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FERC Probed on RTO Governance, Market Issues

By Michael Brooks


From back to front: FERC Commissioners Neil Chatterjee, Cheryl LaFleur, Richard Glick and Bernard McNamee sit before the House E&C Committee's Subcommittee on Energy. | © *RTO Insider*

WASHINGTON — Several members of the House Energy and Commerce Committee's Subcommittee on Energy on Wednesday urged FERC commissioners to holistically review RTO and ISO governance rules, while also pressing them on when to expect decisions on languishing dockets — including PJM's capacity market proposal.

The commissioners did not tell the subcommittee anything they haven't said before in open commission meetings or keynote industry speeches. And because the dockets are still pending before them, they could neither go into specifics nor estimate when any decisions would be forthcoming.

But House members gave RTO issues considerable airplay in an oversight hearing that ran the gamut: the commission's role, if any, in mitigating climate change; landowner complaints over natural gas pipeline siting; and energy storage participation in wholesale electricity markets, to name a few.

Rep. Michael F. Doyle (D-Pa.) scolded FERC for creating uncertainty in PJM, where the Board of Managers decided to move ahead with the RTO's annual Base Residual Auction this year (albeit in August, instead of May) despite the

Continued on page 11

Also in this issue:

EEI 2019

EEI Speakers See Cause for Optimism on Climate Policy

By Rich Heidorn Jr


Paul Tonko | © *RTO Insider*

PHILDELPHIA — U.S. Rep. Paul Tonko (D-N.Y.) knows the kind of dramatic action needed to address climate change won't happen with Donald Trump in the White House and Republicans in control of the Senate.

But he also doesn't want to make the mistake that Republicans made when they nearly repealed the Affordable Care Act without having an alternative to replace it, he told the Edison Electric Institute's 2019 conference June 10.

"I hope that [is] instructive to all of us sitting in this session of Congress: to develop a plan of attack while there isn't the means to get it done so that when the political climate … is ripe, we're ready to go. We have no time to waste."

For now, he says, he chooses to avoid "rhetorical" debates over the Green New Deal and try to make progress on "what lies in the realm of possibility" under the current balance of power.

What's that?

Tonko, chair of the House Energy and Commerce Committee's Subcommittee on Environment and Climate Change, says he sees bicameral, bipartisan support for clean energy research; investments in EV charging infra-

Continued on page 5

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In this week's issue

Counterflow

By Steve Huntoon

Fuel Security: PJM Does 'Seinfeld'

By Steve Huntoon

Jerry: "Well what's the show about?"

George: "It's about nothing."

— "Seinfeld"[1]

Setting the Stage

PJM's capacity market (the "Reliability Pricing Model") reversed a deteriorating reserve margin, efficiently assuring resource adequacy years into the future while integrating demand response and renewable resources.

It's been a bulwark against bailout claims for coal and nuclear units by enabling a transition from dirty coal and inefficient nuclear to cleaner natural gas and clean renewables. And the Capacity Performance refinement to RPM incents resources to be available when needed, further enhancing reliability.[2]

Notwithstanding all this, the coal/nuclear bailout lobby has created doubt about the "security" of generation resources that lack fuel on site, i.e., natural gas generators without oil storage backup and of course renewable (intermittent) resources generally. This has led to a new buzzword, "resiliency," as something other than "reliability" and resulted in a broad inquiry into "fuel security" at PJM.

Solution in Search of a Problem

Let's start by putting "fuel security" as a risk in context. Please recall what the Rhodium Group figured out for us in 2017 and nobody has refuted (emphasis added):[3]

"Between 2012 and 2016, there were roughly 3.4 billion customer-hours impacted by major electricity disruptions. Of that, 2,382 hours, or *0.00007%* of the total, was *due to fuel supply problems*. Interestingly, 2,333 of those customer-hours were due to one event in Northern Minnesota in 2014. And it involved a coal-fired power plant."

Thanks again, Rhodium Group, for this great emperor-has-no-clothes exposé.

Risk, or Lack Thereof, in PJM

So how can PJM come up with a "fuel security" problem? PJM acknowledges there's no problem now. But it creates worst-case scenarios for a potential problem in the future, say 2023-2024.

Here's how it goes. PJM created 324 scenarios, and in some of the most extreme, it found load shedding (outages) could occur.

Let's look at the *worst of the worst-case scenarios*, where PJM finds that there could be 83 hours of load shed for an average of 2,452.8 MW. Now 83 hours sounds like a lot, but we need to remember that load/demand during this peak period is about 140,000 MW. So when load shed is spread across the system, it's an average of 1.5 hours for any given customer.[4] So this worst of the worst-case scenarios is *tiny*.

