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Your Eyes and Ears on the Organized Electric Markets
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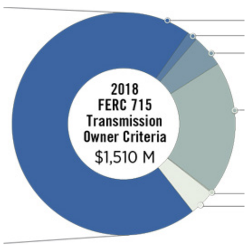
FERC Opens Local Tx Projects to Competition, Cost Sharing

Appeals Court Had Reversed Commission

By Hudson Sangree and Rich Heidorn Jr.

PJM must open Form 715 transmission projects to competitive bidding — with regional cost sharing for those projects involving high-voltage lines — FERC ordered Friday.



PJM's 2018 RTEP included about $1.5 billion in Form 715 projects. | *PJM 2018 RTEP*

The directives came in two orders prompted by the D.C. Circuit Court of Appeals' August 2018 remand that found FERC erred when it assigned all the costs for two Form 715 transmission projects proposed by Dominion Energy to the Dominion zone.

Owners of transmission at or above 100 kV must file Form 715 Annual Transmission Planning and Evaluation Reports that detail the planning reliability criteria that the transmission owners use to evaluate the strength and limits of their systems. About $1.5 billion of the $2.1 billion in baseline spending in PJM's 2018

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Calif. Participants Float 'Central Buyer' RA Plan

By Robert Mullin

A group of California stakeholders last week filed a plan with regulators that would replace the state's current resource adequacy framework with a "central buyer" responsible for procuring resources for multiple years.

Advocates for the plan filed a joint *motion* Friday seeking adoption by the California Public Utilities Commission, which is expected to vote on the measure by the end of the year.

The proposal is the product of a settlement agreement that includes Calpine, the Independent Energy Producers Association, Middle River Power, NRG Energy, San Diego Gas & Electric, Shell Energy North America, Western Power Trading Forum and CalCCA, which advocates on behalf of the state's growing number of community choice aggregators.

The CPUC originally floated the idea of a central buyer earlier this year out of concern that the state's growing number of CCAs were not positioned to meet a new state mandate that they ensure RA three years in advance, rather than the year-ahead requirement that applies to other load-serving entities. That mandate was intended to help CCAs — most of which are still relatively new and have short financial track records — compete in the market for reliability resources. (See *Calif.: CCAs, Decarbonization Pose Reliability Challenges*.)

A bill to require the PUC and California Energy Commission to provide the State Legislature with an assessment of central buyer options is still pending in the State Senate. Friday's motion suggests that industry players are one step ahead of the legislature.

"If adopted, the settlement agreement will advance the commission's stated preference for

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In this week's issue

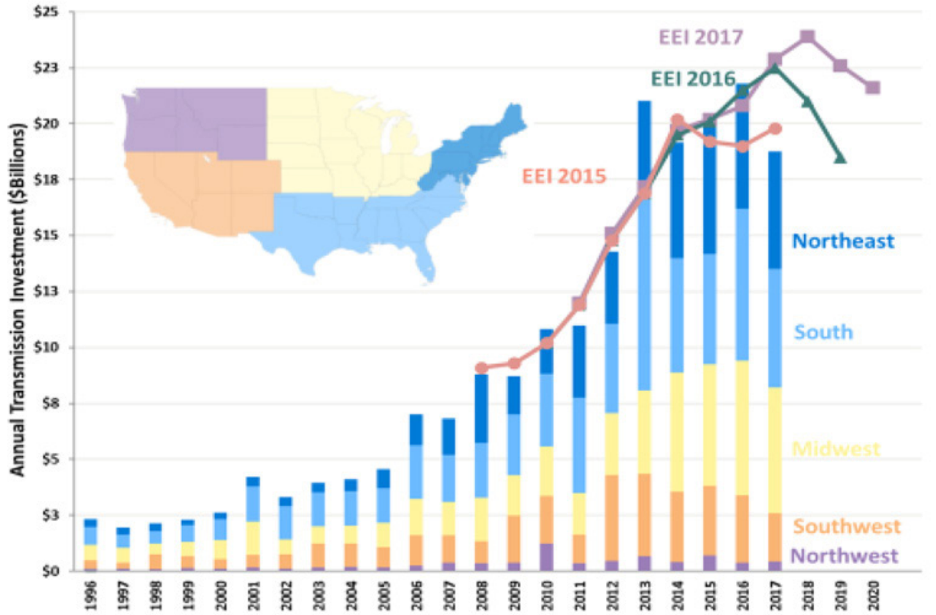
FERC/Federal News

Stakeholders Spar in FERC Tx Incentives Docket

By RTO Insider Staff

A group of grassroots organizations opposed to high-voltage transmission projects summed up the initial comments in FERC's inquiry into its transmission incentive policies quite nicely (PL19-3).

"Those who profit from transmission incentives believe incentives should remain the same or be increased. Those who pay transmission incentives believe incentives should be reduced or phased out entirely. And those who believe transmission incentives are key to saving the planet champion new incentives at any cost," said the group, which included organizations such as the Coalition for Rural Property Rights, the Eastern Missouri Landowners Alliance, Say NO to NECEC and STOP Transource Power Lines MD. "It is the unenviable position of this commission to referee these disparate interests to set policy that best serves its mission to ensure economically efficient, safe, reliable and secure energy services for consumers."



U.S. annual transmission investments for FERC-jurisdictional and ERCOT transmission owners up to 2017, with EEI projections beyond | *The Brattle Group*

Under an inquiry it opened in March, FERC is examining whether it should continue to grant transmission developers certain incentives, whether to increase or decrease them, and whether they should be based on projects' risks and challenges or on the benefits they provide. Initial comments were submitted in late June. (See *Tx Incentives NOI Brings Calls for Broader Reforms*.)

Stakeholders largely reiterated their positions as they rebutted each other in their reply comments in the docket, submitted last week. Below, based on a review of more than two dozen filings, is a sample of what FERC heard.

"Not surprisingly, the initial comments contain conflicting recommendations for how the commission should proceed at this crossroads," the California Public Utilities Commission said. "There is, however, general consensus that the historical decline in transmission investment that motivated Congress to enact Section 219 [of the Federal Power Act] in 2005 has been conclusively reversed."

Defense of the Adders

The Edison Electric Institute said it "does not agree with commenters arguing that because Section 219 of the FPA and Order No. 679 have helped to promote increased transmission investment, the job is done and changes to the commission's incentives policy to continue to encourage transmission development are not needed. Nor does EEI agree with those commenters who go even further and advocate that the commission rollback its incentives policy, because this would be counterproductive to meeting Congress' objectives in implementing Section 219."

The New Jersey Board of Public Utilities and the state's Division of Rate Counsel filed joint comments saying transmission owners should *not* receive an incentive for RTO membership because "the benefits of RTO membership are a sufficient incentive," citing economies of scale and efficiencies in the transmission planning process. "If the commission continues the RTO incentive adder, it should not be generically applied 'regardless' of why transmission owners participate in RTOs," they wrote.

But others argued that FERC is required to provide an RTO/ISO participation adder under FPA *Section 219*. The commission approved the adder in *Order 679* in 2006.

"Some commenters that argue for elimination of the current RTO participation incentive do not even acknowledge that the commission is statutorily obligated under FPA Section 219 to provide an RTO incentive," a group of MISO transmission owners said. "Those that do acknowledge the obligation fail to provide a compelling reason to conclude that the current, modest 50-basis-point adder incentive is no longer reasonable, omit any detail regarding what 'incentive' the commission should offer instead, and do not provide any evidence to demonstrate the reasonableness of any such alternative incentive."

"Some commenters that argue for elimination of the current RTO participation incentive do not even acknowledge that the commission is statutorily obligated under FPA Section 219 to provide an RTO incentive."

— A group of MISO transmission owners

"The initial comments opposing retention of the RTO participation adder do not offer compelling arguments," American Electric Power said. "Some commenters suggest that the RTO participation adder should be elim-

FERC/Federal News

inated, or should be phased out for current RTO members and available for a fixed period only for new RTO members. Such proposals are in tension with the legislative text and the commission's interpretation of that text."

Others defended the participation adder on its own merits.

"The role of RTOs and the need for consistent, stable membership of transmission owners will only be heightened in the next phase of investments into the transmission system," MISO said. "Incremental changes, even changes that may occur in separate proceedings over the course of several years, have the potential to erode the foundation upon which RTOs were built."

MISO insisted the participation adder is necessary to expand voluntary RTO membership, saying that membership has "stalled," far from the "near universal" participation FERC envisioned when it issued *Order 2000* in 1999.

Eversource Energy said that the RTO participation subjects TOs to risks, as they turn over their operational control and transmission planning functions, and they also face coordination issues, such as outage scheduling.

"Transmission-owning RTO/ISO members assume the considerable risks associated with RTO/ISO participation for the benefit of their customers, as many of the benefits of RTO/ISO participation accrue to customers and not to the utilities themselves," agreed Exelon.

In joint comments, Pacific Gas and Electric and San Diego Gas & Electric urged FERC to maintain both the participation adder and the abandonment incentive, which permits recovery of 100% of prudently incurred costs for projects canceled because of factors that are beyond TOs' control. Any reduction, even in certain circumstances, could act as a disincentive to new investment, the utilities said.

Competition

Eversource also said the commission should dismiss the suggestion to condition the application of the RTO participation incentive on the relevant RTO or ISO having at least 33% of the transmission investment in its region originating from competitive solicitations. "There is nothing in the language of Section 219c to suggest that the incentive for joining a regional transmission organization should be conditioned upon the level or percentage of transmission investments subject to the competitive solicitation process. Indeed, in the [Notice of Inquiry], the commission itself pointed out that Order No. 1000 is not related to 'the commission's obligations under Section 219.'"

Both PJM's Independent Market Monitor and LS Power said the existing structure provides enough incentive to attract infrastructure investment and, if anything, should subject more projects to competitive bidding.

"There is nothing in the language of Section 219c to suggest that the incentive for joining a regional transmission organization should be conditioned upon the level or percentage of transmission investments subject to the competitive solicitation process."

— Eversource

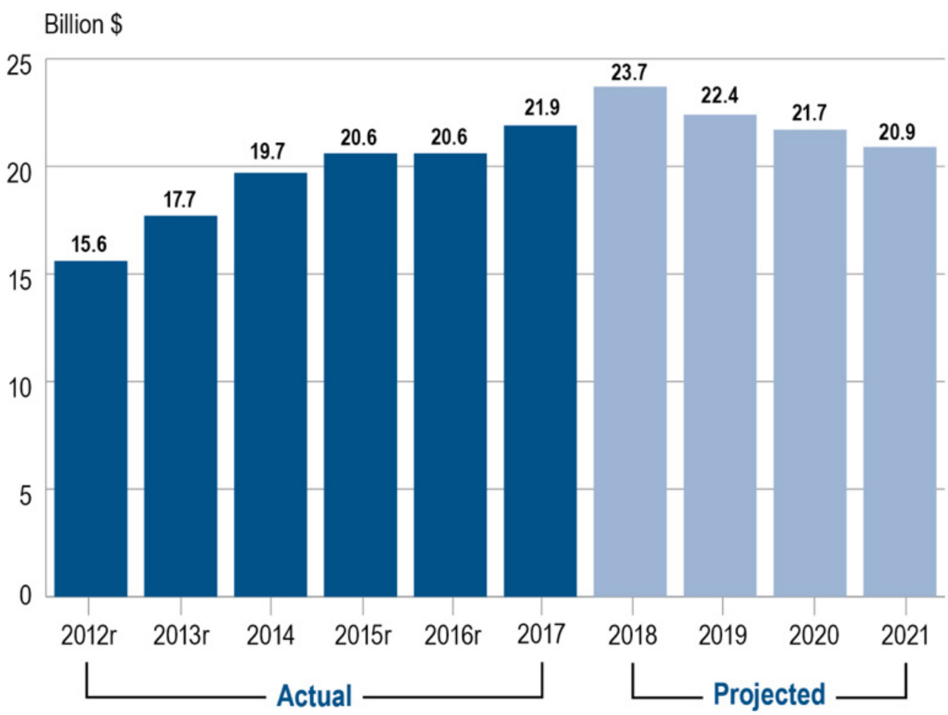
LS Power asked FERC to withhold incentives from upgrades or new builds that aren't "independently reviewed."

"FERC does not need to change its current incentives policies in order for ratepayers to obtain the benefits of competition, but FERC can significantly expand these benefits by taking steps to expand the number of projects selected through competitive transmission solicitations," the company said.

"Rules permitting competition to provide financing for PJM and other RTO transmission expansion projects could reduce the cost of capital for transmission projects and significantly reduce total costs to customers," the Monitor said. "Rules that allow incumbent owners to exclude, limit or condition the development of new or replacement transmission projects create barriers to competitive investment."

Advanced Tech

The Grid Advancement Coalition — 18 companies, environmental organizations and trade groups, including ITC Holdings, the American Wind Energy Association and the Natural Resources Defense Council — called for policies to encourage relatively low-cost investments that could make existing transmission more efficient, such as dynamic line rating and power flow controls. "This action is needed to comply with FPA Section 219b(3), adopted in the Energy Policy Act of 2005, because the commission never introduced specific regulations implementing that section in Order 679 or elsewhere," it said.



EEI's most recent historical and projected transmission investment data | *Edison Electric Institute*

FERC/Federal News

It also asked the commission "act separately to promote a more expansive transmission planning regime that fully considers the benefits of grid expansion and integration across seams."

"There are many benefits of transmission investments that are unrecognized and uncredited in the commission's current regulatory scheme, making 'free riders' of many consumers while others are faced with locally concentrated costs, leading them to oppose transmission development they should favor," the group wrote. "The commission should reset that scheme by focusing its evaluation of transmission incentives on the consumer benefits that proposed transmission investments supported by incentives will deliver, rather than on how 'risky' or 'challenging' a transmission project may be to develop."

Potomac Economics, which provides market monitoring services for MISO, NYISO and ISO-NE, had also proposed an incentive to encourage the use of dynamic line ratings as a way of increasing existing lines' capacity. The MISO TOs, however, came out against that idea.

"Introducing economics into transmission facility rating decisions could work at cross-purposes with actions of utility operators to objectively perform their reliability functions," they said. [On Sept. 10-11, FERC will hold a technical conference on transmission line ratings, with a focus on dynamic and ambient-adjusted ratings (*AD19-15*)].

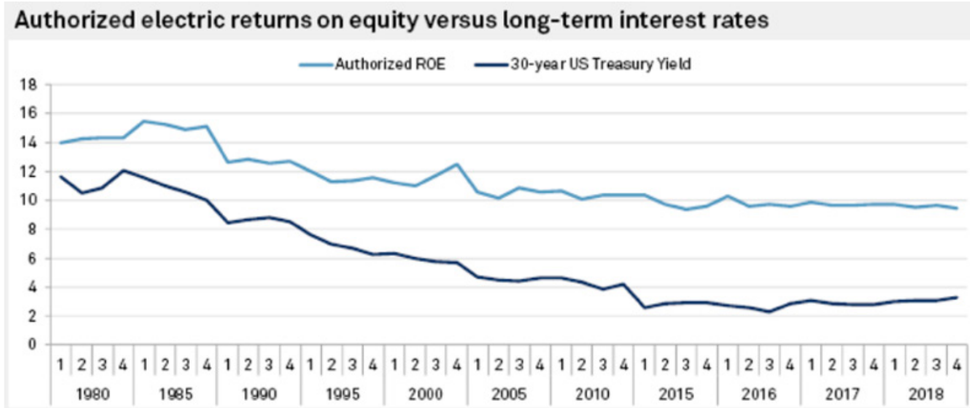
The Working for Advanced Transmission Technologies (WATT) Coalition proposed a new incentive for small projects using advanced technologies that produce quantified congestion benefits, an idea supported by AEP.

No New Incentives

But other stakeholders were vehemently opposed to new incentives, increases to existing adders or making qualification for them easier.

"The commission's incentives policies are already quite flexible and allow transmission owners the ability to seek a range of incentives ... for various purposes," the National Rural Electric Cooperative Association said. "It would be inappropriate, however, to enshrine the various perks that transmission owners want into the commission's incentive regulations."

NRECA called out WATT's proposal specifically, saying such projects "may hold promise of such consumer benefits, but the commission should not approve a new incentive rate treatment for them in this proceeding." It cited FERC's 2012 incentives policy statement, where it explained that "having distinct standards apply to advanced technologies contributes to confusion."



| R Street Institute

"Sticking with this case-by-case process for these kinds of projects is the best way to ensure that regional planning requirements can be established; that the relevant costs and benefits can be identified and defined; and that the appropriate shared-savings rate treatment can be evaluated," NRECA said.

