court of Appeals ruling that confirms FERC's 2017 decision that Old Dominion Electric Cooperative cannot recover its operating costs incurred in excess of its filed rate during 2014's polar vortex. The commission said such a move would constitute retroactive ratemaking (16-1111).

Monitor David Patton at MISO Board Week | *© RTO Insider*

In its June 19 filing in the pseudo-tie complaint (EL17-62), PJM said the ODEC decision importantly included a denial of its own Independent Market Monitor's motion to intervene. PJM said the court's opinion shows that "a market monitor does not have standing to intervene in a proceeding on judicial review of commission orders" and that the case is "instructive" in its motion to dismiss the MISO Monitor's complaint. PJM asked FERC to consider the precedent in its upcoming decision.

The court said that the PJM Monitor "has no legally cognizable interest" in the ODEC case and denied its motion to intervene.

The Monitor's role, the court said, "is much in the nature of an auditor — it is largely confined to observing the market's opera-

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NYISO NEWS

NY Releases 'Roadmap' for 1,500-MW Storage Goal

By Michael Kuser

Peak and off-peak e-value | *NYSERDA*

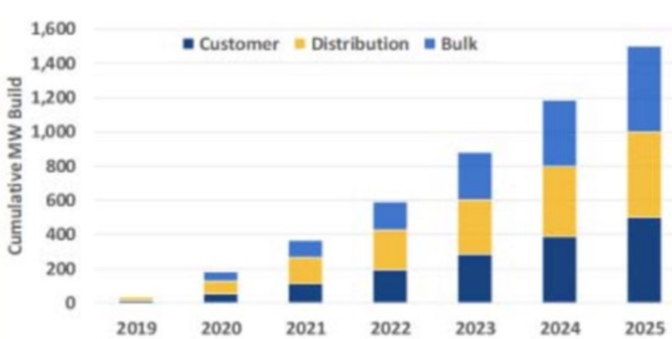
New York officials on Thursday outlined how the state plans to add 1,500 MW of energy storage by 2025, a target set by Gov. Andrew Cuomo in January.

Lt. Gov. Kathy Hochul, who announced the release of the Energy Storage Roadmap in Queens, said it "represents the next crucial step forward to tackle climate change and further develop our clean energy economy."

"Clean energy is the future of our planet, and New York will continue to lead the nation in this technology to fight climate change and conserve resources for generations to come," Cuomo added in a statement.

In his annual State of the State address in January, Cuomo directed the NY Green Bank to invest $200 million to meet the 1,500-MW target — equal to the demand of one-fifth of New York homes. Cuomo also directed the New York State Energy Research and Development Authority to invest at least $60 million in storage demonstration projects and efforts to reduce barriers to deploying energy storage, including permitting, customer acquisition, interconnection and financing costs. (See *Cuomo Pushes Clean Energy in Annual Address*.)

Developed by NYSERDA and the Public Service Commission, the Roadmap groups storage deployment into three market segments — customer-sited, distribution system and bulk system — based on where the storage is located and the needs it serves. In bulk system deployments, energy storage can be a firming resource when paired with large-scale intermittent renewables, can replace or complement peaker plants, and potentially defer transmission investment.



Deployment scenario resulting in 1,500 MW of storage by 2015 | *NYSERDA*

The Roadmap recommends providing $350 million in statewide market acceleration incentives to fast-track the adoption of advanced storage systems for customer sites or on the distribution or bulk electric systems.

The state has approximately 60 MW of advanced energy storage capacity deployed now, with another 500 MW being planned to add to the existing 1,400 MW of traditional pumped hydro storage.

The New York Power Authority is working on several energy storage projects to demonstrate the value of the technology, including work on multiple projects with the State University of New York. The SUNY New Paltz campus, for example, this spring completed a solar energy and battery storage system, and state officials plan a similar system at the SUNY Delhi campus.

New York will also add incentives for energy storage to NYSERDA's successful NY-Sun initiative and plans regulatory changes to utility rates, utility solicitations and carbon values to reflect the system benefits and values of storage projects.

The state also will consider recommending modifications to wholesale market rules to enable storage participation, including allowing storage to meet both electric distribution system and wholesale system needs to provide greater value for ratepayers, NYSERDA said.

NY Green Bank has released a Request for Information to solicit interest from project developers for its $200 million investment.

The Roadmap begins the public input phase of the PSC's storage proceeding, which will include multiple technical conferences to allow for feedback on recommendations and approaches identified (18-E-0130). Public comments on the Roadmap can be submitted via the Department of Public Service's website.

NYISO News

NY Task Force Examines Carbon Pricing Market Impacts

By Michael Kuser

The impact of a carbon price would likely reverberate throughout New York's wholesale electricity markets, industry experts said last week.

Carbon pricing could be "a real game-changer in terms of likely impacts on the market," Couch White attorney Michael Mager said during a June 18 meeting of the state's Integrating Public Policy Task Force (IPPTF), the group charged with exploring how to price emissions into NYISO's markets. Mager represents a coalition of large industrial, commercial and institutional energy customers.

During the meeting, NYISO presented its proposed approach to analyzing the effects of a carbon charge on various wholesale market processes, including its Installed Capacity (ICAP) market and related demand curve reset.

NYISO may have to adjust ICAP rules to reflect carbon pricing if it believes the carbon charge is not appropriately reflected in prices, said ISO staffer Nathaniel Gilbraith.

Capacity prices are generally expected to make up for "missing money" from the energy market, and it's important for capacity rules to capture relevant energy market revenues when setting prices, Gilbraith said.

Issue of Timing

The ISO's estimation of the energy and ancillary services revenue offset is a key component of its annual process for updating its demand curve. (See *FERC OKs NYISO Demand Curve Reset*.) But Mager pointed out that if the ISO's annual update considers only rolling historical revenues and neglects to factor in carbon prices, it will miss the mark.

"One issue is timing. If carbon pricing is implemented, when is it implemented *vis a vis* the demand curve reset process?" Mager said. "The second is how do you deal with the [energy and ancillary services] revenues in light of a dramatic change like this."

Power Supply Long Island Director of Wholesale Market Policy David Clarke said, "We would prefer the demand curve to ramp smoothly ... consistency would be sensible with what's assumed in the [locational-based marginal price] and what's assumed in the bid for demand curve reset purposes."

Transmission Planning

Ethan Avallone, NYISO senior market design specialist, explained that the ISO performs economic analyses of new transmission facilities in its Congestion Assessment and Resource Integration Study (CARIS) studies and as needed for its Public Policy Transmission Needs Planning Process. Those analyses include production cost simulations and already account for the Regional Greenhouse Gas Initiative price, and would similarly incorporate the carbon charges on suppliers, he said.

Representing New York City, Couch White attorney Kevin Lang said, "We don't really build transmission on a CARIS basis or on an economic basis in this state, and I'm not sure when — or if — we ever will. ... So in terms of priorities, this is a much lesser issue than grappling with the demand curve."

"If you're accounting for RGGI you should be accounting for the carbon price; that just makes sense," Lang said. "From our view, we'd like to see the transmission response of how we're going to encourage more transmission to be built, and I don't know whether that's economic, or whether it's public policy, or potentially reliability

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NYISO NEWS

NY Task Force Examines Carbon Pricing Market Impacts

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planning."

Clarke said there is a potential disconnection between the marginal carbon component price in the LBMP and the actual change in carbon emissions associated with a new transmission line.

"For example, suppose wind is on the margin before and after a transmission line is added, but the line also unbundles some additional wind that can be added into the market," Clarke said. "There would be a circumstance where you don't have a price difference associated with that — the marginal unit hasn't changed — but you have changed the amount of low carbon resources that are able to enter the market. The change in the carbon may not be reflected in the marginal price."

IPPTF Chair Nicole Bouchez, the ISO's principal economist, said such deep transmission planning "is probably a bit beyond what we're doing here," adding that the group is "just looking at the impact of a carbon price on the market, not evaluating different transmission opportunities and what the consequences of them are in a carbon adder world."

Customer Impacts

Timothy Duffy, the ISO's manager for economic planning, presented three separate planning scenarios. The first case — the reference case — was modeled for three different years (2020, 2025 and 2030), and the remaining two for 2030 only.

The reference scenario presumes 226 MW of offshore wind by 2020, with the state's full commitment of 2,400 MW calculated into the 2025 and 2030 iterations. All scenarios consider coal plants retired and include western New York and generic AC transmission upgrades.

The scenarios vary on the nuclear component, considering that Indian Point will retire in stages over 2020/21, and that the state's zero-emission credits supporting nuclear will expire in 2030.

Erin Hogan, representing the Department of State's Utility Intervention Unit, asked what would happen in 2023 when Indian Point will be retired and the AC upgrade will not yet be completed.

"We didn't feel that there would be much information gleaned from that particular scenario that wouldn't be gleaned from running, for example, 2025 with both high and low energy loads," Duffy said.

The ISO's broad analysis "captures the bookends of what would be the LMP impacts [and] load-shaving impacts associated with a carbon price," Duffy said.

Bouchez disagreed.

"People talk about price signals, and then the reality is that people have choices with price signals," Bouchez said. "If we are going to have a year with exceptional high price signals with the congestion, not having [Indian Point] and not having the AC transmission, we need to know that. That could go beyond what you're characterizing as the high load scenario."

Catch-22

Lang questioned the ISO's professed need to fit the carbon price analysis into "the allotted time frame."

"There's no Tariff requirement, there's no statutory requirement for that, and we've had lots of other cases where things have been delayed because the analysis takes longer than expected," Lang said.

"I'm extremely troubled that we're looking at something that could have a very significant consumer impact — we don't know yet because we haven't seen the analysis — and all I keep hearing from the ISO is 'we can't do the broad analysis that folks are asking for because we don't have the time to do it.'"

Duffy said the situation was a catch-22.

"You're telling us that you need to know the results of the analysis before you can decide to move forward, but you're not letting us get the analysis because we're debating the assumptions we would use in the analysis," Duffy said. "We're trying to get to the point where actually we can run the analysis and present the results."

If at that point there's a consensus to continue the analysis, "that's fine, but please let us get to the point where we start presenting results so we can start talking about those as opposed to what-ifs and maybes," he said.

The task force next meets July 9 at NYISO headquarters.

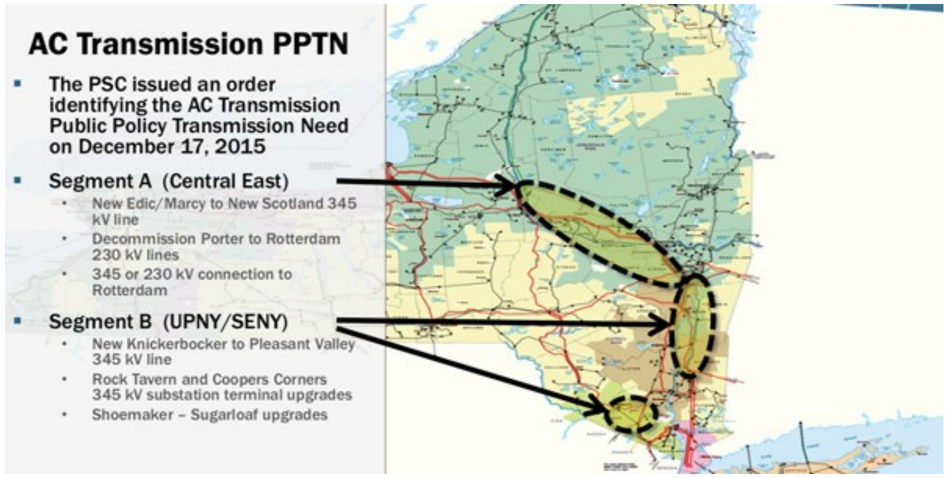
NYISO News

NYISO BIC Backs AC Tx Projects; Losing Bidders Protest

By Michael Kuser

RENSSELAER, N.Y. — NYISO stakeholders last week backed joint proposals by North America Transmission (NAT) and the New York Power Authority to build two 345-kV transmission projects while several losing bidders cried foul.