Now, how *likely* is this worst of the worst-case scenarios to occur in any given year? For starters it's based on a 1-in-20-years extreme-winter condition. And it's based on a "high pipeline disruption," meaning the loss of an entire pipeline flow in a right of way. This is an extremely rare event and has never caused a major detrimental gas supply loss to PJM generation,[5] but let's be very conservative and assume there's a 1-in-10-year chance of that both happening in PJM and happening in the winter. Now, what's the chance of that disruption occurring at the same time as the extreme 14-day winter condition? About 1 in 6, because 14 days are about one-sixth of a three-month winter period.

OK, here's the math: 1/20 times 1/10 times 1/6 equals 1/1,200. Yes, you got that right. Once every 1,200 years we might experience a tiny 1.5 hours of outage for the average PJM customer. We should live so long.

But Wait, There's More

If you can believe it, this tiny risk overstates the real risk. Here's a few reasons why:

1. Winter generation capability is much more than summer capability. PJM doesn't appear to gather that data, but we know from New England that aggregate winter capability is about 8% more than aggregate summer capability.[6] In PJM, 8% more than summer capacity amounts to about 13,300 MW,[7] which is more than five times the 2,452.8 MW of projected average load shed in the worst of the worst-case scenarios discussed above.
2. It is not clear how PJM reflected, if at all, (1) load reductions in response to what would be very high prices in its worst-case scenarios, or (2) load management under PJM's direct control.[8]
3. PJM assumes system load reduction from voltage reduction is 1 to 2%, but elsewhere it says system load reduction capability is 2 to 3%.
4. PJM assumes no load reduction from public calls for voluntary conservation. This is not reasonable, especially in the context of the hypothesized emergency conditions.
5. PJM's assumed forced outage rate includes historical data that are obsolete in the wake of CP incentives/penalties that have increased generation availability.[10]
6. PJM appears to assume no import assistance from neighboring regions despite a history of such assistance, such as during the polar vortex.[11]

Even if there were a realistic scenario that

Columnist Steve Huntoon says PJM's fuel-security "problem" is like "Seinfeld": a show about nothing. | *NBC*

Counterflow

By Steve Huntoon

projects load shed, we would then need to ask what it would cost to avoid an incremental X MWh of lost load relative to the value of lost load of those megawatt-hours. It would be obvious that making consumers pay for more "fuel security" makes no sense.

And it's more than just money. Devoting time and attention to things that don't matter takes time and attention away from things that do, like cybersecurity.

At the end of the day, PJM has hypothesized a tiny risk that has a tiny chance of happening and could not possibly justify significant consumer costs.

It's our version of "Seinfeld": a show about nothing. ■

[1] https://www.youtube.com/watch?v=EQnaRtNMGMI.

[2] https://www.pjm.com/-/media/library/reports-notices/capacity-performance/20180620-capacity-performance-analysis.ashx?la=en (see for example conclusion at pdf page 34).

[3] https://rhg.com/research/the-real-electricity-reliability-crisis-doe-nopr

[4] The math is 83 load-shed hours times average load shed of 2,452.8 MW divided by 140,000 MW of peak load.

[5] "In general, the interstate pipelines have experienced very few major line failures over the last several decades. The frequency and severity of disruptions have not created any major detrimental loss of natural gas supply to PJM generation, in part because the majority of events have occurred during the time of year when demand on the natural gas system is low." https://www.pjm.com/-/media/library/reports-notices/fuel-security/fuel-security-technical-appendix.ashx?la=en (pdf page 12). I am aware of only one "high pipeline disruption" in PJM, the 2016 explosion on a Texas Eastern line in Westmoreland County, Pa.; this event apparently did not affect generation.

[6] https://iso-ne.com/static-assets/documents/2018/04/2018_celt_report.xls ("Seasonal Claimed Capability" in Table 1.1 (Summer) and Table 1.2 (Winter). Monthly capability reports are here, https://www.iso-ne.com/isoexpress/web/reports/operations/-/tree/seasonal-claimed-capability.

[7] If we assume that summer capacity resources are only equal to the reliability requirement of 166,355 MW, https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2021-2022/2021-2022-bra-planning-period-parameters.ashx?la=en, then 8% of those resources is 13,308 MW.

[8] PJM does, of course, include programmatic DR as a resource but does not include any other load response to what would be very high prices. With regard to direct control load management, there are 2,593 MW of such summer capacity, some but not all of which is air conditioning load control not relevant to the winter https://www.pjm.com/-/media/library/reports-notices/load-forecast/2019-load-report.ashx?la=en (pdf page 65, column for year 2013-2014).