FERC in Order 679 established a requirement that each applicant must demonstrate that there is a "nexus" between the incentive sought and the risks and challenges of the investment being made.

"Industry commenters that propose making the nexus test less rigorous and the commission's incentives policy more expansive look ahead to justify their recommendations, by speculating on how the commission's incentive policy must evolve to appropriately incent investment to facilitate the grid of the future," the California PUC said. That argument is flawed for several reasons, it said, including a lack of evidence that FERC's incentives have increased transmission reliability, reduced congestion and lowered costs. FERC needs to show proof before it starts adding new incentives for new purposes, such as ensuring resilience in the face of climate change and extreme weather.

The CPUC rejected suggestions that the commission automatically award the abandoned plant and construction work in progress incentives.

"Instead, the CPUC recommends that the commission should now make the nexus test more rigorous, transparent and data-driven by, for example, implementing a cost-benefit analysis, cost caps and other forms of cost containment, and *ex post* verification of project benefits."

The New England States Committee on Electricity said it "strongly disagrees" on the need for a new category of FERC transmission rate incentives to help implement state-jurisdictional energy and environmental laws. It pointed to the Massachusetts Department of Public Utilities' approval of contracts to deliver power over a new 1,200-MW HVDC line, and the 2015 solicitation by Massachusetts, Connecticut and Rhode Island for clean energy projects, none of which ended up needing new transmission, as evidence that "transmission incentive reforms are not needed to advance New England states' laws."

The Eastern Massachusetts Consumer-Owned Systems (EMCOS) said the commission "should be wary" of any proposal to grant TOs additional incentives. "The evidence shows that continued transmission investment has produced smaller and smaller benefits to consumers at greater and greater costs," the group said. "If the commission chooses to revisit Order No. 679, it should examine whether the costs of its current transmission incentives outweigh the benefits produced."

The grassroots groups were more colorful, urging "the commission to proceed thoughtfully, and with a realization that transmission owners will continue to chase higher returns and profit, no matter the decision reached in this docket."

"Like any spoiled child whose lollipop is taken away, transmission owners may kick and scream and promise to hold their breath until they die. We all know that's an impossibility and that highly profitable transmission investment will continue to happen, even without an incentive lollipop."

Michael Brooks, Amanda Durish Cook, Rich Heidorn Jr., Michael Kuser, Hudson Sangree and Christen Smith contributed to this report. ■

CAISO/West News

Isolation, Illiquidity Drove Avista's EIM Decision

By Robert Mullin

The Western EIM's Regional Issues Forum met last week at BPA headquarters in Portland. | *© RTO Insider*

PORTLAND, Ore. — For years after CAISO rolled out the Western Energy Imbalance Market in 2014, Avista took a wait-and-see approach to joining the effort to bring comprehensive real-time trading to the West.

Once the Northwest Power Pool scrapped its work on a competing regional market initiative in 2016, Avista "went into monitoring mode," the utility's director of power supply, Scott Kinney, told the EIM's Regional Issues Forum at Bonneville Power Administration headquarters Aug. 27.

"The needs and risks that were driving other utilities to join — we just didn't see those same needs and risks ourselves," Kinney said.

Hydroelectric resources currently comprise about 50% of Avista's generation, while other renewables make up only 4%, providing the utility with ample flexibility to firm up its small wind portfolio. That meant it "didn't have a driver from that perspective," Kinney said.

"We had done some assessments around costs and benefits, and the economics at that time just weren't compelling enough for us to join, so we continued to just engage," he said.

That engagement included being "heavily involved" in the public meetings around the EIM and performing "outreach" to learn from the market's existing participants. Avista also became a CAISO scheduling coordinator in 2016, allowing it to trade in that market.

But in late April, the Spokane, Wash.-based utility was finally compelled to commit to the EIM in response to a series of "drivers and risks" taking shape in the Pacific Northwest, Kinney said. (See *Cold Forces NW to Dip More Deeply into EIM as Avista Joins*.)

What changed?

"We started to see some market liquidity concerns in the summer of 2018. We had several days and several hours in those days where it was really difficult to find a counterparty in the near term," Kinney said, adding it was the first time the utility experienced that problem.

"That had a lot to do with the current EIM participants having to meet their ramping and resource sufficiency tests, so they weren't willing to do business with those nonparticipants during the stress times. That started to show as a possible risk for us," he said.

Avista also faced the prospect of further isolation, with neighboring utility NorthWestern Energy last year agreeing to join the EIM, and BPA — by far the largest transmission provider in the Northwest — advancing toward a commitment. (See *NorthWestern Energy to Join Western EIM* and *BPA Marches Toward EIM Membership*.) Avista's other neighboring balancing authorities, Idaho Power and PacifiCorp, already participate in the market.

"That meant that basically all of our neighboring utilities were going to be in the market, and so this liquidity risk really became a concern," Kinney said.

Kinney also noted that Avista is anticipating a surge of new renewables coming into its BA area, with wind and solar comprising all of the nearly 1,100 MW of proposed generation in its interconnection queue — a "fair amount" of that being small projects falling under the Public Utility Regulatory Policies Act.

"We see that definitely there's that risk for additional renewables integrating into our BA, and as others have seen who are participating in the market, there's a lot of benefit to help balance those renewables and bring down that cost to integrate," he said.

Avista has also signed a power purchase agreement to next year bring on 145 MW of capacity from the Rattlesnake Wind project in Central Washington and recently issued a PPA for additional renewables.

"Another thing for us is we did recently issue our own clean energy goals of being 100% clean by 2045 and being carbon neutral by 2027 ... so that will probably drive some additional renewable integration into our system," Kinney said.

Avista is also anticipating the future impact of state policies, including the likely expansion of cap-and-trade in the West. Kinney pointed to Washington's recent passage of Senate Bill 5116, which bars the use of coal-fired generation by 2025 and requires the state's utilities to be emissions-free by 2045. Coal currently accounts for 9% or Avista's generation.

Cost of Joining vs. not Joining

But Avista's decision to join the EIM may have been sealed by the economics.

"We've been monitoring how the market's

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Calif. Participants Float 'Central Buyer' RA Plan

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a central buyer framework, reduce the need for California Independent System Operator backstop procurement, preserve LSE self-procurement autonomy, maintain and enhance a liquid and robust bilateral capacity market, and preserve a meaningful role for the state in ensuring reliability," the motion said.

The state's CCAs had initially resisted the notion of establishing a central buyer out of fear that such a move would compromise local control of resource procurement — a driving principle behind the rapid spread of CCAs, which have promised their customers a quicker transition to renewable generation.

"CalCCA is pleased that parties representing diverse interests came together and reached consensus on a central buyer structure that supports reliability in California while preserving local procurement autonomy," said Beth Vaughan, executive director of CalCCA.

The plan issued Friday would apply to all of the state's LSEs — not just the CCAs — and replace a current *framework* in which all LSEs are required to show the CPUC they have procured 90% of their system RA obligation for the five summer months of the coming compliance year, as well as 90% of their flexible RA and 100% of their local RA requirement for each month of the coming year. The LSEs must additionally submit monthly filings demonstrating they have obtained enough system and flexible resources to cover their full needs for the month.

New Role for New Entity

The proposal laid out in last week's motion is the product of three stakeholder workshops held at the CPUC's direction. Although the workshops failed to reach consensus, the filing parties said they achieved "a better understanding of potential workable central buyer solutions."

"Based on the foundation established through the workshop process, the settling parties met several times to discuss a possible central buyer structure to satisfy the policy goals identified by the commission and developed in greater detail by the workshop participants," the motion explains.

Under the settling parties' proposal, the state's LSEs would no longer have a compliance obligation for procuring resources but could continue to do so voluntarily to meet all or part of

Areas served by community choice aggregators (green) and areas considering a CCA (orange). | *CalCCA*

their portion for the collective obligation. That point is key for CalCCA, because it preserves the right of CCAs to pre-emptively procure resources to meet their own needs.

The plan would establish a Resource Adequacy-Central Procurement Entity (RA-CPE) that would take on the "default" role of procuring local, system and flexible RA capacity to meet the "residual" of the three-year obligation not met by a CCA or LSE. The RA-CPE would also assume the responsibility of ensuring multiyear reliability in the service territories of the state's three investor-owned utilities, in coordination with CAISO and the CPUC.

"This means that the RA-CPE will undertake procurement of collective residual RA needs in lieu of LSEs' RA procurement requirements, but individual LSEs may voluntarily procure RA capacity for any portion of their share of the overall RA requirement," according to the motion. Voluntary purchases would be credited against the LSE's portion of the collective obligation on a megawatt-for-megawatt basis.

"The RA-CPE will be solely responsible to ensure the procurement of the collective RA requirement after LSEs have shown their procured RA capacity to the RA-CPE. On this basis, the RA-CPE serves as the procurer of 'residual' local, system and flexible RA for the three-year forward period," the motion explains. "The RA-CPE will exercise its authority, to the greatest extent possible, to mitigate the need for CAISO backstop procurement," such as the ISO's out-of-market Capacity Procurement Mechanism (CPM).

RA Still a Collaborative Effort

The motion also seeks to establish cost controls, specifying that the RA-CPE would procure capacity needed to meet the residual requirement "only to the extent" that it can obtain RA resources at a cost "not unreasonably in excess of" the CPM soft offer cap defined in CAISO's Tariff — currently set at $6.31/kW-month.

The new entity would be authorized to purchase resources at prices above the soft cap for individual months and when it deems the price to be consistent with CPUC-approved criteria. It would also procure RA-only capacity and obtain the import capability rights needed to meet the residual need through an annual "pay as bid" request for offer process.

Under the plan, the costs for the residual capacity procured by the RA-CPE would be allocated to each LSE in proportion to the capacity type purchased on their behalf. In cases when the RA-CPA is unable to cover the full residual need, LSEs would be charged for the costs incurred by CAISO to make up the deficiency through its own backstop mechanisms.

While the plan does not specify who will fill the role of the RA-CPE, the settlement agreement provides that the entity must be "competitively neutral, independent and creditworthy," likely ruling out the possibility that one of California's IOUs would step into the role, which CPUC officials had discussed in March.

The agreement also stipulates the RA-CPE "will rely on the expertise" of CAISO, the CPUC and the CEC to determine the need for RA capacity. The CEC would continue to develop the load forecasts used by the CPUC to establish collective RA requirements and determine the shares allocated to individual LSEs.

Friday's motion asked the CPUC to approve the agreement and direct the CEC to begin a workshop process to implement the plan. ■

Isolation, Illiquidity Drove Avista's EIM Decision

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been operating and seeing there's significantly more benefits being achieved by participants than what was anticipated through studies. We think the cost-benefit ratio is starting to change based on just the maturity of the market," Kinney said.

And the utility foresaw increasing downsides to not participating.

"Not only the liquidity, but the higher dispatch costs for us if we aren't a participant," Kinney said, noting that Avista expects fewer market resources to be available for the utility to perform its own grid optimization.

"As more and more entities join the market, there's less counterparties to do business with."

Jennifer Gardner, a senior attorney with Western Resource Associates, asked whether Kinney could pinpoint either the liquidity or the renewable integration issue as a bigger factor in Avista's decision to join the EIM.

"I think it's probably that they're equal. The liquidity risks and concerns that we started to see last summer happened at about the same time we saw significant upturn in interconnection requests in our transmission queue," Kinney said. "I think since they both kind of happened together, it really made that decision for us probably easier, because we had several drivers."

Left to right: Matt Lecar, PG&E; Therese Hampton, Public Generating Pool; Suzanne Cooper, BPA; and Scott Kinney, Avista. | © *RTO Insider*

Avista estimates it will earn $3.5 million to $9.2 million in annual net benefits from participating in the EIM. It expects to incur about $21 million in start-up costs to join the market, with technology expenses — largely software — accounting for about half. Ongoing expenses are estimated at $3.5 million to $4 million annually, mostly for new staff. The utility will bring on 12 new full-time equivalent employees to manage its EIM efforts.

"The focus that we've got going on right now is change management. We've heard from those we've visited [that] that's a big component of this project, so we've taken that advice seriously, and we're really working on training and staffing," Kinney said.

RIF Chair Therese Hampton, executive director of the Public Generating Pool, asked whether Avista is still exploring how its transmission assets will participate in the EIM, including the potential for "donating" transfer capacity to the market.

"We haven't determined it yet. Still to come," Kinney said.

Kinney said Avista hopes to secure FERC approval by next April to join the EIM. It is slated to commence participation in the market in April 2021. ■

CAISO/West News

PG&E Bankruptcy Split into 3 Parts

Judge Asks District Court to Estimate Wildfire Damages

By Hudson Sangree

The federal judge overseeing PG&E Corp.'s bankruptcy relinquished a major part of the case dealing with wildfire damages to another federal judge, while a third part of the case is heading to state court for resolution.

U.S. Bankruptcy Judge Dennis Montali said he understood the divided process is awkward, but he wanted to speed up the case and protect the rights of fire victims in the process.

He decided he wanted a federal district court judge, not a bankruptcy judge, to estimate the wildfire damages, which are a key component of the utility's bankruptcy.

Some parties have suggested PG&E might be required to pay $10 billion to $40 billion to victims of the wildfires that scorched Northern California in the past two years.

"I felt compelled to toss the ball to the district court," Montali told lawyers during a bankruptcy hearing Aug. 27. The judge said he would be doing a disservice to victims to try to rush through the complex and unusual proceeding while attending to the rest of the massive bankruptcy case.

Phyllis J. Hamilton, chief judge of the U.S. District Court for the Northern District of California, *approved* Montali's *request* to assign the estimation proceeding to a trial judge. District Court Judge James Donato, whose courtroom is in the same building as Montali's, will now hear the matter.

Montali said the State Legislature's July passage of AB 1054 had increased the pressure to resolve PG&E's bankruptcy more quickly. The law allows PG&E to share in a $21 billion wildfire damages fund administered by the state but only if it exits bankruptcy by June 30, 2020. (See *Calif. Wildfire Relief Bill Signed After Quick Passage*.)

"While that may seem a long way in the future, and no doubt is far too long for thousands of victims, the complexity of these Chapter 11 cases, the requirements of Chapter 11 and the need for parallel hearings and rulings by the California Public Utilities Commission — most of which pertain to regulatory matters and contractual obligations that exist apart from the wildfire claims — impose very difficult time limits on all parties, including the court," the judge wrote.

A CPUC attorney told the judge last month that the commission would need time to weigh the effects of a reorganization plan on ratepayers and PG&E's financial stability.

Earlier last month, Montali agreed to allow claims against PG&E over the October 2017 Tubbs Fire to be decided in state court. The fire, which killed 22 people, destroyed more than 5,600 structures and leveled a section of Santa Rosa, was the most destructive in state history until the Camp Fire in November 2018 killed 86 people and burned 18,804 structures, destroying most of the town of Paradise.

Investigators with the California Department of Forestry and Fire Protection blamed the Camp Fire on a faulty PG&E transmission line but said the Tubbs Fire was caused by shoddy wiring on private property.

PG&E's estimated wildfire damages are being litigated in federal court in San Francisco. | © *RTO Insider*

Plaintiffs' lawyers still want a judge or jury to decide PG&E's liability for the Tubbs Fire, however, and Montali agreed on Aug. 16 to lift a stay on legal actions against the company and allow the matter to go to state court on an expedited basis. (See *Only PG&E Can File Bankruptcy Plan, Judge Says*.)

PG&E has said it plans to file a reorganization plan by Sept. 9, but that plan can't be finalized without a better idea of the damages from the Camp Fire, the Tubbs Fire and a rash of other fires in October 2017, most of which have been blamed on PG&E equipment.

The utility has indicated it wants to establish a "capped fund" to pay wildfire victims, but Montali said he needs to know where to set the cap before approving a compensation fund. ■

CAISO/West News

EIM Governing Body Gains Member, Loses Another

By Robert Mullin

PORTLAND, Ore. — Just as the Western Energy Imbalance Market's Governing Body was poised to fill the empty space within its ranks, another vacancy immediately popped up.

The EIM Governing Body voted Wednesday to fill the seat vacated by one of its original members — but not before revealing that its newest member had also resigned his position the night before.