In an advisory vote, the Business Issues Committee urged the Management Committee on Wednesday to recommend the Board of Directors approve the ISO's draft AC Transmission Public Policy Transmission Planning Report. Dawei Fan, manager for public policy and interregional planning, said the report contains analysis of seven proposals to address persistent transmission congestion at the Central East (Segment A) electrical interface and six proposals for the Upstate New York/Southeast New York (UPNY/SENY, or Segment B) interface.



NYISO staff analyzed seven proposals to address persistent transmission congestion at the Central East (Segment A) electrical interface, and six proposals for the Upstate New York/Southeast New York (UPNY/SENY, or Segment B) interface. | *NYISO*

Advised by consultant Substation Engineering Co. (SECO), ISO staff recommended two 345-kV transmission projects proposed jointly by NAT and NYPA. The BIC voted 76.33% in favor of the report and its recommendations.

Project T027 is a double-circuit 345-kV line from Edic to New Scotland for Segment A. Project T029 for Segment B is a standard 345-kV line from Knickerbocker to Pleasant Valley.

NYISO's analysis was driven by a December 2015 order by the New York Public Service Commission on "Finding Transmission Needs Driven by Public Policy Requirements."

T027 had higher costs than other Segment A proposals, but staff determined them warranted by benefits provided by the double-circuit design, including "significant increase in Central East voltage transfer capability, increased production cost savings, and excellent operability and expandability."

T029 provides similar transfer incremental and production cost savings with the second-lowest cost, and demonstrates excellent operability, staff said. More important, the report said, "T029 poses the lowest siting risk due to the low structure height increase and more than 50% of its new structures with reduced height."

Staff also said that T027 and T029 would result in cost savings when being built by the same developer simultaneously.

The ISO estimated T027 will cost $577 million to $750 million, the higher figure including a 30% contingency. T029 is estimated at $324 million to $422 million. Staff projected the in-service date for the selected projects in April 2023, "assuming the developer will start the Article VII preparation immediately following the approval of this report by the NYISO board."

Challenges to Planning Process

Stakeholders abstaining or opposing the motion June 20 included utilities, transmission owners and other developers whose proposals were not selected for recommendation. Several of them submitted comments to the BIC or read statements.

John Borchert, senior director of energy policy and transmission development for Central Hudson Gas & Electric, which abstained, said his company wanted the benefits of improved transmission capability for its service area but was "dissatisfied with the NYISO's work and its project evaluation."

He said "the lack of transparency, the way that the aspects of the projects were treated during the evaluation, effectively disqualified projects, and the way that the local TO upgrades were handled during the process have led to frustration and confusion for both those developing projects and for those interconnecting transmission owners."

Consolidated Edison and its subsidiary Orange and Rockland Utilities voted against the motion, and O&R submitted written comments.

"We don't feel confident that the recommended selection for Segment B is in the customer's best interest due to a lack of transparency in the selection process, and deficiencies in evaluation," said Jane Quin, director of Con Ed's energy markets policy group. "We are concerned that ... NYISO has not considered the full costs associated with the proposed Middletown upgrades, which are local upgrades on the Orange and Rockland system ... and could cost as much as 20% of the Segment B project cost."

The ISO "failed to make clear the technologies and project attributes it would or would not consider, and the reasons for such decisions, and it did not consider stakeholder input on the matter," Quin said.

Fan responded that the Middletown transformer "is just one of the distinguishing

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NYISO News

NYISO BIC Backs AC Tx Projects; Losing Bidders Protest

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factors for Segment B projects ... [for which] the major drivers are the magnitude of the power delivery and the structure design." He said SECO had included $16 million for the Middletown transformer costs, which it deemed adequate.

Fan said the ISO had already had two meetings with developers and six meetings with the Electric System Planning Working Group and Transmission Planning Advisory Subcommittee to consider comments from stakeholders.

Looking for Fatal Flaws

Zach Smith, NYISO vice president for system and resource planning, noted that "any project recommended for selection does go through our interconnection process ... there has been a system impact study that's been done that's up at [the Operations Committee on June 21] for consideration."

The next step after that is a facilities study, and "what's key here to our evaluation is to understand whether there are any fatal flaws in our assessment," Smith said.

Borchert said, "There was no reason why an interconnecting transmission owner should not be consulted if these solutions are talking about equipment that's going to be installed in their service territory. And the process needs to be done if it's part of the overall selection and it has an impact on the selection, and it needs to be done prior to the selection being made."

Carl Patka, the ISO's assistant general counsel, said, "When we designed the overall planning process, we did not require, and FERC did not approve requiring, a complete interconnection-level analysis for proposed projects. That was proposed during the Order 1000 process, it was proposed during the stakeholder process, and it was rejected. And the reason for that is people did not want to create a barrier to entry and proposal of new projects based upon information that competing developers could not have from the incumbent utility."

Brian Duncan of NextEra Energy Transmission NY (NEETNY) made a presentation arguing that NYISO was picking winners for a $1 billion project "despite a virtual tie on project benefits" among competing projects, which included NEETNY's T022 in Segment B.

The ISO "did not provide analysis on cost-contained pricing ... and three other project combinations that are virtually identical, provide all the quantifiable and quantitative benefits [and] are within 1 to 5% of the cost estimate using SECO's numbers," Duncan said. He also questioned why NYISO made tower height a big issue in its selection when its solicitation made no mention of the factor.

Patka said the PSC order did not mandate the ISO to use cost-contained pricing but required developers to provide two sets of costs, "one based on raw construction costs and one on 80%/20% cost overrun/cost underrun language. ... They said they hoped that FERC will adopt cost containment when they address the rate issue, but their words were exactly, 'The NYISO should evaluate the costs based on raw construction costs.'"

Patka also said that tower heights were considered by NYISO as a risk of project delay and to project completion, as visual impact is a key environmental impact of transmission, and that the ISO had reviewed its analysis with New York Department of Public Service staff.

Duncan also took issue with the concrete pole installation cost estimates, saying that SECO used a metric of dollars per pound on the weight of the pole rather than a more logical figure of total costs, including labor. He also said the ISO's estimate of 5% in synergy savings on the combined projects by one developer was "overstated."

"If those issues are addressed, project T022 would be the lowest-cost project by millions of dollars, probably tens of millions of dollars," Duncan said.

SECO Vice President Joe Allen said he agreed "there would be no synergy" between the two upgrades.

Smith said NYISO could "take that back, but it won't affect the ranking at all."

Kathleen Carrigan, New York Transco general counsel, read comments the company jointly submitted with National Grid.

The two companies submitted proposal T019 for Segment B, including "a basic controllable series compensation element to preserve the proposed 345-kV transmission line physical designs that the commission deemed the most environmentally and siting friendly in the underlying AC transmission proceedings."

Carrigan said series compensation technology is widely used across the U.S., and she submitted a study showing no detrimental system impacts from it. NYISO and SECO "considered proposal T019 as too risky due to the inclusion of the series compensation, despite no technical analysis in support of their conclusion," she said.

Smith said that while the ISO does not oppose the use of series compensation as a technology, it did see potential problems with its application in the National Grid/NY Transco project. In a FAQ document posted with the BIC meeting materials, the ISO cited potential subsynchronous resonance and damage to generators as the major risk of series compensation technology.

Carrigan said NYISO's own metrics show the National Grid/NY Transco proposal paired with T029 produces consistently better performance results than the ISO's favored project.

For example, when combined, T027 and T019 increase voltage transfer across Central East by 875 MW and UPNY/SENY by 2,100 MW. "This is a far *greater* increase than the combination of T027 and T029, which only increases transfer capability along Central East by 825 MW and UPNY/SENY by 1,325," she told *RTO Insider* after the meeting.

"Projects T027 and T019 have the *highest* Central East N-1-1 voltage transfer capability of any studied project combination and far surpass combination T027 and T029 with respect to the incremental UPNY/SENY N-1-1 thermal transfer capability. The baseline 20-year incremental energy produced by projects T027 and T019 nearly *doubles* that of projects T027 and T029 (40,089 GWh vs. 27,524 GWh); and finally, T027 and T019 produce the highest production cost savings than any other Segment B combination," Carrigan said.

NYISO NEWS

Business Issues Committee Briefs

Monthly Energy Prices up 37% Y-o-Y

RENSSELAER, N.Y. — NYISO power prices dropped in May but are up 37% year-to-date, Nicole Bouchez, ISO principal economist, told the Business Issues Committee on Wednesday.

Prices averaged $28.78/MWh in May, lower than $35/MWh in April and $31.74/MWh the same month a year ago.

Year-to-date monthly energy prices averaged $50.20/MWh through May, up from $36.54/MWh a year earlier. May's average sendout was 397 GWh/day, compared with 390 GWh/day in April and 383 GWh/day a year earlier.

Transco Z6 hub natural gas prices averaged $2.55/MMBtu for the month, down 9.4% compared with last month and 8.8% year-over-year.

Distillate prices gained 6.4% compared to the previous month but were up 49.7% year-over-year. Jet Kerosene Gulf Coast and Ultra Low Sulfur No. 2 Diesel NY Harbor averaged $15.96/MMBtu and $15.92/MMBtu, respectively.

Total uplift costs and uplift per megawatt-hour rose from April with the ISO's local reliability share 22 cents/MWh in May, up from 12 cents/MWh the previous month, while the statewide share climbed from -57 cents/MWh to -17 cents/MWh.

ISO Reviewing Rules on PJM Imports

Reviewing the Broader Regional Markets report, Bouchez described the ISO's work on item 26, an effort to clarify the minimum deliverability requirements for capacity from PJM, the subject of three joint meetings of the Installed Capacity (ICAP) Working Group and Market Issues Working Group since February.

The ISO has prepared a detailed overview of the supplemental resource evaluation (SRE) process for external resources, the existing nonperformance penalties for external ICAP suppliers, and a draft proposal regarding SRE process improvements for external capacity resources.

Bouchez also reviewed item 28, a complaint filed with FERC in December by the New Jersey Board of Public Utilities challenging PJM's and NYISO's implementation of the mutual benefits provisions of their joint operating agreement and requesting amendments to the JOA.

FERC rejected the complaint on May 24 (EL18-54). The commission found that because the Bergen-Linden Corridor Project was planned by PJM, and without a voluntary commitment to share cost responsibility by NYISO, "it is just and reasonable for the costs of the project to be allocated solely within PJM." (See *PSE&G on the Hook for Bergen-Linden Costs*.)

Proposal to Extend TCCs Advances

The BIC voted to recommend that the Management Committee approve Tariff revisions to provide extensions of historic fixed-price transmission congestion contracts (HFPTCCs), following a presentation by Gregory R. Williams, manager for TCC market operations.

FERC Order 681 requires that long-term firm transmission rights be made available to allow load-serving entities to support long-term power supply arrangements.

