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EIM OKs 'Simple' GHG Compliance Plan

By Robert Mullin

Energy Imbalance Market officials on Thursday approved a proposal to prevent market participants outside California from skirting the state's greenhouse gas compliance obligations by "shuffling" low-emissions resources into CAISO while ramping polluting resources to serve load closer to home.

The EIM Governing Body's decision nearly completes a two-year effort to reach agreement on the issue among a broad swath of stakeholders, including the California Air Resources Board, environmentalists, and power producers and utility regulators in the inland West.

"This has been a long effort," Governing Body Chair Valerie Fong said during the group's July 12 meeting. "It has required active engagement by market participants. It has required active listening and rethinking by ISO staff and management. So, I do think we're in a better place today than we were a year ago."

Under CAISO rules, the proposal falls under the Governing Body's "primary" decisional authority, meaning it will now advance to the consent agenda of the ISO's Board of Governors before submission for FERC approval.

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Exelon Bids $140M for FirstEnergy's Retail Business

By Rich Heidorn Jr.

Exelon announced last Tuesday it has signed an agreement to purchase the retail business of bankrupt FirstEnergy Solutions for $140 million in cash, an acquisition that would increase the number of customers for its Constellation unit by almost 50%.

The deal, which must be approved by the U.S. Bankruptcy Court for the Northern District of Ohio, would transfer FES' retail

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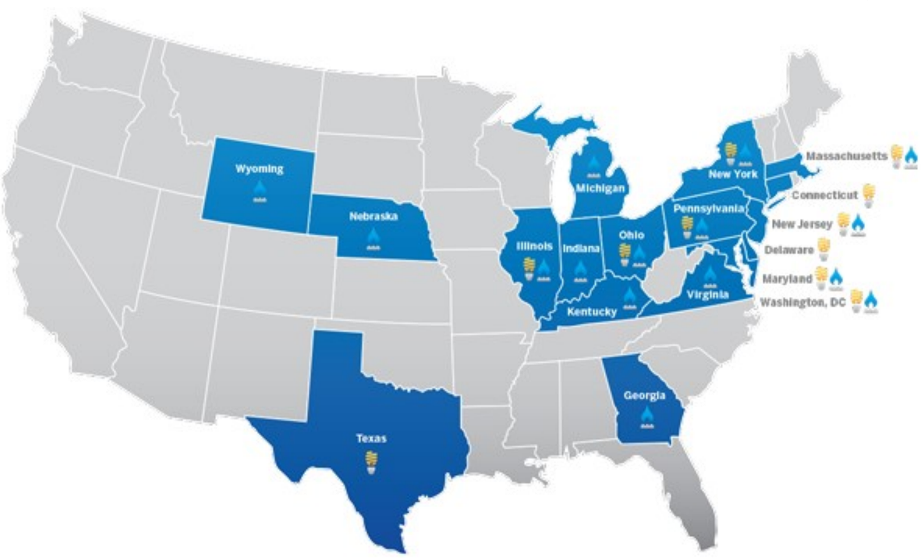

Constellation currently serves about 2 million customers, including residential customers in 17 states and D.C. | *Constellation*

NYPSC: Offshore Wind 'Ready for Prime Time'

By Michael Kuser

ALBANY, N.Y. — The New York Public Service Commission on Thursday voted unanimously to authorize state agencies to procure 800 MW of offshore wind energy by next year, the first phase of a plan to develop 2,400 MW by 2030.

Offshore wind is "viable, valuable and ready for prime time," PSC Chair John B. Rhodes said.

Under the commission's July 12 order (18-E-0071), the New York State Energy Research and Development Authority will issue a solicitation for 800 MW of offshore wind in the fourth quarter, in consultation with the New York Power Authority and the Long Island Power Authority.

NYSERDA will announce the award in the second quarter of 2019 and, if needed, issue a second solicitation next year to meet the 800-MW goal. The agency will hold a technical conference on the solicitation process from July 23 1-3 p.m. at the Department of Public Service's office at 90 Church Street in New York City; it will also be available via webinar.

High-stakes Race

Gov. Andrew Cuomo's office said that

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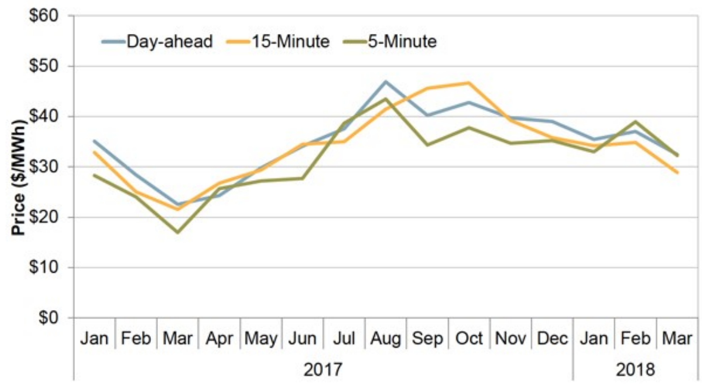
CAISO Q1 Prices Surge on Lower Hydro, Higher Gas

By Robert Mullin



Average monthly prices | *CAISO Department of Market Monitoring*

CAISO prices surged in the first quarter on falling hydroelectric output and increased costs for natural gas, the ISO's Department of Market Monitoring told stakeholders Wednesday.

Speaking during a call to discuss the department's quarterly market issues report, Amelia Blanke, manager of monitoring and reporting, noted that the ISO is accustomed to a pattern of lower prices in the first two quarters followed by rising prices later in the year.

"That was not the case in Q1 of this year," Blanke said.

Average five-minute prices jumped 50% ($12/MWh) compared with the same period a year earlier, while 15-minute prices rose 20% ($6/MWh), putting prices close to levels seen last fall. Day-ahead prices were also up about $6/MWh during the quarter (See chart).

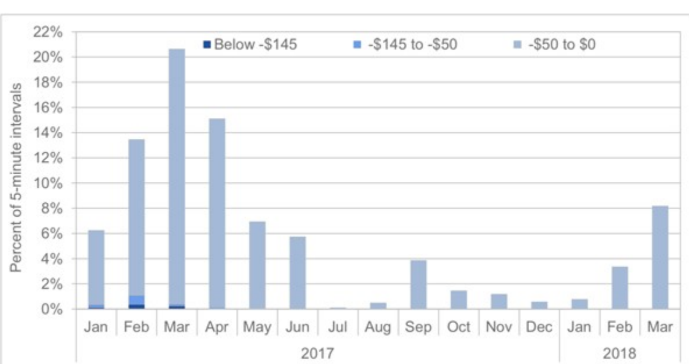
"One of the factors that influenced this include the availability of hydro generation," Blanke said, adding that hydro output was just under half the level seen in the first quarter of 2017.

Despite heavy snowfall in March, snowpack in California's Sierra Nevada mountains ended the winter at just 52% of normal. That was well short of the near-record snowpack many areas reported last year, which required dam operators to release water from reservoirs earlier than usual.

Increased congestion also provided a boost to Southern California day-ahead prices, adding about $2/MWh to average prices in the Southern California Edison area and $5/MWh in the San Diego Gas & Electric area. But the lack of congestion in the north helped reduce Pacific Gas and Electric prices by about $3/MWh.

Tight Gas, High BCR

Tight gas supply was the other key factor driving up power prices, Blanke said. PG&E Citygate gas prices were up 19% over the first quarter of 2017, while SoCal Citygate added 7%, continuing last year's trend of rising gas prices. (See *Gas Costs Drive Sharp Gain in CAISO 2017 Prices*.)



Frequency of negative five-minute pricing | *CAISO Department of Market Monitoring*

"There was a higher frequency of high same-day gas prices and shortage conditions for gas in the southern part of our balancing area," Blanke said.

Grid operations in Southern California are still hamstrung by limited gas supplies from the Aliso Canyon storage facility north of Los Angeles. As a result of market operations intended to preserve that supply, the ISO paid out $11 million in bid cost recovery (BCR) in February because of a cold snap — the highest BCR expense for any month since 2011, the Monitor said.

Limited gas supply in the SoCalGas system during a period of high gas demand led to both high regional gas prices and the reinstatement of Aliso gas cost scalars, both of which contributed to high real-time bid cost recovery in February, the DMM report said.

CAISO implemented the scalars — or price adders — in 2016 to help ensure that gas-fired generators can recover fuel costs in the face of potential price spikes stemming from the Aliso Canyon limitations. (See *FERC Approves CAISO's Aliso Canyon Response Plan Ahead of Summer*.) When activated in the real-time market, the adders boost the commitment proxy gas cost calculation to 175% of the day-ahead gas reference price, while gas prices in the default energy bid calculation are set to 125% of the day-ahead price.

The Monitor has opposed the ISO's reliance on the scalars, instead recommending the ISO develop the ability to update gas prices in real time.

"DMM believes that each use of the Aliso Canyon gas adders on default energy bids and commitment costs highlights the problems associated with the use of these adders," the Monitor said.

The first problem, according to the DMM, is the delay in activating and deactivating gas adders in response to actual conditions.

The second problem is the mismatch between the gas price based on the adders and actual volatility over the same day, the Monitor

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CAISO Q1 Prices Surge on Lower Hydro, Higher Gas

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said.

It noted that bid cost recovery payments totaled $5 million over Feb. 20-23, when SoCal Citygate prices were "significantly high."

"These events also highlight the need for the ISO to develop the capability to update gas prices used in the real-time market based on same-day gas market price information available each morning, as recommended by DMM" in its comments to FERC after CAISO filed to extend its Aliso provisions. The ISO has defended its use of the adders as a needed, if imperfect, tool. (See Gas Adders a Necessary Tool, CAISO Says.)

Less Negativity

Blanke also pointed to the price impact of the "duck curve," which illustrates the precipitous drop in net load at midday as solar and wind resources displace higher-cost fossil fuel generation. "As we have throughout last year, you see lower prices in the middle of the day — in all markets — than we do in the traditional off-peak hours," she said.

But declining hydro output helped reduce the frequency of negative prices in the market, as prices slipped below zero in about 2% of 15-minute market intervals and 4% of five-minute market intervals, compared with 10% and 13%, respectively, a year earlier.

"This is highly correlated with a reduction in self-scheduled hydro generation," Blanke said.

The DMM report noted that a "reduction in self-scheduled generation would result in increased bidding flexibility and reduce the likelihood of negative prices.

The report again called out an issue the DMM has flagged for nearly two years: the continued funding shortfalls stemming from the ISO's congestion revenue rights auctions. (See Report Shows Continued Losses in CAISO CRR Auctions.) The Monitor pointed out that first-quarter CRR auction revenues came up $43 million short of payments made to the non-load-serving entities that purchased the rights at auction, compared with a $12 million shortfall a year earlier. It was the second largest shortfall for any quarter since 2015.

"Losses in the first quarter represent 38 cents in auction revenues paid to transmission ratepayers for every dollar paid out to auctioned rights holders," the report said. "Total ratepayer losses from the congestion revenue rights auction since the market began in 2009 surpassed $770 million."

FERC earlier this month approved the first stage of the ISO's CRR rule changes, which will limit allowable source and sink pairs for CRR transactions to those that align with typical supply delivery paths. The changes also require annual transmission outage reporting to more closely match day-ahead models. (See FERC OKs Tighter Rules for CAISO CRR Auction.) While the DMM expressed support for the ISO's rule changes as "an incremental improvement," the report said it "continues to recommend that the auction process be replaced by a market for financial hedges based on clearing bids from willing buyers and sellers."

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Secondary Dispatch

The reason for "resource shuffling" is that under the EIM's rules, California load-serving entities are subject to GHG emissions caps and compliance obligations, while LSEs elsewhere in the West are not.

The EIM Greenhouse Gas Attribution Enhancements proposal was designed to prevent what CAISO refers to as the "secondary dispatch" of higher-emitting resources in the EIM to replace lower-emitting generation transferred into CAISO. Under current EIM practice, the ISO's least-cost dispatch process typically selects the lowest-emitting resources to serve load in CAISO's balancing authority area because those resources tend to submit the lowest GHG bid adders into the market.

"Because all resources in an EIM balancing area are generally equally effective in supporting energy transfers to another balancing area, the market minimizes costs by designating the resources with the lowest GHG costs as supporting transfers to the ISO balancing area," CAISO management explained in a memo to the Governing Body.

The problem: The market currently designates all of a resource's output with a corresponding GHG adder as supporting a real-time transfer into CAISO, even if that output was already submitted to the EIM as part of a base schedule — indicating the supply was already slated to support load outside ISO.

"The market may designate a resource as supporting a transfer into the ISO even though that resource would have operated at the same output to serve load outside of the ISO without an energy transfer," CAISO said. "The market will dispatch another resource or resources to 'backfill' this dispatch to serve the load outside of the ISO that would have been served by the resource designated as supporting the transfer."

If the backfilling resource has higher emissions than the one supporting the transfer, this "secondary dispatch" results in the market undercounting the actual GHG emissions attributable to California, the outcome ARB was trying to prevent when it prompted CAISO to develop the proposal. (See CAISO, ARB to Address Imbalance Market Carbon Leakage.)

Fort Churchill Generating Station, in Nevada | *NV Energy*

Headroom

CAISO's proposal seeks to address ARB's concerns by limiting a resource's energy transfers into the ISO to "an amount no greater than the headroom" above the resource's base schedule.

Under the plan, the EIM would calculate that headroom by subtracting the base schedule from the megawatt quantity for which a resource has submitted an energy bid and corresponding GHG bid adder. CAISO expects the changes will reduce the GHG emissions from secondary dispatch and more appropriately account for emissions produced by units dispatched to serve California.

"Unfortunately, this approach doesn't fully eliminate the potential for secondary dispatch. It only minimizes it," Don Tretheway, the ISO's senior adviser for market design policy, told Governing Body members.

Tretheway also noted that some EIM stakeholders have expressed concerns the new rules could incentivize suppliers to hold the base schedules for their non-emitting resources such as hydro to zero, while simultaneously base scheduling an emitting resource. That would leave the non-emitting resource with all the headroom in the EIM, possibly positioning it to capture a GHG premium if an emitting resource with a GHG adder sets the marginal price for transfers into CAISO — an opportunity for gaming the market.

"But this concern doesn't recognize that there's consequences for having suboptimal base schedules. Because we will redispatch, and this leads to additional costs," Tretheway said. "So, at a minimum, you're going to have imbalance energy costs as you decrement down that gas resource and increment up the non-emitting resource."

Tretheway also pointed out that an EIM participant would face additional costs for creating real-time congestion if it didn't resolve congestion ahead of an operating hour — resulting in uplift costs for the BAA — before submitting its suboptimal base schedule.

'Simple is Always Better'

CAISO's final GHG plan won out over a

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more complicated proposal that would have developed a "two-pass" market mechanism to address secondary dispatch. Under that proposal, a first pass in the market would have determined the optimal schedule across the EIM footprint while restricting net transfers into the ISO. A second pass would allow transfers into the ISO but limit each EIM resource's GHG bid quantity to the difference between the resource's upper economic limit and the optimal schedule determined in the first pass. (See *EIM Members Seek More Details on GHG Accounting Plan*.)

"We were, as [were] other stakeholders, concerned about the two-pass approach that was considered, so the final approach we think is very reasonable," said Eric Hildebrandt, director of CAISO's Department of Market Monitoring. "There is the issue of monitoring the base schedules and looking for that potential gaming opportunity. We think that is something the ISO is committed to doing."

Speaking ahead of the vote, Governing Body member Kristine Schmidt applauded ISO staff for developing a proposal that "has resolved a really strong, outstanding issue … very important to the state of California."

Body member John Prescott congratulated staff for a solution "that seems to be workable."

"I can understand it, which means its fairly simple," Prescott joked. "But simple is always better."

Prescott said the proposal allows California to meet its environmental goals with "minimal impact to the external EIM participants — that's very important." He added that he hoped EIM participants would monitor the proposal after it becomes policy.

"If those out there that are actually implementing this find that it is a problem for them, that it causes unanticipated results, I'd sure like to hear that, so I just put that request out there," Prescott said.

While Governing Body Vice Chair Carl Linvill added his praise, he reminded his fellow members they will likely have to deal with the issue again after CAISO deploys its day-ahead market to the EIM.

Speaking during his first meeting as a Governing Body member, Montana Public Service Commission Vice Chair Travis Kavulla said he would support the proposal "with a little bit of reluctance."

"I wouldn't want the opportunity to pass by without at least questioning a little bit of the premise of what we're trying to do here," Kavulla said. "I do think we have to realize that resource shuffling is a natural and economically rational consequence of having a local carbon dioxide price that doesn't persist across the entire footprint of the market."

Kavulla said that by assigning a "local" emissions price to backfill generation, CAISO was doing what it has admitted is impermissible, "which is to subject generation outside of California to a California air regulation even when the generation is not being used to serve California load."

ERCOT NEWS

Texas Regulators Fear Customer Risk from Wind Catcher

By Tom Kleckner

PUC Chair DeAnn Walker and Commissioner Arthur D'Andrea listen as Thompson & Knight's Rex VanMiddlesworth makes a point. | *© RTO Insider*

AUSTIN, Texas — Regulators threw a wrench in American Electric Power's massive Wind Catcher Energy Connection on Thursday, expressing concerns over whether the company will protect ratepayers from the project's risks.

Public Utility Commission Chair DeAnn Walker made that clear following oral arguments in the contested proceeding involving AEP subsidiary Southwestern Electric Power Co. and several consumer groups (Docket No. 47461).

"I'm going to be upfront with you," Walker said, addressing AEP CEO Nick Akins, her fellow commissioners and others in the PUC's hearing room. "At this point, I can't approve the [project]."