Former EIM Member Travis Kavulla | © *RTO Insider*

Member Travis Kavulla was notably — but not surprisingly — absent from the body's monthly meeting in downtown Portland. After all, his wife had just recently given birth, Governing Body Chair Carl Linvill told a hotel conference room packed with regional stakeholders.

But Linvill then delivered unexpected news: "We received a letter from Travis that he has been offered an opportunity which he plans to accept, which will mean that he will no longer serve — effective immediately — on the EIM Governing Body."

A former member of the Montana Public Service Commission, Kavulla was elected to the Governing Body in June 2018 after being term-limited out of his commission seat. (See *CAISO Board Approves More CRR Auction Changes*.) He currently serves as the energy director for R Street Institute, a D.C.-based think-tank that advocates for "free markets and limited, effective government."

Kavulla, who joined R Street last October, shared his resignation *letter* with the EIM but told *RTO Insider*, "I'm not in a position to make any announcements at the moment." The letter said he had accepted a job with a "market participant" and would be starting work this month.

Kavulla's term as a Governing Body member was set to expire in 2021. His resignation marks the second premature departure from the body since April, when Kristine Schmidt, the group's inaugural chair, vacated her seat to join the board of embattled PG&E Corp. Allowing Schmidt to hold both positions would have presented a conflict of interest, then-Chair Valerie Fong said at the time. (See *PG&E Departure Leaves EIM Vacancy*.)

To replace Schmidt, the body on Wednesday confirmed Anita Decker, a familiar name to industry participants in the Pacific Northwest.

From 2014 until earlier this year, Decker served as executive director of the Northwest Public Power Association, an advocacy group representing about 150 community-owned electric utilities in nine Western states and British Columbia. She was chief operating officer of the Bonneville Power Administration from 2007 to 2014, when she also performed a stint as acting administrator for the Western Area Power Administration. Prior to that, Decker had a 27-year career with PacifiCorp, where she rose to the position of a business unit vice president, having worked for the utility in Oregon, Wyoming and Utah.

"We had an incredibly qualified pool of candidates this year," said EIM Nominating Committee Chair Jennifer Gardner, a senior attorney with Western Resource Advocates. Gardner described the deliberations leading to the nomination of Decker as being "consensus-driven," bringing together representatives from the EIM's various sectors in a "time-intensive process." In addition to seeking someone with subject matter expertise, the committee put a high priority on experience in the West, with a focus on geographic diversity, she said.

"It was a difficult decision because we had some very qualified candidates, which I think speaks well to the Energy Imbalance Market in general," member John Prescott said. "There's a lot of interest out there from very qualified people that would like to serve on this Governing Body."

Decker's term, which began Sunday, will run until June 30, 2020, when Schmidt's term was set to expire.

Not 'Discretionary'

After the Governing Body's three remaining members voted unanimously to confirm Decker, Fong quickly posed the question of whether the body should prompt the Nominating Committee to begin searching for Kavulla's replacement.

"That's technically not on the agenda," said CAISO Senior Counsel Greg Fisher, who was sitting with the EIM leaders.

"Is it actually an action item? It's just a recommendation that they move forward," Fong said.

Fisher advised against proceeding so informally, saying the matter was not "discretionary" for the Governing Body, given the amount of time left before the expiration of Kavulla's term, which leaves uncertain the process for replacing him.

"So, we'll wait to hear back with a formal opinion from you on that and we'll proceed," Linvill confirmed.

Speaking to *RTO Insider* about Kavulla's resignation after the meeting, Linvill said, "We'll miss his contributions. He was an important member of the Governing Body — and we'll leave it to him to announce what his plans are."

"Travis is a big loss. He brings a wealth of expertise to the Governing Body," Gardner said. But having recently vetted the list of industry hopefuls seeking to take over for Schmidt, she was optimistic about finding yet another replacement.

"I think a lot of folks have an interest in seeing the EIM succeed. I have no doubt we'll have an excellent pool of candidates." ■

Left to right: CAISO's Mark Rothleder and Keith Casey; EIM Governing Body members Valerie Fong, John Prescott and Carl Linvill; and CAISO's Greg Fisher and Stacey Crowley. | © *RTO Insider*

ERCOT News

Texas PUC Briefs

ERCOT CEO Briefs Commission on Summer Performance

ERCOT CEO Bill Magness briefed the Texas Public Utility Commission last week on his organization's response to the intense August heat, when the grid operator met record demand peaks and saw several price spikes.

ERCOT called two energy emergency alerts (EEAs) last month, its first in five years. Staff had warned before the summer began that EEAs were likely, given the system's tight 8.6% reserve margin, but it did not have to resort to more drastic measures such as rotating outages. (See *ERCOT: More Capacity, but Emergency Ops Still Expected*.)

"I feel a little like the air traffic controller telling you how great the air show was," Magness told the PUC during his *presentation* Thursday. "As you know, [ERCOT doesn't] fly the planes. I wasn't out there on a Saturday when it was 105 degrees [Fahrenheit] fixing a tube leak so the plant could run. The entire industry worked very hard under difficult conditions, and that's how we were able to keep the power on effectively for the state during a very rough period."

Commissioner Arthur D'Andrea offered thanks and kudos to Magness and the staff, saying, "We asked you to run a grid with very tight reserve margins. You stepped up and have given us reliability and probably the most efficient grid in the world. You've saved Texans a lot of money."

Demand soared in August following the coolest June-July period since 2007. ERCOT set a new all-time peak of 74.7 GW on Aug. 12, smashing the record set in July 2018 by more than 1 GW. In all, the system topped the 2018 record seven times that week.

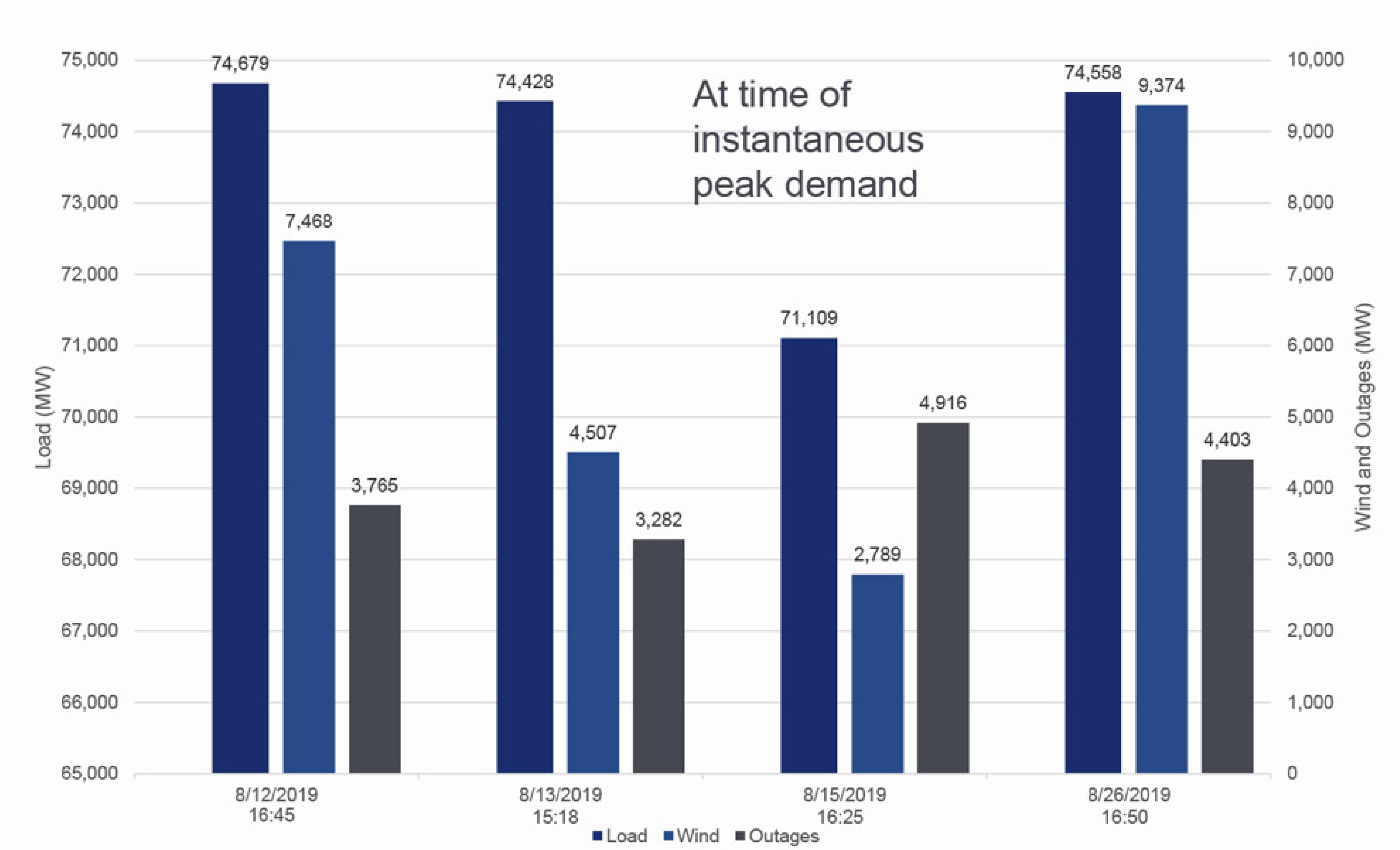
The Texas grid operator recorded its second-highest demand peak on Aug. 26 at 74.6 GW, along with two other top 10 marks.

Ironically, the EEAs were declared on two of the three days following the record peak, when temperatures and load were lower, but wind production dropped and thermal generation outages increased. Prices briefly hit the $9,000/MWh maximum during both energy alerts.

As he has before, Magness explained that ERCOT sees a trough in wind production during the early afternoon hours, when West Texas winds die down and before the coastal winds pick up.

"We have a fairly consistent pattern established in the summer where the West Texas and the coastal wind support the system at various times of the day," he said. "As we have an increasing amount of intermittent resources on the system, there's a divergence between the peak load of the day and when the reserves are lowest."

Magness said forced outages were to be expected, considering the stress placed on generating units.



Load, wind output and outages for ERCOT's highest demand days in August. ERCOT set a new all-time peak of 74.7 GW on Aug. 12, smashing the record set in July 2018 by more than 1 GW. The system topped the 2018 record seven times that week. | *ERCOT*

ERCOT News

"When you've been running units through August with that kind of heat," he said, "running units can become limping units, and limping units can become stopping units, if you don't let them take a break and fix mechanical problems that come from running them so hard.

"The forced outages are not out of the ordinary, but when combined with a loss of wind generation and continued high load, that's what took us into the EEAs," Magness said.

ERCOT filed detailed reports on the *Aug. 13* and *Aug. 15* EEAs in a reopened docket (*27706*). The commission also opened a docket to review the grid operator's summer performance (*49852*).

The PUC has tentatively scheduled an Oct. 11 workshop for a final and more in-depth debrief on ERCOT's summer performance. The grid operator and its Independent Market Monitor are among those who will deliver presentations.

Commission Chair DeAnn Walker, who requested Magness' presentation, said she and Magness will both be attending NERC's quarterly meeting in November. "NERC is concerned about the reliability of our grid, and Bill and I are going to go tell them we've got it," she said.

ETEC OK to Transfer 35 MW into ERCOT

The commission *approved* East Texas Electric Cooperative's (ETEC) request to move 35 MW of load and related facilities into ERCOT from SPP (*47898*).

ETEC, which provides wholesale service to eight smaller cooperatives straddling the ERCOT, SPP and MISO footprints, said the transfer will reduce energy costs and better balance its load among the three grid operators. The co-op will have 185 MW in ERCOT, 965 in SPP and 450 in MISO when the load transfer is completed during the last three months of 2020.

To transfer the load, ETEC will disconnect three substations from SPP and connect them into ERCOT through interconnections on a 138-kV line transmission line. The co-op and Oncor are responsible for building the interconnections.

PUC Rejects T&D Waiver Request

The PUC *denied* a petition by Oncor, CenterPoint Energy and Texas-New Mexico Power for a waiver of the commission's quarterly retail market performance-measure reports, as required of ERCOT, retail providers, and transmission and distribution entities (*49301*).

The companies said it was "impractical and unduly burdensome" to comply with the rule and its reporting form because of changes over time in the applicable tariff and the market. Walker disagreed with their assertion, saying a rulemaking would be a more appropriate proceeding to change the rule.

"CenterPoint and others have been filing these in May and August, so it can't be burdensome and impractical," she said. "This is not the way to fix a rule or a form."

ERCOT CEO Bill Magness briefs the Texas PUC on meeting August demand.

Hearing Scheduled for El Paso Purchase

The PUC is working to schedule a hearing on an investment fund's proposed acquisition of El Paso Electric (*49849*).

Commission staff are trying to schedule a hearing in November. A prehearing conference Thursday will set a procedural schedule and address pending motions.

EPE and J.P. Morgan Investment Management's Infrastructure Investments Fund *announced* the $4.3 billion deal June 1. The sale must be approved by EPE shareholders, the city of El Paso, and Texas, New Mexico and federal regulatory agencies.

The parties filed a merger application with the PUC on Aug. 13, starting the 180-day clock to rule on the application. Texas Industrial Energy Consumers, El Paso and the Texas Office of Public Utility Counsel have intervened.

Commission Approves Rate Recovery, $328K in Fees

In other business, the commission *approved* Southwestern Public Service's request to recover $2.16 million in rate-case expenses (*47588*).

The commission also approved six settlement agreements, totaling $328,500 in administrative penalties.

- Electric wholesaler Twin Eagle Resource Management agreed to pay $180,000 for capacity shortfalls, inaccurate telemetry and failure to send notifications to all required parties (*49784*).
- Retail provider American PowerNet Management was fined $10,000 for a history of failing to timely file annual reports (*49408*).
- Spark Energy, another retailer, was assessed $90,000 over improper enrollment, bills and disconnection notices (*49684*).
- Three qualified scheduling entities were fined for violating the use of the emergency response service (ERS) demand response tool. Power Generation Services was fined $8,500 for failing to maintain the required ERS load (*49281*), the city of Garland was hit with a $25,000 fine for not maintaining the required portfolio-level ERS availability factor (*49698*), and Links EP was docked $15,000 for not maintaining the required ERS load and availability factor (*49731*). ■

— Tom Kleckner

ERCOT News

ERCOT TAC Endorses Co-optimization Principles

By Tom Kleckner

ERCOT's Technical Advisory Committee last week endorsed three additional "foundational pieces" to real-time co-optimization (RTC), the market tool being designed to procure energy and ancillary services (AS) every five minutes to find the most cost-effective solution for both requirements.

TAC members unanimously approved the key principles in an email vote following a briefing by ISO staff Thursday. The briefing was held in lieu of the committee's regularly scheduled meeting to help the task force drafting RTC key principles stay on track.

"We want to harden [the principles] and move on. We don't want to be like nodal and do it over again," said ERCOT's Matt Mereness, who chairs the Real-Time Co-Optimization Task Force (RTCTF), referencing the cumbersome effort to design and implement the grid operator's nodal market.

ERCOT's Matt Mereness | © *RTO Insider*

"I didn't think we needed to spend a whole meeting on this," said TAC Chair Bob Helton, of ENGIE.

The key principles (KPs) reviewed by the TAC were:

- KP 1.4 will modify the systems and applications that provide input for the current real-time market (RTM) optimization engine to accommodate the awarding of AS in real time. AS will be a resource specific award, and regulation instructions will be generation resource-specific.
- KP 1.5 will modify processes for deploying AS to accommodate real-time awards. The principle will look at systems and communications between ERCOT and qualified scheduling entities in dispatching and deploying AS.
- KP 3 will modify the reliability unit commitment (RUC) process to be consistent with how energy and AS will be awarded in the RTM. RUC will review resources scheduled to be available to determine whether additional resource commitments are needed to meet the load forecast and minimum AS requirements and resolve transmission congestion under defined penalty curves and factors.

The TAC held an email vote following the online session to endorse the principles. Members had until Friday to send in their votes.

The Texas Public Utility Commission directed ERCOT to add RTC to its market. The grid operator has estimated it will take four or five years and at least $40 million to modify its market, but its Independent Market Monitor says the grid operator could save as much as $400 million annually in reduced congestion costs and AS costs. (See *PUCT Continues Review of Potential Market Improvements*.)