The HFPTCCs initiated by NYISO in 2008 allow LSEs to obtain such contracts for up to 10 years, with some service grandfathered for up to 12 years; 1,748 MW of HFPTCCs are currently active. Those offered in 2008 are now approaching the end of their 10-year term and will expire after Oct. 31.

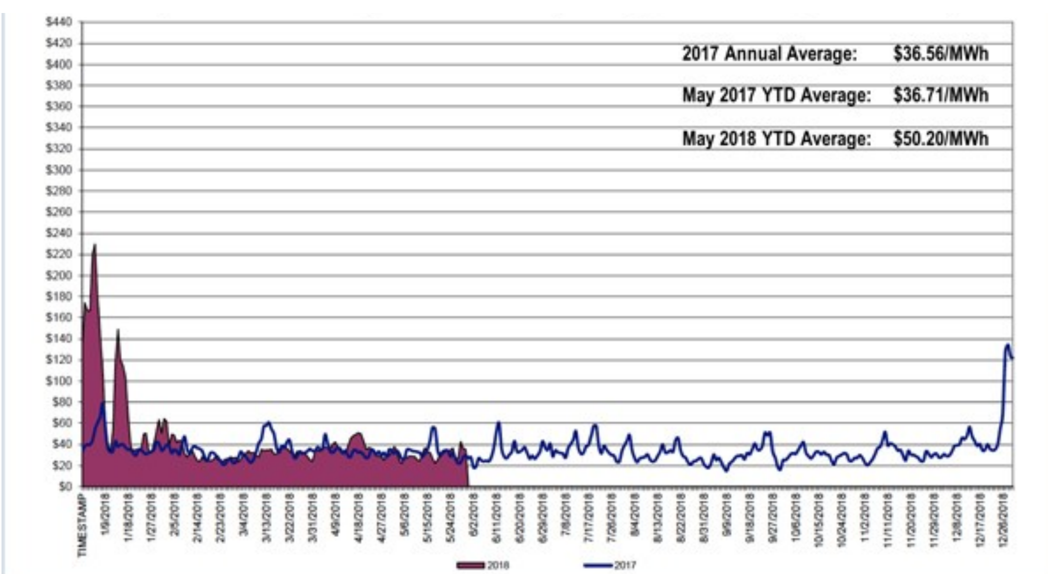
As part of developing the HFPTCCs, the ISO had committed to explore an option to renew the contracts after the initial term.

Contract extensions would be made available to LSEs that convert existing transmission agreements to HFPTCCs and continued to purchase them throughout the entire 10- or 12-year term.

The ISO is required to make all transmission capacity not used to support existing TCCs available for sale in its centralized TCC auctions. The bidding and offering period for the first round of the fall 2018 centralized TCC auction is expected to begin in mid-August.

Assuming the current proposal is accepted by FERC, the ISO would need to seek a waiver for permission to reserve 256 MW of transmission capacity from the upcoming auction to support the potential award of HFPTCC extensions that would begin on Nov. 1, 2018, and ensure feasibility issues do not arise from offering such extensions to qualifying LSEs.

— Michael Kuser



Daily average cost/MWh (energy & ancillary services) | *NYISO*

PJM NEWS

Cost Containment Clears MC Vote Despite PJM Plea

By Rory D. Sweeney

Left to right at the PJM Members Committee meeting June 21, 2018: Chris O'Hara, PJM; Dave Anders, PJM; Mike Borgatti, Gabel Associates; and Andy Ott, PJM. | © *RTO Insider*

WILMINGTON, Del. — A controversial proposal to bring cost-containment measures into PJM's transmission planning cleared its final hurdle in the stakeholder process last week despite a late attempt to block it by CEO Andy Ott.

The proposed Operating Agreement changes have been among the most contentious in recent memory. Originally developed by LS Power, the proposal gained sponsorship from several consumer advocates and PJM's Independent Market Monitor, withstanding strong opposition from transmission owners. (See *Cost Containment Coming to PJM Transmission Bids*.)

It was queued up for one final endorsement vote at last week's Members Committee meeting when Ott took the unusual step of addressing the membership to seek a delay on the vote. "I think this might be the first time I've ever done this," he said.

Ott used his platform to make one final plea to stakeholders that his staff can't handle much more.

"I think it risks the [Regional Transmission Expansion Plan] getting so complex that it becomes even more burdensome than it is today," he said. "If you all would just take a step back. My planning staff is not infinite. … We'll deploy our resources and do the best we can. But I think it's unreasonable to expect that the next day we should make the baseline process more transparent. … Certainly, we can do things over time, but if you're saying do things quickly … we cannot do all of this in the same time frame."

He argued there are other areas in which increased efficiency would provide greater savings than the transmission cost caps. He suggested the Liaison Committee consider the issue.

"I don't think there has been constructive engagement from all stakeholders," he said. "I think there's room to have more constructive engagement."

Several of the proposal's supporters responded to Ott's comments. American Municipal Power's Ed Tatum said Ott made "good observations" about the need for transparency for end-of-life projects in the RTEP process — a discussion that has been ongoing in the Transmission Replacement Processes Senior Task Force since March 2016. But, he added, "we are not proposing that PJM do the impossible." He asked that staff "facilitate those [task force] meetings."

"We think we're asking for things TOs have already done to justify these discretionary projects to their management; no more, no less," he said.

"It's precisely because PJM and CAISO are national leaders on Order 1000 that it's extremely important to get this right," said LS Power's Sharon Segner, who has shepherded the proposal from the beginning.

Susan Bruce, representing the PJM Industrial Customer Coalition, said even a 1% improvement would be "tremendous" and that the comparisons of financial significance might change as more projects become competitively bid instead of awarded to incumbent TOs.

"This will not stop us from demanding improvement in all spheres," she said. "If I went back to my members and said [the cost-containment proposal] was deferred, they would be very disappointed in that."

If PJM needs more staff to complete the intent of the proposal, "that's an investment they're willing to pay," she said of her members.

Dominion Energy and Exelon requested and received approval for a friendly amendment to forbid PJM from requiring bidders to include cost-containment measures in their bids. That was immediately followed by a point of order challenge from PPL's Frank "Chip" Richardson, who noted a section in the OA that required input from the Board of Managers before the MC can vote. He noted that the board hasn't responded to a letter TOs sent to it more than a month ago to block action on the proposal. Richardson's motion initiated a parliamentary process requiring that MC Chair Mike Borgatti, of Gabel Associates, determine whether the vote could proceed.

Ott said the board has seen the letter but hasn't deliberated on it. Because it was sent right after the board held one of its bimonthly meetings, Ott considered whether it was of enough consequence to reconvene the board to discuss it. He decided it was not, he said.

Chris O'Hara, PJM's legal counsel for the MC, said the board has been briefed on the topic and provided comments to the RTO. Board members attending the MC meeting in addition to Ott were Mark Takahashi and Dean Oskvig. O'Hara said the OA provision noted by Richardson "should not provide a legal impediment to stop the vote today"

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PJM NEWS

PJM Gens Pitch Order 842 Compliance Plans

By Rory D. Sweeney

VALLEY FORGE, Pa. — Calpine and American Electric Power are offering stakeholder alternatives to plans from PJM and its Independent Market Monitor for complying with FERC Order 842, which requires certain generators to provide primary frequency response.

Generation stakeholders have resisted proposals that would require existing units to provide PFR and any mandates that don't include compensation for the service. (See *Stakeholders Oppose PJM PFR Mandate for Existing Units*.)

Calpine's David "Scarp" Scarpignato explained the proposal at a June 19 meeting of the Primary Frequency Response Senior Task Force (PFRSTF). The plan hinges on requiring existing resources that provide PFR to continue doing so, along with the order's requirement of new resources and any generators that must revise their interconnection agreements after making modifications to their facilities. The plan also calls for allowing any resources that aren't able to fulfill their obligation to enter bilateral contracting with resources that can.

Stakeholders at the PFRSTF meeting on June 19. | *© RTO Insider*

Units entering into such contracts would have to alert PJM annually. Calpine's proposal would also require that units be able to both ramp up and down to respond to frequency changes. Just like today, PJM would have the ability to dispatch units to ensure the necessary flexibility of output. Units would also be compensated for their lost opportunity costs, especially during system restoration.

PJM has filed request for clarification on whether Order 842 was meant to include both new and existing resources. The RTO argues it does.

"A lot of the PJM way of doing this thinks that there will be natural headroom on the system," both up and down, Scarp said. "Those are not my presumptions. Those are

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Cost Containment Clears MC Vote Despite PJM Plea

Continued from page 26

given his interpretation of the OA language and PJM's practice since its inception of holding MC votes without the board weighing in beforehand. However, he said the final call was up to Borgatti.

"Don't worry; the bus tires don't hurt at all," Borgatti responded.

Greg Poulos, executive director of the Consumer Advocates of the PJM States, said he was "disappointed" that Richardson waited until the last second to unveil his challenge and suggested that TOs and PJM were playing a "game."

"I don't think the conversation is advanced by suggesting there was a surprise," O'Hara said.

"What I can offer you is that [if you think] this was a backdoor dealing, it was not. This is a real-time issue," Borgatti said. "I have been advised that Roberts Rules require me to render a decision before we continue the meeting."

Bob O'Connell of Panda Power Funds announced he would challenge Borgatti's ruling either way to force a membership vote on the issue and relieve Borgatti of the weight of the decision.

"I don't believe I or any other MC chair should be asked to dictate when the MC can vote on an issue. This is a very uncomfortable position to be in," Borgatti acknowledged, before siding with O'Hara's opinion and allowing the vote to proceed.

O'Connell challenged the ruling as promised, and it went to a vote, requiring a simple majority. It was taken as a sector-weighted vote, which meant it had a 2.5 threshold out of 5. It passed easily with 4.5.

The subsequent vote on the proposal also received overwhelming support with 4.28 in favor. The total was later adjusted to 4.17 with votes that hadn't been recorded at the time, but it was still well above the 3.33 threshold necessary for endorsement.

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

PJM NEWS

PJM Gens Pitch Order 842 Compliance Plans

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the presumptions that must be made under the PJM proposal for it to work. They are not directing anywhere in their proposal to create real-time headroom for primary frequency response. They're assuming it naturally occurs," he said. "This proposal is not a small change. It requires a significant amount of work and also encompasses more recordkeeping."

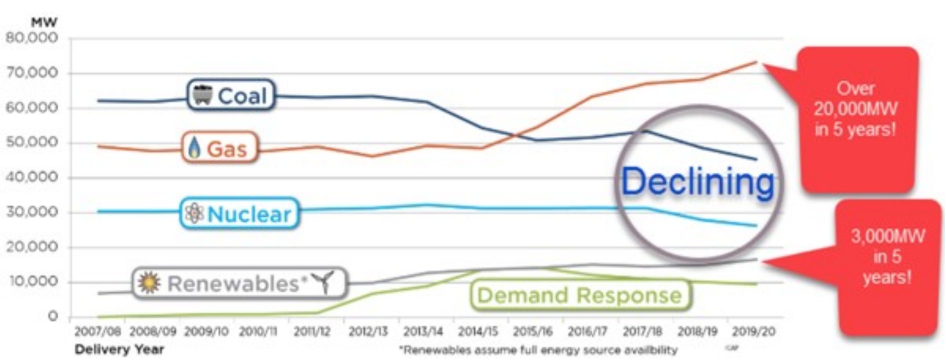
His plan didn't contemplate any market transactions beyond the bilateral contracting, he said, because he "didn't see a ton of dollars" in it, but he would be open to supporting any proposals that do want to address development of a market mechanism.