Walker said she would need additional consumer protections from SWEPCO, which would own 70% of the $4.5 billion project. It includes a 2-GW wind farm being built by Invenergy in the Oklahoma Panhandle and a 360-mile, 765-kV line from the facility to Tulsa. Sister company 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.

"I have issues and concerns … on the financial impacts to the company," Walker said, alluding to a recent court decision remanding a SWEPCO rate case back the PUC.

The Texas Court of Appeals for the Third District on July 10 granted a rehearing request by the Texas Office of Public Utility Counsel (OPUC), Texas Industrial Energy Consumers (TIEC) and Cities Advocating Reasonable Deregulation (CARD), reversing a district court's ruling that the utility's John W. Turk Jr. Power Plant should be included in cost recovery (No. 03-17-00490-CV).

Commissioner Arthur D'Andrea said he too would like to see the parties develop additional consumer protections. "But it doesn't do us any good to protect the consumers, and then have the company fail," he said.

Moody's Investors Service's also recently issued a downgrade watch for Sempra Energy following its $9.45 billion acquisition of Texas utility Oncor earlier this year. (See *Texas PUC OKs Sempra-Oncor Deal, LP&L Transfer*.)

As is their normal practice following oral arguments, the commissioners will review the arguments and the financial data submitted before issuing a decision. The PUC's next scheduled open meeting is July 26.

"I'd like some time to look at the transcript," D'Andrea said.

"I am really struggling with where I am on this," Walker said. "I was hoping to get more solid on where I am."

The commission was unmoved by the AEP delegation's reminder that it faces a time crunch to take advantage of expiring federal production tax credits. Paul Chodak, AEP's executive vice president of utilities, said the company must give contractors a notice to proceed by Aug. 6 to qualify. He said the company is already moving dirt, securing rights of way and spending "tens of millions of dollars" in legal fees.

AEP's Paul Chodak (left) and Nick Akins | *© RTO Insider*

"We are on a critical path. Whatever the answer is, we would like it as quickly as possible," Akins said. "If it's a bad answer, we can deal with that. If it's a good answer, we can certainly deal with that too."

"We're very aware of the timing implications," Walker responded.

She encouraged AEP and the other parties to try and "address the customer benefits or protections" before the next open meeting. "Right now, I think there's more that can be done for the consumers," Walker said.

"We're hopeful we can have additional settlement discussions with the intervenors, especially given the PUCT's encouragement," said SWEPCO spokesperson Carey Sullivan.

PUC staff, which oppose Wind Catcher, met after the hearing with OPUC, TIEC, CARD and fellow intervenor Golden Spread Electric Cooperative. The group did not commit to further settlement discussions.

SWEPCO operates in East Texas, Louisiana and Arkansas. AEP says Wind Catcher will save SWEPCO's Texas customers $1.7 billion over 25 years. Company representa-

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Texas Regulators Fear Customer Risk from Wind Catcher

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tives pointed to settlement agreements in Arkansas and Louisiana that insulate customers from the project's risks, including a cap on construction costs, minimum production levels and qualification for 100% of the federal PTCs. They also noted components of Wind Catcher's 800 turbines will be built in Texas and Houston-based Quanta Services will build the transmission line.

Representatives of TIEC and CARD argued Wind Catcher would saddle Texas consumers with hundreds of millions of dollars in future rates, saying it would be more expensive and less efficient than the recently approved Xcel Energy wind facility. (See *Texas PUC Issues Final Order for SPS Wind Farm*.)

"This project is not needed in any traditional sense," said TIEC's Rex VanMiddlesworth, pointing to AEP's argument that Wind Catcher will provide a hedge against higher natural gas prices. "All these parties that have dug into that — staff, the cities and OPUC — have disagreed with that and have presented [countering] evidence. If [SWEPCO's estimate] was the case, we'd all be saying we want it, like we did for the [Xcel] wind facility."

"Our concern is not the accuracy of SWEPCO's forecasts. ... Our concern is that the risk of those projections being accurate is on the ratepayer," said CARD's Alfred Herrera. "Our concern is that when this project goes into the rate base, the customer will pay.

"SWEPCO is asking you to approve a multibillion project and guarantee its returns," Herrera said. "That's the effect of what will happen if this plant comes into the rate base. That's not how competitive markets work. If this deal is such a good deal, then let the competitive market build it."

PUC staff oppose an administrative law judge's preliminary decision approving AEP's application, saying "the evidence presented does not support a sufficient probability of improvement of service or lowering of costs to ratepayers."

Staff are recommending that the commission condition its approval on a requirement that SWEPCO guarantee tax credits in the amounts represented by the utility, and some level of net benefits to customers.

PUC Grants Utilities' SMT Rehearing Request

The PUC granted a motion for rehearing and issued a final order for Smart Meter Texas (SMT), a website that provides customers and authorized market participants access to electric usage data (Docket No. 47472).

The utilities involved in SMT (AEP Texas, CenterPoint Energy Houston Electric, Oncor and Texas-New Mexico Power) filed the request in June "to address limited clarifications."

The utilities agreed to provide on-demand meter readings as a substitute for home area network (HAN) functionality. Walker filed a memo clarifying that the utilities can't discontinue support of a customer's existing HAN device unless the customer requests that the device be disconnected.

SMT allows customers to download and view their energy data or share them with competitive service providers, companies that market energy efficiency, demand response, distributed generation and other services. (See "Commission Streamlines Smart Meter Texas Portal," *Texas PUC Issues Final Order for SPS Wind Farm*.)

ISO-NE News

FERC Advances Mystic Cost-of-Service Agreement

By Michael Kuser

Mystic Generating Station

FERC on Friday tentatively accepted a cost-of-service agreement between Exelon and ISO-NE for Mystic Generating Station Units 8 and 9, ordering an expedited hearing process on unresolved issues (ER18-1639).

The order drew sharp rebukes from Commissioners Robert Powelson and Richard Glick, both of whom called it "yet another rush to judgment."

The agreement would allow the gas-fired units in Massachusetts an annual fixed revenue requirement of almost $219 million for capacity commitment period 2022/23 and nearly $187 million for 2023/24. But the commission found the information Exelon provided to support those figures insufficient, setting for hearing the company's proposed capital expenditures, fuel costs, and operations and maintenance expenses.

Notably, FERC did not hold the hearing in abeyance and appoint a settlement judge, as it often does when it suspends an accepted filing. Instead, it ordered an expedited hearing schedule, citing Exelon's Jan. 4, 2019, deadline for deciding whether to retire the units and the beginning of Forward Capacity Auction 13 on Feb. 4. The agreement goes into effect June 1, 2022, subject to the outcome of the hearing.

The commission ordered the presiding judge to certify the record by Oct. 12, with initial briefs due Nov. 2 and reply briefs Nov. 16.

ISO-NE's Tariff does not allow for reliability-must-run agreements, and only allows cost-of-service agreements to respond to local transmission security issues. FERC on July 2 denied the RTO's request for a Tariff waiver to allow for the Mystic agreement. Exelon said in March that it would retire the 2,274-MW plant when its capacity obligations expire on May 31, 2022 (ER18-1509). (See *FERC Denies ISO-NE Mystic Waiver, Orders Tariff Changes*.)

The commission instead ordered the RTO to revise its rules to allow cost-of-service agreements for facilities needed to address fuel security issues, or show cause as to why it shouldn't have to (EL18-182). ISO-

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ISO-NE NEWS

FERC Advances Mystic Cost-of-Service Agreement

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NE's response is due Aug. 31.

Powelson and Glick also dissented in that order, and both cited it in their dissents last week.

"The commission is not even waiting for stakeholders' responses to the show cause order it issued *last week* before plunging ahead with its plans to bail out Mystic and Distrigas," Glick said. Exelon included in the agreement the costs of purchasing fuel from and operating the nearby Distrigas LNG import terminal, which it is buying from ENGIE North America.

"By setting the agreement for modified settlement and hearing procedures, the majority is expressing a preference for a short-term cost-of-service mechanism to address fuel security," Powelson said. "That message may have been implied in the waiver order, but after today's order there is no question as to the majority's direction. …

"Over the next few months, interested participants will focus time and energy on the agreement in an attempt to reach consensus on a host of challenging issues. Because the commission has failed to narrow the issues to be addressed in this proceeding, today's order has opened a proverbial can of worms. Thus, instead of working collaboratively to respond to the commission's Section 206 inquiry or consider more cost-effective alternatives, stakeholders will be working on the Mystic agreement."

Distrigas, Cost Allocation

While FERC said it could not determine whether the agreement was just and reasonable, it did comment on several issues raised by protesters in the proceeding.

Several protesters questioned whether including an entire LNG facility in a cost-of-service rate violated the Federal Power Act.

The commission said it would set the matter for hearing, but "in advance of the hearing, we find unpersuasive arguments that the FPA prohibits any recovery of the fuel supply charge for the Distrigas facility."

"This finding as to jurisdiction does not mean that Mystic is entitled to recover all costs that it claims in connection with the Distrigas facility," the commission said. "Whether individual components of a cost-of-service rate, including fuel-related costs, are recoverable turns on whether they are just and reasonable, not whether the commission has regulatory authority over all aspects of those rate components."

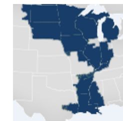
Other protesters were concerned that there was no cost allocation mechanism in the agreement. FERC noted that in its show cause order, it directed ISO-NE to include such a mechanism in any Tariff revisions the RTO proposes.

The commission also said that while capital expenditures would be subject to hearing, the Mystic units should be allowed to collect actual prudently incurred costs, subject to true-up.

"We find that given the inherent difficulty in projecting costs in advance of the agreement's effective date, and the concerns raised as to whether certain expenditures will be necessary to keep the Mystic units operational during the proposed service period, a true-up mechanism is necessary to ensure that the rates established reflect actual costs incurred," the commission said.

The order directed the participants to present evidence regarding the appropriate design of the true-up mechanism in the agreement, noting that ISO-NE may also address the related clawback provision in EL18-182.

MISO NEWS



MISO Weighing Feedback to Storage Proposal

By Amanda Durish Cook

MISO last week outlined the range of stakeholder feedback it has received since revealing its straw proposal for energy storage resources (ESRs) in June.

The RTO's proposal for complying with FERC Order 841 called for ESRs participating under four modes of commitment: charging, discharging, continuous operations and outage/offline. When in online mode, storage would be treated as must-run resources. (See *MISO Offers Straw Storage Proposal to Meet Order 841*.)

At a July 12 Market Subcommittee meeting, MISO said that stakeholders have stressed the importance of coordination with distribution system providers and expressed concern that requiring hourly offers might limit storage's flexibility. Others reminded the RTO that storage resources are not generation and said they should not be bound to a must-offer requirement. Some said storage should be treated like load-modifying resources while others said storage should be restricted to the ancillary services market, despite FERC's requirement that it be allowed to provide capacity and energy.

Stakeholders asked how hybrid storage-and-renewable formats will fit under the proposal and requested optimized pumping and withdrawal options for pumped storage facilities. MISO dismissed the latter as beyond the scope of Order 841 but said it will meet with market participants to discuss ways to fully incorporate pumped storage into the market.

MISO Director of Market Design Kevin Vannoy said the RTO would return in August with more detail around the proposal and examples of how storage will function under the model. It will focus examples on non-market services, storage modeling, metering, commitment and dispatch rules, Vannoy said. Market clearing prices or LMPs will set emergency pricing for injecting and withdrawing during maximum generation events.

"There might be restoration payments when energy storage resources provide black start restoration from an event," he added.

MISO also said it will rely on its existing ramp performance measures — excessive and deficient energy flagging and deployment failure penalties — to evaluate storage performance.

Vannoy said he's gotten at least two requests for private meetings with MISO staff to discuss the straw proposal. While MISO isn't opposed to setting up one-on-one meetings, he said, staff are busy working on Order 841 compliance and have limited time. He also said it may be best to raise storage issues and suggestions in public meetings.

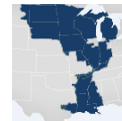
"We're not necessarily looking to facilitate private discussions," Vannoy said, urging stakeholders to bring their storage questions and recommendations to the Resource Adequacy, Market and Reliability subcommittees.

Vannoy said while MISO usually doesn't solicit extensive stakeholder feedback on FERC compliance directives, Order 841 compliance is a "special case" that warrants more intensive stakeholder involvement, and MISO plans to collect more feedback through summer.

"I don't think this is a pure vanilla compliance filing. It's not where FERC says, 'Do A, B and C,' and we file A, B and C," Vannoy said.

MISO will solicit feedback through fall while presenting more refined versions of the plan. It plans to have a draft compliance plan by mid-October. Its Tariff filing is due

Continued on page 12



MISO Weighing Feedback to Storage Proposal

Continued from page 11

in December.

Storage Model on Old Platform

MISO plans to implement its new storage participation model before it replaces its current market platform with a more sophisticated modular system. Responding to the straw proposal, stakeholders asked that the RTO not make a storage participation model dependent on the new platform's capabilities. Instead, they asked that MISO design the market platform with storage needs in mind.

Kevin Larson, MISO market and modeling director, said the RTO will continue to assess principal vendor General Electric's performance on project deliverables and will evaluate alternate vendors through the end of 2019. MISO last month said GE was overly optimistic in its original timeline for the replacement, which may lead to delays and a small budget overrun. (See MISO Platform Replacement Risks Delay, Budget Overrun.)

"We're in an evaluation phase with General Electric," Larson said.

MISO reported in June that, as part of its multiyear market platform replacement, it had improved its day-ahead solve time by more than six minutes, about a 10% improvement. Larson said the additional headroom will allow for "select market enhancements while the new market system is being developed."

Storage Capacity Accreditation

At the July 11 RASC meeting, MISO presented its proposal on how it will accredit storage capacity, another requirement of Order 841.

Senior Adviser of Capacity Market Administration Rick Kim said MISO is proposing to require that storage resources continuously discharge energy equivalent to their zonal resource credits committed in the Planning Resource Auction.

The continuous discharge would be subject to a minimum run time, either 24 hours or four hours for limited-use resources. Storage resources would also have to submit the generator verification test capacity (GVTC) data required of other planning resources. MISO would ask for a storage resource's GVTC by Oct. 31, 2019, for the 2020/21 planning year capacity auction. The RTO said it would also want storage resources to provide documents to support the megawatt-hours of capacity they claim. MISO will apply default outage rates to determine unforced capacity calculations for storage resources that have less than a year of operational data.

Storage assets should also secure either firm transmission service or network resource interconnection service before offering as a capacity resource. If the storage resource is interconnected at the distribution level, the resource will be subject to coordination with the distribution provider, transmission owner and MISO.

Kim asked stakeholders for specific ideas on the calculations and tests for capacity accreditation.

FERC Denies Cloverland PURPA Exemption

By Amanda Durish Cook

FERC last week denied Cloverland Electric Cooperative's request for relief from its mandatory purchase obligation under the Public Utility Regulatory Policies Act, citing the co-op's lack of RTO membership as a primary reason (QM18-11).

Cloverland, which serves customers in Michigan's Upper Peninsula, filed in April to terminate its PURPA obligation to buy power from qualifying facilities over 20 MW, arguing that, as a transmission-dependent utility that purchases transmission service from American Transmission Co., QFs over 20 MW could not "safely interconnect" to the co-op's distribution system "even with significant upgrades."

Cloverland argued "the only practical way" for a QF over 20 MW to sell its input to the co-op would be to interconnect to ATC's transmission system. It also contended that although it doesn't participate in MISO, ATC is a member of the RTO, where QFs have nondiscriminatory market access. The co-op said QFs within its service territory could utilize ATC's transmission system to gain nondiscriminatory access, a prerequisite for utilities seeking relief from PURPA purchase obligations.

Cloverland's hydroelectric plant | *Ontonagon County*

A utility can be exempted from its PURPA energy and capacity purchase obligations if it can demonstrate a need for relief and is a member of an RTO/ISO market.

But FERC said Cloverland could not use ATC's MISO membership as a proxy for securing its own RTO/ISO membership.

"In essence, Cloverland, while not itself a MISO member, is seeking to claim the benefit of ATC's MISO membership in requesting relief from the mandatory purchase obligation under PURPA. ... We are not persuaded to grant Cloverland's application," FERC said.

FERC determined that, because Cloverland is not a member of MISO, it is not entitled to relief from the purchase obligation despites its claim that nearby QFs nevertheless have access to MISO's markets.

"We are not persuaded to change our position on the reach of PURPA. ... Membership in an RTO/ISO remains a requirement for claiming an exemption under PURPA," FERC said. "Accordingly, since Cloverland is not itself a member of MISO, it is not entitled to relief."

MISO NEWS

MISO Delays Combined Cycle Model Update

MISO will not implement improved combined cycle modeling until it has a new market platform in place, stakeholders learned last week.

The RTO plans to initially offer seven different modeling options, including combinations of combustion and steam turbines, but operators of combined cycle generators must now wait until 2022 for the improved model.

MISO last month completed a conceptual design for the more sophisticated modeling that can accommodate different combinations of combined cycle units and their dependencies. And while the RTO originally hoped to have software in place by 2020 to offer new modeling options, its outdated market platform is limiting what improvements it can undertake. (See "Limited Improvements for Old Platform," *MISO Platform Replacement Risks Delay, Budget Overrun*.)

Speaking at a July 12 Market Subcommittee meeting, MISO market analyst Chuck Hansen said the conceptual design will still be turned over to a third-party vendor for more in-depth work during the 18-month pause on the project. He said most of that work is not dependent on having the new market platform operational and can be advanced without delay. He also said MISO's legal team will begin drafting Tariff language during the hold.