The task force faces a February deadline to complete 13 *key principles*. It is currently working on AS demand curves and an offer structure, and it has begun discussions on changes to the day-ahead market.

The TAC in July approved the first set of five principles. (See "TAC Approves First Real-time Co-optimization Principles," *ERCOT Technical Advisory Committee Briefs: July 24, 2019*.)

The task force next meets Sept. 19 and 24. The latter meeting includes a half-day lessons-learned session with MISO, PJM and SPP representatives. ■

ERCOT's day-ahead market, as it is today (top) and as it will be under real-time co-optimization | *ERCOT*

ISO-NE News

FERC Extends ISO-NE Fuel Security Filing Deadline

FERC on Friday granted ISO-NE another six months to file a long-term fuel security mechanism, the second extension since its original order last July (*EL18-182*). The new deadline is April 15, 2020.

ISO-NE in January filed a motion requesting an extension of the original July 1 deadline, which the commission granted, extending the deadline to Oct. 15. On July 31, the New England States Committee on Electricity filed a motion requesting an additional six months to allow ISO-NE and the region to work through issues related to the RTO's proposed mechanism.

The Pilgrim Nuclear Power Station on Cape Cod shut down on May 31, increasing New England's fuel security risks. | *Entergy*

Several commenters, including Energy New England, the Environmental Defense Fund and National Grid, supported the motion, while ISO-NE, the New England Power Pool, Repsol Energy North America and Verso Corp. told the commission they took no position on the request.

The New England Power Generators Association opposed the request, insisting the commission issue an order on the proposal by Sept. 26, "before key deadlines lapse for the next scheduled Forward Capacity Auction, FCA 14."

"Sept. 26 is a key date because it is the final day before the start of the submission window to finalize static delist bids in FCA 14," NEPGA said. "By that date, generation resources must decide whether to delist or not. Basic market fundamentals — such as whether fuel security resources will be required to offer at zero or submit cost-based offers — must be established by that date."

In the alternative, NEPGA said, FERC should at least issue an order by Jan. 31, 2020, just days before FCA 14 is scheduled to start. "In no event should an order be delayed beyond Jan. 31, 2020," it said.

FERC did not respond to NEPGA's arguments. ■

— Michael Kuser

MISO News

FERC Blocks GridLiance's Door into MISO

By Amanda Durish Cook

FERC on Wednesday halted GridLiance Heartland's entry into the MISO markets by blocking its $11.7 million purchase of six transmission lines from a Vistra Energy subsidiary (*EC19-42*).

The commission said GridLiance and the subsidiary, Electric Energy Inc. (EEI), failed to prove the acquisition wouldn't adversely affect MISO rates. The deal involved two 161-kV substations and six 161-kV transmission lines that cross the Ohio River and connect to the EEI-owned Joppa Power Plant in southern Illinois. Vistra owns an 80% interest in EEI, with Kentucky Utilities controlling the remaining 20%. The assets in question currently sit outside the MISO footprint.

The move would have marked GridLiance's first foray into MISO, while increasing revenue requirement rates in the Ameren Illinois transmission pricing zone. GridLiance estimated it would incur $8.2 million a year to operate the lines, 8 to 10 miles in length, compared with EEI's $4.6 million in costs. Once the transaction closed, GridLiance said it would transfer functional control of all six lines to MISO by 2022. The request was submitted to FERC late last year.

GridLiance and EEI claimed the increased rate requirement would be offset by the transaction's benefits, including use of EEI's existing interconnection with the Tennessee Valley Authority to ease the burden on MISO's north-to-south constraint, elimination of some pancaked rates and the expansion of the RTO's footprint by adding transmission that can import power from neighboring balancing authorities.

But the six lines, originally constructed for the sole purpose of powering the U.S. Energy Department's now-defunct *Paducah Gaseous Diffusion Plant* uranium facility, aren't exactly in high demand now, incumbent transmission owner Ameren argued. EEI reconfigured its transmission system to disconnect from the Paducah plant in 2017. Four of the lines connect with TVA, while the other two connect with the Louisville Gas & Electric/Kentucky Utilities balancing authority area.

Ameren challenged GridLiance and EEI's beneficial claims, arguing that no entities — except those already affiliated with EEI — have ever requested service over the lines in the last 25 years. Ameren also contended that neither GridLiance nor EEI undertook analysis to determine the likelihood of new transmission customers and pointed out that MISO already has interconnections to the TVA and LG&E/KU areas.

FERC agreed with Ameren, calling the supposed benefits "non-quantifiable" and unable to counteract an "admitted" increase in rates.

The commission also pointed to a GridLiance witness statement that "regardless of whether GridLiance Heartland purchases the EEI transmission facilities, those facilities will be placed into MISO's functional control" because Vistra was already in the process of transitioning "several" units at the Joppa station into the RTO.

"We conclude that the benefits from integration of the transmission assets into MISO would occur irrespective of the proposed transaction," FERC said.

While FERC wouldn't speak to other factors regarding the merger because of the rate impact issue, it said its rejection was without prejudice and it invited the parties to file a revised acquisition proposal. ■

Paducah Gaseous Diffusion Plant | *DOE*

MISO 2019 Transmission Expansion Plan Takes Shape

By Amanda Durish Cook

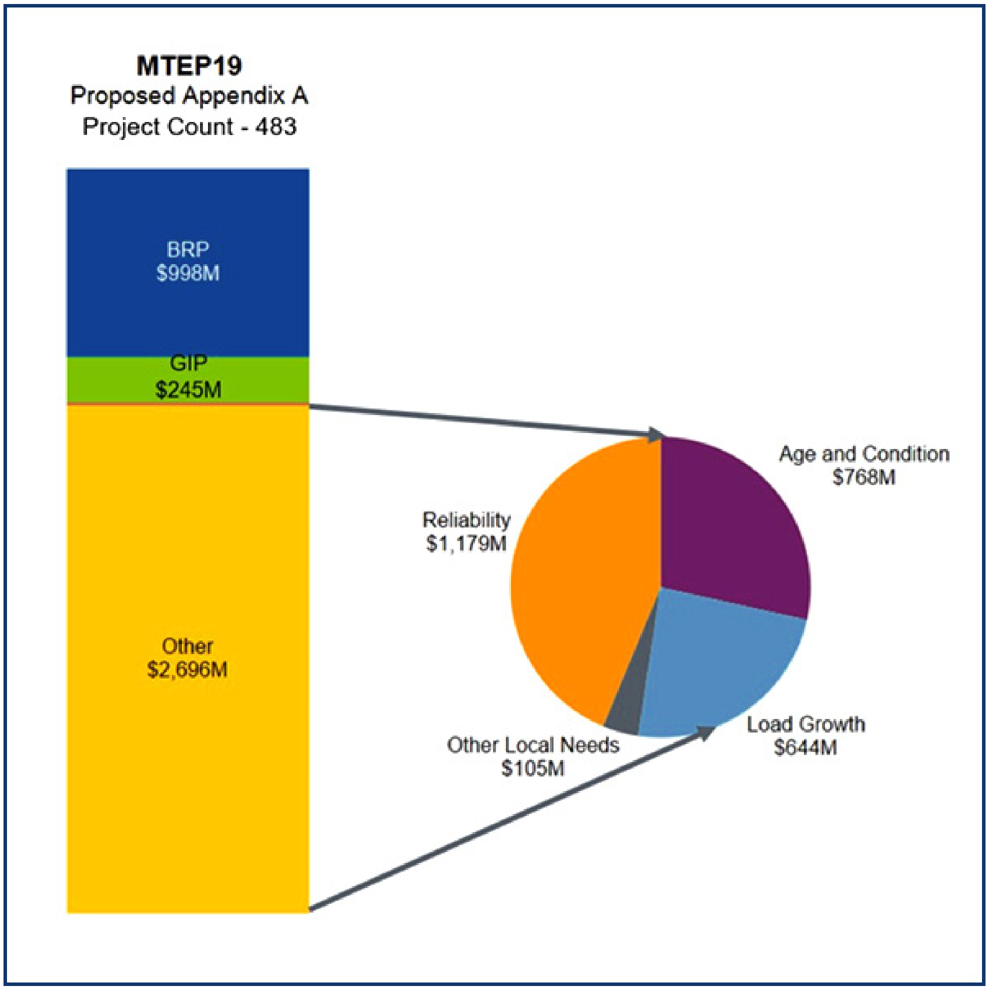
MISO is poised to recommend nearly $4 billion in spending in its 2019 Transmission Expansion Plan (MTEP), making it the second costliest such package in the RTO's history.

The draft *MTEP 19* was brought into focus over a final *series* of subregional planning meetings last week. The transmission projects in the bundle so far number 483 at a total cost of $3.95 billion, with MISO South's 72 proposed projects accounting for $760 million. The priciest *projects* are clustered in southern Illinois, southern Michigan and southern Louisiana.

MISO will post a final draft on Sept. 16, a day before putting the plan before the System Planning Committee of the Board of Directors at its meeting in St. Paul, Minn.

Last month, MISO was positioned to *recommend* 529 new projects at $4.4 billion. Even with the loss of about four dozen projects, the latest MTEP is positioned to be second most expensive behind the 2011 package that contained the multi-value project portfolio. Last year, MTEP 18 rang in at $3.4 billion and 442 projects. (See *MTEP 19 Revealing High Price Tag*.)

During an East subregional planning meeting Wednesday, Thompson Adu, MISO senior manager of transmission expansion planning, advised stakeholders that the cost and project figures are still subject to change, but he said the numbers are "almost finalized."



MTEP 19 breakdown | *MISO*

MTEP 19 contains new breakdowns in MISO's "other project" category to capture the specific drivers of projects. This year's $2.7 billion "other" category is now broken down into about $1.2 billion in reliability projects, $768 million in age- and condition-based projects, $644 million in load growth projects and $105 million worth of other local needs. Baseline reliability projects *account* for almost $1 billion in spending, while generator interconnection projects make up $245 million. MISO said the majority of MTEP 19 projects are expected to be in service within five years.

Director of Planning Jeff Webb said MISO had been mulling creating an MTEP project classification for age- and condition-based upgrades to avoid having so many projects simply labeled as "other."

Webb said the number of MTEP projects falling into the "other" category is a "carried-over legacy" from when the RTO had to separate regional reliability projects from local reliability projects for cost allocation purposes.

"Every time we take the [project] bar charts to the board, it's mostly 'other.' … We're thinking of changing that. We're tired of having to explain exactly what 'other' is over and over," Webb said during a June planning meeting.

During an Aug. 23 West subregional planning meeting, stakeholders criticized MISO for modeling too few future wind resources in congestion relief planning. Multiple staff members pointed to the planned overhaul of futures in time for the 2021 transmission planning schedule. But some stakeholders said MISO was planning for less wind for 2030 than would be actually installed in 2020.

"I find myself wondering why we're building futures with significant future generation and don't include the likely associated interconnection upgrades," WPPI Energy's Steve Leovy said.

Some stakeholders at the meetings also said the MTEP timeline is challenging, only allowing for stakeholders to suggest alternative projects in June and July.

1 Possible Project from MCPS

Stakeholders last week also learned that few proposals were able to demonstrate enough benefits to pass the first round of scrutiny in this year's *Market Congestion Planning Study* (MCPS), designed to identify congestion-relieving projects.

Among the proposals, MISO will only take a deeper look at two possible solutions to resolve the congested Bosserman-Trail Creek 138-kV line in northern Indiana. Both projects are also under consideration as part of the MISO-PJM Coordinated System Plan, and the RTOs will make a recommendation at the Sept. 20 Interregional Planning Stakeholder Advisory Committee meeting if they plan to pursue

MISO News

one of the two.

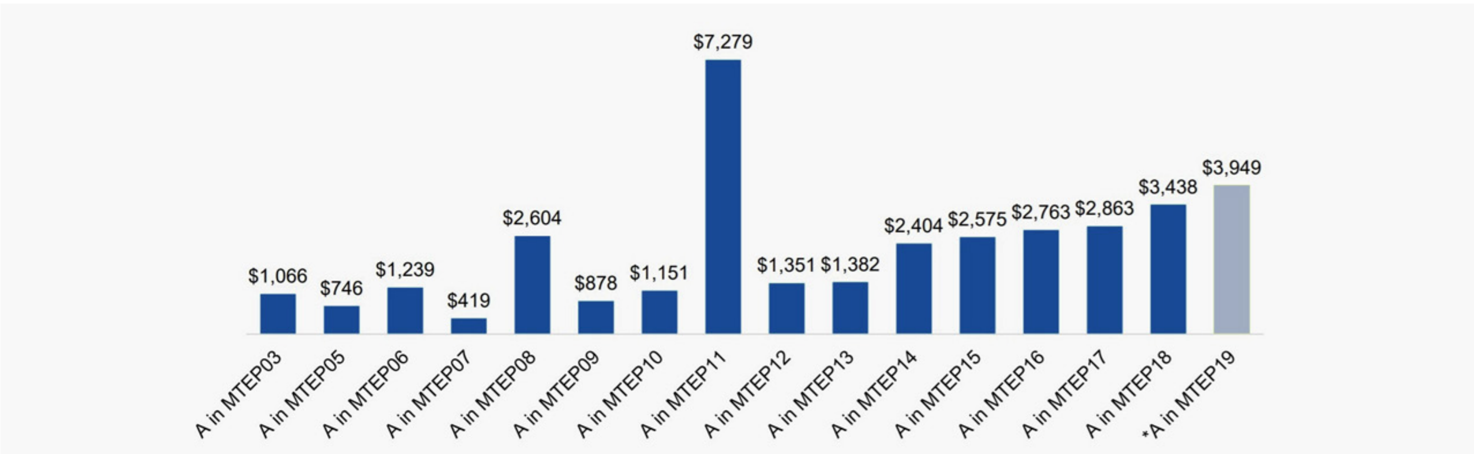
MISO has until Sept. 23 to file another cost allocation plan with FERC to cover PJM interregional projects under 345 kV. (See *MISO Mulling Next Steps on Cost Allocation Overhaul*.) MISO staff said they hope to have a revised interregional cost allocation structure in place before project approvals in December.

MISO planning staffer David Severson said no projects in the RTO's North region or along the SPP seam met requirements in the MCPS.

Project candidates to address congestion on the Helena-to-Scott County 345-kV line in southern Minnesota did not pass a robustness analysis, MISO said. The $32 million line was one of eight initially promising projects to come from the MCPS. (See "8-Project Draft from Congestion Study," *MISO Studying Projects to Cut North-South Tx Reliance*.)

This year's MCPS included the MISO-SPP interregional study, but the RTOs announced last month that no projects could pass MISO's 1.25:1 benefit-cost ratio. (See *MISO, SPP Empty-handed After 3rd Project Study*.)

Last week's planning meetings did not address the ongoing analysis into a possible project to ease traffic on the North-South transmission constraint. That effort is being conducted separately from the MCPS and will continue beyond the MTEP 19 approval deadline in December. MISO staff earlier this year said they weren't bound to an MTEP 19 deadline to submit any project recommendations and could take more time to conduct thorough testing of candidates. ■



Historical MTEP spending with draft MTEP 19 data | *MISO*

MISO News

MISO, PJM Eye Nov. Freeze Date Defrost

By Amanda Durish Cook

MISO and PJM said last week they will propose changes to how they determine flowgate rights in a white paper in November.

The RTOs use an April 1, 2004, "freeze date" to determine firm rights on flowgates based on historical firm flows that occurred before the creation of their seam. That date is used to determine both firm flow entitlements (FFEs) used in market-to-market settlements and firm flow limits (FFLs) used in transmission loading relief (TLR).