Locational Issues

In response to criticism that his proposal didn't address the importance for PFR of units' geographic location on the grid, Scarp said his proposal, like the others, relied on "expecting diversity of location with new megawatts."

"I think the locational issue is a significant issue, and it's not being addressed in the matrix in a very good way under any of the proposals. ... I would not be surprised if five years down the road, we reconvene to start talking about locational issues, but right now there are no locational requirements," he said.

PJM's Vince Stefanowicz said the RTO's plan is intended to address locational issues and expressed concern about Calpine's bilateral contracting idea because during a restoration event, "we really don't know where the system is going to break up and island," and "we have to make sure that units in [those] areas have the [PFR] capability."



A presentation from AEP argues that "declining" resources, such as coal and nuclear, shouldn't be required to make investments necessary to supply PFR. | *AEP*

Resource Connections

Scarp suggested that a second stage of the proposal address units that are interconnected via wholesale market participation agreements (WMPAs), a concern that GT Power Group's Dave Pratzon also expressed. That phase would examine "not whether to do it [require WMPA resources to provide PFR], but how to do it," Scarp said.

He said he'd received comments that the package should treat all resources equally, including energy efficiency and demand response, but he acknowledged concerns that adding the necessary inverters to such projects might be infeasible because they don't inject power into the grid and don't have WMPAs.

"It seems like a stretch," CPower's Bruce Campbell said. "I suspect the commission would consider that a substantive barrier to entry" to require all resources to have to install an inverter, he added. FERC included distributed energy resources in Order 842 because it believed they already needed such inverters, but doing so for DR and EE would be trying to "add capability that just isn't there," he said.

"If you require an EE resource to have an inverter, you won't have any EE resources," he said.

PJM's Glen Boyle, who facilitates the PFRSTF, seemed to agree.

"By definition, I don't know how EE could provide PFR. I don't know technically if that

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PJM: MISO Monitor Lacks Standing in Pseudo-tie Complaint

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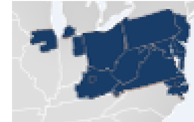
tions and then offering recommendations to PJM. The Monitor has no authority to enforce or to interpret the PJM [Operating] Agreement or Tariff, to direct changes in the market's operations, to alter market rules or to police individual members' compliance."

The court added that "other than making some regulatory filings," the Monitor is confined to informing FERC, other government agencies and RTO participating members "if it disagrees with PJM's implementation of the market rules or operation of the PJM market."

"Beyond its contractually assigned tasks, the Monitor has no independent legal interest of its own in the PJM markets," the court determined. It characterized the PJM Monitor as "an outside observer hired to study and report objectively on the market's operations ... not a creature of statute, and operates under no affirmative duty imposed by public law."

PJM originally asked FERC to dismiss the complaint last May on the grounds that Potomac "lacks the capacity by statute, order, contract or tariff to bring such a complaint in its role as an independent market monitor against PJM."

PJM NEWS



MRC/MC Briefs

Adequacy Analysis Approved Despite Concerns

WILMINGTON, Del. — Members at last week's Markets and Reliability Committee meeting approved PJM's proposed revisions to adjust the methodology for developing the capacity model for winter peak weeks, despite strong dissent from stakeholders concerned about how the modifications might affect capacity procurement.

PJM's Patricio Rocha-Garrido said the theoretical approach used by the RTO's PRISM modeling software to derive aggregate outage levels during the winter peak week is not representative of actual aggregate historical outage levels because it relies on historical outage data at the individual unit level rather than the aggregate level.

To "better account for the risk caused by the volume of concurrent [outages] observed historically during this week," the changes to Manual 20 create a "cumulative capacity outage probability table" using the historical forced outage data aggregated across the RTO. Planned outages will be based on the average historical planned outages aggregated across the RTO. (See "Winter Modeling Changes," *PJM PC/TEAC Briefs: May 3, 2018*.)

However, several stakeholders expressed concern that the changes would reduce the potential for using seasonal resources.

"Given the summer-dominated loss-of-load-expectation, it is my takeaway that this change isn't really going to have a measurable impact on the installed reserve margin," Old Dominion Electric Cooperative's Mike Cocco said. "However, if FERC orders changes to PJM's annual capacity construct in response to several FERC [Federal Power Act Section] 206 complaints, then these Manual 20 changes potentially would have an effect by limiting the ability of seasonal capacity market resources to contribute. I would say there's been a fundamental design change in [Capacity Performance], and I wouldn't personally put so much focus on historical data but be looking at developing projections based on the design changes."

"The challenge is making assumptions for the future; the only anchor point we have is the past," Rocha-Garrido said.

"I believe that the assumption that planned outages is not a PJM-controllable level is not correct. It implies that PJM does not have control of planned outages," CPower's Bruce Campbell said.

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PJM Gens Pitch Order 842 Compliance Plans

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would be capable," he said.

AEP Proposal

Under AEP's proposal, units that already provide PFR would be "encouraged to continue to do so" and can seek compensation at FERC. Units would annually confirm whether they will continue to provide the service, and PJM and transmission owners would revise system restoration plans accordingly.

A company representative attempted to dispel "public assertions by PJM" that AEP's proposal might "dismiss the important requirement of having primary frequency response during system restoration" by explaining that it "focuses the system restoration conversation where it should be, with transmission owner/operators/PJM and individual generators."

If a TO discovers it has "inadequate" PFR in its zone, the proposal calls for issuing a request for proposals "so that the most efficient resources, that actually want to provide the service, can participate" in "the most cost-effective mechanism for obtaining services: as needed." The RFPs would be temporary until enough new units come online or existing units upgrade — both of which would already be required to provide PFR — to mitigate the need.

AEP says PJM's proposal would force companies to pay to upgrade "resources that are in decline," namely coal and nuclear, and that prioritizing PFR would limit units' ability to optimize emissions.

The company touts its proposal as the only one "that recognizes the potential future need of adequate synchronous inertial response," meaning from resources that have rotating masses such as nuclear, coal- and gas-fired units.

"Did you know that simple cycle [combustion turbines] have less inertial response than a combined cycle CT? Both have much less than a coal unit," a company presentation said.

AEP says that units can't change PFR controls based on immediate needs.

"There is no switch! If you want PFR during system restoration, the unit must be tuned to provide it at all times. Re-tuning valves and governor action when there is a restoration event could increase chance of resource tripping significantly," it said.

The company also criticized what it sees as PJM's request to "bypass control limits" to optimize its PFR output.

PJM's Stefanowicz contested that assertion.

"We're not intending for anybody to bypass any safety functions," he said. "We're talking about removing outer loop controls like megawatt set point in a restoration mode and being responsive to frequency. We realize there's tuning and controls in place to run unit efficiency day in and day out."

AEP and Scarp agreed that the wording in PJM's proposal suggests that company should disable any controls that would impact PFR performance, such as emissions controls.

The task force has canceled its planned meeting for today but is maintaining one scheduled for July 25. Boyle predicted the agenda will be "fairly light unless we hear something back from FERC in the interim" on PJM's request for clarification.

Boyle said a stakeholder vote on the proposals would be planned tentatively for a Sept. 26 or Oct. 24 meeting if FERC hasn't responded.

Scarp endorsed a vote to at least clarify stakeholder positions in the absence of any word from FERC.

"My tolerance is not indefinite. FERC can and might sit on things," he said.

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He explained that lowering the expectations of units' availability in the winter increases the overall procurement of annual resources, which means there would be less opportunity for seasonal resources to fill in the difference between the baseline amount of always-available resources and seasonal peak demands.

Carl Johnson, who represents the PJM Public Power Coalition, said he would be requesting a review for next year's analysis of the model's sensitivities and incorporating a different set of assumptions about how CP resources should be operating.

Some generation owners defended the revisions as necessary.

"We do need to do this. We cannot ignore it," said Calpine's David "Scarp" Scarpignato, who said he's seen windmills in Texas stop working when the weather gets too cold.

Despite the concerns, stakeholders overwhelmingly endorsed the changes with 4.56 in favor and 0.44 opposed in a sector-weighted vote. The threshold for endorsement was 3.33.

The vote came on the same day PJM released a study analyzing the first year of partial implementation of CP in delivery year 2016/17 compared to the previous 2015/16 delivery year, which found that generator performance has improved since implementing CP even though the model has not been extensively tested by the extreme weather it was designed to address.

Unrelated to the MRC, Robbie Orvis of the clean energy consulting firm Energy Innovation, tweeted his own takeaways from the analysis. He noted the report's acknowledgement of poor performance from coal-fired units during the January cold snap known as the "bomb cyclone."

"Coal and oil Capacity Performance resources did not perform as well as their non-Capacity Performance counterparts during the cold snap. Understanding the source of this issue requires some additional analysis," the report said. "Both coal and oil Capacity Performance resources showed no improvement in forced outage rates from the polar vortex to the cold snap."

PJM said in the report that owners of coal-fired resources are making "major equipment overhauls and upgrades to ensure the longevity of these resources," winterizing equipment to prevent icing and freezing, and "performing routine testing and inspections to ensure the quality of their equipment."

Trust in Short Supply

A routine agenda item about cleaning up PJM's governing documents turned into an impromptu stakeholder referendum on the RTO's trustworthiness when stakeholders refused staff's request for authority to file similarly innocuous revisions for FERC approval without stakeholder endorsement.

> ***"Accidents have been made in the past, and sometimes we catch them for you."***
>
> **Carl Johnson,**
> **PJM Public Power Coalition**

Members endorsed revisions to the Tariff to clarify cross references with the Operating Agreement and Reliability Assurance Agreement, but they drew the line when staff asked for stakeholders' consent to file such non-substantive revisions in the future without having to bring them for an endorsement vote. Members allowed that staff wouldn't need to make a presentation on the revisions but demanded they be on the consent agenda so stakeholders can review the changes.

American Municipal Power's Steve Lieberman repeated his concerns that PJM was not affording the members sufficient time to review proposed changes to the governing documents and was shocked that the RTO's response to that criticism was to seek the approval to make future non-substantive changes without prior member approval. Lieberman called into question whether the changes would be deemed non-substantive from a stakeholder perspective even if considered as such by PJM.

"Accidents have been made in the past, and sometimes we catch them for you," Johnson added.

The reaction prompted Vince Duane, PJM's general counsel, to weigh in uncharacteristically, saying he was "disappointed" given that members often complain they are overwhelmed by the slow pace of the stakeholder process and the extreme time commitments necessary to meaningfully engage in it.

"If you can't trust us to make clerical changes … we've got a long way to go, and I don't like the future at all," he said.

Variable Operations & Maintenance Packages

Voting on whether to allow units to add certain variable costs in their cost-based offers derailed after American Electric Power asked to make several friendly amendments to its own proposal.

The proposed changes were a combination of proposals made by AEP and PJM that would allow units to include variable maintenance costs in cost-based energy offers as part of variable operations and maintenance (VOM). The package was endorsed at the Market Implementation Committee earlier this month. (See "Accounting for Maintenance Costs in Cost-based Offers," *PJM Market Implementation Committee Briefs: June 6, 2018*.)

The revisions appeared to be an effort to ensure the proposal is the first option to be voted on related to the matter. With the revisions, the proposal much more closely resembled a proposal brought for consideration at the meeting by Rockland Electric Co., which had previously expressed interest in a largely unpopular proposal from the Independent Market Monitor that eliminated all maintenance costs from energy offers. While RECO's proposal was not as strict, it eliminated some double counting that the PJM/AEP proposal overlooked.