MISO Market Design Engineer Congcong Wang said the proposal will represent one of the most complex participation models in the RTO's energy and ancillary service markets to date. The RTO has predicted the new model could save an annual $14 million to $34 million in production costs.

MISO currently has 44 combined cycle gas turbine resources, with more predicted to come online. Since its markets began, MISO has been modeling combined cycle units as either a single aggregate resource or as individual units.

— Amanda Durish Cook

FERC: MISO Merchant HVDC Procedures Incomplete

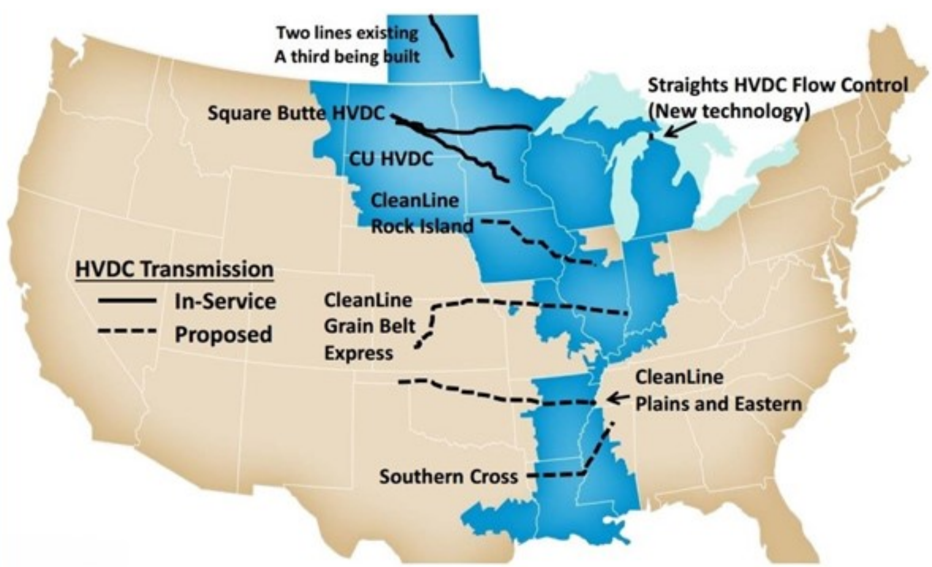
By Amanda Durish Cook

MISO's proposal to allow merchant HVDC lines to connect to its system is incomplete, FERC informed the RTO last week in a deficiency letter.

In its filing with the commission, MISO said it based the proposed merchant agreement on its existing generator interconnection agreement and procedures, but FERC on July 12 asked it to explain why it was appropriate to do so — among other questions (ER18-1410). The commission gave MISO 30 days to file a response.

The RTO's proposal involves treating merchant HVDC as transmission rather than generation, and requires merchant developers to acquire MISO injection rights or a precertification that the system will be able to reliably manage the capacity and energy from proposed lines at the point of connection. (See *MISO Plan Provides Tx Treatment for HVDC Lines*.)

FERC asked MISO why the timeline and termination provisions for the proposed agreement differ from those in the GIA, given the RTO's claim that the former is based on the latter.



Direct current lines in MISO's footprint | *MISO*

The proposed HVDC agreement stipulates that if injection rights are not converted to external network resource interconnection service within three years of a line's commercial operation date, MISO will terminate interconnection service. With the RTO's GIA — which doesn't include the concept of injection rights — an interconnection customer can extend its commercial operating date for up to three years without risking queue withdrawal. MISO had said the termination provision matched that of its GIA because in both cases, the "underlying agreement may be terminated if commercial operation is not achieved within three years of the commercial operation date."

FERC also asked MISO to clarify whether it plans to simultaneously update its merchant HVDC connection agreement when it proposes to make changes to its GIA.

The HVDC agreement also includes a provision stating that transmission owners will be able to review any modifications to a connection facility that affects them, but FERC asked MISO how it would move forward with a HVDC connection request if a party to the connection agreement does not accept a modification.

The commission also asked MISO to describe the processes behind examining injection rights and its proposed merchant HVDC connection service study.

MISO News

Resource Adequacy Subcommittee Briefs

MISO, Stakeholders Debate Capacity Import Limits

Responding to a stakeholder query, MISO staff have determined that it's appropriate and possible for capacity import limits between local resource zones to bind in the RTO's annual Planning Resource Auction.

MISO says that while, historically, the local clearing requirement has always bound before the CIL, it is "mathematically possible and reasonable" for CILs to be more restrictive than LCRs.

In this year's capacity auction, MISO Local Resource Zone 3 in Iowa and Zone 6 in Indiana and Kentucky came closest to binding on their CIL, with Zone 3 coming within 938 MW and Zone 6 within 1,290 MW. MISO said the two zones could have bound if either the LCR or amount of exports varied.

During a July 11 Resource Adequacy Subcommittee meeting, MISO engineer Matt Sutton said it remains "highly unlikely that the capacity import limit" will bind in future capacity auctions, although that could be subject to multiple variables, such as transmission transfer capability.

"Though we've not seen a capacity import limit bind, it is a necessary parameter in the auction," Sutton said.

Some stakeholders said they could not understand how CILs could bind before LCRs. WPPI Energy's Steve Leovy said MISO staff have previously told him that CILs should not be enforced. Sutton said he thought MISO staff responsible for resource adequacy would disagree with that viewpoint.

Other stakeholders pointed out that market participants can replace capacity from other resources at midyear and that MISO must still ensure that import limits are not violated.

RTO staff committed to more discussion on the topic at future RASC meetings.

Stakeholders Quiet on Uncertain OMS-MISO Survey Results

Stakeholders offered muted reaction to this year's annual resource adequacy survey by MISO and the Organization of MISO States, which predicts adequate reserves through 2019 but is less certain about thereafter.

"It's important to keep in mind that this is a point-in-time forecast," Ryan Westphal, MISO resource studies manager, told stakeholders.

Over the next five years, MISO's footprint could see anything from a 7.5-GW surplus to a 4.5-GW shortfall. The results were less optimistic than last year's survey, which showed MISO would have anywhere from 0.7 to 7.3 GW of excess resources in 2018-2022.

Westphal said the forecast is even more uncertain as MISO continues its conversion from coal generation to a mixture of gas, wind, solar and load-modifying resources.

Stakeholders asked why Zone 4 in Illinois experienced such a large dip in forecasted reserves year over year. Westphal attributed the decline to a combination of retirements, potential retirements and changes in generator performance.

Coalition of Midwest Power Producers' Mark Volpe asked if MISO adjusts survey responses to reflect interzonal transactions that may go unreported. Westphal said MISO staff reach out to load-serving entities for clarification on some survey responses.

— Amanda Durish Cook

FERC Seeks Details on Proposed MISO Retirement Rules

By Amanda Durish Cook

FERC has questions on MISO's plan to transform its retirement notification process into a catch-all three-year suspension period.

The commission on Wednesday issued a deficiency letter ordering MISO to provide more specifics and an explanation of how it currently plans for suspension and retirements within 30 days (ER18-1636).

MISO this spring proposed that generation owners planning to retire or suspend their units submit a catch-all suspension notice that would have the RTO terminate their interconnection rights after three years of inactivity. (See "Matching Modeling with Proposed Retirement Process," *MISO Planning Subcommittee Briefs: June 12, 2018*.)

The commission wants to know how MISO's open-ended suspension plan may affect its process for designating system support resources — those scheduled for retirement that the RTO needs to keep operating for reliability. It asked MISO whether it would model units in the catch-all as three-year suspensions or permanent retirements.

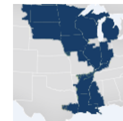
FERC also asked how MISO currently plans for uncertainty in its suspension and retirement process. In a second filing June 21, MISO told FERC that "the future status of a suspended generator is usually unknown, and the requirement to specify an end-date when the return to service is actually uncertain can lead to false assumptions and unreasonable assurance regarding future developments."

"For planning purposes, what assumptions are made about a generator's future status under the current suspension provisions, and how will those assumptions change given this proposal?" FERC asked. The commission also asked MISO to explain how generators' information on their future status may be unreliable and told MISO to provide it with five years of data on the outcomes of generators that entered suspension. FERC also ordered MISO to explain the difference between how it currently treats suspensions versus retirements in transmission planning.

Earlier this year, Economic Studies Senior Engineer Tim Kopp said less than a third of generators return to service after submitting Attachment Y notices to MISO, and that treating all suspending generation as if it will never return would make for better modeling in transmission planning.

FERC also asked if MISO intends to keep its current 26-week minimum notice requirement for Attachment Y filings.

MISO NEWS



MISO, SPP Loosen Interregional Project Requirements

By Amanda Durish Cook

MISO and SPP announced Friday they plan to relax barriers that have prevented them from agreeing to develop interregional projects.

The two RTOs will remove their $5 million cost threshold and joint modeling requirement for the projects, staff revealed during a July 13 conference call of the Interregional Planning Stakeholder Advisory Committee.

Removal of the $5 million cost standard will not affect other criteria, such as the 5% or higher benefit threshold for each RTO and the requirement that projects be in service within 10 years of approval, the RTOs said.

Instead of creating a joint model, MISO and SPP will now leverage their existing regional planning models to evaluate interregional projects. Eliminating the joint model requirement will shorten a lengthy study process and allow the RTOs to examine more potential projects, they said. MISO and PJM removed a similar requirement almost two years ago in response to a FERC complaint filed by Northern Indiana Public Service Co. (See FERC Orders Changes to MISO-PJM Interregional Planning.)

MISO Planning Adviser Davey Lopez said removing the joint model will eliminate inconsistencies between the joint model and the RTOs' respective regional models.

"We're both doing very robust regional reviews," SPP Interregional Coordinator Adam Bell added.

Concerns over Cost Allocation

Bell said stakeholders were split over removal of the joint model; while some wanted the triple hurdle eliminated, others were concerned about equitable cost allocation absent a joint model. Had MISO and SPP approved an interregional project, the joint model would have determined each RTO's share of the cost.

The RTOs said they will calculate adjusted production costs and avoided costs for all interregional projects using their regional calculations of benefits. They have pledged to provide interregional cost allocation examples to address stakeholders' concerns about inequities and explore the possibility of adding a market-to-market benefit metric.

The Wind Coalition's Steve Gaw stressed the need for the RTOs to develop an objective cost allocation plan rather than promising negotiations.

"For me, this isn't sweeping things under the rug. This is sweeping things into a different room," Gaw said. "If you've got two RTOs determining what their benefits are. … I think you have to have something that avoids you arguing over how the benefits are calculated in each of your regions."

Other stakeholders also asked for a more specifics on cost allocation, and Lopez

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NYISO NEWS

Business Issues Committee Briefs

BIC OKs Change on Congestion Data Reporting

RENSSELAER, N.Y. — The NYISO Business Issues Committee voted Wednesday in favor of changing how the ISO reports on historic congestion, agreeing with management that the current process is resource-intensive and the resulting data underutilized.

The BIC's vote recommends that the Management Committee endorse the new process, which will require Tariff changes, to the Board of Directors.

Some of the congestion metrics required by the Tariff can be extracted from production security-constrained unit commitment (SCUC) runs but other data require rerunning SCUC to calculate the difference between the actual constrained grid and an unconstrained system.

"In our review of the site traffic, we realized there was not much use of the historic congestion data, so it's of limited value in finding where congestion is on the system," said Timothy Duffy, manager of economic planning. "We don't believe there are any stakeholders using that data meaningfully."

The proposed changes would eliminate the requirement to compare historic data to an unconstrained system.

The ISO will continue providing the historic metrics generated by SCUC: the value of demand congestion by constrained element or contingency; load and generator payments; and total load and generation scheduled.

It will add a new set of metrics: actual congestion rents by constraint, based on modeled flows and shadow prices.

Consolidated Edison's Jane Quin representative abstained, saying it was premature to change the current reporting before the ISO has moved ahead with an economic transmission project to address congestion. Quin also said NYISO had not shown that the current Tariff requirement was unduly burdensome.

"Data we are pulling is not used in any settlement proceeding at all … and the data we are presently required to produce [that we would no longer produce] would not be of any value in planning an economic transmission project," Duffy responded.

By the fourth quarter, the ISO will provide a report of historic congestion information relating to 2018 data utilizing the new metrics, broken into quarterly figures to mesh with quarterly reports beginning with 2019 data.

The data will continue to include actual demand ($) congestion by constrained element/contingency; load and generator payments ($); and total load and generation scheduled (MWh).

The reporting of historic congestion will incorporate actual congestion rents by constraint based on modeled flows and shadow prices.

Supplemental Resource Evaluation Improvements

NYISO has made progress in clarifying the minimum deliverability requirements for capacity from PJM, Rana Mukerji, ISO senior vice president for market structures, told the BIC.

ISO officials made presentations on the current Supplemental Resource Evaluation process and potential changes at joint meetings of the Installed Capacity Working Group and Market Issues Working Group in April and May. The ISO will present the market design proposal for process improvements at a joint ICAPWG/MIWG meeting July 26.

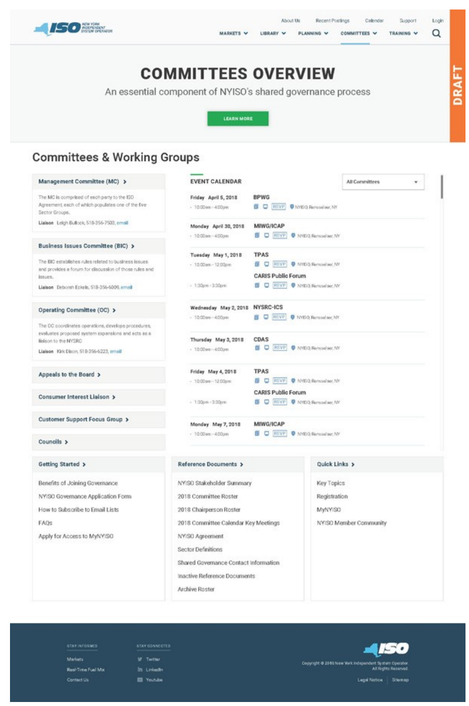
In his Broader Regional Markets Report, Mukerji also discussed NYISO's efforts since 2016 to find an alternative approach for calculating locality exchange factors, which measure the capability of import-constrained regions relative to neighboring control areas.

NYISO has concluded the stability and transparency of the current approach is preferable to a probabilistic approach. The ISO has told stakeholders that further work on this effort is unlikely to yield an implementable methodology and continued investigation of a probabilistic approach is not warranted.

Mukerji also discussed Public Service Electric and Gas' May 3 complaint against Consolidated Edison concerning two transmission lines, B3402 Hudson-to-Farragut (B line) and C3403 Marion-to-Farragut (C line). PSE&G alleged that underwater portions of the lines may have been permanently damaged and should be removed; however, the complaint acknowledged that a prior leak in the B line has been repaired.

NYISO filed a protest with FERC on June 6 indicating that removal of the lines would undermine resilience in both New Jersey and New York. The lines support grid resilience by providing opportunities for operational flexibility and emergency service in both the New York Control Area and PJM. The ISO's protest noted that PSE&G's complaint did not demonstrate that another leak from either of the lines was imminent and requested that the complaint be denied.

Public Website Redesign Update



A draft webpage from NYISO's redesigned website | *NYISO*

Dave O'Brien, NYISO project manager, provided an update on the project to redesign the ISO's public website.

The main objectives of the redesign are to improve the site navigation and search engine capability and implement a document library. The project will recategorize the most frequently accessed documents to

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NYISO NEWS

NYPSC: Offshore Wind 'Ready for Prime Time'

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John B. Rhodes | © RTO Insider

offshore wind will not only help achieve the state's Clean Energy Standard goal of obtaining 50% of electricity from renewables by 2030 but also will support nearly 5,000 new jobs, nearly 2,000 of them long-term career opportunities in operations and maintenance.

"We're in a race right now with our fellow states along the Eastern seaboard to get these staging and fabrication facilities for this new industry built in our state, and of course they want it in their states," Commissioner Gregg C. Sayre said. "I think it would be appropriate for us to get moving quickly and win this one for New York." (See Competition, Cooperation and Costs the Talk at OSW Conference.)

The U.S. Department of Energy in June awarded a $18.5 million grant to NYSERDA to lead a nationwide research and development consortium for the offshore wind industry, with the state to match the federal funds.

In May, Massachusetts awarded a contract for 800 MW of offshore wind and Rhode Island agreed to procure 400 MW. (See Mass., R.I. Pick 1,200 MW in Offshore Wind Bids.) New Jersey committed in May to build 3,500 MW and Connecticut signed on for 200 MW in June. (See Gov. Signs NJ Nuke Subsidy, Renewables Bills.)

Massachusetts officials hope to develop supply chains for the nascent industry in the Port of New Bedford but will have to avoid interfering with fishing operations there, the No. 1 fishing port in the U.S. (See Overheard at ISO-NE Consumer Liaison Group Meeting.)

According to the environmental impact statement issued by NYSERDA in June, the New York offshore wind projects will affect only 3% of the state's fishing grounds.

Bidding Details

David G. Drexler, DPS managing attorney, told the commission that NYSERDA will solicit two separate bids from each participating bidder. One would be for a fixed-price offshore wind renewable energy certificate (OREC), while the other would be based on a variable OREC tied to an index.

To contain costs, NYSERDA will reject bids higher than a confidential "upset price," like the method used in Renewable Energy Standard Tier 1 procurements, Drexler said.

"NYSERDA … would at all times have the authority to reject any and all bids, taking into account not only the benchmark upset price but also recent auctions and market conditions," Drexler said.