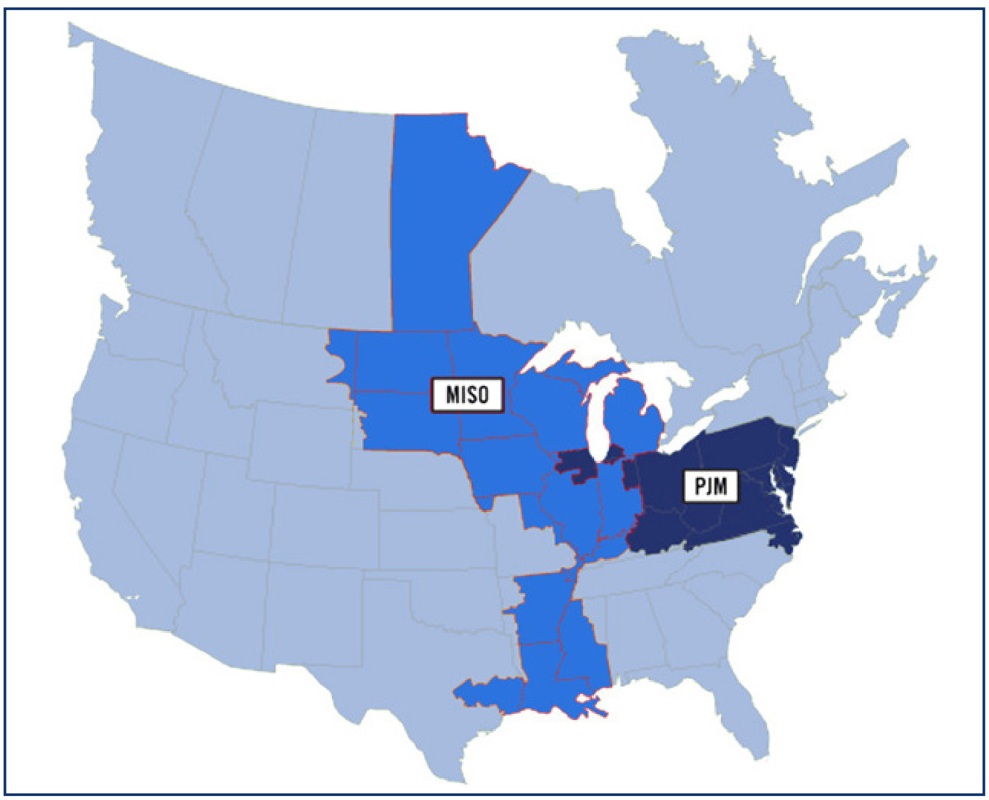
Earlier in August, MISO staff said the RTOs were considering filing a freeze date solution that would almost certainly be opposed by nonmarket parties to the congestion management process, leaving a decision up to FERC.

During a Joint and Common Market conference call Aug. 27, however, the RTOs said they hope they will be able to find an agreement with the nonmarket parties — including SPP, the Tennessee Valley Authority, Manitoba Hydro, the Minnkota Power Cooperative and Associated Electric Cooperative Inc. — by November. (See *Outside Parties Slow MISO-PJM Freeze Date Thaw*.)

MISO and PJM's proposed solution would divide flowgate rights by age, with priority to network resources from 2004 and earlier, followed by: network resources from 2004 or later; transfers between local balancing authorities to make up shortages on a pro rata basis; and RTO load served by RTO dispatch — in that order.

"Of course, the current freeze date process is not suitable for markets right now. … Of course, the solution will increase transfer rights for markets over nonmarket entities. That's been a big concern for the nonmarket," Andy Witmeier, of MISO's seams administration team, said earlier in August. Witmeier said nonmarket neighbors of the RTOs are concerned that their reliability may be impacted by a decrease in non-firm transfer availability. They also fear that an increase in firm limits for post-2004 network resources could lead to more curtailments of non-firm transfers for those outside the two markets.

Witmeier had said MISO and PJM could either file the freeze date changes with changes only to the RTOs' FFEs, leaving FFLs alone. But MISO staff said they would prefer a full solution that includes FFLs or to file a contested solution and let FERC decide.



PJM and MISO footprints | *MISO, PJM*

The white paper will discuss the solution only as it applies to FFEs. Joe Rushing, of PJM's interregional market relations team, said last week that the RTOs will continue to discuss with neighboring balancing authorities how FFLs can be updated from the freeze date.

Rushing said the RTOs may consider creating a market mechanism to cut a portion of firm market flows when curtailment of nonmarket flows doesn't provide enough relief to avoid TLRs. He also said they plan to study individual flowgates to figure out if some might be overtaxed.

He promised more discussion on the issue at the JCM meeting Nov. 19, when the RTOs expect to unveil the white paper.

No MISO Guarantee on PJM Customers' Revenue Rights

Meanwhile, the RTOs have conceded there is no way for MISO to guarantee PJM's customer-funded incremental auction revenue rights (IARRs) will result in a corresponding increase in FFEs.

However, the RTOs are promising more accurate *estimates* of increased flowgate entitlements when an IARR requires a joint coordinated study on the transmission upgrade.

Rushing said the grid operators have received little stakeholder comment on the small potential for financial risks to PJM members.

Both RTOs offer IARRs, which reflect upgrades that increase capability on their transmission facilities. IARR megawatts are awarded for the additional capability created for the life of the upgrade or 30 years, whichever is less, and valued each year based on annual financial transmission rights auction clearing prices. However, PJM's process provides an additional option that allows a specified IARR to be awarded when a customer agrees to fund transmission upgrades necessary to support the new auction revenue rights request. PJM is also obligated to guarantee at least 80% of IARR megawatts. (See *PJM, MISO Plan Study to Coordinate Incremental ARRs*.)

MISO has repeatedly said it cannot make guarantees on future FFE allocations to PJM members. PJM staff have said it's possible they won't be able to guarantee the 80% share if transmission upgrades affect the MISO system. ■

NYISO News

NYISO Q2 Congestion up Despite Drop in Load, Prices

By Michael Kuser

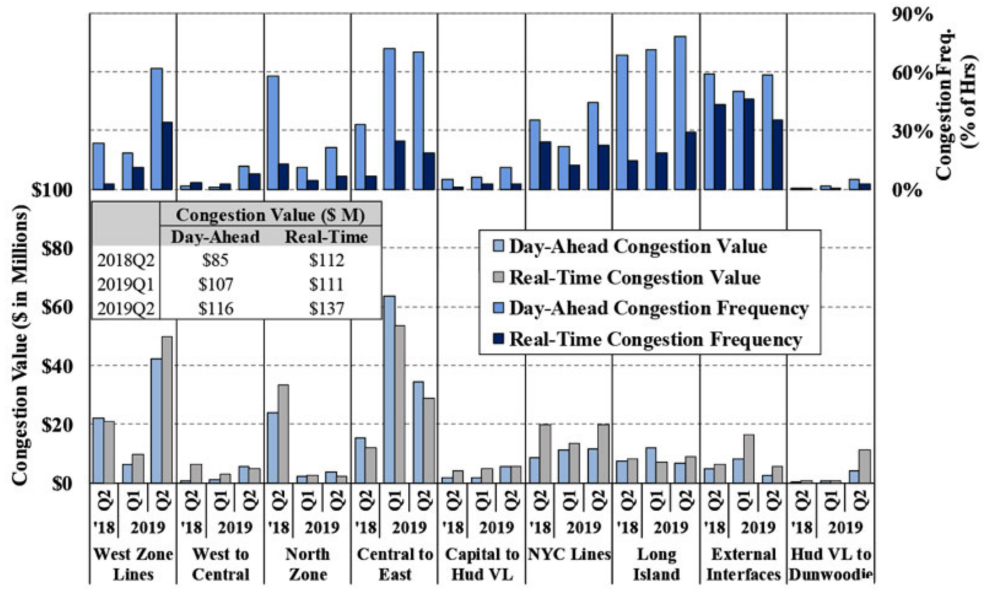
RENSSELAER, N.Y. — NYISO energy prices fell sharply in the second quarter, but congestion costs surged during the period despite lower gas price spreads and load levels, according to the Market Monitoring Unit.

Energy prices fell by 9 to 36% in the second quarter compared to the same period last year, while average load dipped to the lowest second-quarter level since 2008, Pallas LeeVanSchaick, of MMU Potomac Economics, told the ISO's Installed Capacity/Market Issues Working Group on Thursday in presenting its quarterly report on the markets.

Falling locational-based marginal prices and lower capacity costs in most areas accounted for the overall price decline. Average all-in prices fell in all areas and ranged from $20/MWh in the North Zone to $55/MWh in New York City.

While capacity prices were up 4% in the city, they fell by 14 to 56% in other areas of the state because of lower peak load forecasts, uprates and new generation coming online. The report also showed that energy costs fell by 11 to 34% in most regions because of lower natural gas prices, which dropped 17 to 29% from the previous year in Eastern New York.

The Monitor's 2018 State of the Market Report, presented by LeeVanSchaick in May, showed that rising natural gas costs and increased load levels drove up NYISO electricity prices by 23 to 36% last year, with peak load up 7% — "quite a large increase," he said. (See "State of the Market: Peak Load Up 7%," *NYISO Business Issues Committee Briefs: May 13, 2019*.)



Frequency (top) and value (bottom) of day-ahead and real-time congestion along major transmission paths by quarter | *Potomac Economics*

DA Congestion Revenues Rise 37%

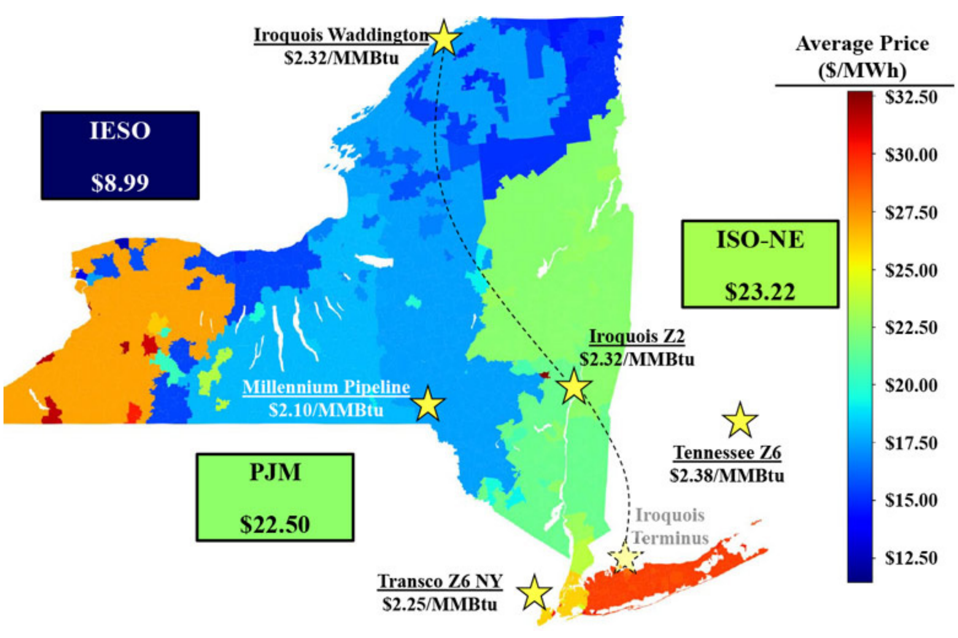
Day-ahead congestion revenues rose 37% from the second quarter of 2018, the Monitor reported.

The West Zone marked the largest increase in congestion costs because of the combined effects of modeling 115-kV constraints in the market software; more costly transmission outages; the return to operation of the South Ripley-Dunkirk 230-kV line on the PJM-NYISO seam, which has increased the impact of loop flows; and an increase in imports stemming from low Ontario spot prices.

"West Zone constraints were hard to manage despite recent modeling enhancements," LeeVanSchaick said. "The most significant factor leading to BMS [Business Management System] limit reductions was the cap on clockwise changes."

The BMS and Energy Management System (EMS) encompass the critical core reliability functions on the grid. When physical (EMS) flows exceed flows considered by the scheduling models (BMS flows) by a significant margin, the ISO reduces scheduling limits to ensure flows remain at acceptable levels.

The cap on clockwise changes in circulation was previously set at 75 MW per real-time dispatch (RTD) interval, which prevented



Second-quarter electric and natural gas prices in NYISO and neighboring regions | *Potomac Economics*

NYISO News

dispatch from reducing flows sufficiently after sudden changes in loop flow. NYISO increased the cap to 125 MW in June and 200 MW in July.

NYISO increased the constraint reliability margin (CRM) on the Niagara-Packard 230-kV lines and the Niagara-Robinson Road 230-kV line from 20 MW to 40 MW in June and to 60 MW in late July to assist in managing the constraints.

Noting the change to the Niagara-Packard and Niagara-Robinson Road CRMs and cap on loop flow changes, Chris Wentlent, representing the Municipal Electric Utilities Association of New York State, asked, "Are those going to remain in place going forward?"

"They're not temporary, but the CRMs and the cap on circulation changes can always be modified," LeeVanSchaick said. "The increased cap on circulation changes recognizes that the dispatch model needs to redispatch generation when circulation changes by a large amount."

Moving East and South

"NYISO is looking whether to relocate the proxy bus for Ontario to reflect that those imports tend to increase unscheduled power flows in the clockwise direction around Lake Erie," LeeVanSchaick said.

Another issue has to do with the Saint Lawrence phase angle regulator (PAR), which can be used to reduce congestion in the West Zone by diverting a portion of Ontario imports to northern New York, but the PAR is generally less flexible than assumed by RTD.

In August, the ISO reduced the optimization range used by RTD to be more consistent with the anticipated operation of the PAR, which "tightened up some of the modeling assumptions to better reflect how it's actually going to be operated," LeeVanSchaick said.

Asked by Wentlent when the St. Lawrence PAR might be evaluated, LeeVanSchaick said he was not sure, "because those are complicated issues. Hopefully we can answer by the next quarterly report."

Asked how the transmission build-up in the western part of the state would affect constraints, LeeVanSchaick said, "You might see more Ontario imports, which would hit hidden downstream bottlenecks, like perhaps Central East, but it's not something that we've looked at carefully."

Central East congestion increased primarily because of increased exports to New England from eastern New York, which were up approximately 400 MW, and more transmission outages leading to reduced transfer capability in April and May.

"Modeling these 115-kV constraints allows the market to reflect the congestion appropriately," he said. "In the Hudson Valley-Dunwoodie category, we saw significant constraints, which is due to some new combined cycle natural gas generation in the Hudson Valley, and not as much energy being wheeled from the Hudson Valley through New Jersey to New York City."

When the Indian Point nuclear plant retires in 2021, it will shift the location of congestion to another area south of the UPNY-SENY interface, LeeVanSchaick said.

New York City

NYISO's efforts to manage constraints "have greatly reduced out-of-merit actions, especially in the West Zone," LeeVanSchaick said.

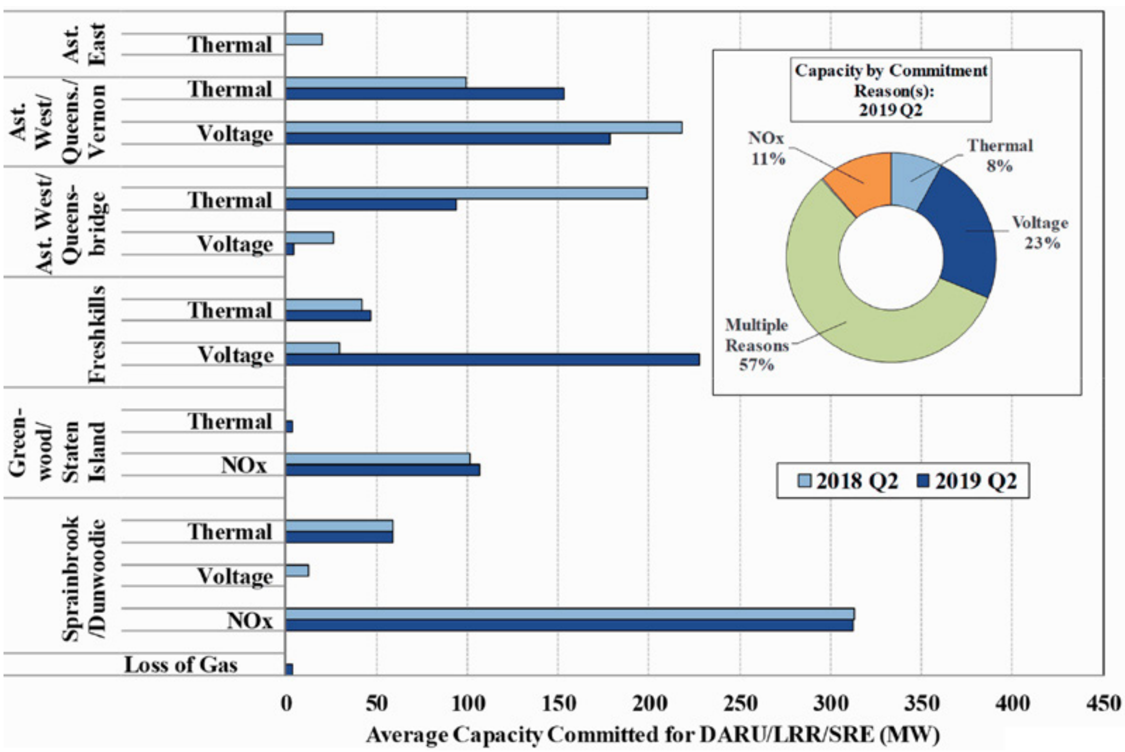
However, most reliability commitments occur in New York City because additional generation is needed to satisfy operating reserve requirements that have not been reflected in the NYISO market, he said. On June 26, the ISO began to model city-wide requirements in the day-ahead and real-time markets.