Because the proposal had been endorsed by the lower committee, AEP was no longer allowed to revise it, so it had to offer "friendly amendments" that required endorsement from the membership to be included in the proposal. When some stakeholders balked at being asked to consider last-minute amendments, others suggested the vote be deferred to a later meeting to give everyone a chance to review the changes.

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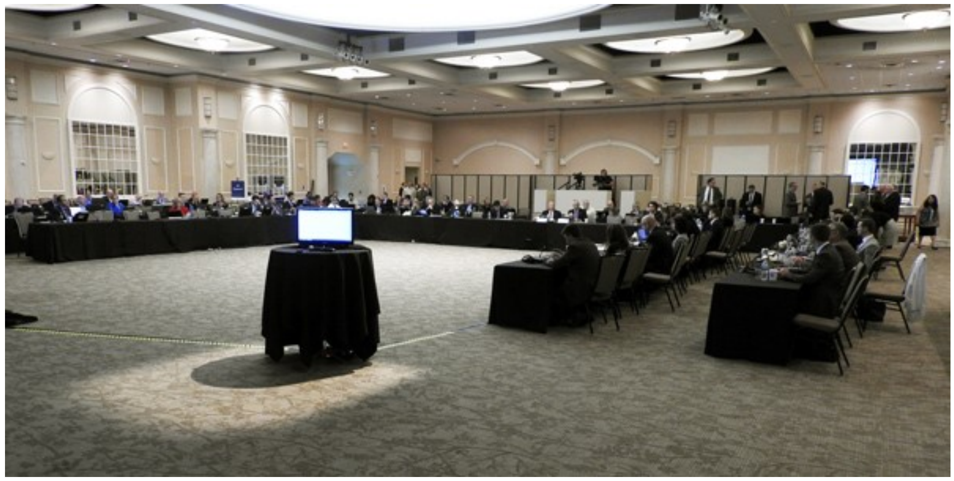

| © RTO Insider

PJM pushed members to commit to voting on the changes at the July MRC, explaining that the outcome affects the quadrennial review of the variable resource requirement curve in capacity auctions, which must be finalized in August. NRG Energy's Neal Fitch questioned that argument, saying the parameters are cemented in August but the actual calculations don't happen until January.

"I remain unconvinced that they're tied together," he said.

AMP's Ed Tatum echoed that, saying the MRC "does have the ability to make changes to VOM as it sees fit," irrespective of any "urgency" PJM desires to put on the timeline.

Stakeholders eventually agreed to defer the vote to the August MRC meeting, maintaining the current voting sequence for the proposals and declining to remand it to the MIC.

Waiting to make the revisions until after the quadrennial review is finalized will mean that these variable costs continue to be included in the cost of new entry calculation that is part of the foundation of PJM's capacity auction for the next four years. Any subsequent changes that would include them in the VOM component of energy offers would mean that generators could be paid for those costs in both the energy and capacity markets until the VRR can be revised again in four years.

Credit and Default

Staff announced two member issues that will impact market participant accounts.

On Thursday, PJM declared GreenHat Energy in payment default for failing to pay its weekly invoice from June 5 of $1.2 million. The RTO will liquidate the financial transmission rights portfolio GreenHat defaulted on by bidding the balance of the 2018/19 positions into the auction that opens on July 16. Any remaining positions that aren't liquidated there will be offered into the Aug. 16 auction.

Positions for 2019/20 and 2020/21 will be offered into the long-term FTR auction on Sept. 4. Those that aren't liquidated will be offered into the Dec. 3 long-term auction.

The net loss or gain on these liquidated positions will be added to the actual unpaid net charges or net credits that accumulate on these positions prior to being liquidated and will be included in the total default amount that will be allocated to PJM's members. Staff said they can't estimate the amount of the default allocation assessment but believe it is likely to be "in the tens of millions of dollars."

PJM will calculate each member's estimated default allocation assessment percentage that will be applicable to GreenHat's default after the June 2018 month-end invoices are issued on July 9, which staff hope to post by July 13. Staff said they will pursue "reasonable avenues of collection of GreenHat's default amounts" and that any money recovered would be allocated back to members that are charged a default allocation.

Staff stressed that they have made revisions to the credit policy that they estimated would have created a $60 million credit requirement for GreenHat to acquire its portfolio had they been in place at the time. Stakeholders are also considering additional revisions to the credit policy. (See "DC Energy FTR Credit Policy Complaint to FERC," *PJM Market Implementation Committee Briefs: June 6, 2018*.)

Staff also outlined a plan for allocating funds disgorged by PSEG Energy Resources and Trade as part of a FERC enforcement settlement. The more than $31 million — $26,905,736 plus interest of $4,494,264 — will be allocated as a negative operating reserve charge to market participants that received operating reserve charges during the period covered by the settlement. (See *PSEG to Pay $39.4M to Settle FERC Investigation*.)

The allocations will be made using a formula "consistent with the methodology utilized to allocate the original PSEG operating reserve credits" and staff hope to have the allocations credited by either June or July.

Stakeholder Process Revisions

During the Members Committee meeting, Chairman Mike Borgatti of Gabel Associates detailed several different initiatives to consider revising the stakeholder process, which had been a source of confusion.

First, he outlined an "academic" exercise being performed by Christina Simeone at the University of Pennsylvania's Kleinman Center for Energy Policy. Earlier last week, Simeone sent a letter to the committee explaining that her Aug. 2 workshop is outside the stakeholder process and had been planned prior to the announcement at May's committee meeting of similar initiatives within the stakeholder process. Simeone said she invited approximately 20 undisclosed PJM stakeholders that formed a "representative sample" of the membership and that "increasing the number of invitees risks distorting the representative sample and inhibiting in-depth group dialogue." The chosen few will discuss "data analysis pertaining to PJM governance

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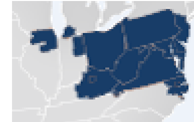

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trends," receive a presentation on the topic from Pennsylvania State University researchers and consider "a mock FERC-proposed rule on governance."

Borgatti offered no endorsement of the workshop.

"I don't control what Christina does. PJM doesn't. I didn't tell her I think this is a good idea," he said. "In my opinion, this is exactly what it states to be: It's an academic exercise."

He assured members that the workshop wouldn't be used to redesign the stakeholder process without their involvement and input.

PJM CEO Andy Ott echoed that view.

"I don't believe her scholarship has any direct impact on what we're going to do here," he said.

The initiative within PJM will begin with a half-day discussion in late July to consider "target-rich opportunities to improve our process," Borgatti said. He said the goal won't be to fix any problems identified, but rather to decide whether they're worth pursuing. The goal of the July session is to develop a recommended path forward that could be voted on at a future MC meeting.

Ott said he is aware of concerns about the stakeholder process and a "resignation" that nothing can be done to improve it.

"I think that feeling may not be the best situation," he said.

"On the thorny issues, I think we do have opportunities to do better," Tatum said, adding that collaboration will require opponents to not "immediately dig in their heels" and instead move forward without "preconceived notions."

Stakeholders Approve Manual, Operational Changes

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

- Manual 11: Energy & Ancillary Services Market Operations. Revisions developed to modify how the RTO estimates the synchronized reserve maximums for Tier 1 units in response to stakeholder concerns about significant overestimations. (See "Synch Reserve Changes," *PJM Operating Committee Briefs: May 1, 2018*.)
- Manual 6: Changes to address replacing terminated nodes that are part of FTR paths. These are changes to the manual only, so they will go into effect without a vote at the MC. (See "Modeling Node Changes," *PJM Market Implementation Committee Briefs: May 2, 2018*.)
- Revisions to the confidentiality provisions of the OA to specify that PJM may share member confidential information with reliability entities in addition to NERC. (See "Stakeholders Approve Changes to Manuals, Operations," *PJM Markets and Reliability Committee Briefs: May 24, 2018*.)
- Changes to the long-term FTR auction construct to correct current processes that allow participants to obtain the rights to congestion on transmission paths before the owners of the underlying auction revenue rights. The Monitor reiterated its opinion that the revisions are positive but don't go far enough. (See "Long-term FTRs Undercut Annual FTRs," *PJM Market Implementation Committee Briefs: June 6, 2018*.)

— Rory D. Sweeney

SPP News

SPP: No Need for 2018 Joint Study with AECI

SPP staff told stakeholders last week that the RTO will not conduct a joint transmission planning study with Associated Electric Cooperative Inc. this year, saying they were unable to find any "reasonable projects on either side of line."

"The next shot will be in 2020," said SPP's Clint Savoy during a June 21 conference call of the SPP-AECI Interregional Planning Stakeholder Advisory Committee. "We will have plenty of time to get our hands around what we want to look at in the next study."

New Madrid Power Plant transmission lines | *AECI*

A needs assessment along the seams identified more than 200 violations, but most were eliminated through model corrections or system adjustments, or because they were invalid contingencies. Most AECI violations were voltage issues, SPP said.

The RTO is proposing that one identified project, a 161-kV transmission line, be included in its 2018 near-term assessment.

A final report will be published at the end of July.

SPP and AECI have been performing joint studies every other year since 2010, as outlined in their joint operating agreement. Their only success was in 2016, when their study identified two projects near Springfield, Mo.: a new 345/161-kV transformer at AECI's Morgan Substation and uprate to an existing 161-kV Morgan-to-Brookline transmission line, and installation of a new 345-kV 50-MVAR reactor at City Utilities of Springfield's existing Brookline substation.

SPP would have been responsible for $17.1 million of the projects' estimated $18.75 million cost, but FERC last year rejected the proposed cost allocation for both projects.

The Brookline reactor project is now being addressed through the RTO's regional planning process as part of the 2018 near-term assessment, and the Morgan transformer project is being prepared for another filing at FERC.

AECI, based in Springfield, is owned by and provides wholesale power to six regional generation and transmission cooperatives.

— Tom Kleckner

FERC & FEDERAL NEWS

NERC: Grid Resilience, Reliability Improved in 2017

By Rich Heidorn Jr.

The bulk power system showed improved ability to rebound from severe storms last year while continuing to improve on most other reliability metrics, NERC said last week.

NERC cited two Category 5 events — the most severe — last year in hurricanes Harvey and Irma. "While wind and water damage were record setting, the restoration efforts and subsequent recovery times were improved from historical benchmarks," NERC reported in its State of Reliability 2018 report.

Harvey damaged 85 substations and more than 850 transmission line structures in South Texas, resulting in 225 transmission line outages. But utilities' use of amphibious vehicles, airboats and aerial drones allowed them to perform damage assessments even before roads were clear of flooding and storm debris, NERC noted.

Irma caused a record number of electric outages in Florida, with 4.45 million customers losing power in Florida Power & Light's territory, up from 3.24 million from Hurricane Wilma in 2005. But system hardening between the two storms reduced restoration time to 10 days from 18, NERC said.

The report recommended NERC encourage increased use of mutual assistance programs and drones and increase information sharing by publishing event reports and conducting other outreach on the lessons learned from the storms.