NYSERDA will rank bids based on the following weights price (70%); economic benefits (20%); and project viability (10%). The agency will have discretion in fixing the specific terms of the contract, which will run for 20 to 25 years.

Transmission Component

The Phase 1 order for the initial 800 MW makes the generation developer responsible for its own radial transmission to shore, calling it "the most easily implementable and feasible option for jump-starting offshore wind development in New York."

NYSERDA recommended that backbone

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Business Issues Committee Briefs

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make them easier to find.

O'Brien indicated that existing webpage and document links on www.nyiso.com would be changing because of the project, but he emphasized there would be no changes to existing mis.nyiso.com (OASIS) links. The project is targeting a launch by year-end.

BIC Elects Breidenbaugh Vice Chair

The BIC elected Aaron Breidenbaugh of energy management consulting firm Luthin Associates as its vice chair.

In addition to helping clients in procuring electricity and natural gas, Luthin also represents an unincorporated group of non-profit institutional customers known as Consumer Power Advocates before the ISO, Public Service Commission and FERC.

"I'm happy to be able now to pay back into the NYISO governance structure," Breidenbaugh said.

Energy Prices up 32% YoY

NYISO prices averaged $32.53/MWh in June, up from $28.78 in May and higher than $31.76 in the same month a year ago, Mukerji said.

Year-to-date monthly energy prices averaged $47.70/MWh through June, a 32% increase from $36.01 a year earlier. June's average sendout was 445 GWh/day, higher than 397 GWh/day in May but down from 454 GWh/day a year earlier.

Transco Z6 hub natural gas prices averaged $2.45/MMBtu, down 4% from May but up 4.5% year-over-year.

Distillate prices dropped slightly compared to the previous month but were up 56.3% year-over-year. Jet Kerosene Gulf Coast and Ultra Low Sulfur No. 2 Diesel NY Harbor averaged $15.47/MMBtu and $15.32/MMBtu, respectively.

Total uplift costs and uplift per megawatt-hour rose from May, with the ISO's local reliability share at 18 cents/MWh in June, lower than 22 cents the previous month, while the statewide share climbed from -17 cents/MWh to 12 cents.

Thunderstorm Alerts in New York City, which cause more conservative operations with reduced transmission transfer limits, cost 39 cents/MWh, up nearly fivefold from 8 cents in May.

— Michael Kuser

NYISO NEWS

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transmission and independent ownership be reserved for consideration in Phase 2, to procure the remainder of the 2,400 MW total. It noted that the Bureau of Ocean Energy Management has sold only one wind energy lease directly off New York — Equinor's site, which is capable of hosting approximately 1,000 MW. The agency said a shared radial system would create unnecessary risks of stranded assets and provide limited cost advantages.

Equinor and Vineyard Wind supported the direct generator lead approach in the early stages of development, arguing in joint comments that "requiring a separate transmission provider would increase project uncertainty and the risk of delay."

The Green Building Council, the Sustainability Institute and transmission developer Anbaric argued that the first phase should include soliciting bids to develop an "Open Access Offshore Transmission" system, with Anbaric saying it would provide more information about the best options and potentially reduce the costs of the procurement.

Anbaric said that requiring direct generator leads would lead to a piecemeal approach and would not optimize the interconnection, potentially increasing costs for later stages of development. The Green Building Council and the Sustainability Institute concurred with Anbaric's argument, saying that the generator lead approach would result in a highly inefficient array of separate transmission cables.

Central Hudson Gas & Electric, Consolidated Edison, New York State Electric and Gas, National Grid, Orange and Rockland Utilities, and Rochester Gas & Electric, filing as "Joint Utilities," also argued that the state should immediately consider developing a transmission backbone and optimizing onshore interconnection locations. They said utility ownership of the transmission portion could produce substantial ratepayer savings. NYPA and New York City also urged that "a coordinated approach to transmission should be initiated immediately," with NYPA adding it was prepared to assist in the effort.

"Anbaric remains eager to deliver offshore wind to the New York onshore grid quickly and economically," Anbaric CEO Edward Krapels said in a statement Friday. "We will intensify our development of our New York OceanGrid and look forward to working with generation companies to link the first 800 MW of offshore wind to the New York state grid."

Cryptocurrency Tariff Change

The PSC also approved new electricity rates for an upstate utility, Massena Electric Department, that will allow high-density load customers, such as cryptocurrency companies, to qualify for service under an individual service agreement.

"As part of our continuing effort to balance the needs of existing customers with the need to attract new companies, we must ensure that business customers pay a fair price for the electricity that they consume," Rhodes said. "However, given the abundance of low-cost electricity in upstate New York, there is an opportunity to serve the needs of existing customers and to encourage economic development in the region."

The commission's order (18-E-0211) said that the individual service agreement tariff includes provisions to protect customers from increased supply costs resulting from the new service.

The program will apply to customers who have a maximum demand of at least 300 kW.

The new rates become effective today.

Low-income CDG Initiatives

The commission also adopted three measures to enhance the ability of low-income residents to participate in community distributed generation (CDG) programs: a bill discount pledge program; an income verification service; and a loss reserve fund (15-E-0082).

CDG projects are generating facilities located behind a nonresidential host meter coupled with a group of off-takers who receive bill credits based on the generation of that facility. New York defines low income as at or below 60% of the state median income.

Public funds will be held in reserve to cover losses that CDG project owners or their lenders may incur if low-income subscribers default on or terminate their subscriptions at a higher rate than other customers. DPS staff reported that "a relatively modest amount could provide surety for hundreds or even thousands of subscriptions" but did not define the amount.

Con Ed Smart Solutions Program

The commission approved, with modifica-

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NYISO NEWS

New York Looks at Carbon Price Impact on LBMPs

By Michael Kuser

RENSSELAER, N.Y. — NYISO last Monday presented stakeholders details on how a carbon charge would affect locational-based marginal prices (LBMPs) and imports and exports.

The ISO's market software will not automatically calculate a carbon component of LBMPs because the carbon charge will be included with fuel and other relevant costs when bid into the current structure. Instead, the ISO envisions calculating an after-the-fact estimate of the LBMP carbon impact, said Ethan Avallone, senior market design specialist.

NYISO will report the estimated LBMP carbon impact for each of its 11 load zones, as well as for each external interface proxy bus.

"What information exactly we would use to make these calculations remains to be seen," Avallone said at a July 9 meeting of New York's Integrating Public Policy Task Force (IPPTF), the group charged with developing ways to incorporate the cost of CO_2 emissions into wholesale energy markets.

"I think we would tie the emission rate to reference levels for the generation resources, so it would be close to the actual," Avallone said. "But that's why we say estimates, because it could differ depending on the mix of the fuel, etc."

He added, "We're considering whether the estimated LBMP carbon impact could be calculated and posted at a time granularity consistent with today's LBMPs or if a different frequency would be more appropriate."

IPPTF Chair Nicole Bouchez, NYISO's principal economist, said the stability of the emission rates will determine how well the ISO can predict them and the consequences of estimates versus using a detailed cost breakdown.

Marginal Emission Rates

Several complications prevent NYISO from capturing the exact LBMP carbon impact, including the difficulty in identifying the marginal units because of product trade-offs (energy, spin, regulation), and time interval trade-offs involved in the ISO's look-ahead for the next megawatt of supply, Avallone said.

"To me the big concern is that when you rank the marginal units in terms of costs, break up the costs for different units, that the CO_2 component might vary or be rather erratic," said Pallas LeeVanSchaick of Potomac Economics, the ISO's Market Monitoring Unit. "First, that might be unnecessarily volatile, and secondly, it would gloss over the impacts of changes in commitment and other things that might not be marginal for one five-minute period, but they're still marginal."

Bouchez said, "Just to remind everyone, when we talk about marginal, we mean what unit would you be moving to serve the next megawatt of load, so the unit that is on a fixed schedule would not be the one that would be moved. … Pallas is also thinking a bit larger, which is do you actually change commitment to serve that next megawatt of load?"

Mark Reeder, representing the Alliance for Clean Energy New York (ACE NY), asked, "If a generator is in a zone, do you know how often the carbon on the margin on their bus would likely be quite different from what you get in terms of a zonal calculation?"

"The point to consider is that the generator at the bus that receives the carbon charge (impact in its bus LBMP) must pay the carbon charge for its emissions," Avallone said.

Carbon Charge on External Transactions

NYISO staffer Nathaniel Gilbraith summarized the ISO's proposal to rely on a "status quo" carbon pricing approach (referred to as Option 1) that would not consider the specific carbon content in energy trades from out of state. A second option under consideration would evaluate marginal emissions rates from out-of-state imports. (See *NYISO Floats Carbon Pricing Straw Proposal*.)

The ISO's first consideration "was to avoid distorting import and export incentives, so that the goal here was to avoid creating a seam at the border where certain resources were compensated differently than others, which would result in a reshuffling of

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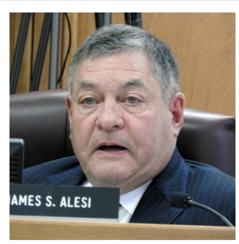
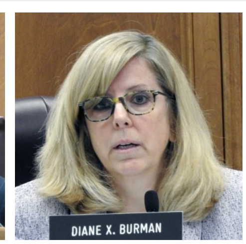
tion, Con Ed's request for a Smart Solutions Program, which included an enhanced gas energy efficiency program, a new gas demand response program, a new "Gas Innovation" program to encourage renewable alternatives to natural gas heating technologies, and a new market solicitation for non-pipeline solutions.

The order (17-G-0606) established criteria for continued development of the gas innovation program and denied the company's request "to recover costs associated with parallel pipeline development efforts, thereby maintaining customer protections associated with unsuccessful pipeline development projects."

The commission said Con Ed's proposed gas DR program and non-pipeline proposal both "require further information from the company, input from stakeholders, and review from staff, and therefore, these components of the petition will not be considered in this order."



Commissioner James Alesi | © *RTO Insider*



Commissioner Diane Burman | © *RTO Insider*

NYISO NEWS

New York Looks at Carbon Price Impact on LBMPs

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resources or fundamentally change import-export engineering," Gilbraith said.

Representing New York City, Couch White attorney Kevin Lang said, "If what we're trying to do is lower carbon emissions, then I'm not sure what the concern is about incentivizing more carbon-free imports into New York. In other words, we should be trying to create a level playing field for imports, just like what we're doing in-state, where we're trying to incentivize renewable resources.

"By trying to avoid the carbon character of imports and exports, you're really creating an unlevel playing field, when what we are really trying to do is create a fundamentally competitive market with anyone to be able to compete on an equal basis."

"I'd rephrase it as we're trying to draw a specific border, and I think you would like to expand that border to include a broader set of resources that are potentially subject to the carbon pricing," Gilbraith said.

Howard Fromer, director of market policy for PSEG Power New York, asked whether the complexity of calculating the marginal emission rate in neighboring areas is still the "driving reason" for the preference for this Option 1.

"There are several reasons why Option 1 is preferable and that's one of the major ones," Gilbraith responded.

Erin Hogan, representing the Department of State's Utility Intervention Unit, said, "A generator that wants to export will have their carbon charge in the LBMP, but yet they'll get a credit back at the border; so theoretically, if it's equal, we could be exporting a significant amount of energy outside the state and ... that would be the status quo."

"That's exactly right," Gilbraith said. "If a generator is currently competitive with generation in an external control area and would like to export its power, let's say in New England, it can do that today and they can profit on its relative efficiency compared to New England's current system."

"So then the drawback is not necessarily that it doesn't incentivize cost-effective carbon abatement outside of New York, but that it also could limit the carbon abatement within New York," Hogan said.

Warren Myers, DPS director of market and regulatory economics, said, "This has become focused on the technical aspect of the quantity of the emissions external to New York, and everybody's just glossing over the fact that ... it's not just the quantity, it's the value of carbon.

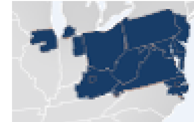
"In this proposal, New York state, not Pennsylvania, not Tennessee, not Massachusetts, would be saying how much each ton of carbon is worth," he said. "To my mind, Option 1, for good or ill, minimizes the exporting of a New York state policy when it comes to interstate trade."

Revised Charter

NYISO Senior Manager for Market Design Michael DeSocio presented a revised charter for the task force, which requires that all proposed analyses and their methodologies go through the ISO's stakeholder process, starting at the Market Issues Working Group before going to the Business Issues Committee.

The task force met yesterday at NYISO headquarters to review draft recommendations for issue Tracks 2, 3 and 4. See next week's *RTO Insider* for coverage.

PJM NEWS



OC Briefs

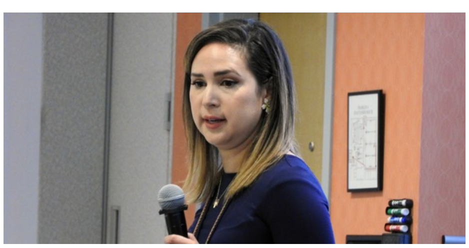
Operators Unfazed by High Demand in June

VALLEY FORGE, Pa. — Grid operators faced several high load forecasts and hot weather alerts last month but never had to take emergency procedures, PJM's Chris Pilong told attendees at last week's Operating Committee meeting.

Pilong reviewed five hot-weather alerts for the month, along with several that were called for early July, in his system operations report. On July 2, for example, the load forecast called for a roughly 152-GW peak, but several factors mitigated the actual demand to about 140 GW, he said, including showers in the RTO's western region and the fact that date fell on a Monday going into a holiday.

"We were on track for 152 [GW]. Had we gotten there, we would have been OK, but that western rain did bring the loads down," he said.

PJM's Stephanie Monzon detailed the operations report for June, which included three spin events. David Mabry, who represents the PJM Industrial Customers Coalition, requested more detail on a June 4 event, caused by a trip loss of 1,210 MW from Unit 1 of the Braidwood nuclear plant. He said it seemed "unusual" the event was resolved in six minutes when the estimate for Tier 1 response was more than 1,000 MW higher than what actually responded. Monzon agreed to investigate and report back.



Stephanie Monzon | © *RTO Insider*

Real-time 30-minute Reserves

Stakeholders endorsed PJM's proposal to create a real-time 30-minute reserve product along with a methodology for how to calculate a procurement objective for each year. PJM's Vince Stefanowicz reviewed the proposal, which has remained consistent throughout the stakeholder process. (See "30-Minute Reserves Target Set," *PJM Operating Committee Briefs: May 1, 2018*.)

Mabry urged staff to send the proposal to the Energy Price Formation Senior Task Force, which is focused on revisions to PJM's energy market. He said working through it there would help him become more "comfortable" with the methodology and the justifications for the target procurement, which would be 3,784 MW for 2018.

While the proposal was endorsed with no objections, there were 48 abstentions that included Mabry's coalition.

Black Start Fuel Assurance

PJM's Glen Boyle outlined revisions to the issue charge for setting black start fuel requirements, which include pushing the anticipated start date for the stakeholder group back a month to September.

Staff also added "critical non-fuel consumables" to the list of requirements to develop and minimum tank suction level to compensation-related issues to hash out.

Load Shed Details

Pilong presented a detailed review of the May 29 load shed event in northwest Indiana. The event was short and the impact localized, but it was the first such event that might trigger the financial penalties implemented as part of Capacity Performance.

The incident analysis found that the Twin Branch-Jackson Road 138-kV line and the Jackson Road 345/138-kV transformer 3 tripped after the line contacted a tree around 12:30 p.m. Five other lines in the area were already offline for maintenance.

A contingency analysis found that if the South Bend-Twin Branch line or transformers at Twin Branch also went out, the Edison-Kankakee line might trip offline and potentially cause a cascading failure. To address this, PJM recalled two of the lines on planned outages and ordered the local utility, American Electric Power, to shed approximately 21 MW of load to relieve the Edison-Kankakee line.

About 15 minutes later, the transformer was restored to service, allowing PJM to end the load shed. The recalled lines didn't come back online for at least another 90 minutes. The tripped line was back online slightly less than 12 hours after it tripped.

GT Power Group's Dave Pratzon asked about a sixth line in the area that was also on a planned outage. Pilong said recalling it wouldn't have relieved the situation because it's on the western side of the Edison-Kankakee line and the issue was on power flowing from west to east, so it couldn't have pushed power into the area.

"There were a lot of outages this day. That [one] didn't have any impact," Pilong said.

He said one of the lines had been on a planned outage since April 18, while the two lines that were recalled had started outages that day. Because the situation was resolved so quickly, operators never got the point of dispatching DR but might have if the situation had persisted, he said.

Regulation Update

PJM's Eric Endress reviewed performance of the RTO's regulation signal, which changed in January 2017. FERC has since rejected the compensation portion of PJM's plan to revise its regulation market, but the signal has remained the same. (See *FERC Postpones Tech Conference on PJM Regulation Market*.)

Endress showed that the marginal benefits factor, which PJM has argued to use and FERC has repeatedly denied, has stayed fairly consistent since May 2017, ranging between 1.01 and 1.33 each month.

Combustion turbines have consistently been top performers in both the slower, sustained-output RegA signal and the faster, dynamic RegD signal. Hydro was also a top RegA performer, followed by demand response and steam. Storage was a top RegD performer, followed by DR and hydro.

RegD units were pegged for more than 30 minutes no more than four times in a given month, reaching that rate only in March 2017. The RegD signal is meant to peg unit response for short durations. RegA resources, which don't have response limitations, were generally pegged more often and for longer periods.