[9] https://www.pjm.com/-/media/training/nerc-certifications/gen-exam-materials/gof/20160104-capacity-emergencies.ashx?la=en (slide 46). After that range was developed, American Electric Power added voltage reduction capability in Ohio.

[10] "During the cold snap of 2017-18, Capacity Performance resources' forced outage rates were significantly lower than the same resources' outage rates during the 2014 polar vortex (5.5% vs. 12.4%)." https://www.pjm.com/-/media/library/reports-notices/capacity-performance/20180620-capacity-performance-analysis.ashx?la=en (pdf page 4).

[11] "Data Request for January 2014 Weather Events," Letter from PJM Counsel James M. Burlew to FERC Representative David J. Burnham, Jan. 10, 2014 (pdf pages 18-19).

EEI 2019

EEI Speakers See Cause for Optimism on Climate Policy

Discussing the Green New Deal are from left: Dominion Energy CEO Thomas Farrell; U.S. Rep. Paul Tonko (D-N.Y.); Sarah Ladislaw, Center for Strategic and International Studies; Aliya Haq, NRDC; and Rich Powell, ClearPath. | © *RTO Insider*

Continued from page 1

structure and grid modernization; workforce development; energy efficiency; and investment tax credits for energy storage.

"I don't want to get trapped in the rhetoric of Green New Deal, no Green New Deal. I embrace many of the principles of the Green New Deal. But let's move forward and develop science-based, evidence-based … policies that take us forward."

Tonko wasn't the only speaker who saw reason for optimism on climate policy, even at a time when CO_2 levels have reached the *highest level in 400,000 years*.

Rich Powell | © *RTO Insider*

Rich Powell, executive director of *ClearPath*, which supports nuclear power and "small government, free market" policies to nurture clean energy innovation, said he's seen a change in Washington recently.

"If you watch the rhetoric in D.C. for the past six months, something pretty surprising has happened," he said, recounting his experience testifying as a Republican witness at two House hearings on climate change.

"There was generally consensus that climate change is real; that global industrial activity from … human sources is a significant contributor to that, and that the federal government ought to take significant, ambitious action beyond what it's doing now to tackle that challenge. I think there was consensus on that issue. So now I think we're at a space where we can begin to move from a vigorous discussion of whether there is a problem meriting federal action to a vigorous discussion about the right solutions to that problem."

Aliya Haq | © *RTO Insider*

"If you really just look at the environmental provisions … [the Green New Deal is] not actually that crazy," said Aliya Haq, director of the Natural Resources Defense Council's Climate and Clean Energy Program. "It's extremely ambitious. But there's no prescription. No policy about how we get there. It's a blank slate for how we achieve these goals."

"I think we're at a space where we can begin to move from a vigorous discussion of whether there is a problem meriting federal action to a vigorous discussion about the right solutions to that problem."

— Rich Powell, executive director of ClearPath

Sarah Ladislaw | © *RTO Insider*

Sarah Ladislaw, a senior fellow in the Energy and National Security Program at the Center for Strategic and International Studies, said the economic justice goals of the GND are also important.

"As we observe technological resource base changes that are taking place in the U.S., there's actually a fair degree of commonality at the state and local level about what direction we should take," she said. "It should broadly be lower carbon. It should definitely create jobs and economic opportunity. And it should make communities feel like they have a competitive part in this future.

"The problem, though, is that energy alone can't sustain economic vitality at the local level. … So, one of the most attractive things about the Green New Deal is … the part of it that's about trying to secure economic security and a greater degree of equality. … That's the bigger political moment that we're living in, and energy [policy] has this tendency to get carried along with those types of political sentiments."

Bringing Clean Energy to the Developing World

Powell acknowledged setbacks, citing the loss of carbon-free nuclear generation and the expansion of coal-fired generation in the developing world.

"Right now, for a lot of the developing world, the right thing for pure [economic] development is coal. There are hundreds of new coal-fired power plants being built around the world. China has 250 more in its domestic pipeline in addition to the terawatt of … coal — average age 11 years — that are already [operating]. … They're building at least another 100 GW around the world for their Belt and Road initiative.

EEI 2019

"Too often in the past these facts — and they are brutal facts, they're intimidating facts — have been used to shield against climate action. They've been used to saying, 'Well, it doesn't matter what we do here in the United States because all the other countries are going to make their own decisions.' And I refuse to accept that. … Actually, we can do quite a bit about climate change."

The solution, he said, is innovation that makes clean alternative generation as cheap as coal. "And that can be done, because we've done it here in the United States."

Role for Innovation

Powell called for "technology-inclusive tax credits that cover all innovative, clean or very low-emission energy technologies and that permanently changes the incentive set for utilities … whenever they're going to be building anything new."