The storm observations were among six findings in the NERC report. The organization also found that:

- Inverter disconnects during transmission disturbances are becoming an emerging risk. It cited phase-to-phase faults on 220-kV and 500-kV lines during the Canyon 2 Fire east of Los Angeles last October, which resulted in the loss of more than 900 MW of solar PV in Southern California Edison's territory. It also noted a 500-kV line fault during the 2016 Blue Cut Fire in San Luis Obispo County, Calif., that led to the loss of 1,000 MW of BPS-connected solar PV. "The majority of these inverter-based resources tripped offline due to sub-cycle transient overvoltages and instantaneous protective action at the inverters to disconnect them from the grid," NERC said. (See *Solar Inverter Problem Leads CAISO to Boost Reserves*.)
- There was no loss of load because of cyber or physical security events, but "grid security, particularly cybersecurity, is an area where NERC and the industry must continually improve defenses as threats continue to rapidly evolve." It said the industry should continue to push for security improvements through "technological hardening, growing a culture of security, and effective information exchange between entities, the E-ISAC [Electricity Information Sharing and Analysis Center] and trusted partner organizations." It urged continuing to improve critical infrastructure protection standards and giving "particular attention" to supply chain risks. It called for expanding participation in the E-ISAC by lowering the cost of participation and seeking Department of Energy funding.
- Transmission outages resulting from failed protection system equipment, AC substation equipment (e.g., breakers, transformers) and human error — historically among the largest causes of transmission outages — all decreased over the last five years. "However, these areas remain major contributors to transmission outage severity and will remain areas of focus," NERC said.
- Frequency response performance remained acceptable but varied among the four interconnections. The Eastern, Texas and Quebec Interconnections "trended 'improving' during the arresting period," while the Western and Texas Interconnections "experienced statistically significant improvement during the stabilizing period" for 2013-2017. No interconnection fell below its interconnection frequency response obligation (IFRO).
- Protection systems misoperations rates declined for the fifth consecutive year but remain high priorities. The overall NERC misoperation rate fell to 7.1% in 2017 from 8.3% in 2016, while the three largest causes of misoperations remained the same year-over-year: incorrect settings/logic/design errors, relay failure/malfunctions and communication failures. "Protection system misoperations exacerbate the impact of transmission outages, thereby increasing their severity," NERC said.

The report said the only metric "indicating cause for concern" is planning reserve margins, with all regions except for the Texas Regional Entity projecting sufficient reserves for the next five years.

It cited ERCOT's preliminary summer seasonal assessment of resource adequacy (SARA), which reported that operational tools such as load management and distribution voltage reductions could be needed to maintain sufficient operating reserves.

In its final SARA for summer, ERCOT reported that its anticipated resources had increased by 581 MW, NERC noted. (See *ERCOT Sees Enough Generation Through 2022, 73-GW Peak for Summer*.)

Annual frequencies of automatic outages of 200-kV+ transformers for 2013–2017. Green arrows indicate overall improvement. | *NERC*

FERC & FEDERAL NEWS

FERC Grants Stay on Klamath Hydro License

By Michael Kuser

FERC on Thursday granted PacifiCorp a stay on the commission's March 15 order regarding an application to partially transfer the company's license for its Klamath Hydroelectric Project to the Klamath River Renewal Corp. (Project Nos. 2082-065, 14803-002).

The 169-MW Klamath project (No. 2082) is located in Oregon and California and includes federal lands administered by the U.S. Bureau of Reclamation and U.S. Bureau of Land Management. The project consists of eight developments, seven with hydroelectric generation.

In September 2016, PacifiCorp and the Renewal Corp. proposed that the existing license for the project be amended to remove four developments and place them into a new license for the Lower Klamath Project (No. 14803), to be held by the Renewal Corp.

The application was made in accordance with the Klamath Hydroelectric Settlement Agreement, signed in 2010 and resigned in 2016 by all concerned parties, including the Yurok and Karuk Tribes, to resolve disputes over PacifiCorp's efforts to relicense Klamath.

The Renewal Corp. also filed an application to surrender the Lower Klamath Project license and physically remove those four developments from the river, contingent on the commission's approval of the amendment and transfer application.

'Duplicative and Wasteful Work'

In its March 15 order, the commission found that "transferring a project to a newly formed entity for the sole purpose of decommissioning and dam removal raises unique public interest concerns, specifically whether the transferee — the Renewal Corp. — will have the legal, technical and financial capacity to safely remove project facilities and adequately protect project lands."

The commission thus "authorized only the administrative amendment of the license for the Klamath project, effective as of the day the order was issued, such that PacifiCorp would remain the licensee for both the Klamath project and the Lower Klamath Project until we receive certain additional information."

Klamath River Project

In its motion for a stay, PacifiCorp stated that compliance measures associated with dividing the Klamath project into two separate licenses could exceed $3.1 million.

PacifiCorp argued that requiring it to complete the license amendment compliance "would result in duplicative and wasteful work" in the event the license transfer is subsequently approved and the Renewal Corp. is required to undertake the same tasks. Alternatively, PacifiCorp stated that the measures would serve no purpose and may later need to be reversed in the event the transfer is not approved.

FERC stayed the order pending its ultimate ruling on the license transfer. "PacifiCorp's arguments demonstrate that justice requires a stay," the commission's June 21 order said.

The commission also dismissed PacifiCorp's alternative request for rehearing as moot.

FERC Seeks More Info on CPV Plants' Ownership

By Rory D. Sweeney

Four Competitive Power Ventures gas-fired generators must provide additional information to prove they have adequately mitigated market power before they can make market-based sales, FERC ruled Thursday (ER13-343-008, *et al.*).

The four plants are the 785-MW CPV Towantic Energy Center in Oxford, Ct.; 680-MW CPV Valley in Wawayanda, N.Y.; the 725-MW CPV Shore, which appears to have been renamed CPV Woodbridge in Keasbey, N.J.; and the 725-MW CPV Maryland, which appears to have been renamed CPV St. Charles in Waldorf, Md. They filed on June 30, 2017, for permission from the commission to sell power at market-based rates and amended the filing twice, most recently on Feb. 2.

CPV Towantic Energy Center | *CPV*

CPV is owned by six funds within the Global Infrastructure Partners private equity portfolio. Towantic is also partially owned by another fund, the Ullico Infrastructure Master Fund, that is managed by Ullico Investment Advisors, which is partially owned by two pension funds.

FERC's market-based rate rules require applicants to provide information regarding affiliates and upstream ownership. It considers as affiliates any entity that owns at least 10% of the outstanding voting securities of the applicant.

The pension funds own more than 10% of Towantic, but CPV argued that they are only allowed to vote 9% of their shares. FERC said that doesn't account for their entire ownership.

"Because the pension funds are included among the stockholders whose votes determine how the votes of the excess shares will be allocated, the sum of votes by the pension funds of their 9% of the shares plus the proportional vote of their excess shares gives the pension funds an effective vote greater than 10%," the commission said.

It instructed the applicants to update their horizontal and vertical market power analysis with their affiliates' generation and transmission assets and inputs to electric power production. FERC gave them 30 days to comply.

FERC & FEDERAL NEWS

FERC Denies WestConnect's Order 1000 Rehearing Request

By Tom Kleckner

FERC last week denied a rehearing request of its November 2017 order on remand regarding transmission cost allocation in the WestConnect planning region. WestConnect's transmission providers requested the rehearing in December after FERC affirmed its original order in the proceeding (ER13-75-012).

In 2016, the 5th U.S. Circuit Court of Appeals remanded a commission order rejecting the utilities' Order 1000 compliance filing.

The utilities' initial compliance filing included a provision stipulating that costs for projects selected in a regional plan would be allocated only to beneficiaries who agreed to participate in those projects. Other WestConnect members participating in the planning process would not be obligated to pay for those projects' costs, a measure designed to avoid discouraging nonpublic utility transmission providers from participating in planning.

FERC found that WestConnect's "non-binding" process did not comply with Order 1000, which prohibits planning participants from claiming an exemption from cost allocation merely by asserting they receive no benefits from the resulting infrastructure. The commission noted that the "fundamental driver" of Order 1000 was to minimize "free ridership" within the system.

The court asked FERC for "additional factual findings" on WestConnect's planning process, saying the commission's mandates regarding the role of nonpublic utility transmission providers were arbitrary and capricious and that it had not shown its orders would not produce unjust rates.

FERC's November order upheld the original ruling and added further explanation of its reasoning. (See *FERC Affirms WestConnect Cost Allocation Ruling*.)

The WestConnect transmission providers argued the order on remand did not address deficiencies identified by the court and therefore violated "both the express purpose of Order No. 1000 and the principle of cost causation under the Federal Power Act."

FERC countered that the rehearing request relied primarily on WestConnect's free-rider argument, and it said that its order on remand explained "at length" why the commission often "expects nonpublic utility transmission providers will accept allocation of the costs of transmission projects that benefit them (i.e., they will pay their share of the costs of those projects), and why any potential free ridership would occur for only a limited subset of transmission projects."

"We continue to expect that free ridership in the WestConnect region will be limited, and we note that the complete elimination of free ridership is not required by the just and reasonable standard of the FPA or Order No. 1000," FERC said.

The commission said attempts to eliminate free ridership "may not be feasible" given the region's "uniquely integrated nature" and the fact that Order 1000's requirements do not apply to nonpublic utility transmission providers. The group's planning region covers Arizona, California, Colorado, Nevada, New Mexico, South Dakota, Texas and Wyoming.

"We continue to believe that the approach to regional transmission planning and cost allocation accepted in the compliance orders and order on remand is consistent with Order No. 1000 and will result in just and reasonable rates while taking into account the unique characteristics of the WestConnect region," FERC said.

FERC & FEDERAL NEWS

Courts Uphold Minn. ROFR, MISO Cost Allocation

By Amanda Durish Cook

Federal courts last week rejected two challenges from MISO stakeholders involving FERC Order 1000.

Court Upholds Minn. ROFR

The U.S. District Court for Minnesota on June 21 dismissed competitive developer LS Power's challenge to the state's right of first refusal law (17-4490).

The ruling allows Minnesota to continue to grant in-state transmission owners a ROFR to build new high-voltage transmission lines that connect to their facilities. LS Power had claimed that state ROFRs essentially invalidate Order 1000's elimination of the federal ROFR and undermine FERC's goal of competition. The U.S. Justice Department had joined the company's challenge, claiming Minnesota's law unconstitutionally regulates interstate commerce, in violation of the Constitution's dormant Commerce Clause. (See *Justice Department Joins Challenge to Minn. ROFR Law*.)

But the court said the law neither overtly discriminates nor imposes a burden on interstate commerce.

The ROFR "is part of Minnesota's broader regulation of the provision of electricity to the consumer market," the court said.

It cited 1997's *General Motors Corp. v. Tracy*, in which the U.S. Supreme Court allowed Ohio to continue to tax natural gas sales differently depending on whether they were made to in-state regulated public utilities or out-of-state marketers. The Supreme Court determined that when evaluating a challenged state statute, controlling weight must be given to the possibility of negative consequences on the ability of regulated utilities to serve their captive consumers in a monopoly market.

In last week's decision, the district court said many of the entities that own existing transmission facilities in Minnesota are regulated public utilities that serve captive markets and operate as monopolies.

"The reasons cited in support of giving greater weight to the monopoly market in *Tracy* apply here; namely, to avoid any jeopardy or disruption to the service of electricity to the state electricity consumers and to allow for the provision of a reliable supply of electricity," the court concluded.

As in *Tracy*, the court said it could not predict the economic consequences of upending the ROFR.

"Minnesota not only gives existing owners a right of first refusal to build new transmission lines that will connect to their existing facilities, but in return Minnesota also places extensive regulatory burdens on those owners. Any intervention by the court could upset the balance between those burdens and regulation."