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FERC Allocation Order Details

VALLEY FORGE, Pa. — PJM's Ray Fernandez told attendees at last week's Market Implementation Committee meeting that his staff are still completing calculations for part of FERC's ruling on retroactively reallocating costs for certain transmission projects in the RTO's territory (EL05-121).

Staff have requested to extend the compliance filing deadline until July 30, Fernandez said. In May, FERC issued an order approving a settlement on the RTO's procedure for allocating the costs of major transmission projects. The settlement created a cost allocation formula for projects approved prior to Feb. 1, 2013, when PJM abandoned a "postage stamp" method that billed all utilities in proportion to their load, regardless of where the projects were located. (See "Response to FERC's Cost Allocation Order," *PJM Market Implementation Committee Briefs: June 6, 2018*.)

Staff are revising the allocations on 14 technical worksheets to reflect the approved split of 50% on the original annual load-ratio share basis and 50% on the solution-based distribution factor (DFAX) method. Market participants will need to review all the worksheets to understand the full implications of the revisions, Fernandez said. He hopes to have them completed within two weeks.

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The order also includes a "black box" settlement for projects from 2007 through 2015 that will be rebilled over the next 10 years. Fernandez said those reallocation amounts were published as part of the settlement.

Seasonal Aggregation

Andrea Yeaton | © RTO Insider

Stakeholders unanimously endorsed proposed revisions for aggregating seasonal resources. PJM's Andrea Yeaton presented the proposal, which is designed to better account for the resources' accumulated capability. (See "Seasonal Aggregation," *PJM Market Implementation Committee Briefs: June 6, 2018*.)

Independent Market Monitor Joe Bowring questioned staff's planned procedure for day-ahead notification because PJM continues to use demand response as an emergency resource.

"Typically, you don't have a day's notice; you have an emergency," he said.

PJM's Pete Langbein said grid operators will continue to dispatch DR as necessary during emergencies but will use this approach "if we have the luxury" of receiving notification the day before. He said operators will continue the practice of dispatching resources with registration-level granularity, which is usually limited to a single customer.

Credit Requirements

Stakeholders resoundingly endorsed PJM's recommended revisions to the financial transmission rights credit policy, rejecting both a pre-existing alternative and a proposal offered by DC Energy's Bruce Bleiweis during discussion. Stakeholders also indicated that they strongly preferred the endorsed revisions to the status quo in a sector-weighted vote, with 193 (or 0.92) voting in favor of the changes, with 16 opposed and 11 abstentions. The votes had an endorsement threshold of 0.5.

PJM wants to implement a per-megawatt-hour minimum credit requirement to address potentially large FTR positions that have little or no credit requirements. (See "DC Energy FTR Credit Policy Complaint to FERC," *PJM Market Implementation Committee Briefs: June 6, 2018*.)

The endorsed proposal, which PJM recommended, would implement a 10-cent/MWh minimum monthly credit requirement applicable to both FTR bids submitted in auctions and cleared positions held in FTR portfolios. It received 208 votes (0.95) in favor, with 12 opposed and 21 abstentions.

The alternative proposal, which would implement a 5-cent/MWh requirement, received 77 votes (0.35) in favor, with 141 opposed and 15 abstentions.

DC Energy's proposal received 51 votes (0.44) in favor, with 66 opposed and 119 abstentions. The proposal would have required the credit calculation to account for profits or losses in the market. For

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Resilience

PJM's Dean Manno announced that the RTO plans to substantially expand its procedures for addressing cyberattacks. The details came as part of a presentation on operational changes planned to increase system resilience, which include a procedure to freeze system changes and requiring transmission owners to inform PJM when they disable the auto-reclose feature on any transmission facilities.

The procedures will address responses to cyberattacks against PJM or its members, as well as the telecommunications network between them.

— Rory D. Sweeney

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example, if PJM calculated a $10 credit requirement and the market participant gained $2 in profit from market positions, the participant would submit $8 in collateral to the RTO. If the participant lost $2, collateral necessary would increase to $12.

Bleiweis said he was supportive of the endorsed proposal but hoped for additional revisions. That his proposal progressed to a vote was itself dramatic, as it appeared to have died without being seconded. However, it was announced during voting on the endorsed proposal that Panda Power Funds' Bob O'Connell had seconded the proposal from the phone, and it was allowed to receive a vote.

PJM's Bridgid Cummings also reviewed the results of a Credit Subcommittee poll on additional proposals the subcommittee hadn't endorsed, which found 2% support for a 1- to 5-cent minimum monthly credit requirement on a declining tiered scale based on megawatt-hour volume; 25% support for a $50 million cap on the total minimum monthly credit requirement; 20% support for a $100,000 deductible applicable to the current undiversified adder; and 28% support for status quo.

Balancing Ratio

For anyone confused by the complexities of balancing ratio calculations and performance assessment intervals (PAIs), staff and stakeholders have agreed to develop a presentation for next month's meeting to compare the proposals on the issue. Currently, there are four.

PJM's Pat Bruno provided a first review of two proposals developed by staff to revise the method for calculating annual balancing ratios. (See "Balancing Ratio Recalculation," *PJM Market Implementation Committee Briefs: June 6, 2018*.)

Bruno said the first proposal was "straightforward" because it would calculate the balancing ratio using the average balancing ratios from the three delivery years that immediately precede the base residual auction or, for years that don't have at least 30 hours of PAIs, supplementing the actual number of PAIs with estimated balancing ratios calculated during the intervals of the highest RTO peak loads that do not overlap a PAI. PAIs are five minutes apiece.

The second proposal would estimate the number of PAIs expected in the delivery year using the past three years of data, but floored at five hours for calculating the default market seller offer cap (MSOC) and 15 hours for calculating the nonperformance charge rate in Capacity Performance. The proposals would include revisions to the formulas for the nonperformance charge and the MSOC.

Exelon's Jason Barker noted the proposed MSOC formula wouldn't always arrive at net cost of new entry multiplied by the balancing ratio if different assumptions for the expected number of penalty hours is employed.

He argued that FERC specifically approved a formula that uses a single assumption about the expected penalty hours and pegs the default offer cap to net CONE. Bruno contended that the commission approved the methodology to arrive at the formula rather than the result itself.

In response to a question by Barker, Bruno said staff "didn't really have a formulaic approach" for choosing the 15-hour floor for the nonperformance charge, and that they "looked at the data" and came up with "what we thought was a reasonable estimate."

David Mabry, representing the PJM Industrial Customer Coalition, called it "a balanced proposal."

Additional proposals from Exelon and Calpine differed with PJM on the PAI calculations for the MSOC and nonperformance charge rate formulas. Calpine's would floor both at 10 hours and calculate a number based on the past 10 years of data. Exelon's would use a probabilistic model to look forward. Both would keep constant the number of PAIs used in the two formulas.

Energy Market Caps

PJM's Susan Kenney reviewed staff's two-phase plan for addressing issues with Order 831. The proposal offers a short-term fix to address conflicts in PJM's governing documents, along with a more comprehensive long-term solution. The long-term solution will be less cumbersome than the short-term fix but will require more time to develop. The updated proposal comes after PJM's short-term proposal failed to receive stakeholder endorsement at the May meeting of the Markets and Reliability Committee. (See "Offer Cap Revisions Stalled Again," *PJM Markets and Reliability Committee Briefs: May 24, 2018*.)

PJM is hoping to have the long-term solution ready by Nov. 1, so it should be available several weeks ahead of that so stakeholders can familiarize themselves with the changes prior to implementation, Kenney said.

She outlined some "risks" of the short-term proposal, which would cap all offers at $1,000/MWh by default and allow higher offers to submit a request for verification. The Monitor's Catherine Tyler said those concerns are the basis for the Monitor's preference for the "switch to cost" method, which would provide generators the option to exclude price schedules from dispatch. Otherwise, generators can request the ability to submit price-based offers in line with verified cost-based offers, but they are then on the hook to ensure price-based offers at each segment remain compliant with verified cost-based offer caps.

The long-term solution will automate the process.

VRR Curve Update

PJM's Jeff Bastian reviewed the RTO's proposed revisions for its quadrennial review of the variable resource requirement (VRR) curve in its Reliability Pricing Model capacity market construct, including a table comparing how the different revisions would impact the gross CONE calculation.

Based on an analysis it commissioned from the Brattle Group, PJM is recommending switching its reference resource from the Frame F to the Frame H of a General Electric turbine and updating the unit heat rate, Bastian said. The frame switch would reduce the net CONE from $405/MW-day of unforced capacity to $308. Some generators have argued against the recommendation. (See *Factors in New PJM VRR Curve Still in Question*.)

In the table, PJM estimated the gross CONE for 2019 by escalating the 2018 figure by nearly 3%. Bastian said PJM

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believes it's important to get the 10% cost adder into the dispatch cost of the reference resource. Overall, PJM's recommendations would reduce the energy and ancillary service offset by 22% from $72/MW-day of unforced capacity to $56 and reduce the net CONE from $333 to $251.

PJM is targeting Oct. 12 to file for FERC approval, and seeking endorsement votes by the Markets and Reliability Committee on Aug. 23 and the Members Committee during an Aug. 31 teleconference.

VOM Update

As time runs out to square away where generators can recover variable operations and maintenance (VOM) costs, stakeholders remain separated on the issue. PJM is attempting to resolve those differences prior to concluding its quadrennial review of the VRR curve since the costs could be recoverable in either the capacity or the energy market.

There are four proposals set for a vote at the July meeting of the MRC, and while the voting order on the proposals is set, a recent submission from Orange and Rockland Utilities/Rockland Electric Co. has threatened to upset the likely voting. A proposal from American Electric Power that allows use of default U.S. Energy Information Administration calculations will be up first, followed by PJM's proposal, a proposal from the Monitor and finally RECO's offering.

AEP's Brock Ondayko walked through the default proposal, which includes a friendly amendment introduced at the June meeting of the MRC that would prohibit units that failed to clear in the year's capacity auction from including fixed costs in their energy offers. (See "Variable Operations & Maintenance Packages," *PJM MRC/MC Briefs: June 21, 2018*.)

PJM's Melissa Pilong reviewed the RTO's package, which remains unchanged from past discussions. It's the only proposal that would allow units to include fixed costs in their energy offers if they failed to clear in the year's capacity auction.

Tyler presented the Monitor's proposal, which would limit costs allowed in energy offers to short-run marginal costs.

"The governing documents are just not clear on these costs and only the IMM package would clean up the definitions," she said.

Stakeholders have been reluctant to support the Monitor's proposal because of concern about the definition.

"Part of our disagreement comes down to the definition of short-run marginal costs," Pratzon said.

RECO's Brian Wilkie said his proposal was meant to strike a compromise between the generator-friendly and load-friendly proposals to ensure that stakeholders wouldn't be stuck with the status quo if coalitions stood their ground and those proposals failed to win endorsement. RECO's proposal would allow generators to recover VOM costs up to limits that would be posted into Manual 15. Almost all unit types would be capped at $3.50/MWh for the costs. Sub- and super-critical coal and biomass would be capped at $4/MWh; nuclear at $3/MWh; and wind, solar and hydro at $0/MWh.

"We agree with the IMM's definition of VOM is the simplest way to put it," Wilkie said.

He said PJM staff told him there could be "exponential" cost increases for load if either the PJM or AEP proposal is implemented and later combined with the fast-start or convex hull revisions being considered in PJM's Energy Price Formation Senior Task Force. (See *PJM Board Seeks Reserve Pricing Changes for Winter*.)

Generation representatives criticized Wilkie's use of the term "exponential," arguing that characterization was validated by estimates. Gary Greiner of Public Service Electric and Gas said it's unfair to group in various issues when considering isolated proposals.

"I guess that depends on what you throw into the toy box," he said. "The proper way to do it is to look at this issue [individually] and see what impacts it would have on price."

"Exponential implies a big change," Barker said. "To date, I don't know what that value is."

The Monitor supported the proposal, along with Mabry and Greg Poulos, executive director of the Consumer Advocates of the PJM States (CAPS).

"It's not our proposal," Tyler said of RECO's caps, but "we believe it is better than the status quo."

Chenchao Lu | © RTO Insider

PJM attorney Chenchao Lu expressed concern about whether it would be permissible to ask FERC to approve rules that would potentially cap cost recovery below actual operating costs. Wilkie had said earlier that he was not an attorney and therefore wasn't sure whether FERC would accept the proposal.

Wilkie said he was willing to revise the proposal to incorporate feedback from generators. Greiner had noted the changes could create a "cycling nightmare for our ops people," and Wilkie said he would consider how to address the concerns. Pratzon said more discussion might be necessary.

Wilkie agreed to let PJM know on Thursday — before the agenda is published for the July meeting of the MRC — whether they have received much engagement on their proposal. PJM will decide, depending on that update, whether to put the issue for a vote on the agenda.

Must-offer Revisions

Bruno presented a proposal on revising the rules for what units must offer into capacity auctions. The proposal addresses many of the concerns Exelon expressed when it proposed investigating the issue. (See "Exelon-backed Analyses Approved," *PJM Market Implementation Committee Briefs: March 7, 2018*.)

Bowring criticized the proposal, specifically noting his concern that this could allow hoarding of capacity injection rights and block new entry when a unit is uneconomic. He said units should offer their costs in the auction and if they do not clear, the market message is that the units are not needed and not wanted by the market at that price.

— Rory D. Sweeney

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Load Model Compromise Endorsed

VALLEY FORGE, Pa. — Stakeholders at last week's Planning Committee meeting endorsed PJM's recommended load model for the 2018 reserve requirement study, which uses data from 2003 through 2012.

The study was adjusted to reflect the fact that load within the RTO's footprint peaks during a different week than the area outside the footprint included in the model.

PJM selects a model for the study because the coincident peak distributions from the load forecast can't be used directly in the PRISM modeling software, the RTO's Patricio Rocha-Garrido said.

American Municipal Power's Ryan Dolan asked why staff chose not to use the best-performing model from 2004 to 2012.

"We prefer more data to less data," Rocha-Garrido replied, adding that the extra year "is a close second."

"What's the point of doing the test if we're not going to accept the result?" Dolan asked.

"The test informs the decision," Rocha-Garrido said.

CETL Changes

The complex interdependency of PJM's procedures was on display when a presentation on proposed revisions to Attachment C of Manual 14B — billed as improving transparency and clarity — evolved into a discussion on potential impacts to capacity emergency transfer limits (CETLs) and concerns about how that might affect zonal capacity requirements.

The RTO's Jonathan Kern presented the proposal, which would also "correct any conflicts between how the procedures are described and how PJM actually implements them" and include "a few minor procedural changes." Many of the revisions focus on procedures for the load deliverability test or calculating CETLs.

Several stakeholders asked PJM to delineate how each revision might potentially affect CETL calculations. Kern said staff could provide all the distribution factors but that it was "premature" to perform full CETL analyses because the RTO hasn't yet decided to include any of the external facilities. Staff believe considering them is "prudent" to ensure they're not "turning a blind eye" to the potential impact of external systems if PJM analyses don't account for them.

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Market Efficiency

It appears the toil at a July 5 meeting of the Market Efficiency Process Enhancement Task Force has paid off. PJM's Brian Chmielewski reviewed results of a last-minute poll that was requested to be completed in the few days between the task force's meeting and the PC. (See *PJM Market Efficiency Project Rules Could Slip Deadline*.)

At issue was a set of six proposals to address how PJM evaluates and selects discretionary transmission projects. The poll showed majority support for Package G, which would exclude from the base case those units with facility study agreements (FSAs) and suspended interconnection service agreements and their associated network upgrades at the time of case build, unless they are needed for reliability.

Energy benefits of projects that are proposed to be in service later than the Regional Transmission Expansion Planning year would be adjusted to account for any savings forgone because of the later in-service date. Annual mandatory sensitivity studies would include FSA units only if they were excluded from the base case analysis. Sensitivities would be used for evaluation of a proposals' robustness and sizing, but not for benefit-to-cost ratio tests. Parameters would be decided prior to the beginning of the project proposal window. In all simulated years, generation and transmission topology would be set at the RTEP-year level.

LS Power's Sharon Segner asked that the proposed Tariff language be ready to review at the task force's next meeting on July 20 so it can be discussed prior to the July meeting of the Markets and Reliability Committee.

Greg Poulos, executive director of the Consumer Advocates of the PJM States, asked for more clarity on FSA issues because they are "certainly of concern" to some advocates.

Segner and Public Service Electric and Gas' Alex Stern, who had requested the fast turnaround on the poll, praised Chmielewski and other staff on the task force for compiling it so quickly.

Cascading Trees

PJM's Aaron Berner reviewed staff's efforts to incorporate resilience objectives into transmission planning. As part of that initiative, staff have developed a visualization tool called "Cascading Trees" that considers the potential impact to the grid of "more extreme" events and analyzes probabilities of what issues such events could cause.

"That will play an important piece in how we develop plans," Berner said. He clarified that the current analyses assume the trigger event has occurred and said it's unclear whether staff will consider calculating the probability of the triggering event happening in the first place.

Stakeholders seized on the analysis with questions about PJM's plans for addressing resilience. Berner turned many of those questions away, emphasizing that the analysis remains in its infancy.

"That's more in depth than I planned on going into today," Berner said.

In response to a question from Dolan, Berner confirmed that staff are working with TOs, many of which already have resilience factors included in their internal planning assumptions.

"We do not intend to move forward in isolation. We are having conversations with

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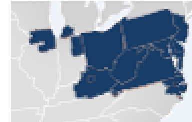

FERC Rejects PJM Exemption for Incumbent TOs

By Rich Heidorn Jr.

FERC on Friday rejected PJM's proposal to exempt incumbent transmission owners from signing designated entity agreements (DEAs), saying it gave them an undue advantage over non-incumbents (ER18-1647).