Couch White attorney Kevin Lang, representing the city, questioned the extent to which market-based approaches would reduce the need to dispatch particular units in specific locations for reliability purposes.

"That's a legitimate concern," LeeVanSchaick said. "If you have higher energy and ancillary services prices, there's going to be an decrease in uplift. ... Generators should be able to earn more of what they need through providing those energy and ancillary services products."

The ISO's "granular operating reserves" project would define a set of locations so that the market is procuring what the system needs, he said.

"If we can shift investment toward areas where new resources provide real value in the day-ahead and real-time markets, it will be more efficient, even if the investment is driven by subsidies, and it will reduce the likelihood of needed [reliability-must-run] contracts," LeeVanSchaick said. "Now is a particularly important time to have more efficient market signals." ■



Supplemental commitments for reliability in NYC by reason and location in New York City, where most reliability commitments occur | *Potomac Economics*

Rehearing Denied on PJM Designated Entity Agreements

By Christen Smith

PJM's incumbent transmission owners must sign designated entity agreements (DEAs) just the same as the nonincumbent developers building projects in their zones, FERC said last week in an order denying rehearing on the issue.

The commission held firm to its position, explained in its original July 2018 ruling, that PJM's proposal to exempt incumbent TOs from signing DEAs because it would give them an undue advantage over non-incumbents (*ER18-1647*). (See ***FERC Rejects PJM Exemption for Incumbent TOs***.)

It also rejected arguments by PJM and incumbents that the two groups of TOs were not "similarly situated" because each face different service mandates and penalties for falling short of those mandates.

"'To say that entities are similarly situated does not mean that there are no differences between them; rather, it means that there are no differences that are material to the inquiry at hand,'" FERC said in its Aug. 27 order, quoting language in a separate February 2018 ruling involving NYISO TOs (*ER15-2059-002, ER13-102-008*). "Likewise, the courts have explained that entities are similarly situated if they are in the same position with respect to the ends that the law seeks to promote or the abuses that it seeks to prevent, even if they are different in many other respects."

FERC said that in past rulings it has held new and existing generators to the same standards for reactive power compensation, and equally applied transmission curtailments among non-federal renewable resources and federal hydroelectric and thermal services "because they all take firm transmission service."

PJM and incumbent TOs requested rehearing in August 2018. Under current rules, both incumbent and nonincumbent TOs sign DEAs, which terminate once construction is complete. Nonincumbent TOs — competitive developers whose project proposals are selected by PJM through the FERC Order 1000 process — must also execute a consolidated transmission owners agreement (CTOA) before the prior contract can expire.

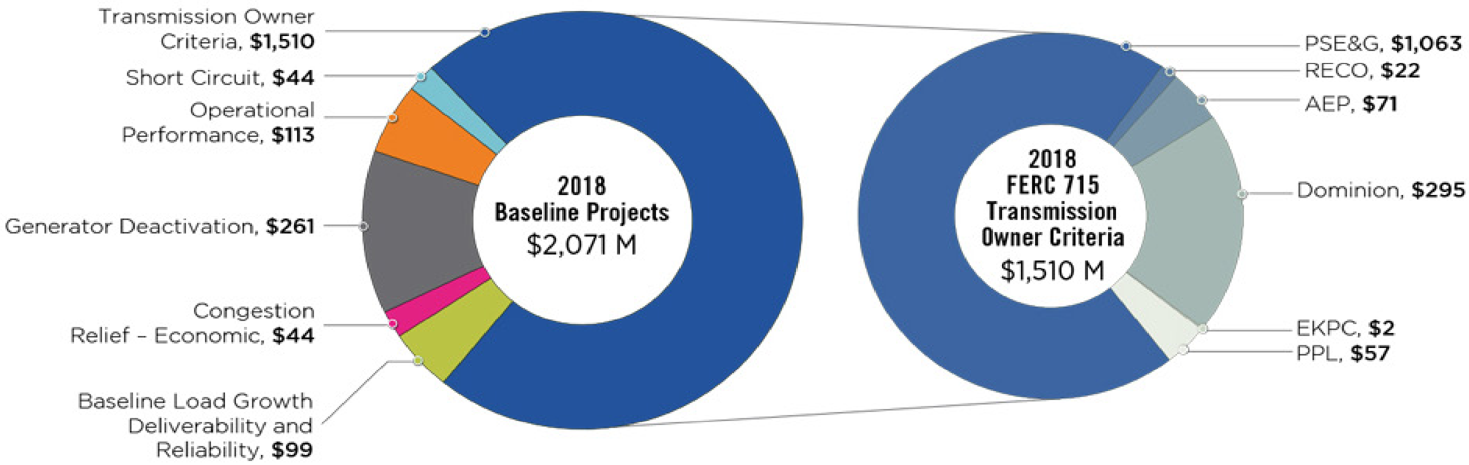
Construction of Ameren's Illinois Rivers transmission line | *Plocher Construction*

Notably, the commission said, breaching a DEA proves far easier and more expensive for nonincumbent TOs, which are subject to meeting construction milestones that may be delayed for reasons beyond their control. However, incumbent TOs only risk breaking the terms of a CTOA by missing scheduled in-service dates. Unlike incumbents, nonincumbent TOs must also "obtain a letter of credit or other financial instrument equal to 3% of the incremental project cost in the event of a breach," meaning this extra cost must factor in project submissions, making the incumbent TO's proposal cheaper by default.

The incumbent TOs "fail to recognize that the penalties for such noncompliance are not comparable to the upfront costs associated with the security requirement in the Designated Entity Agreement," FERC wrote. "The penalty provisions of the Consolidated Transmission Owners Agreement are implicated only in the event of breach or other specified noncompliance, while the security requirement of the Designated Entity Agreement, as discussed above, necessarily increases a nonincumbent transmission developer's costs. Further, due to the potential number and frequency of breach events, [the incumbent TOs'] comparison is inapt."

FERC did accept PJM's proposed Tariff revision that sets the time period for a transmission developer to accept its designation as a designated entity for 60 days after receiving an executable DEA, effective July 16, 2018. ■

PJM News



About $1.5 billion of the almost $2.1 billion in baseline spending in PJM's 2018 Regional Transmission Expansion Plan was for Form 715 projects. | *PJM 2018 RTEP*

FERC Opens Local Tx Projects to Competition, Cost Sharing

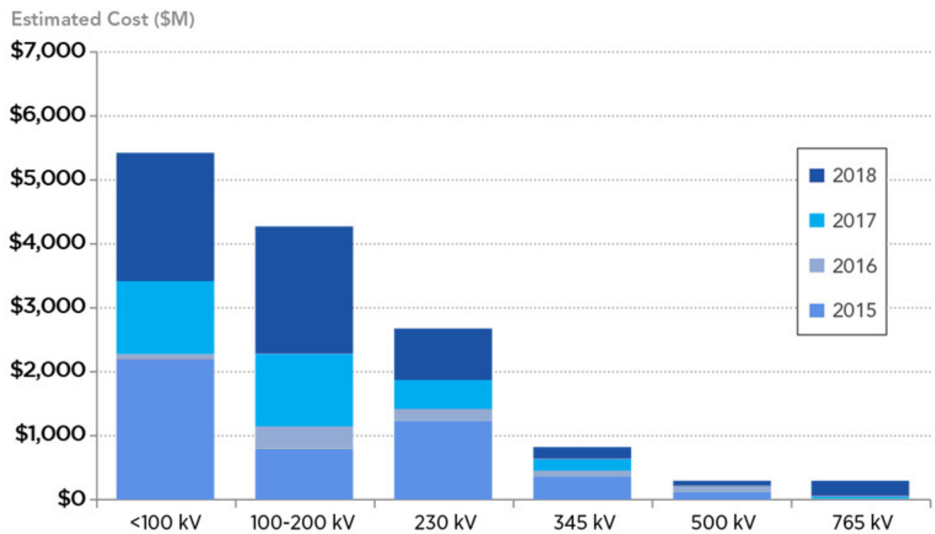
Continued from page 1

Regional Transmission Expansion Plan was for Form 715 projects.

In its order on remand Friday, FERC rejected a PJM Tariff amendment that had assigned all costs of projects included in the RTEP solely to address Form 715 local planning criteria to the respective TOs' zones. It also directed PJM to refile the assignment of cost responsibility for transmission projects in its RTEP between May 25, 2015, and Aug. 30, 2019, "that solely address individual transmission owner Form No. 715 local planning criteria" (*ER15-1387-004*).

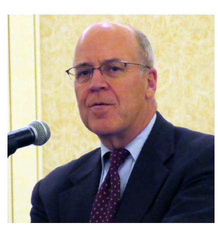
In a separate order, FERC opened a Federal Power Act Section 206 proceeding requiring PJM to revise its Operating Agreement, ruling that because the Tariff amendment is no longer applicable, neither is the provision that allows projects without competitive bids (*EL19-61*).

"Because the costs of projects needed solely to address individual transmission owner Form No. 715 local planning criteria will no longer be allocated 100% to the transmission zone of the transmission owner whose Form No. 715 local planning criteria underlie each project, we are instituting a proceeding pursuant to Section 206 of the FPA to require PJM to revise the PJM Operating Agreement to no longer exempt from the competitive proposal window process such projects, or to show cause why such changes are not necessary," FERC said.



Most baseline projects since 2015 have been below 345 kV. | *PJM 2018 RTEP*

"This is a significant win for competitive transmission developers," said Sharon Segner, vice president with LS Power. "This should increase the number of competition windows in PJM and bring the benefits of more transmission competition to PJM customers."



Ed Tatum, AMP | *© RTO Insider*

"I think it is [a good order], but there's a lot more to do," Ed Tatum, vice president of transmission for American Municipal Power (AMP), said in an interview Monday. "This ruling gets us back on track to the structure and concept that was envisioned 22 years ago where transmission was planned by … the regional transmission organization."

But Tatum said AMP will continue to push for PJM to assert control over TOs' supplemental projects, which dwarf even Form 715 spending.

Supplemental projects are not required for compliance with grid criteria governing system reliability, operational performance or economic efficiency. PJM does not approve

PJM News

supplemental projects but does study them to ensure they won't harm reliability.

Since 2015, PJM has evaluated more than $13.5 billion in supplemental projects, including $5.7 billion in 2018 alone. AMP says supplemental projects have tripled over the last 13 years, accounting for 62% of the submitted RTEP project costs since January 2017.

Dispute over Cost Allocation for Dominion Projects

The D.C. Circuit's ruling stemmed from two Form 715 transmission projects by Dominion; the first one, *Elmont-Cunningham*, was proposed in 2013. PJM's rules then required that half of the cost of high-voltage projects be assessed on a pro rata basis to all 24 utilities in the RTO based on customer demand, with the remainder allocated to zones based on benefits, as determined by a distribution factor (DFAX) analysis.

Dayton Power & Light objected to using the 50% *pro rata* allocation for the Elmont-Cunningham project, prompting PJM to propose a Tariff amendment that would prohibit cost sharing for projects proposed to satisfy TOs' own planning criteria.

FERC initially rejected the proposal, saying it violated Order 1000 and was inconsistent with the commission's earlier finding that high-voltage transmission lines provide "significant regional benefits that accrue to all members of the PJM transmission system."

After a technical conference, however, the commission reversed its decision, ruling that projects such as Elmont-Cunningham belonged in a new category of projects included in the RTEP for coordination but not selected for cost allocation. The commission then used the amendment to reject regional cost sharing for the Elmont-Cunningham and a subsequent *Cunningham-Dooms* project.

Commissioner Cheryl LaFleur dissented, saying that the commission should preserve regional cost allocation "for certain high-voltage projects, even if those projects are selected solely to address local planning criteria."

The D.C. Circuit agreed, saying FERC's approval of the Tariff change was "arbitrary" and would result in a "severe misallocation of the costs" of high-voltage projects. It noted that the Dominion zone would receive less than 50% of the benefits of each of the two projects.

"High-voltage power lines produce significant regional benefits within the PJM network, yet the amendment categorically prohibits any cost sharing for high-voltage projects like those at issue here," Judge Gregory Katsas wrote for the three-judge panel. (See *DC Circuit Rejects PJM Tx Cost Allocation Rule*.)

In its Friday orders — issued on LaFleur's last day at the commission — FERC rejected the Tariff amendment it had previously accepted and ordered PJM to make all Tariff corrections necessary to reflect the rejection within 30 days. It also gave PJM 30 days to amend its OA to eliminate the competitive exemption for Form 715 projects or make a show cause filing.

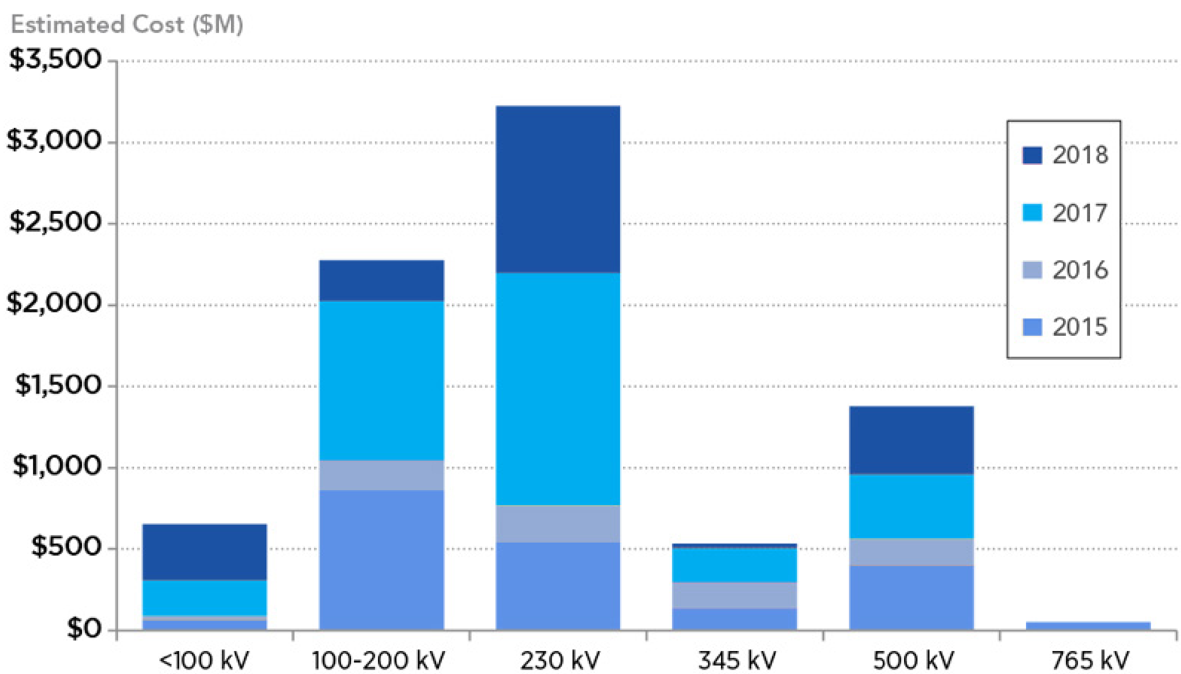
Most of the Form 715 projects in 2018 were proposed by Public Service Electric and Gas ($1.1 billion), Dominion ($295 million), American Electric Power ($71 million) and PPL ($57 million).

PJM did not respond to a request for comment Monday. Efforts to obtain comments from Dominion, PSE&G and PPL also were unsuccessful. An AEP spokeswoman said the company was "still digesting the orders" and had no immediate comment.

It was unclear from FERC's order whether the commission expects PJM to open all Form 715 projects to competition or only those that are subject to regional cost sharing.

In 2016, the commission approved PJM's proposal to exempt reliability upgrades on facilities below 200 kV from competitive windows under Order 1000 (*ER16-1335*).