The court's ruling recognized that both Congress and FERC have said Minnesota has a right to adopt a ROFR for new transmission lines. It also said the state's statute does not discriminate against out-of-state entities because it "draws a neutral distinction" between existing TOs whose facilities will connect to a new line and all other entities, "regardless of whether they are in-state or out-of-state."

Were it not for the state's ROFR, the Huntley-Wilmarth line — ITC Midwest and Xcel Energy's planned 50-mile, 345-kV transmission line in southern Minnesota — would have been opened for MISO's competitive bidding process in 2016 under Order 1000.

| Ameren

Review of MISO-SERTP Allocation Denied

In a separate case, the D.C. Circuit Court of Appeals on June 22 denied Ameren's petition for review of a cost allocation proposal under Order 1000 because the appeal introduced an argument that was not first raised in a FERC proceeding (16-1150).

The case dates to 2013, when MISO filed a cost allocation methodology under Order 1000 for interregional projects developed with seams neighbor Southeastern Regional Transmission Planning (SERTP). The RTO had proposed to allocate its costs for those projects based on a cost-avoidance method that would include the estimated costs of displaced regional transmission projects rendered unnecessary by the interregional project.

However, MISO proposed that its calculation would include only those costs for avoided projects that had been identified in its annual Transmission Expansion Plan but not yet approved, while excluding costs for approved projects.

FERC rejected the proposal, saying that excluding approved regional projects from the analysis would undervalue potential benefits of an interregional project, especially because approved projects tend to be the most cost-effective. Order 1000 requires the costs of an interregional project to "be allocated in a manner roughly commensurate with the project's benefits."

In appealing FERC's decision, Ameren argued that the commission's mandated change in cost allocation could harm developers — and by extension, their

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Lott, Breaux Join Push for Baker-Schultz CO2 Dividend Plan

By Rich Heidorn Jr.

Former Senate Majority Leader Trent Lott (R-Miss.) and former Sen. John Breaux (D-La.) have joined a new organization to build political support for the carbon dividend proposal offered last year by Republican party elders James A. Baker III and George P. Schultz.

Lott and Breaux are co-chairing the advisory board of Americans for Carbon Dividends, which announced itself Wednesday with financial backing from Exelon, First Solar and the American Wind Energy Association, along with a poll it said shows wide bipartisan support for the Baker-Schultz proposal.

Baker and Schultz's Climate Leadership Council, formed last year, proposed a carbon fee of $43/ton starting in 2021 that would return the funds to Americans as monthly dividends. Backers say the plan would provide net payments to 70% of Americans while reducing emissions more than the U.S. commitment under the Paris Agreement.

Escalating the fee by 3 to 6% per year would reduce carbon emissions by 34 to 36% from 2005 levels by 2025, they say, and eliminate the need for existing carbon regulations such as the Clean Power Plan. (See *Baker's Carbon Dividends Plan Reaches Across Aisle*.)

"This is the inevitable climate solution and the most likely to lead to a grand bipartisan climate compromise," said Hill+Knowlton Strategies Managing Director Richard Keil, the newly formed group's spokesman in a press conference Wednesday. Keil noted that former Federal Reserve Chairs Ben Bernanke and Janet Yellen and former EPA Administrator Christine Todd Whitman have signed on to the plan as founders of the CLC.

Keil said the new group was formed to signal the move to an "inside the Beltway strategy" after the CLC spent last year on policy development and working outside the Beltway.

Breaux acknowledged Congress is unlikely to embrace the plan any time soon. "This is an educational program that we're embarking upon … which means we will be talking to leaders in the Congress in both parties. … This is not a sprint. It's going to be a marathon."

"I think that both parties are desperate … to find something that they can agree on," he added.

"I took quite some time to look at this issue and think about it," Lott said. "I'm convinced this is the solution that we have been looking for as a country and, frankly, in the world."

Ted Halstead, CEO of the carbon dividends group and the CLC, said Republicans' views on climate change have shifted over the last five years. "[There's] no real differences numerically between where younger Republicans and younger Democrats are on this. I don't want to overstate it because I don't have a side-by-side comparison of numbers to do this, but it at least in general reminds me about how … attitudes within the Republican Party shifted on issues like gay marriage over the last 10 years. The next generation of Republicans thinks

Trent Lott | *Bipartisan Policy Center*

about these and other things differently than some of their older peers."

The group released a poll showing 81% of likely voters, including 71% of moderate Republicans and 58% of conservative Republicans, agree the government should act to limit carbon emissions. It said the tax-and-rebate strategy is favored by a 2:1 margin overall.

"Members of Congress pay attention to polls," Breaux said.

In addition to bringing on Hill+Knowlton to handle communications, Americans for Carbon Dividends has hired Squire Patton Boggs — where Lott and Breaux are senior counsels — as lobbyist and Margaret Lauderback, an ally of Rick Perry and House Majority Leader Kevin McCarthy, to lead fundraising. Political consultant Mark McKinnon, a former adviser to Sen. John McCain (R-Ariz.) and former President George W. Bush, and Joe Lockhart, White House press secretary under President Bill Clinton, have signed on as senior advisers. Former Bush aide Karen Hughes is of counsel.

Courts Uphold Minn. ROFR, MISO Cost Allocation

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customers — that had already invested in MTEP-approved projects that were later displaced.

The company also raised a new concern in the appeals case: that FERC's decision did not comport with its obligation to ensure just and reasonable rates.

The D.C. Circuit seized on the new argument and said that petitioners must first raise arguments in front of FERC before approaching an appeals court.

Ameren contended that the argument of just and reasonable rates lies at the heart of every FERC rate order and should not be considered a new argument in a petition for review, but the court countered that the company misunderstood the Federal Power Act's requirement that arguments be exhausted at FERC before an appeal.

"If we were to accept petitioners' rationale, parties would never need to raise specific legal arguments before the commission as long as they broadly challenge the justness and reasonableness of rates," the court said.

At any rate, the court said, FERC had already adequately explained its decision requiring MISO to account for approved MTEP projects in its SERTP cost allocation methodology.

"In the end, we conclude that the commission adequately responded to petitioners' concerns about the possible effects of including approved regional projects in the cost allocation calculation. Petitioners ultimately disagree with the commission's policy judgment about whether the importance of properly calculating an interregional project's benefits outweighs the effects of potentially displacing approved regional projects. Petitioners' disagreement with the commission's resolution of that issue does not render the commission's explanation any less thorough or reasoned," the court concluded.

Louisiana Regulators Approve AEP's Wind Catcher Project

By Tom Kleckner

American Electric Power on Wednesday announced that Louisiana's Public Service Commission has approved its proposed mammoth Wind Catcher Energy Connection project.

AEP's Louisiana operating company, Southwestern Electric Power Co., would own 70% of the $4.5 billion project, a 360-mile, 765-kV line to Tulsa from a 2-GW wind farm being built by Invenergy in the Oklahoma Panhandle. AEP affiliate Public Service Company of Oklahoma would own the other 30%. The two utilities would purchase the wind facility upon its completion, scheduled for the fourth quarter of 2020.

SWEPCO agreed to a cap on construction costs, qualification for 100% of federal production tax credits and minimum annual production goals, among other commitments.

"Wind Catcher is a major investment in clean energy that will produce long-term savings for Louisiana customers and further diversify our energy resource mix," AEP CEO Nick Akins said in a press release. "The Louisiana Public Service Commission's decision recognizes the benefits Wind Catcher will bring to Louisiana customers."

AEP says it expects to save its customers more than $4 billion over the 25-year life of the wind farm, primarily through a reduction in the fuel portion of their bills that begins in 2021.

The PSC joined Arkansas regulators in approving the project. The Oklahoma and Texas commissions have yet to weigh in, but AEP appears to face longer odds before those two agencies.

The head of the Oklahoma Corporation Commission's Public Utility Division and the state's attorney general have indicated in regulatory filings that they remain opposed to the project, and landowner opposition to the transmission line has been running high.

The OCC has scheduled a public comment hearing for July 2. A law firm hired by Bixby to represent the city, however, has requested the hearing take place no sooner than Sept. 1 to allow time for the city to prepare additional comments.

Texas' Public Utility Commission staff has disagreed with an administrative law judge's preliminary decisions approving Wind Catcher, saying "the evidence presented does not support a sufficient probability of improvement of service or lowering of costs to ratepayers."

Staff recommend that the commission condition its approval on a requirement that SWEPCO guarantee tax credits in the amounts represented by the utility, and that it guarantee some level of net benefits to customers over and above the annual revenues that customers are obligated to pay for the project's base rate costs. The PUC will take up the issue at its July 12 open meeting (Docket No. 47461).

Company Briefs

Appeals Court Stays Verification of Mountain Valley Pipeline Permit

The 4th U.S. Circuit Court of Appeals on June 21 granted a motion by five environmental groups to stay an Army Corps of Engineers water permit for the Mountain Valley Pipeline.

The permit included a condition from the West Virginia Department of Environmental Protection that work on the natural gas pipeline at river crossings had to be completed in 72 hours. But the pipeline's developers said crossings of the Elk, Gauley, Greenbrier and Meadow rivers would take four to six weeks to complete, leading the environmental groups to argue that the developers shouldn't have been able to get the permit.

The court stayed the verification of the permit until it can hear the broader challenge to the corps' approval of the pipeline in late September.

More: *Charleston Gazette-Mail*

Tesla to Close a Dozen Solar Installation Facilities in Downsizing

Tesla plans to close about a dozen solar installation facilities in nine states as part of its recently announced downsizing, Reuters reported on June 21, citing internal company documents and seven current and former employees of the electric car maker and solar power installer.

The company also will end the retail partnership that its solar division had with Home Depot, even though the employees said the partnership generated about half the division's sales.

Tesla declined to say which sites it planned to shut down, as well as how many employees would lose their jobs or what percentage of its solar workforce they represent.

More: *Reuters*

New Orleans City Council Names Team to Investigate Actor Hiring

The New Orleans City Council on June 21 named former Assistant U.S. Attorney Matt Coman to lead a team of attorneys from his law firm (Sher, Garner, Cahill, Richter, Klein & Hilbert) to investigate the role Entergy New Orleans played in the hiring of actors to appear at council hearings to support a gas-fired power plant it wants to build.

The council also put retired Criminal District Court Judge Calvin Johnson on the team, which initially is contracted to work for 30 days but could work longer if its findings indicate it should.

More: *The Advocate*

Colorado Supreme Court Remands Boulder-Xcel Dispute

The Colorado Supreme Court on June 19 sent a lawsuit filed by Xcel Energy against Boulder, which is trying to form a municipal utility, back to Boulder District Court.

Xcel contended in the lawsuit that Boulder hadn't shown a utility could meet the city charter's requirements. Boulder District Judge Judith LaBuda ruled against Xcel, but the Colorado Court of Appeals reversed LaBuda's dismissal of the lawsuit, finding instead that the lawsuit had been filed

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prematurely.

The Supreme Court agreed with Boulder's assertion that the Court of Appeals erred in its ruling, but it also agreed that Xcel had asserted a viable claim against the city.

More: *Daily Camera*

Suniva Requests Permission To Abandon Solar Panels

Suniva, which was one of the two companies that initiated the trade case that led to President Trump imposing tariffs on solar manufacturing equipment, on June 19 asked a U.S. Bankruptcy Court in Delaware to let it abandon solar panels with a liquidation value of more than $6 million.

The company sold off its technology, licenses and manufacturing equipment last month in an auction that was won by its biggest creditor, SQN Capital Management.