In May, PJM proposed two changes to the competitive proposal window process mandated by Order 1000.

The commission approved PJM's request to allow transmission developers 60 days to accept a DEA after receiving it as the winner of a project. The agreement includes a development schedule and a requirement to provide a letter of credit equal to 3% of the estimated project cost.

But the commission rejected the RTO's proposal to exempt incumbent TOs from the requirement to execute a DEA for Regional Expansion Transmission Plan projects that the Operating Agreement requires PJM to designate to an incumbent. Such projects include TO upgrades; projects that would alter the TO's use of its right of way; and those located solely within a TO's zone that are not allocated outside.

PJM argued that the terms of the Consolidated Transmission Owners Agreement (CTOA) governing incumbents are comparable to the DEA. It said the security requirement — to protect ratepayers from additional costs if the original developer abandons a project and it must be reassigned — was unnecessary for incumbents because they cannot abandon projects and that requiring it would only increase costs.

The commission said PJM's proposal would provide an advantage to incumbent TOs in the RTO's evaluation of transmission proposals. FERC noted that it had rejected similar exemptions in Order 1000 filings by SPP in 2013 and NYISO in 2015. (See *FERC Accepts Order 1000 Compliance Filing*.)

"The less stringent requirements in the Consolidated Transmission Owners Agreement also could spare an incumbent transmission owner from a breach (and the associated remedies) that would otherwise be triggered if it executed the designated entity agreement. Although PJM argues that the proposal to exempt incumbent transmission owners from the requirement to execute a designated entity agreement in certain cases will further administrative efficiency, any such benefits do not overcome undue discrimination concerns," the commission said.

"Under PJM's proposal, an incumbent transmission owner proposing a transmission owner designated project in PJM's competitive proposal window process could reflect the cost savings associated with not having a security requirement in its proposal," FERC added.

The commission also said the CTOA's milestone requirements are less stringent than that in the DEA, which includes "several interim milestone obligations and consequently, more potential events for breach."

FERC said the DEA could prevent a transmission developer from assigning its rights to an affiliated limited liability company or C-corporation as financing vehicles, or from meeting legal requirements for state public utility status. "Such prohibition could inhibit the developer's ability to seek siting approval from that state, particularly if the state requires that the developer be incorporated as a public utility under state law," FERC said.

The commission approved PJM's proposal to change the time period for a transmission developer to accept its designation.

Rather than having 60 days from receiving notification of its designation to accept, PJM proposed that the developer have 60 days after receiving the DEA.

"We agree that this proposal will provide PJM with more time to develop and issue the designated entity agreement, as well as for the transmission developer to respond to the initial designation with a development schedule with milestones and relevant project information," FERC said.

PC/TEAC Briefs

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the transmission owners on how this might work," Berner said.

PJM's Steve Herling reminded stakeholders that staff are simply acting on their marching orders.

"The direction we're taking to pursue resilience is coming from the board," he said.

RTEP Processes

Berner and PPL's Frank "Chip" Richardson presented plans for reorganizing the processes for reviewing transmission projects. Berner covered plans for the subregional RTEP and Transmission Expansion Advisory Committee. Richardson explained TOs' plan for supplemental projects.

The process designs are similar and stick to the requirements outlined in FERC's ruling that TOs weren't properly complying with their obligations under Order 890 to involve stakeholders early enough to solicit their needs and provide required information before making decisions to proceed with "supplemental" projects — transmission expansions or enhancements not required for compliance with PJM reliability, operational performance or economic criteria. TOs describe them as projects planned by each company individually to address items not addressed by PJM, such as customer service, replacement of failing, poor performing or antiquated equipment and enhancements to the security of their transmission system. (See *Group Contests 'Supplementals' Ruling as PJM, TOs Advance*.)

Stakeholders pressed TOs for more detail on how they plan to engage in the meetings, but Richardson emphasized the TOs' focus on implementing the changes.

"Certainly, as we implement this, people will be able to voice opinions about what they think ... but we're not focused on changes right now. We're focused on getting it implemented," he said. "When we're ready to have you take a look at it, we'll let you know. ... We'll think about [feedback] after we get through a few cycles."

— Rory D. Sweeney

SPP NEWS

Monitoring Unit: Load up, Prices down in Spring

SPP's Market Monitoring Unit said last week that energy prices averaged about $23/MWh in the spring, despite higher loads.

The MMU's quarterly State of the Market report also highlighted the recent merger between Westar Energy and Great Plains Energy, the parent company of Kansas City Power and Light, although its completion happened outside the report's March-May range. (See *Westar-Great Plains Merger Wins Final Approval*.)

The Monitor said the combined company would have accounted for 19.2% of total system load over the period, making it the largest energy user in SPP's market footprint. Additional information will likely be included in the summer report, MMU Executive Director Keith Collins said.

The report indicates that spring hourly average load was up 8% from 2017 — and 14% for May alone — as a result of abnormally high temperatures. Average day-ahead prices increased 13% to $23/MWh over last spring, while average real-time prices gained 10% to $22/MWh.

Spring's average monthly gas price at the Panhandle Eastern hub was $2.14/MMBtu, down from $2.70/MMBtu in 2017. Gas prices in spring 2016 were $1.68/MMBtu.

Coal-fired resources continued to account for a smaller share of the RTO's energy production at 37%. Wind resources accounted for almost 29% of generation, with nameplate wind capacity increasing to 17.7 GW by June, up from 12.8 GW at the end of May 2016.

The Monitor said occurrences of negative price intervals decreased from the winter period and last spring. This spring, prices were negative in just over 5% of real-time intervals, and just under 2% of day-ahead hours.

According to the report, overall congestion in the footprint has declined, with real-time intervals with a breached or binding flowgate dropping from 40% last spring to 20% this spring.

The Monitor recently conducted a study of day-ahead market congestion and auction revenue rights bidding behavior following complaints by market participants that were unable to obtain hedges in the ARR process. The study led to three main conclusions, the MMU said: Successful ARR nominations have decreased; the market's overall need for hedges has increased; and nomination behavior has remained relatively consistent.

| SPP

The growth in day-ahead congestion correlates with the overall increase in wind production, the Monitor said. It said the 28 GW of additional wind capacity planned in the generation interconnection queue will likely increase the need for hedging.

The MMU recommends "further review and consideration of the auction revenue right process by the RTO and stakeholders" going forward. It will host a webinar July 25 to discuss the spring report.

SPP Preps AECI Seams Project for 2nd Crack at FERC

David Kelley, SPP's director of seams and market design, told the Seams Steering Committee on Friday that the RTO has performed additional analysis in order to gain FERC approval of a seams project with Missouri-based Associated Electric Cooperative Inc.

Kelley said staff intends to present "new evidence" on regional cost allocation to FERC in July or August. He said SPP will be presenting the avoided costs of regional projects — a metric the commission has already approved — and the reduced regional costs of day-ahead market uplift.

"We're thinking we're in really good shape," said Kelley, who last met with FERC on July 12. "It's been a little challenging to figure out a way to do regional cost allocation for a single project."

SPP is trying to reverse FERC's October rejection of cost allocation for the Morgan project, one of two potential seams projects with AECI. It consists of a new 345/161-kV transformer at AECI's Morgan Substation near Springfield and the rebuild of a 161-kV line.

The other project, a 345-kV, 50-MVAR reactor at City Utilities of Springfield's existing Brookline substation, has been included in SPP's Integrated Transmission Planning Near-Term assessment that will be presented to the Markets and Operations Policy Committee and Board of Directors/Members Committee this month.

The Brookline project's costs will be allocated under SPP's normal processes, but Kelley said AECI wants to pick up its share. The two projects have a combined estimated engineering and construction cost of more than $18 million.

The SSC agreed to take a crack at developing a Tariff mechanism to allocate costs for seams projects. With no such mechanism in place, SPP has to take seams projects to FERC on a case-by-case basis.

SPP, MISO Discuss Jan. 17 'Big Chill'

The Regional Transfers Operating Committee (RTOC), a six-person committee that includes two representatives from SPP and MISO, met twice in June to discuss what Kelley called "The Big Chill," the Jan. 17 event when unusually frigid weather forced MISO to initiate a maximum generation alert for its South region.

MISO exceeded its 3,000-MW regional dispatch limit on transfers between its North and South regions over the SPP transmission system for an hour and was forced to make emergency purchases from Southern Co.

Continued on page 28

SPP NEWS

MISO, SPP Loosen Interregional Project Requirements

Continued from page 15

promised more discussion on the issue during the August IPSAC meeting.

"This is a difficult conversation to have without examples in front of us," Bell acknowledged. He assured stakeholders the RTOs only arrived at the decision to remove the joint model after substantial discussion about how it would affect project cost allocation.

MISO and SPP agreed in February not to pursue a 2018 coordinated system plan, which could have resulted in an interregional project, instead promising to examine their joint planning process and seek ways to improve interregional coordination.

The two have completed two coordinated system plan studies to date, but neither has resulted in a viable interregional project. During their 2016/17 study, the RTOs identified three possible projects, but all were disqualified by the $5 million cost requirement, Lopez said.

"I think the studies have shown us that there are some barriers," Lopez said.

Bell said MISO and SPP will likely return to the IPSAC next month to seek approval to revise their joint operating agreement, which will be filed by the end of the year.

Bell said the RTOs hope to produce another coordinated system plan study in 2019, although filing timelines could interfere with the goal.

No Dent in MISO 345-kV Threshold

The JOA revisions will not include a provision to lower MISO's requirement that market efficiency interregional projects be at least 345 kV.

"SPP continues to encourage MISO to pursue lowering its current 345-kV voltage threshold for SPP-MISO interregional projects," SPP said. However, MISO said it continues to view the voltage threshold as a strictly regional issue, not up for discussion in the IPSAC because there is no voltage threshold criteria in the JOA. Lopez said MISO's Regional Expansion Criteria and Benefits Working Group will continue to explore the effects of lowering the threshold.

MISO last month said it will revise its regional — not interregional — cost-sharing practices for market efficiency interregional projects with SPP in order to match its process for PJM seams projects, lowering the voltage threshold to 100 kV over some stakeholders' objections. (See *MISO to Lower SPP Interregional Project Thresholds*.) MISO lowered its 345-kV threshold for MISO-PJM projects to 100 kV in 2016 under FERC's orders.

The MISO-SPP plan also excludes a requirement that prospective interregional projects that were evaluated but didn't pass a cost-benefit ratio be reviewed and voted on by both boards of directors. MISO said requiring such a move was unnecessary: Interregional projects that pass all criteria would still need to be approved by the boards.

Continued from page 27

Kelley said the RTOC reviewed the use of NERC's transmission loading relief process during the event and processes for acquiring and delivering emergency energy. He said improved communications will be the key to preventing a recurrence and improving operations and reliability.

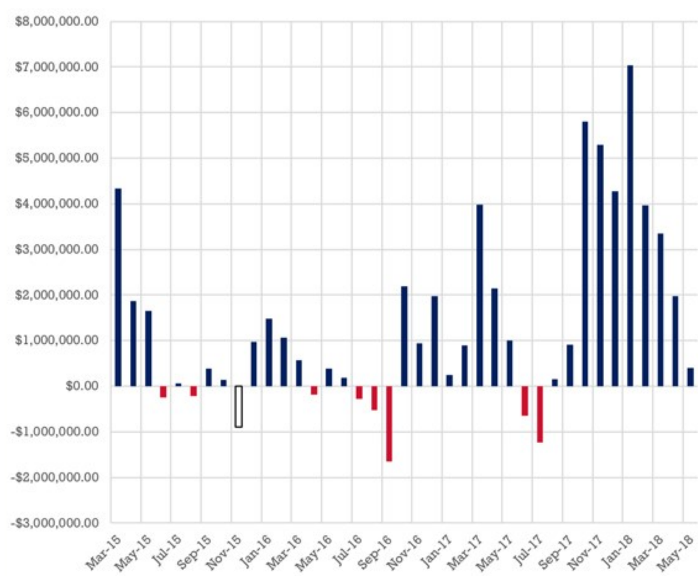
"Situations like Jan. 17 don't just show up without advance warning," he said. "We and MISO had multiple warnings days before. We feel, and MISO feels, we can do a better job of communicating in advance."

The RTOC is an operating committee created by a 2016 settlement agreement between SPP, MISO, Southern and the Tennessee Valley Authority. (See *SPP, MISO Reach Deal to End Transmission Dispute*.) It will meet again in late July.

M2M Generates $397,428 in Payments to SPP in May

Market-to-market (M2M) payments between SPP and MISO dropped to $397,428 in May, the lowest amount since last August. However, it was also the 10th straight month, and the 18th of the last 20, in which the payments have been in SPP's favor.

The RTO has incurred $53.7 million in M2M payments from MISO since the two began the process in March 2015.



Note: Positive values are payments to SPP from MISO; negative values are payments from SPP to MISO.

M2M settlements March 2015-May 2018 | *SPP*

Current and temporary flowgates were binding for 254 hours in May, SPP staff told the SSC.

— Tom Kleckner

Senate Focuses on Gas Infrastructure amid Increasing Delays

Murkowski Laments Powelson Departure

By Michael Brooks

WASHINGTON — The Senate Energy and Natural Resources Committee returned Thursday to the issue of natural gas infrastructure permitting following reports of increasing delays at FERC.

Two former FERC chairmen, James Hoecker (1997-2001) and Joseph T. Kelliher (2005-2009), agreed with J. Curtis Moffatt, general counsel for Kinder Morgan, and James Murchie, CEO of investment advising firm Energy Income Partners, that failing to build adequate pipelines would lead to higher prices for consumers. They also said delays in state and federal approvals cause uncertainty and could discourage down investment.

While these sentiments aren't new, they came on the heels of a report by Bloomberg on Wednesday that FERC has notified several developers of LNG export terminals that their applications could be delayed by 12 to 18 months as it struggles to deal with its backlog. The commission asked the developers to consider sending private contractors to help, according to Bloomberg's sources.

In a series of tweets before the story broke, Commissioner Neil Chatterjee suggested better pay for staff and opening a regional office in Houston, "the center of the world" for natural gas.

FERC Chairman Kevin McIntyre told the committee at an oversight hearing last month that the commission has 14 pending LNG applications, up from four in 2007.

McIntyre said the commission has hired private contractors to supplement its workforce and is seeking to hire additional engineers, while also considering reallocating other staff and hiring additional contractors. It also is seeking to improve coordination with the Department of Energy and the Department of Transportation and seeking internal efficiencies.

The panelists at Thursday's hearing made no mention of commission staffing as a problem. Rather, they mostly offered suggestions for how the commission could more efficiently process pipeline applications.

Kelliher, executive vice president for federal regulatory affairs for NextEra Energy, said FERC could be more transparent in its certificate orders about how it weighs the benefits and adverse impacts of projects. "There is a need to clarify whether and how environmental impacts should be weighed in this balancing, and whether the commission's environmental review is under the auspices of the National Environmental Policy Act of 1969 or part of the broader public interest determination in the Natural Gas Act," he said.

Former FERC Chairmen James Hoecker (left) and Joseph T. Kelliher | © *RTO Insider*

Kelliher said the pre-filing process that formerly took six to eight months now takes up to 12, while the certificate process that used to take nine to 11 months now takes two years or longer. "One factor that has contributed to the length of the certificate process is delays in approvals from other federal agencies," he said. "If these delays are driven by resource limits at these agencies, the cost incurred by these agencies could be reimbursed by pipeline developers in a manner consistent with how the costs of other federal agencies in the hydropower licensing and relicensing process are recovered from hydropower licensees."

The witnesses, along with several senators, noted that one of the major factors leading to delays is local opposition from environmentalists and landowners.

Murchie said the challenge for regulators was "getting people to understand that, while their land is being taken [under eminent domain], it's being taken for a greater good, just like it is with a highway."

FERC is already considering many of the issues discussed at the hearing as it reviews its 1999 policy statement on gas pipeline approvals. (See *FERC Outlines Gas Pipeline Rule Review*.)

Fears of FERC Deadlock

Committee Chair Lisa Murkowski (R-Alaska) said Thursday's hearing was prompted by questions on gas and electric transmission infrastructure remaining following last month's FERC oversight hearing. The Department of Energy's efforts to provide financial support to coal and nuclear plants took up most of that discussion. (See *FERC: No Emergency on Grid*.)

It was not, she said, in reaction to the coming departure of Robert Powelson after only a year on the commission. (See *Powelson Leaving FERC to Head Water Lobby*.)

"We had all five commissioners here; it was good to see them," Murkowski said in her opening remarks. "I don't know, maybe we jinxed the whole thing."

Murkowski asked Hoecker and Kelliher later in the hearing what they thought the committee should be looking for in Powelson's replacement.

"I have long advocated that the members of the commission should include some seasoned economists [and] industry engineers, not just lawyers, as much as I love lawyers," replied Hoecker, executive director and counsel to the trade group WIRES.

"I think they need someone who is comfortable with criticism," Kelliher said. He also said they should be willing to work with their colleagues, "but only up to a point. It's not supposed to be 5-0 on everything. It's OK to dissent."

Speaking to reporters after the hearing, Murkowski said she has not yet spoken to the Trump administration regarding a nominee, but that she hoped it would make the commission a priority. "You know, we worked very aggressively last year to get the FERC filled up," she said, "and we'll just do it again."

FERC & FEDERAL NEWS

Appellate Court Rejects Challenge to FERC Funding

By Rich Heidorn Jr.

The D.C. Circuit Court of Appeals last week rejected environmentalists' claim that FERC is incented to award pipeline certificates because it collects its operating expenses from regulated parties.