PJM said such projects are almost always assigned to incumbent developers, and the change would enable its engineers to focus on problems more likely to result in a competitive greenfield project. The commission limited the exemption to projects within a single transmission zone, saying those involving two or more zones must be opened to a proposal window. (See *FERC Orders PJM TOs to Change Rules on Supplemental Projects*.) ■



Since 2015 PJM has evaluated more than $13.5 billion in supplemental projects, including $5.7 billion in 2018 alone. | *PJM 2018 RTEP*

PJM News

FERC Sets Hearings in PJM Hydro Pseudo-tie Spat

By Christen Smith

FERC ordered paper hearings last week in disputes over the criteria PJM used to reject several hydroelectric resources from pseudo-tying into the RTO's grid.

Both Brookfield Energy Marketing and Cube Yadkin Generation said PJM erred when it determined some of their generating resources didn't meet the RTO's pseudo-tie requirements, preventing the companies from offering capacity.

Brookfield Energy Marketing's Calderwood Dam is on the Little Tennessee River in Blount County, Tenn.

Brookfield Complaint

In January, Brookfield challenged PJM's assertion that its Calderwood and Cheoah generating facilities did not pass the market-to-market flowgate test or meet its extraterritorial deliverability requirements, despite maintaining a firm point-to-point service from the Tennessee Valley Authority into Duke Energy's balancing authority area at an annual cost of $5 million. The company says it has held capacity obligations in PJM since 2014.

PJM told Brookfield in March 2018 its tests determined the facilities failed for 38 flowgates. A follow-up test three months later found the facilities failed "19 transmission elements." PJM rejected as insufficient a report prepared by Quanta Technology that affirmed Brookfield's point-to-point service complies with the RTO's requirements.

PJM's current pseudo-tie rules were approved by the commission in November 2017. The order included a five-year transition period for resources that had an existing pseudo-tie and had cleared in a capacity auction before May 2017 (*ER17-1138*). As a result of the failed tests, PJM said the Brookfield generators would be ineligible to participate in its capacity auction for the 2022/23 delivery year, after the transition period expired.

FERC ruled Aug. 26 that Brookfield's complaint raised legitimate concerns about how PJM applied its requirements (*EL19-34*). The commission noted PJM's Tariff and manuals do not specify the "deliverability criteria" the RTO uses for its evaluations.

"The record is not clear as to what deliverability criteria PJM uses to determine whether pseudo-tied resources can participate in the auctions, whether it uses those deliverability criteria consistently for all projects or how PJM evaluated the Brookfield facilities," the commission said. "PJM has not sufficiently explained why the Brookfield facilities failed the M2M flowgate test while other external generators affecting the same flowgate (flowgate No. 93209) did not."

However, the commission denied Brookfield's request to extend the five-year transition period. PJM said doing so would be inappropriate because the transition period is memorialized in the Tariff and would require a showing that the original transition was unjust and unreasonable. "Brookfield has presented neither a basis on which the commission could grant its requested interim relief nor a demonstration such relief would be appropriate in these circumstances," FERC said.

Cube Complaint

Cube filed its complaint after PJM informed it in June 2018 that its 220-MW *Yadkin Project* — the Tuckertown, High Rock, Falls and Narrows hydroelectric sites on the Yadkin River about 75 miles from Charlotte, N.C. — did not meet the "electrical distance" requirement under its pseudo-tie rules.

FERC approved the electrical distance test in its 2017 order, saying it struck an appropriate balance between allowing external resources to participate in PJM's capacity market while providing the RTO with reliability assurance. The commission said it accepted PJM's representation that the further its state estimator model extends beyond its own borders, the less resilient its system becomes to data losses and inaccuracies.

In its Aug. 26, order, the commission said Cube had raised factual questions about how PJM conducted the electrical distance test (*EL19-51*). Cube said PJM's identification of three electrically closest buses for the project is impossible because the series arrangement of the resources — with grid connections to only High Rock and Badin — means there can only be two closest buses.

FERC said PJM did not directly dispute Cube's arguments but responded that each site's location has a "unique set of paths through and out of the Yadkin area to the PJM border and, given these unique paths, finding differences between each location is not unexpected."

The commission said that raised questions as to how PJM's algorithm selects the buses and paths used in the electrical distance test and whether the selection of the wrong bus could cause a generator to fail when it would have otherwise passed.

FERC gave PJM 30 days to respond to its questions about its methodology, with responses by Brookfield and Cube due within 15 days of the RTO's filings. "After receipt of these filings, commission staff is authorized to establish additional procedures, including a staff technical conference," FERC said. ■

PJM News

NY Merchant TO Loses FERC Rehearing Bid on TMEPs

By Christen Smith

FERC on Wednesday dismissed a second request from Linden VFT to rehear its order denying reconsideration of cost allocations for several PJM cross-seams projects (*ER18-614*).

The commission said Linden just rehashed its original rehearing request. The company also can't offer new arguments unless the order it's protesting changed the outcome of the proceeding, it said.

"The commission has explained that the successive rehearing of an order on rehearing lies only when the order on rehearing modifies the original order's result in a manner that gives rise to a wholly new objection," FERC wrote. "If it were otherwise, the commission would be faced with countless successive requests for rehearing as parties raised argument after argument, in search of a winner."

In June, the commission *reaffirmed* a July 2018 order that directed PJM and its transmission owners to submit compliance filings regarding cost responsibility assignments for four targeted market efficiency projects (TMEPs) with MISO.

In that order, Linden and Hudson Transmission Partners, each of which operates merchant lines into New York City and had recently converted its firm transmission withdrawal rights to non-firm, were ordered to partially pay for TMEPs b2971, b2973, b2974 and b2975 after FERC said existing Tariff language indicated the congestion benefits accruing to the lines justified subsequent cost responsibility. (See *FERC Rejects PJM TMEP Rehearing Requests*.) PJM TOs then submitted a compliance filing clarifying that TMEP allocations would be assigned to merchant facilities in the future too.

The New York Power Authority joined with Hudson and Linden in opposing the order, arguing that the Tariff "limits all cost allocations … based on their actual firm transmission withdrawal rights."

In its second rehearing request submitted in July, Linden alone argued that TMEPs are a subset of required transmission enhancements, which carry associated charges that are "not to exceed the firm transmission withdrawal rights specified in the applicable interconnection service agreement."

Linden also said FERC gave it no notice that it would impose costs once the merchant TO dropped the rights and argued that assigning the company cost responsibility for TMEPs from which it does not benefit conflicts with the commission's cost-causation principle. ■

Ohio Nuke Ballot Petition Approved

By Christen Smith

Ohio Attorney General Dave Yost last week approved a draft petition to repeal the state's nuclear subsidy program, giving supporters just seven weeks to collect more than 265,000 signatures to get the referendum on the November 2020 ballot.

Gene Pierce, spokesperson for Ohioans Against Corporate Bailouts and sponsor of the petition, said the "quick resolution will help Ohio voters exercise their constitutional right to put controversial legislation up to a statewide vote."

Yost rejected the first draft last month, citing disparities in its language compared with the Ohio Clean Air Act signed into law on July 23. (See *Ohio Activist Unfazed by Denial of Nuke Petition*.) The act replaces the state's renewable energy mandates with ratepayer surcharges to support FirstEnergy Solutions' Davis-Besse and Perry nuclear plants and two Ohio Valley Electric Corp. (OVEC) coal plants. (See *Ohio Approves Nuke Subsidy*.)

The controversial law makes Ohio the third state in the PJM footprint to provide subsidies for its nuclear plants as cheap natural gas floods the wholesale power market and drives energy prices down to record low levels. (See *Monitor: PJM Markets Remain 'Under Attack'*.)

Supporters say keeping the reactors operating will reduce carbon emissions — a primary target of clean energy bills across the country — and provide around-the-clock reliability to support the intermittency of solar and wind power.

Pierce's group argues the law amounts to a "corporate bailout" that wastes money on less efficient resources at the expense of continuing to expand Ohio's renewable energy portfolio. And it has some powerful, if not unlikely, allies on its side: the natural gas industry, independent power producers, environmental activists and clean energy groups.

But not everyone agrees. Last month, *Ohioans for Energy Security* launched a $1 million television and radio ad campaign that links the petition to furthering the interests of the Chinese government, warning residents not to sign away the state's jobs and energy security.

The *Energy and Policy Institute*, a renewable energy advocacy group, said Ohioans for Energy Security's spokesperson, Carlo LoParo, has connections to FES and also fronts the Ohio Clean Energy Jobs Alliance, a known proponent of the subsidy program.

"These ads are designed to intimidate and threaten our petitioners who are exercising their constitutionally guaranteed right to place this ridiculous bailout on the ballot," Pierce said. "This is the kind of garbage that will get someone hurt, and we will hold all parties associated with their campaign responsible for any harm that comes to our circulators."

Davis-Besse nuclear power plant

But Pierce is also tight-lipped about where his group's money comes from, telling *RTO Insider* previously that he will disclose its financial supporters as required by Ohio campaign finance law.

"Until then, I can say that you will find that they are many of the same groups and individuals who testified against the bill in the legislative debate over the bill," he said. ■

PJM News

Another Win for PJM Monitor on Fuel-cost Policies

By Christen Smith

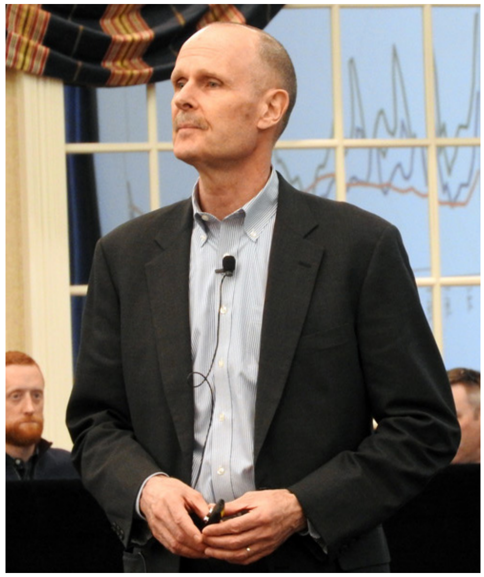
FERC last week reaffirmed the authority of PJM's Independent Market Monitor to file complaints against the RTO over fuel-cost policies, dismissing concerns about hypothetical conflicts of interest and overly broad interpretations of the Tariff (*ER16-372*).

"As the commission found, the review of fuel-cost policies directly relates to the Market Monitor's ability to review offers or cost inputs to ensure they are reasonable in the event market power mitigation is required," FERC wrote. "The filing of a complaint on a market seller's fuel-cost policy is a method of initiating a regulatory proceeding and therefore falls within the language of this provision."

The fuel-cost policies that generators submit showing how they calculated their cost-based offers have been a repeated source of conflict between PJM and its Monitor.

In April, FERC shot down PJM's attempt to prevent the Monitor from protesting policies other than market seller offers in capacity auctions, rejecting what the commission called the RTO's "narrow" reading of Attachment M. (See ***FERC Upholds PJM Monitor's Right to Protest Fuel-cost Policies***.)

In its request for rehearing of the April order, PJM argued that Attachment M of the Tariff permits the Monitor to file complaints against market sellers over fuel-cost policy violations, but not against the RTO itself. It also said that its Board of Managers' oversight of the Monitor's budget creates a conflict of interest, an argument that FERC said it found "unconvincing."


Joe Bowring, PJM Market Monitor | © *RTO Insider*

"PJM has failed to explain why the PJM board can fulfill its responsibilities in circumstances in which the Market Monitor makes filings with the commission, such as protests to PJM filings, but cannot do so with respect to complaints regarding fuel-cost policies," the commission wrote. "In any event, PJM's assertion of the potential for a hypothetical complaint to create a conflict of interest for the PJM board does not alter our interpretation of the Tariff, which is based on the text of the Tariff read in conjunction with other provisions addressing the role of the Market Monitor."

The proceeding dates back nearly three years to when the Monitor filed a protest saying a proposed Tariff revision by the RTO was an attempt to usurp its authority to regulate the policies. (See *PJM Attempting to Usurp Market Mitigation Role, Monitor Says*.)

FERC sided with PJM on that dispute, saying the changes didn't alter the fundamental roles of the RTO and the Monitor, "but rather codify the role of the IMM in advising and providing input to PJM in its determination of whether to approve a fuel-cost policy submitted by a market seller."

Still, it agreed that the Monitor didn't violate the Tariff by complaining and said such disputes between the two should only be resolved through the commission and its administrative law judges, not the Office of Enforcement as PJM's Operating Agreement requires. In last week's ruling, FERC ordered the RTO to submit a compliance filing within 30 days removing this language from the OA.

FERC also denied a rehearing request from the Electric Power Supply Association over the commission's decision to allow PJM to assess penalties for a minimum of one day for failure to comply with its fuel-cost policy.

EPSA argued that the rule results in retroactive penalty circumstances — an issue that FERC contends was resolved when PJM submitted an amendment in July 2017 that clarified the penalty will be applied on a prospective basis after the market seller is notified.

"Although EPSA styles its pleading as a request for rehearing of the April 2019 order, its challenge to the commission's acceptance of the penalty structure is, in essence, a late-filed request for rehearing of the February 2017 order and is thus statutorily barred," FERC wrote. ■

PJM News

FERC Reverses ALJ on PJM Tx Study Process

By Rich Heidorn Jr.

FERC last week rejected an administrative law judge's finding that PJM's transmission study process is unjust and unreasonable for developers seeking to secure incremental auction revenue rights (IARRs) by making upgrades to reduce grid congestion (*EL15-79*).

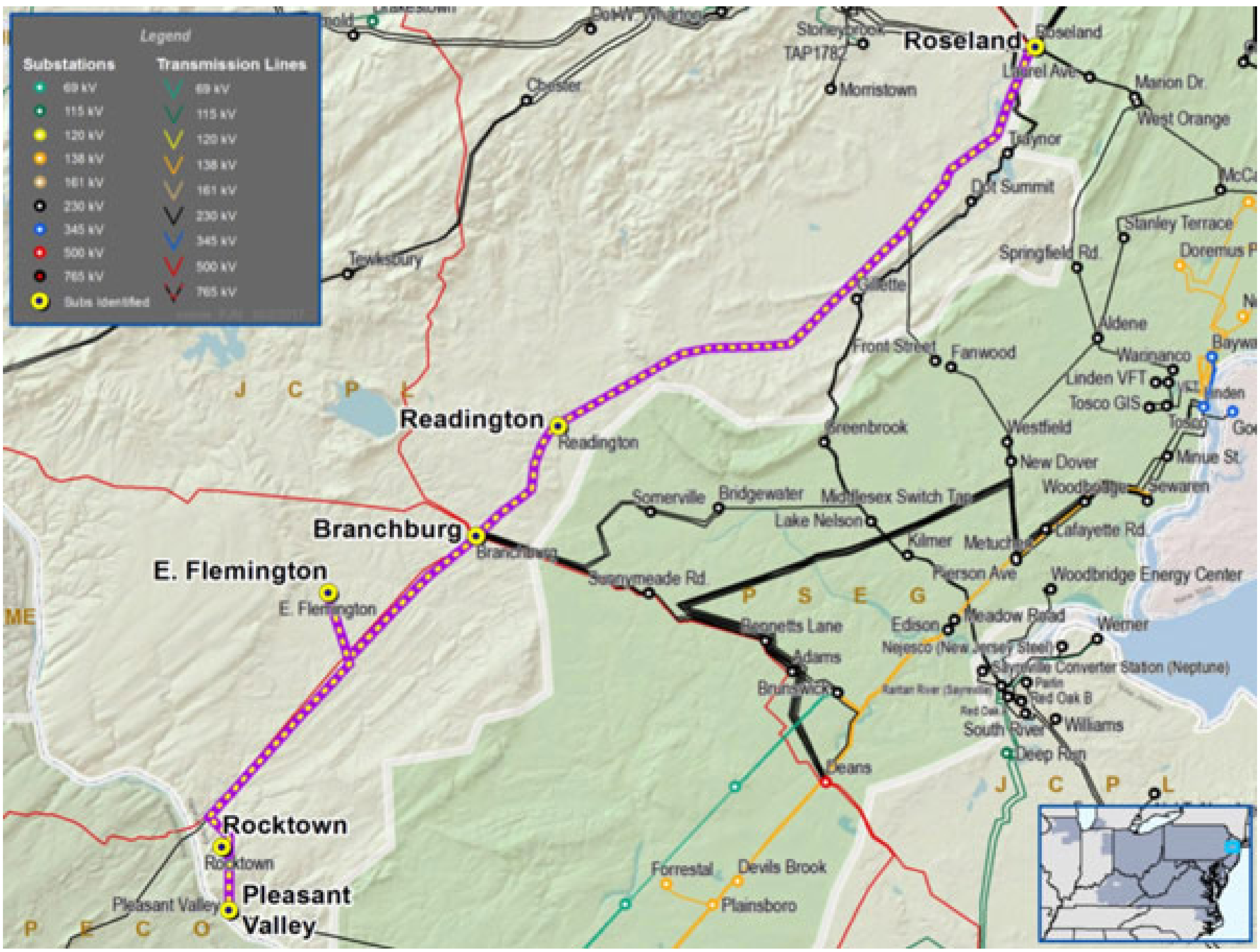
The commission reversed ALJ Philip C. Baten's January 2018 initial decision ordering PJM to reinstate three interconnection queue positions he said were unfairly eliminated when developer TranSource refused to pay for a facility study, the next stage of its interconnection process after the system impact study (SIS). FERC also reversed Baten's conclusion that PJM should refund TranSource's SIS application fees. (See *FERC Judge Faults PJM, TOs on Transmission Upgrade Process*.)