More: *Reuters*

PG&E Taking $2.5 Billion Charge for Fire Liabilities

Pacific Gas and Electric said June 21 it will take a $2.5 billion charge against its second-quarter earnings for losses it expects to realize for its liabilities from the fires that swept through Northern California last fall.

The company said its liabilities could exceed $10 billion after state fire officials determined that PG&E power lines started several of the fires. PG&E said more than 200 lawsuits have been filed against it because of the fires.

More: *The Associated Press*

ERCOT TAC's June 28 Meeting Canceled

The June 28 meeting of ERCOT's Technical Advisory Committee has been canceled. TAC Chair Bob Helton cited the small number of items in canceling the meeting.

The TAC's next scheduled meeting is July 26.

Entergy Selects Arkansas CEO To Head New Organization

Entergy said June 18 it will name Entergy Arkansas CEO Rick Riley to the newly created position of senior vice president of distribution operations and asset management, effective July 1.


Riley

The company said Riley will head a new organization that will support its customer-centric strategy at its five operating companies as they modernize and strengthen their electric grids. He will report directly to Rod West, group president of utility operations.

Laura Landreaux, Entergy Arkansas' finance director, will replace Riley as CEO.

More: *Entergy*

Leach Xpress Pipeline to Resume Operations in July

TransCanada's Columbia Gas Transmission unit said June 18 that the section of the Leach Xpress natural gas pipeline in Marshall County, W.Va., that was damaged in a June 7 blast will resume operations early next month.

The company said it is continuing to work with federal pipeline safety regulators on a repair plan for the pipeline.

Columbia hasn't disclosed the cause of the explosion.

More: *Reuters*

Federal Briefs

Puerto Rico Governor Signs Bill to Privatize PREPA

Puerto Rico Gov. Ricardo Rossello on June 20 signed a bill to privatize the Puerto Rico Electric Power Authority.

The bill allows the Puerto Rican government to sell PREPA's power generation plants and create public-private partnerships for the transmission and distribution of electricity and for billing, meter-reading and other services.

The territory's legislators now have 180 days to approve a measure establishing a public energy policy and regulatory framework that its Energy Commission will use as a guide to award contracts.

More: *The Associated Press*

Couple Involved in Pruitt Condo Suggested EPA Hire Friend


Pruitt

The woman who rented EPA Administrator Scott Pruitt a room in a D.C. condo at a below-market rate and her lobbyist husband tried to get the agency to hire a family friend, according to recently released emails.

In an email to Ryan Jackson, who is Pruitt's chief of staff, the lobbyist, J. Steven Hart, said his wife, Vicki, had talked to Pruitt about hiring Jimmy Guilliano, a recent college graduate.

EPA spokesman Jahan Wilcox said in an email June 24 that the agency didn't hire Guilliano and it stands by its previous statement that Hart did not lobby it.

More: *The Washington Post*

OSC Investigating Claims Pruitt Retaliated Against Employees

The Office of Special Counsel is looking at claims that EPA Administrator Scott Pruitt retaliated against employees who pushed back against his spending and management, *Politico* reported June 24, citing three people familiar with the matter.

At least six current and former agency officials reportedly were fired or reassigned, allegedly for questioning Pruitt's need for 24-hour security protection, as well as his other spending and practices. The sources told *Politico* that OSC is

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interviewing some of those employees.

More: *Politico*

EPA Nixes Plans to Open Office in Pruitt's Hometown

EPA said in a June 19 letter to a Democratic representative that it has scrapped plans to open an office for Administrator Scott Pruitt in his home town of Tulsa, Okla.

"Although the EPA staff did explore whether office space was available in Tulsa, this possibility was ultimately abandoned," Troy Lyons, EPA associate administrator for congressional affairs, said in the letter to Rep. Eddie Bernice Johnson (D-Texas), the top Democrat on the House Science Committee.

Johnson and two other high-ranking Democrats on the committee had obtained documents that showed EPA staff were trying to establish the office.

More: *The Hill*

US Oil, Gas Operations Methane Leakage 60% Above Estimates

U.S. oil and gas operations emit 13 million metric tons of methane annually — nearly 60% more than current estimates and enough to offset much of the climate benefits of burning natural gas rather than coal, according to a study published in *Science* on June 21.

The study, which was led by Environmental Defense Fund researchers and included 19 coauthors from 15 institutions, estimated that the U.S. oil and gas supply chain has a leak rate of 2.3%, significantly higher than EPA's 1.4% estimate.

The study said the additional amount of gas leakage it identified is enough to fuel 10 million homes and is worth an estimated $2 billion.

More: *The Washington Post*

McIntyre Says Perry Will Make 'Right Decision' on Emergency Declaration


McIntyre

FERC Chairman Kevin McIntyre said June 19 that Energy Secretary Rick Perry will make "the right decision" on whether to declare a grid emergency to keep struggling nuclear and coal-fired power plants open.

"If anybody is going to make a decision, right or wrong, it's going to be him," McIntyre told reporters on the sidelines of a natural gas roundtable sponsored by the American Gas Association in D.C. "The law assigns that role to him. And I trust he will make the right decision."

McIntyre said the Department of Energy has not conferred with FERC and doesn't have to.

More: *Washington Examiner*

STATE BRIEFS

CONNECTICUT

Malloy Signs Climate And Energy Bills

Gov. Dannel P. Malloy on June 20 signed two bills that increase the state's greenhouse gas emission reduction target to 45% of 2001 levels by 2030; boost the amount of electricity that power suppliers must get from renewable sources to 40% by 2030; and change how electric customers with solar generation systems are compensated for electricity they produce but don't use.

The changes in compensation for solar power must be reviewed by the Public Utilities Regulatory Authority, which also will determine the rate solar customers are paid for their excess power.

Environmentalists praised the increases in the emission reduction target and the amount of renewable power that electricity suppliers must buy but were critical of the change in the method of compensating solar customers.

More: *Connecticut Post*

DELAWARE

EV Rebate Program Extended to End of Year

The Department of Natural Resources' Division of Energy and Climate said June 19 it will extend its Clean Transportation Incentive Program to the end of the year.

The rebates offered by the program — which range from $1,000 for a personal vehicle to $20,000 for a natural gas truck — will remain the same, but the program's eligibility requirements will be updated slightly for clarity and flexibility and will take effect July 1.

The state says the program, which was launched in July 2015, has provided rebates to more than 750 drivers for the purchase or lease of electric and plug-in hybrid electric vehicles. It also has provided more than 200 rebates for EV charging stations at residential and commercial properties and workplaces.

More: *The News Journal*

MAINE

PUC Approves 5.34% Rate Hike for Emera

The Public Utilities Commission on June 19 approved a distribution rate increase of $4.48 million, or 5.34%, for Emera Maine, less than the $10 million, or 12%, increase the company had sought.

An Emera spokeswoman said most of the difference was a result of the Tax Cut and Jobs Act. Commission staff had recommended a 5.28% increase.

More: *Bangor Daily News*

MARYLAND

Hogan Nominates Replacement For Departing Chair

Gov. Larry Hogan on Wednesday nominated Jason Stanek, senior counsel to the U.S. House Energy and Commerce Committee's Subcommittee on Energy, to replace Public

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STATE BRIEFS

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Service Commission Chairman W. Kevin Hughes, who said June 19 he will leave the commission when his term ends June 30.


Stanek

Stanek has worked on Capitol Hill for about a year. Prior to that, he worked at FERC for 16 years, including a position in its Office of Enforcement.

Gov. Martin O'Malley appointed Hughes to the PSC in September 2011 and named him chairman in January 2013.

More: *The Baltimore Sun*; Public Service Commission

NEW YORK

Cayuga Applies to Convert Lansing Unit to Gas

Cayuga Operating Co. said June 22 it has submitted an air permit modification application to the Department of Environmental Conservation that would allow it to convert a 155-MW coal-fired generation unit at its Lansing power plant to natural gas. The company doesn't plan to convert the plant's other generation unit, only using it to meet demand.

Additionally, Cayuga has applied for more than 1.5 million New York State Energy Research and Development Authority renewable energy credits to help pay for the construction of an 18-MW solar farm on the plant site. The company said this is its second attempt to obtain the credits, and it's optimistic it will be awarded them in the round scheduled to be announced in October.

More: *The Lansing Star*

OHIO

Siting Board OKs Harrison Power's Gas Plant

The Power Siting Board on June 21 authorized Harrison Power to build a 1,050-MW natural gas-fired, combined cycle electric generation facility in Cadiz.

The facility will interconnect to the grid via a 138-kV transmission line to AEP Ohio Transmission's Nottingham Substation.

Harrison Power proposes to begin constructing the power plant in October and begin commercial operation of it by June 2021.

More: *Harrison News-Herald*

PENNSYLVANIA

County Commissioners Vote to Oppose Transource Tx Project

The Franklin County Commission voted June 21 to oppose a proposal by Transource Energy to construct 29 miles of transmission lines through the county.

The commissioners haven't discussed getting legally involved in the deliberations over the power line before the Public Utility Commission, but in February they sent the PUC a letter that, Commissioner Bob Thomas said, "showed strong support for the folks who have been fighting the project."

More: *Herald-Mail Media*

Study: Power Prices Remain Low Even with Nuke Closures

Power prices in the state will remain low even if the Three Mile Island and Beaver Valley nuclear power plants close, according to a study by a Pennsylvania State University professor that will be published in an upcoming issue of *The Electricity Journal*.

The university said June 19 that Associate Professor of Energy Policy and Economics Seth Blumsack studied the impact of the two plants closing and found wholesale energy prices would rise 4 to 10% each year over a three-year period if they weren't replaced. If they are replaced by natural gas power plants, however, wholesale energy prices will decline each year by 9 to 24%.

Both Exelon, which owns TMI, and FirstEnergy Solutions, which owns Beaver Valley, have announced plans to close the plants, barring moves by the state and/or federal government to subsidize them.

More: *Penn State*

Nine States Call for Rules to Boost ZEVs

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the report acknowledges that ZEV adoption so far has been focused mainly on "enthusiastic early adopters" and that much wider deployment, including commercial/utility vehicle fleets, will be needed to make an impact on climate change.

The report says that automakers are now required to deliver fully electric vehicles to meet specific sales goals in Oregon and other coalition states in the Northeast. More than $500 million in charging infrastructure is planned for the Northeast corridor, and California is now focusing on bolstering its infrastructure through $738 million in utility incentives. (See *CPUC Approves Utility EV Infrastructure Programs* and *California to Require Sharp EV Charger Growth by 2025*.)

Total U.S. ZEV sales grew from 200,000 to 750,000 since 2013, as battery costs declined and the number of available models and options increased. The states say light-duty vehicle adoption and public-private partnerships are important tools in wider adoption.

California Attorney General Xavier Becerra and others have challenged in court EPA's April 4 decision to roll back previous GHG emission standards related to light-duty vehicles, which the agency said "may be too stringent."

Several governors referenced the EPA decision when announcing the new action plan, with Connecticut Gov. Dannel P. Malloy saying: "When it comes to taking aggressive steps to fend off the most damaging impacts of climate change, the Trump administration not only continues to bury its head in the sand but is actively working to dismantle common sense efforts to reduce carbon pollution."

Light-duty vehicles, classified as those with gross vehicle weight of 10,000 pounds or less, are the largest contributor to GHGs in the nine states (24% of emissions), followed by the electricity sector (19%) and industry (17%), with the remainder coming from heavy-duty vehicles, agriculture, the residential sector, other transportation and the commercial sector.