Upholding a lower court ruling, the D.C. Circuit also rejected the Delaware Riverkeeper Network's challenge to FERC's use of tolling orders to meet its statutory deadlines for acting on rehearing applications (17-5084).

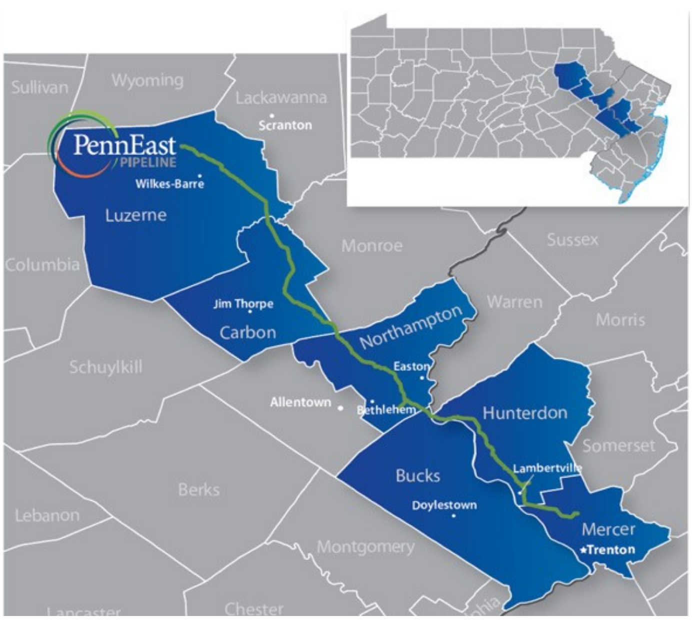
The case arose from PennEast Pipeline's 2015 application with the commission to build a 114-mile natural gas pipeline through Pennsylvania and New Jersey. Riverkeeper, which works to protect the Delaware River and its tributaries, intervened in opposition.

In 2016, while FERC was still reviewing the application, the group filed a complaint in U.S. District Court alleging that the commission's funding structure creates structural bias in violation of the Due Process Clause of the Fifth Amendment. Riverkeeper also said the commission's use of tolling orders to satisfy its 30-day deadline for acting on rehearing applications violates its members' due process rights.

FERC's Funding Mechanism

Although it receives an annual Congressional appropriation, FERC is required to recover its costs from regulated industries. Riverkeeper said the structure creates improper incentives for FERC to approve more pipelines so that it could seek larger appropriations from Congress.

The district court dismissed the case for failure to state a claim, agreeing with FERC and PennEast that Riverkeeper had failed to identify any liberty or property interest protected by the Due Process Clause.



PennEast Pipeline

The D.C. Circuit agreed, citing the Supreme Court's 1928 *Dugan v. Ohio* ruling, which concerned a mayor who served a judicial function as one of five members of a city commission. Although the mayor's salary came from the same general fund in which fines were deposited, the court said the salary was "not dependent on whether [the mayor] convicts in any case or not."

As in *Dugan*, the appellate court ruled, "the adjudicator does not control the funds collected," because FERC's fees and charges are "'credited to the general fund of the Treasury,' not placed into its own coffers. Moreover, the commission's budget, like the mayor's salary in *Dugan*, is fixed by a distinct legislative body."

"Regardless of how many pipelines FERC may approve, it 'shall' charge, for each year, a total amount 'equal to all of the costs incurred by the commission in that fiscal year,'" the court said.

Due Process Standing

The Due Process Clause forbids the federal government from depriving a person of "life, liberty or property without due process of law."

Riverkeeper based its due process claim on the 1971 Environmental Rights Amendment to the Pennsylvania Constitution, which guarantees its citizens "a right to clean air, pure water and to the preservation of the natural, scenic, historic and esthetic values of the environment."

But the court said the amendment "protects not private property rights, but public goods," and therefore is "too vague and indeterminate to create a federally cognizable property interest."

In addition, the court said, "the rights created by the amendment bind only state and local government, not the federal government. … For all of these reasons, we conclude that the Environmental Rights Amendment does not create federally protected liberty or property interests, much less ones that FERC could infringe."

Tolling Orders

The court also rejected Riverkeeper's challenges to the commission's use of tolling orders, which grant rehearing for the limited purpose of giving the commission more time to consider such challenges. Riverkeeper complained that the process frustrates judicial review in violation of the Due Process Clause because FERC routinely allows construction to proceed while the rehearings are pending.

"Regardless of whether any protected liberty or property interests are implicated, the commission is not a structurally biased adjudicator, and its use of tolling orders is not facially unconstitutional," the court said. "We have long held that FERC's use of tolling orders is permissible under the Natural Gas Act, which requires only that the commission 'act upon' a rehearing request within 30 days, not that it finally dispose of it."

Montana Order on Avista Sale Includes Colstrip Protections

By Tom Kleckner

The Montana Public Service Commission's final order approving Hydro One's acquisition of Avista includes several conditions designed to prevent the early closure of the troubled Colstrip power plant.

Most notably, the order released late last Tuesday points to pledges by corporate executives that the sale would not shorten the coal-fired plant's operational life. The commission approved the sale by a 4-1 vote on June 12.

Avista owns 15% of Colstrip Units 3 and 4, which were built in the mid-1980s and have a combined net generating capacity of 1,480 MW. Low natural gas prices and regional opposition to coal resources have bedeviled the Colstrip plant in recent years. The plant's operator, Pennsylvania-based Talen Energy, has been exposed to low power prices on the open market as a merchant generator.

Hydro One's $5.3 billion acquisition would result in Spokane, Wash.-based Avista becoming a wholly owned indirect subsidiary of the Canadian power firm.

The sale, however, could be in jeopardy. Ontario Premier Doug Ford, who took office June 29, had campaigned on replacing Hydro One CEO Mayo Schmidt and the company's board of directors, and on Wednesday, Schmidt retired and the board resigned under an agreement with the province of Ontario, which owns 47% of Hydro One.

Avista on Wednesday said it was surprised by the moves but not how they might affect the sale.

Avista, an electric and gas utility with customers in Alaska, Idaho, Oregon and Washington, has only 32 retail electric customers in Montana, most of whom are affiliated with the company.

"As a result, a traditional examination of this sale and transfer is not appropriate," the commission said. "Instead the commission examines this transaction under the public interest standard focusing on the potential impacts on electric generation as a whole in Montana."

Under settlements in their Washington and Idaho merger dockets, Avista and Hydro One proposed a 2027 depreciation end date for Units 3 and 4, although the units' expected 50-year lifespans would run through 2034 and 2036, respectively.

Owner	Colstrip Unit 3		Colstrip Unit 4	
	Ownership Percentage	Current Terminal Depreciation Year	Ownership Percentage	Current Terminal Depreciation Year
Avista	15%	2027	15%	2027
Puget Sound Energy	25%	2027	25%	2027
Pacificorp	10%	2046	10%	2046
Portland General Electric	20%	2030	20%	2030
Northwestern Energy, LLC	0%	No Ownership	30%	2043
Talen Energy, LLC	30%	Not a rate-regulated entity	0%	No Ownership

| *Montana Public Service Commission*

The PSC noted that accelerated depreciation is a strategy sometimes used to "facilitate premature retirement of disfavored utility generation assets" and said the practice "potentially creates regulatory and operational risks for the other Colstrip owners, as each has diverging economic incentives to operate their respective share of the assets."

The other owners of Units 3 and 4 are Talen, Puget Sound Energy, PacifiCorp, Portland General Electric and NorthWestern Energy.

The commission said it approved the transaction because it had been assured "that the accelerated depreciation adopted in other jurisdictions will not result in an early or different retirement date for Colstrip Units 3 and 4." It noted that the applicants committed that the units' depreciation "will not deviate from the existing scheduled as currently approved."

The PSC declined to endorse any depreciation schedule for the units, saying the issue would be addressed, if necessary, in future rate cases or other contested case proceedings before the commission. It asked Hydro One and Avista to provide the commissioners with their integrated resource plans for their Montana generating resources "when those plans became available."

The commission also reserved the right to incorporate any increased commitments made in other jurisdictions into its own approval.

Along with the states in which Avista operates, the companies must gain regulatory approval of their merger from several federal agencies.

Colstrip's other two units, owned by Talen and Puget Sound, are scheduled to be shut down by 2022 under the terms of a 2016 agreement with environmental groups. The units were built in the 1970s and can produce 614 MW of energy. (See *Puget Sound Energy, Talen Agree to Close Colstrip Units*.)

Colstrip Power Plant | *Talen Energy*

FERC OKs Dominion's Proposed SCANA Buyout

By Peter Key

FERC last week authorized Dominion Energy's proposed acquisition of SCANA and its South Carolina Electric & Gas subsidiary, saying the transaction was consistent with the public interest (EC18-60).

"We are pleased by the FERC's considered and timely action," Dominion Energy CEO Thomas Farrell II said in a statement. "We will continue working toward achieving the other required regulatory approvals and completing our transaction by the end of this year."

The deal has been approved by the Georgia Public Service Commission and federal antitrust regulators. It still requires approval by SCANA shareholders, the North Carolina and South Carolina public service commissions, and the Nuclear Regulatory Commission.

| South Carolina Gas & Electric

Dominion offered to buy SCANA on Jan. 3 for $7.9 billion in stock and the assumption of $6.7 billion in SCANA debt. (See *Dominion to Buy Distressed SCANA for $8B*.) SCANA became an acquisition target after its failed attempt to add two reactors to the V.C. Summer nuclear plant. The company and its partner on the project, Santee Cooper, which is owned by the state of South Carolina, spent $9 billion on the expansion before pulling the plug on it last summer.

The decision created a firestorm in South Carolina, where SCE&G and Santee Cooper ratepayers have been shouldering the project's cost. The state late last month enacted a law directing the Public Service Commission to cut SCE&G's rates by an amount that would cover nearly all the portion of the rates that go to covering the failed nuclear project's cost. SCE&G responded with a lawsuit challenging the law's constitutionality in federal court.

SCE&G has been sued by its customers over the project, which is being investigated by the FBI, the South Carolina State Law Enforcement Division and the Securities and Exchange Commission, none of which has filed any charges.

SCANA said Friday it has added two independent directors to its board and appointed them to a Special Litigation Committee charged with investigating claims alleged against some of its current and former directors in shareholder lawsuits against it in federal and South Carolina courts.

Exelon Bids $140M for FirstEnergy's Retail Business

Continued from page 1

electricity and wholesale load-serving contracts and other commodity contracts to Constellation.

In an 8-K filing, Exelon said it will close the deal in the fourth quarter if it is successful in a bankruptcy court-supervised auction. Either party can cancel the transaction if it is not complete by the end of the year.

FES filed for a Chapter 11 bankruptcy restructuring on March 31. (See *FES Seeks Bankruptcy, DOE Emergency Order*.) Last Monday, FES filed a motion seeking approval for bidding procedures and scheduling an auction for Sept. 6, with bids due Aug. 23.

FES' retail power business serves 900,000 commercial, industrial and residential customers in Michigan, Ohio, Pennsylvania, Illinois, Maryland and New Jersey.

"The purchase would leverage Constellation's significant retail platform and is in line with our generation-to-load strategy, strengthening our position as the nation's largest competitive energy supplier and bringing Constellation's total customer base to more than 3 million residential and business customers across the continental United States," Exelon said in a statement.

"We would honor all existing retail customer contracts and look forward to offering newly acquired customers the same quality products and services that existing Constellation customers currently enjoy."

FES said in a press release that it expects to receive a net of $280 million in cash from the transaction "subject to certain purchase price adjustments, including the return of cash collateral and collection of retained net working capital."

"We believe this transaction is another important step in our restructuring plan," said FES Chief Financial Officer Kevin Warvell. "If approved, we will work with Constellation to ensure the transition of customer accounts is seamless. During the sale process, our daily operations will continue as usual."

FES hired Barclays Capital early last year in a bid to sell the assets but decided not to proceed after receiving initial proposals from eight suitors. The company said it abandoned the sale because the purchasers' proposed terms "made it challenging" for the company to complete a deal outside of a bankruptcy proceeding.

Before entering bankruptcy in March, FES retained Lazard to handle an in-court divestiture. Lazard contacted 35 potential buyers, including "broadly focused financial investors, power- and energy-focused financial investors, strategic retail and power generation companies," FES said.

The second effort yielded offers from six bidders in March, one of which was rejected because it did not include FES' entire retail business. FES said it ultimately selected Exelon's offer as the best, or "stalking horse," bid.

Under the proposed auction procedures, a bidder challenging Exelon would need to offer an "initial topping bid" of $146.6 million, with subsequent bids in increments of at least $1 million. The auction will be canceled if no bids other than Exelon's are received.

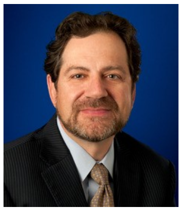
In a separate motion last Monday, FES sought to file the unredacted sale agreement under seal to prevent it from disclosing the details of a mechanism that could adjust the purchase price and that allocated value by individual customer accounts. FES said disclosure of those details could reduce the ultimate purchase price.

Constellation serves residential customers in 17 states and D.C. after acquiring retail operations from Consolidated Edison in 2016 and Integrys Energy Group in 2014. (See *Exelon's Constellation to Buy Con Ed's Retail Operation*.)

FirstEnergy shares closed last Tuesday at $35.39, up 0.2%. Exelon rose 0.76% to $42.17.

COMPANY BRIEFS

Stavropoulos to Step Down As PG&E President, COO


Stavropoulos

Nick Stavropoulos said July 13 that he intends to retire from his role as president and chief operating officer of Pacific Gas and Electric at the end of September. Stavropoulos also will step down from the utility's board.

Stavropoulos joined PG&E in 2011 to lead the multibillion-dollar effort to enhance the company's natural gas system after the San Bruno, Calif., explosion. He was promoted to his current position in March 2017.

More: *Pacific Gas and Electric*

Eversource Committed to Northern Pass Despite Rehearing Denial

The New Hampshire Site Evaluation Committee on July 12 denied the request by Northern Pass Transmission and Eversource Energy for a rehearing of its decision denying a permit to the Northern Pass project.

Eversource said it remains committed to Northern Pass and intends to pursue all available options to move the project forward.

The project would bring 1,090 MW of Canadian hydropower generated by Hydro-Quebec to New England. It was originally chosen in Massachusetts' clean-energy solicitation, but after New Hampshire wouldn't issue all the permits for it, Massachusetts selected another project.

More: *New Hampshire Site Evaluation Committee*; *Eversource*

Duke Energy Incurred 650M+ Cyberattacks Last Year

Duke Energy was hit by more than 650 million cyberattacks last year, Brian Harrell, managing director of Enterprise Protective Services, said July 13.

"The fact that we have this statistic means that we are focused on it, we are looking at it, we are monitoring it, we're penetrating our own system to ensure that we are moving the envelope," Harrell said at an event at George Washington University's Center for Cyber and Homeland Security, where he is a senior fellow.

Duke spent $200 million on physical security upgrades for many electricity substations over the past 18 months and is investing "millions and millions" of dollars into its cybersecurity defenses, Harrell said.

More: *Bloomberg BNA*

Sempra Plans $1.6B Stock Offering To Finance Oncor Purchase

Sempra Energy said July 10 it is planning a $1.6 billion stock offering to finance its purchase of Oncor. The company plans to sell $1.1 billion in common stock and $500,000 in preferred stock.

Sempra previously said it would finance its purchase of Oncor with 65% equity and 35% debt. It raised $4.6 billion in equity in January, and the stock offering will enable it to meet the 65% target.

More: *The San Diego Union-Tribune*

Apex Clean Energy Planning 800 MW of Wind in Texas

Apex Clean Energy plans to spend $1.4 billion to build two 400-MW wind projects in the Texas Panhandle.

The company plans to start and complete work on the wind farms in 2021, a spokes-woman said.

The projects are planned for Moore County north of Amarillo in SPP.

More: *Houston Chronicle*

8minutenergy Energizes First Phases of Calif. Solar Project

8minutenergy Renewables said July 11 it has energized Phases 1 and 2 of the 328-MW Mount Signal 3 solar project in Calexico, Calif., and expects to bring the project to complete operation by the end of the year.

The project is part of the 800-MW Mount Signal Solar Farm, which is one of the largest in the world.

8minuteenergy and Capital Dynamics acquired Mount Signal 3 less than a year ago.

More: *8minutenergy*

Innogy, Duke Among Anchor Investors in Clean Tech Fund

Innogy and Duke Energy are among the anchor investors in a $130 million clean technology venture capital fund raised by the Westly Group.

The fund will make investments of $3 million to $5 million in startups working on clean technology innovations in energy, buildings and transportation, said Steve Westly, the Westly Group's founder and managing partner.

The fund's other investors include CLP Holdings, American Electric Power, Chubu Electric Power and tire-maker Bridgestone.

More: *Bloomberg*

MidAmerican to Begin Work on Another Wind XI Wind Farm

MidAmerican Energy said July 12 it will begin work this month on a 90.8-MW wind farm in Grundy County, Iowa, that is part of its $3.6 billion Wind XI project.

The company expects to have the wind farm completed by the end of the year.

MidAmerican has begun construction on four other wind farms as part of Wind XI and has two others operating. The entire project is scheduled for completion in December 2019.

More: *Courier Lee News Service*

Court Upholds Dismissal of Lawsuit Over Duke, FPL Nuclear Billing

A three-judge panel of the 11th U.S. Circuit Court of Appeals on July 11 upheld a district court decision to dismiss a class-action lawsuit that sought to recover $2 billion Duke Energy Florida and Florida Power & Light collected from their custom-ers under a 2006 Florida law that allowed utilities to collect money for nuclear power plants that might never be built.