TranSource filed a complaint in June 2015 contending that PJM and transmission owners Public Service Electric and Gas, PPL, Jersey Central Power & Light and Delmarva Power & Light inflated the cost of upgrades necessary to approve three requests for IARRs. (TranSource is not to be confused with Transource Energy, a joint venture of American Electric Power and Great Plains Energy.) (See *Transmission Developer: PJM TOs Inflating Upgrade Costs for ARRs*.)

The commission affirmed Baten's decision to reject other remedies TranSource sought, including its claim for $63.6 million in "lost business" opportunities. And it agreed with Baten that it could not determine whether the $1.7 billion in upgrades PJM identified were indeed necessary, noting that the case focused on the impact studies, which are supposed to produce only "good faith" cost estimates.

Readington-Roseland Line

TranSource's upgrade proposals used facility



Analyses of the condition of the Readington-Roseland line was a source of contention in the TranSource case. | *PJM*

PJM News

ratings from FERC Form 715 filings made by PJM on behalf of the TOs. Baten said that was a "reasonable" assumption based on "statutory and regulatory provisions" and language in PJM's Tariff.

PJM testified its cost estimates were based on the line ratings expected at the time that the project being studied would be in service, including planned upgrades. PJM's estimates also incorporate the host TO's review of limiting elements based on the methodologies they file under NERC reliability standard FAC-008-3. The methodologies are not public and not the same as those used for Form 715.

A primary conflict was over estimates for upgrading PSE&G's Readington-Roseland 230-kV line in New Jersey.

PJM's analysis of transmission upgrade requests under Tariff Attachment EE is done in two steps. The SIS provides developers with an estimate of what their plan will cost with +/- 40% accuracy.

The first component of the SIS is the simultaneous feasibility test, in which PJM tests whether the developer's IARR request can be accommodated without diminishing the income of the current ARR holders. After that, PJM identifies the facilities that are impacted by the IARRs, and the relevant TOs conduct "desk-side" studies — so called because they do not involve site visits — using the confidential methodology to identify upgrades needed to accommodate the IARRs and their estimated cost.

If the developer chooses to proceed based on the SIS results, PJM conducts an in-depth facilities study that requires a refundable deposit of at least $100,000 and is supposed to provide a more accurate itemization of required upgrades.

A facilities study done for Exelon in late 2014 pegged the cost to repair the Readington-Roseland line at about $14.2 million. Although the towers had been in service for 80 years, "based on visual observation only, tower replacements are not anticipated," the study said.

But an SIS done for TranSource six months later increased the estimate more than nine times to nearly $126.5 million. When Richard Crouch, a PSE&G electrical engineer, reviewed the project three months later, he called for a complete wreck and rebuild for more than $142.7 million, a $16 million increase.

By 2016, PSE&G engineers had put the line on its list of facilities violating the company's Form 715 end-of-life criteria.

TranSource contested the SIS for Readington-Roseland and its other requested upgrades, saying it lost financing because of what it called PJM's "badly inflated" estimates. The RTO eliminated TranSource's queue positions when it refused to pay for the studies.

Baten ruled that the lack of transparency in PJM's SIS process made it "unduly discriminatory" to merchant developers by depriving them of business opportunities.

But while the commission directed PJM to add more detail regarding its SIS methodologies and assumptions to its Tariff, it ruled that the RTO's treatment of TranSource "represent a transparent process that is just and reasonable." It said the Exelon facilities study cited by TranSource was an interconnection study, not a transmission planning study.

The commission also reversed Baten's findings that the line rating methodology lacked transparency and that it was reasonable for TranSource to rely on Form 715 ratings in conducting its own evaluation of its upgrade requests.

And it said the judge ignored precedent and the facts in concluding that PJM's SIS process was unduly discriminatory. Citing Congress' creation of classes under civil rights statutes, Baten concluded that FERC had "created a class" of merchant developers and established "benefits for the class." He said that since the IARR program began in 2007, only one project (combining five queue positions) had been awarded IARRs out of 41 Attachment EE queue positions.

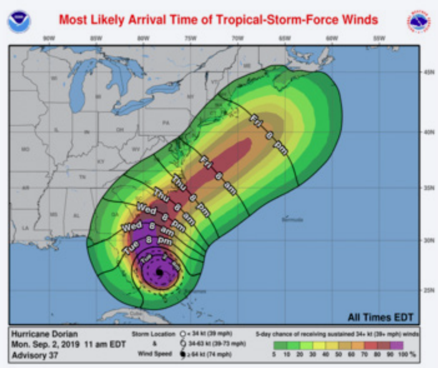
FERC said Baten failed to make a finding that PJM treated TranSource differently than other Attachment EE customers or that Attachment EE customers were treated differently than other classes of customers.

"We agree with PJM, the PJM transmission owners and trial staff that the presiding judge's reliance on the fact that very few Attachment EE requests have resulted in IARRs being awarded is misplaced," the commission said. It added that he ignored testimony from David Egan, then manager of PJM's Interconnection Projects Department, that "to make a profit under Attachment EE, a developer must find a 'sweet spot' where the transmission upgrades reduce congestion, but enough congestion remains so that the resulting IARRs have value."

The commission dismissed as moot TranSource's request to require PJM to add a pre-SIS phase to the Attachment EE process, noting that FERC approved the addition of a feasibility study to the process in April 2018. ■

Company Briefs

Fla. Utilities Brace for Dorian, Linemen Flock to State



Ahead of Hurricane Dorian, electrical utilities in Central Florida have brought hundreds of workers from around the country who are prepared to restore power after the storm.

Florida Power & Light has assembled its largest pre-storm restoration workforce with 17,000 workers employed with the company and out-of-state contractors, spokesman Richard Gibbs said.

Over the weekend, the Orlando Utilities Commission brought several hundred workers from states like Indiana, Kansas, Nebraska, Texas and Massachusetts under mutual aid agreements, spokesman Tim Trudell said. Aside from the utility's employees and recent retirees, the utility plans to secure nearly 1,000 workers, including 500 line technicians, 250 tree trimmers and 70 damage assessors from out of state to respond to the storm. "We will ride out the storm together and get on the field as soon as the winds die down," Trudell said. "We have on hand probably four times our normal resources."

More: *Orlando Sentinel*

IESO Demo Project to Test Ontario's 1st Local Electricity Market

The Independent Electricity System Operator (IESO) will launch Ontario's first-ever local electricity market in York Region, with support from Alectra Utilities and Natural Resources Canada, in an effort to save costs and find affordable alternatives to building new transmission infrastructure, the ISO announced last week.

The local electricity market will allow resources such as solar panels, energy storage and demand response to compete to be available during periods of high demand, IESO said. Electricity demand in York is expected to grow and exceed system capability in the next 10 years, making it an ideal location to test how distributed energy resources can provide affordable alternatives to building new transmission infrastructure, according to the ISO.

More: *IESO*

PG&E Starts Publicly Predicting Power Shutoffs Week Ahead

Pacific Gas and Electric is starting to publicly forecast how likely it is to turn off power so it does not start more wildfires.

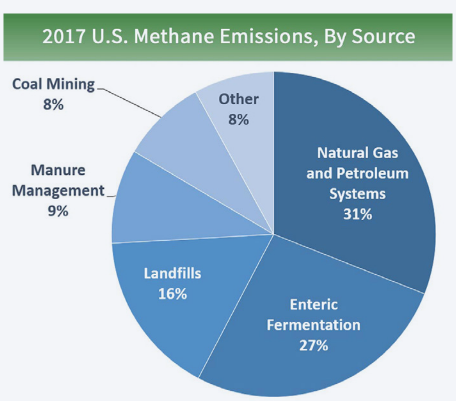
The utility last week unveiled a new section of its website that breaks down a seven-day potential for public safety power shutoffs (PSPS) across its nine geographic zones. Each day, PG&E will assign a category to the different zones showing how strongly it is considering a shutoff. The company will use four categories: not expected, elevated, "PSPS Watch" and "PSPS Warning."

A "PSPS Watch" means the company is staffing its emergency operations center because it has decided the area has a "reasonable chance" of losing power and will usually assign that category 72 hours in advance. A "PSPS Warning" means customers are being notified or have already been told that the company will likely turn off their power.

More: *San Francisco Chronicle*

Federal Briefs

EPA to Roll Back Regulations on Methane



The Trump administration last week laid out a plan to sharply curtail the regulation of methane emissions.

In a proposed rule, EPA will aim to eliminate federal requirements that make oil and gas companies install technology to inspect and fix methane leaks from wells, pipelines and storage facilities. Under the proposal, methane would be indirectly regulated. A separate but related category of gases, known as volatile organic compounds, would remain regulated under the new rule, and those curbs would have the side benefit of averting some methane emissions. The new rule must go through a period of public comment and review and would most likely be finalized early next year.

Smaller oil and gas companies have complained about the current Obama-era rule, saying it is too costly for them to perform the required leak inspections. However, major companies have called on the administration to tighten restrictions on methane and are against the new rule.

More: *The New York Times*

East Coast Governors Push Feds on Wind Power

The governors of five East Coast states last week urged federal regulators not to put any additional roadblocks in the way of the country's nascent offshore wind industry.

The governors of Connecticut, Massachusetts, Maine, New Hampshire and Virginia wrote a letter to Interior Secretary David Bernhardt and Commerce Secretary Wilbur Ross, saying offshore wind power will help strengthen U.S. energy independence while creating thousands of jobs.

They also said they were disappointed by a recent decision to delay final permitting of the planned 84-turbine Vineyard Wind project. "While we support assessing and mitigating impacts of large-scale offshore wind development, we are disappointed that this review has adversely affected the timeline for the Vineyard Wind Project," the governors wrote. "Like other industries, it is critical that states and the federal government establish and maintain clear regulatory timelines so as to incentivize the necessary capital investment."

More: *Hartford Courant*

FERC Revises Regs for Hard-copy Submissions

FERC last week issued an order requiring that all physical copies of filings or other correspondence, other than those sent using the Postal Service, be sent to a secure off-site location in Rockville, Md.

The commission cited the case of Cesar Sayoc, who in October 2018 sent package bombs to several Democratic politicians, media organizations and celebrities critical of President Trump. Sayoc *pled guilty* and was sentenced to 20 years in federal prison early last month. The commission also cited several reports and recommendations by the Government Accountability Office and the Department of Homeland Security.

"Upon review, the commission has determined that sending hard-copy/hand-de-

livered submissions to an off-site facility for security screening and processing, prior to being delivered to the commission's principal office, would better protect the safety of the commission, its employees and the public," FERC said. "The off-site facility will sort, screen and prepare the filings and submissions for delivery to the commission. Filings and submissions sent though USPS can continue to be mailed to the commission's principal office in Washington, D.C. because USPS has existing 'security, screening and control processes' that comply with DHS best practices."

More: *RM19-18*

State Briefs

REGIONAL

NECPUC Hiring New Executive Director

The New England Conference of Public Utilities Commissioners is looking for a new executive director to replace Rachel Goldwasser, who is leaving after four years to take a job in the private sector.

The executive director is responsible for the day-to-day management of the organization and for all NECPUC activities, including, but not limited to: training and education; monitoring national and regional activities and trends; developing common positions when appropriate; and facilitating effective communication among state commissions and various stakeholders at the state, regional and national levels.

The job is detailed on NECPUC's website, and applications are due by Sept. 23.

More: *NECPUC*

NEW HAMPSHIRE

Sununu Taps Top Asst. Attorney General to Chair PUC

Gov. Chris Sununu last week nominated the attorney general's chief of staff, Dianne

Martin, to be the next chair of the Public Utilities Commission. Martin is the Department of Justice's lead attorney on state agency contracts and procurements.

Martin's nomination is expected to go up for an Executive Council vote in September. Sununu formally nominated her at the council's meeting.

In her statement released by Sununu's office, Martin said the PUC chair will give her "the opportunity to extend and broaden my work over the last decade in protecting the public as a member of the attorney general's office."

More: *New Hampshire Public Radio*

NEW MEXICO

Energy Transition Act Challenged in State Supreme Court

The state's new Energy Transition Act is facing its first legal battle as environmental and consumer advocacy groups filed a petition with the state Supreme Court last week over concerns that certain provisions are unconstitutional.

The groups contend language within the law erodes the state's ability to regulate utilities and puts electric customers at risk of having to pay unchecked costs. Other critics say the law would allow Public Service Company of New Mexico and other owners of the San Juan Generating Station to recover investments in the plant by selling bonds that will be paid off by utility customers.

New Energy Economy and the other groups are asking the court to throw out provisions of the law that they say would remove the Public Regulation Commission's authority to review the prudence of utility investments and consider how much of the costs should be borne by customers.

More: *The Associated Press*

Xcel to Move Forward with Wind Farm

Xcel Energy said the construction of the $900 million Sagamore Wind Project will begin later this year in the eastern part of the state.

The utility said the 522-MW project will make up the final component of a major wind energy expansion that was first rolled out in 2017. It will be the largest single wind facility in the state when completed.

More: *The Associated Press*

NEW YORK

Steuben County Approves Solar Farm

Steuben County legislators have approved a 25-year lease and subscriber contract with Abundant Solar for a 19-MW project at the county landfill, with smaller sites expected to be set up in the future.

The landfill project is expected to be completed within the next two years and could bring in annual revenues of $10,000.

The state Board on Electric Generation Siting and the Environment last week also granted approval to Eight Point Wind to build and operate a wind farm in the county.

More: *WETM*

VIRGINIA

SCC: Dominion Claimed Excess Profits of $277M in 2018

Dominion Energy claimed excess profits of $277.3 million in 2018, a return of 13.47%, topping the 9.2% approved by regulators, according to a report by the State Corporation Commission. It comes a year after the utility made more than $300 million in excessive profits in 2017.

The report also shows typical residential bills in the state have increased by 26% since 2007 ($90.59 to $113.76) but are down $2.76 from last year. The figures, part of an annual review by the commission of Dominion's earnings to state lawmakers, come as the state monitors the rollout of a contentious law passed in 2018 that reconfigured how Dominion handles overearnings.

As part of the new law, Dominion will be allowed to divert excess earnings into new capital investments that modernize the state's electric grid and boost renewables instead of refunding the money to ratepayers or reducing electricity rates. At the same time, the utility is seeking to up its rate of return to 10.75% in a case pending before the commission.

More: *Richmond Times Dispatch*; *The Associated Press*

WISCONSIN

Settlement Would Trim $124M from Rate Increases for WE, WPS

An agreement between We Energies, Wisconsin Public Service and ratepayer groups would trim WE's proposed rate increase to $100 million (down from $176 million) and WPS' rate increase to $46 million (down from $94 million). The rate increases would be the first for WE in four years and for WPS in five years.

WE's overall rates would increase by 1.3% instead of 5.8%, while WPS' rates would increase by 4.7% instead of 9.8% if the settlement is approved by the Public Service Commission. How any rate increases would be allocated among residential, commercial, industrial and other customers would be determined by state regulators.

More: *Milwaukee Journal Sentinel*