The lawsuit alleged "unjust enrichment" and contended that the law is both unconstitu-tional under the Commerce Clause of the U.S. Constitution and pre-empted by the federal Atomic Energy Act.

FPL has used part of the money it has collected under the law to upgrade its existing nuclear plants. Duke billed custom-ers $800 million for two reactors it decided

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COMPANY BRIEFS

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in 2013 not to build.

More: *News Service of Florida*

Duke Scraps Wind RFP Issued Last August

Duke Energy has decided not to accept any of the proposals submitted in response to a request for up to 500 MW of wind energy it issued in August 2017.

The company instead on July 10 issued a request for proposals for large-scale solar or other renewable generation facilities in its North Carolina and South Carolina territories. A Duke spokesman said it won't accept proposals for wind projects.

More: *Windpower Monthly*

Entergy Seeks to Scrap Emergency Zone After Plymouth Closes

Entergy has asked the Nuclear Regulatory Commission to grant it an exemption to the requirement that it maintain a 10-mile emergency planning zone around its Plymouth Nuclear Power Station starting April 1, 2020, nine months after the date on which it intends to close the power plant.

In a letter to the commission, the company said the requirement is expensive and unnecessary because of an analysis that shows that 10 months after the plant is shut down, the radioactive fuel rods in the spent fuel pool will have cooled enough to significantly reduce the risk of a fire that could release radioactivity into the environment.

Entergy said the analysis shows it would take about 10 hours for the hottest fuel rods in the spent fuel pool to reach 900 degrees Celsius and start a fire, which would give communities near the Plymouth, Mass.-based power plant sufficient time to react.

More: *Cape Cod Times*

NRG Drops Plan to Convert, Reopen Dunkirk Power Plant

NRG Energy said July 11 it is not going to pursue a plan to convert its coal-fired Dunkirk power plant that it closed in 2016 to natural gas and reopen it.

Dunkirk plant

A company spokesman said NRG dropped the plan because reconnecting the plant to the NYISO grid and bringing the connection up to current reliability standards could cost nearly $114 million and upgrading the connection might take until 2024.

State Sen. Catharine Young blasted NRG, saying the interconnection costs could be considerably lower and accusing the company of "bail[ing] out before they had all the information."

More: *The Buffalo News*

NorthWestern Issues RFI For Capacity Resources

NorthWestern Energy on July 9 issued a request for information about new or existing capacity resources to serve its peak demand periods, which are primarily in winter but also in some parts of summer, and generally are served by dispatchable generation.

The company said the resources could include, but wouldn't be limited to, electric generation, energy storage and demand response/demand-side management products, and could be in its Montana service territory or elsewhere in the northwestern U.S.

Interested parties must respond to the RFI by 5 p.m. MT on July 30.

More: *NorthWestern Energy*

DTE Restores Fermi Nuclear Plant to Full Power

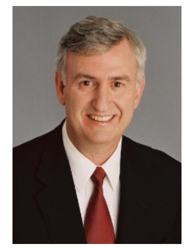
DTE Energy had restored its Fermi 2 nuclear power plant in Newport, Mich., to full power as of July 10.

The company reduced the plant to 60% power on July 3 to make repairs to an electrical component in its non-nuclear portion, a DTE spokesman said.

The spokesman said the component wasn't related to safety systems and the plant remained safe and stable during the reduction.

More: *Monroe News*

Exelon Board Adds Former EFH CEO



Young

Exelon's board of directors has elected former Energy Futures Holding CEO John Young to be a director.

Young led EFH from 2008 through 2016. He held several executive positions at Exelon from 2003 through 2008.

EFH filed for bankruptcy in 2014. It sold its 80.03% stake in Oncor, Texas' largest electric utility, to Sempra Energy in March.

More: *Exelon*

PG&E Creates Wildfire Group, Names Leader

Pacific Gas and Electric said July 10 it has selected Barry Anderson to head its newly formed Wildfire Resiliency and Emergency Management group, which will be part of its Electric Operations division.

Anderson will be replaced as vice president of electric distribution by Michael Lewis, who is joining PG&E from Duke Energy, where he was chief distribution officer. The two will assume their new roles Aug. 1 and report to Pat Hogan, senior vice president of electric operations.

The creation of the new wildfire group comes eight days after a California appeals court overturned a lower court's ruling that PG&E could be forced to pay punitive damages under Section 3294 of the state's Civil Code for the 2015 Butte Fire. The appeals court said it expressed "no opinion as to PG&E's potential liability for punitive damages under Public Utilities Code Section 2106" (JCCP4853).

More: *Pacific Gas and Electric*

FEDERAL BRIEFS

Improving Tech Lead to Drop In Wind Installation Costs

The capacity-weighted average cost of U.S. wind installations as measured in 2016 dollars declined by one-third between 2010 and 2016, according to a report by the Department of Energy.

The cost fell from $2,361/kW to $1,587/kW, according to the Wind Technology Market Report put out by the DOE's Office of Energy Efficiency and Renewable Energy. Reasons for the decline include improvements in technology and manufacturing capability and an increasing concentration of builds in the regions with the lowest installation costs.

More: *Energy Information Administration*

Trump Announces Intent to Appoint ARPA-E Head

Genatowski

President Trump on July 10 announced his intention to appoint Lane Genatowski to be the director of the Department of Energy's Advanced Research Projects Agency-Energy.

Genatowski is a managing partner in investments in Dividend Income Advisors, which he founded in 2012. Prior to that, he was a senior energy investment banker and business group manager at JP Morgan Chase, Kidder, Peabody, Bank of America and Wells Fargo. He first got involved with the energy industry in 1976 as an attorney at Hawkins Delafield & Wood in New York.

More: *The White House*

ACORE Announces Three New Board Members

The American Council on Renewable Energy announced July 11 that three people have been appointed to its board of directors: Mit Buchanan, managing director of energy investments at JP Morgan; Pooja Goyal, managing director at Goldman Sachs; and James Murphy, Invenergy's president and chief operating officer.

ACORE is a national group of companies that finance, develop, operate and use power from renewable energy projects.

More: *American Council on Renewable Energy*

EIA Expects Natural Gas Generation To near Record this Summer

The Energy Information Administration said July 11 that it expects 37% of the power generated this summer (June, July, August) to come from natural gas-fired power plants.

That would be near the record high generation share posted by natural gas power plants two summers ago.

The agency said in its July 2018 Short Term Energy Outlook that it expects the share of generation from coal-fired power plants will drop slightly to 30%, continuing a multiyear trend of declines in coal-fired electricity generation.

More: *Energy Information Administration*

DOE Awards $20M to 9 Advanced Nuclear Technologies Projects

Energy Secretary Rick Perry said July 10 that the Department of Energy has selected nine projects to receive nearly $20 million in funding for cost-shared research and development for advanced nuclear technologies.

Perry said the projects were selected through the Office of Nuclear Energy's U.S. Industry Opportunities for Advanced Nuclear Technology Development funding opportunity announcement and were the second group to be selected under that FOA.

DOE intends to select projects to receive $30 million in 2018 fiscal year funding under the FOA in the next quarterly award cycle, Perry said.

More: *Department of Energy*

Report: Loans to Become Most Popular Solar Financing Option

Solar lending products will become the most popular way for homeowners to finance solar generation units this year, according to a report by GTM Research released July 11.

Their popularity will come at the expense of third-party ownership of the units and cash, which homeowners often obtain for the units through personal and/or home-equity loans, the research company said.

The solar loan market grew 81% last year, according to the report. Much of the growth was from big solar installers, such as SolarCity and Vivint Solar, turning to such solar lending companies as Mosaic and Sunlight Financial, the report said.

More: *Greentech Media*

White House Touts Kavanaugh Overruling Federal Regs

Kavanaugh

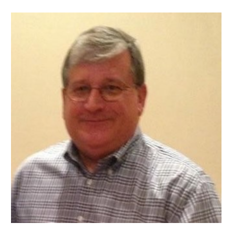
Supreme Court nominee Brett Kavanaugh has overruled federal regulators 75 times in cases involving clean air, consumer protection and net neutrality, among other things, the White House said July 9.

The White House made the claim in an email it sent to business groups it asked to support his nomination, according to two people familiar with the request.

In 2012, Kavanaugh, who has been a judge on the D.C. Circuit Court of Appeals since 2006, disagreed with the court's decision to uphold the first efforts by the Obama administration to regulate greenhouse gas emissions. In 2014, Kavanaugh criticized the administration for not considering the costs of the Mercury and Air Toxics Standards.

More: *Politico*; *Reuters*

Office of Fossil Energy Names Hrkman to Clean Coal Post



Hrkman

The Department of Energy's Office of Fossil Energy named Lou Hrkman deputy assistant secretary for Clean Coal and Carbon Management. Hrkman will oversee research into and development and demonstration of advanced coal-based power systems.

Hrkman most recently served as a policy adviser to Rep. David McKinley (R-W.Va.), who chairs the House Coal Caucus and is the vice chair of the Energy and Commerce Committee's Environment Subcommittee.

More: *Department of Energy*

STATE BRIEFS

CALIFORNIA

PUC: Utilities Must Notify Customers When De-energizing Lines

The Public Utilities Commission ruled July 12 that utilities must notify customers and follow other set procedures when they de-energize power lines in extreme weather to reduce fire risk.

San Diego Gas & Electric already has the requirements placed on it because it was the first utility in the state to de-energize its lines when it felt they were at risk of sparking fires.

Pacific Gas and Electric began de-energizing lines in high fire-risk conditions after the Wine Country fires last fall.

More: *The Press Democrat*

GHG Emissions Reach 2020-Mandated Level Four Years Early

The Air Resources Board said July 11 that the state's greenhouse gas emissions fell below 1990 levels in 2016, putting the state four years ahead of its mandated goal of having them equal 1990 levels in 2020.

The state's greenhouse gas emissions fell 2.7% in 2016 — the latest year for which figures are available — to about 430 million metric tons, just below the 431 million metric tons produced in 1990. That's 13% below their 2004 peak, even though the state's economy has grown 26% since then.

State law requires them to be 40% below 1990 levels by 2030.

More: *The Associated Press*

KANSAS

Westar Gets Approval for Renewable Program for Businesses

Westar Energy said July 11 it has received approval from the Corporation Commission for a renewable energy program that will allow companies to buy power from a 300-MW wind farm that will be built northeast of Manhattan.

The company said it has reached a 20-year agreement with an affiliate of NextEra Energy Resources to purchase power from the wind farm. That will allow businesses that take part in Westar's program to use part of the energy generated by the wind farm and lock in part of their electricity rates for 20 years.

Westar expects the wind farm will be online in the fourth quarter of 2019.

More: *Wichita Business Journal*

MAINE

PUC Expands CMP Audit to Include Handling of Complaints

The Public Utilities Commission on July 10 authorized Liberty Consulting Group, which it hired to investigate complaints about significant increases in Central Maine Power customers' bills last winter, to expand its audit to include how CMP handled the complaints.

The PUC is conducting its own investigation of CMP's metering, billing and customer service in tandem with Liberty's audit.

The expansion of Liberty's audit will increase the cost of its contract with the PUC by $31,220 to $401,040, some of which may be borne by CMP after lawmakers voted July 9 to override Gov. Paul LePage's veto of a bill that would allow the PUC to allocate the cost of an audit of a public utility between its customers and shareholders if the audit finds fault on the part of the utility.

More: *Portland Press Herald*

MICHIGAN

Court: PSC Can't Require Alternative Suppliers to Use In-state Power

The Court of Appeals ruled July 12 that the Public Service Commission can't require alternative electric suppliers to use only energy produced in the state to satisfy the requirement that they demonstrate sufficient capacity three years in advance.

A 2016 law that empowers the commission to require alternative electric suppliers to demonstrate sufficient capacity "does not specifically authorize the MPSC to impose local clearing requirements upon alternative electric suppliers individually," the court said in its order.

A PSC spokesman said July 13 that the commission would review the ruling before determining how it would respond to the order.

More: *The Detroit News*

MISSOURI

PSC Approves Part of Empire District's 600-MW Wind Plan

The Public Service Commission on July 11 issued an order approving part of Empire District Electric's proposal to build 600 MW of wind generation assets.

The PSC gave Empire permission to record the costs of building turbines and include them in its next rate case if it completes the project it is proposing. It also gave the company the authority to establish a framework to account for the depreciation of the wind turbines' value.

"Empire's proposed acquisition of 600 [MW] of additional wind-generation assets is clearly aligned with the public policy of the commission and this state," the commission said. "However, it is premature for this commission to make a legal conclusion that Empire's decision to acquire wind generation using a tax equity partner is reasonable."

More: *The Joplin Globe*

NEW JERSEY

JCP&L Files $387M Reliability Improvement Plan with BPU

Jersey Central Power & Light on July 12 filed a four-year plan with the Board of Public Utilities under which it would spend $387 million to improve the reliability of its distribution network.

JCP&L said the proposal includes nearly 4,000 upgrades to help the reliability and resilience of its overhead and underground power lines, as well as new equipment to reduce the frequency and duration of outages. It also calls for the utility to boost its vegetation management program to reduce outages caused by falling trees.

The utility said it hopes the BPU will rule on the program by the end of the year.

More: *Asbury Park Press*

DEP Approves Highland Rules Exemption for Proposed Gas Plant

The Department of Environmental Protection has approved an exemption from the rules governing the Highlands Preservation

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STATE BRIEFS

Continued from page 36

Area for Abatis Advisors, which wants to build a 663-MW natural gas-fired power plant on the site of a former paper mill on the Musconetcong River in Holland Township.

The DEP ruled that the Phoenix Energy Center qualified for an exemption under the Highlands regulations governing the redevelopment of sites where building already has occurred.

At the same time, however, the DEP found that the plan for the plant inconsistent with the Upper Delaware Water Quality Management Plan. That decision prohibits the agency from issuing any permits for the power plant until Abatis brings its plan for the facility in line with the water quality management plan.

More: *NJSpotlight*

SOUTH DAKOTA

PUC Gives Xcel Permit for 300-MW Dakota Range Wind Farm

The Public Utilities Commission on July 10 approved, with conditions, a permit for Xcel Energy to construct the $380 million, 300-MW Dakota Range wind farm in the northeast part of the state.

The conditions require the wind farm to monitor bird mortality and have aircraft warning lights that only go on when aircraft are near.

Xcel expects to complete the wind farm in 2021.

More: *Star Tribune*

PUC Approves Xcel Refund from Tax Cut

The Public Utilities Commission on July 10 approved a proposal by Xcel Energy to pass through its savings from the Tax Cuts and Jobs Act to its customers via a refund in August and a rate freeze for the next two years.

Refund amounts will be based on customers' electrical usage last year, with the average at $55.73. Xcel is projected to save $10.87 million this year as a result of the bill.

More: *Argus Leader*

VERMONT

PUC Considering Efforts to Boost EV Ownership

The Public Utility Commission said July 10 it has begun a formal process to consider how the state and electric utilities can promote electric vehicle ownership without hurting electric customers who don't own EVs.

The investigation was launched under a general transportation bill that became law in May. It will culminate in a report to the legislature next July that will include recommendations for laws to address barriers to EV usage.

Although Vermont has the highest EV market share of any East Coast state, less than 5% of the new cars sold in the state are EVs.

More: *VTDigger*

PUC Postpones Ruling on Vermont Yankee Sale Until NRC Acts

The Public Utility Commission said July 6 it will put off ruling on a proposed sale of the shuttered Vermont Yankee nuclear power plant until the Nuclear Regulatory Commission rules on the license transfer that the sale would require.

"The NRC ruling on the license transfer may have relevance to some of the issues raised by this case," the PUC said.

The plant's owner, Entergy, has agreed to sell it to NorthStar Group Services, which plans to decommission it and remediate its site for redevelopment.

More: *VPR*

VIRGINIA

DEQ Issues Notice of Violation To Mountain Valley Pipeline

The Department of Environmental Quality on July 10 issued a Notice of Violation to Mountain Valley Pipeline for allegedly breaking laws governing stormwater management, erosion and water quality, and a water protection program.

The department said the alleged violations include failure to take corrective actions within required amounts of time, failure to install best management practices in accordance with approved erosion and sediment control plans, releasing sediment off the pipeline's right of way, and depositing sediment in surface waters.

The notice requires Mountain Valley Pipeline to contact the department within 10 days to discuss remedies and how to prevent future violations.

More: *Department of Environmental Quality*

WASHINGTON

Council Approves Seattle City Light Plan Calling for Rate Hikes

The Seattle City Council voted 8-1 on July 9 to approve the city power utility's six-year strategic plan, which calls for rate hikes averaging 4.5% per year.

Under the plan, the monthly bill of a typical Seattle City Light residential customer would go from $65 this year to nearly $85 in 2024.

The increases would have been higher, but Mayor Jenny Durkan recently directed the utility to cut its projected costs by $350 million over the life of the plan.

More: *Seattle Times*

Solar Farm Exposes Divide Between Seattle, Rural Regions

A 250-acre solar farm proposed for the central part of the state has spurred a battle between residents who would profit by leasing their land to the project's developer against others in the mostly conservative region who complain they're being forced to accommodate the environmental aims of the liberal Seattle area.

The project in rural Kittitas County on the eastern slopes of the Cascade Mountains would be one of the biggest solar farms ever in the state.

The Energy Facility Site Evaluation Council is considering the application for the project. It will send its recommendations to Gov. Jay Inslee, who has the final say on the project and could make a decision as early as next month.

More: *The New York Times*