"I agree with Chairman Tonko that this is clearly a bicameral, bipartisan place where we can make a lot of progress on this issue," he continued. "And I say that because we made a lot of progress on this issue in the last Congress," citing passage of the 45Q *Carbon Sequestration Tax Credit*, the 45J *Nuclear Production Tax Credit* and other legislation on nuclear and storage innovation.

"So, we think there's a broad, robust agenda where we can get started … on climate change immediately and use the United States as a test bed for global clean energy technology that can help decarbonize the rest of the world."

Sacrifices

Thomas Farrell | © *RTO Insider*

Dominion Energy CEO Thomas Farrell, who moderated the EEI discussion, said it will be impossible to meet climate goals without nuclear power, citing research that electrification of transportation and other sectors could increase electric demand by 50%.

"To do that with zero-carbon [energy] — unless you can figure out a magic switch, carbon capture or something — you will need more and more and more renewables, which use enormous amounts of land," he said. "Those of us who are actually doing this for a living are already getting very significant pushback from local jurisdictions saying, 'I'm not going to change the zoning. … We have enough solar in our town;d we don't want any more solar.'"

NRDC's Haq offered a cautionary note, citing research that even climate change "alarmists" are resistant to higher taxes on gasoline.

More sobering news came June 11 from Deloitte's *annual resources survey*, which reported that while most businesses have increased their initiatives on sustainability, the action by residential consumers has lost momentum.

"Consumer complacency may be settling in as costs outweigh climate as a motivator in adopting new technologies and cleaner energy sources," said Marlene Motyka, Deloitte's U.S. and global renewable energy leader. "On the other hand, most businesses don't perceive a choice between climate and cost. They see green energy choices as a win-win: Doing the 'right thing' is good for the environment and the bottom line." ■

Perry: No Progress on Coal, Nuke Supports

By Rich Heidorn Jr.

PHILADELPHIA — Energy Secretary Rick Perry hasn't given up on his campaign for coal and nuclear generation, but he conceded last week that he hasn't made much progress either.

Speaking at the Edison Electric Institute's 2019 annual conference June 11, Perry said he continues to support an "all of the above" generation mix, praising coal and nuclear as the "most reliable" generation resources and criticizing the "blatantly discriminatory rules and regulations" he said are hampering them.

Perry called out the Obama administration and Green New Deal Democrats who he said want to ban anything but wind and solar power. "They will ruin our ability to run our economy when the sun doesn't shine and the wind doesn't blow," he said.

He also criticized New York officials for blocking new natural gas pipelines, saying they were to blame for the "bizarre spectacle" of New England having to import Russian LNG last winter.

In a press conference later, Perry conceded "we're pretty much at the same point where we were" after the White House failed to act on the Department of Energy's proposal for price supports for "fuel secure" generation last fall. (See *Chatterjee Dodges as DOE Spins on Coal Bailout*.) It followed FERC's January 2018 rejection of Perry's call for cost-of-service payments to coal and nuclear generators. (See *FERC Rejects DOE Rule, Opens RTO 'Resilience' Inquiry*.)

Perry said he has seen "no movement from FERC or the White House."

But it's not all bad, Perry said, citing "progress" on research into carbon capture and expanded coal exports.

After his speech, Perry sat for a brief interview with incoming EEI Chair and Exelon CEO Chris Crane.

Crane thanked Perry for the electric load provided by the Department of Energy's Argonne National Laboratory in Commonwealth Edison territory in Lemont, Ill.

Rick Perry | © *RTO Insider*

"Keep the prices down," Perry responded.

"Keep the nuclear plants running," Crane shot back, before fist bumping with the secretary.

"We rehearsed that," Perry joked. ■

Overheard at EEI 2019

Utility CEOs See Path, Obstacles to Carbon-free Power

PHILADELPHIA — In the last two years, oil giant Royal Dutch Shell has purchased a U.K. electric utility and two electric vehicle charging *companies*. Shell CEO Ben van Beurden and his wife both drive EVs themselves.

"On the other hand, in this country, we have 43,000 zip codes," oil expert Daniel Yergin said. "One hundred eighty-nine of them — which represent two-tenths of 1% — reflect 25% of all EV sales in the country."

Yergin, founder of IHS Cambridge Energy Research Associates, offered that statistic to set the stage for a discussion on electrification and decarbonization at the Edison Electric Institute's annual conference last week. The three U.S. electric utility CEOs who joined him agreed: While the industry has come a long way in reducing its carbon emissions, the road to carbon-free power won't be a freeway.

Exelon CEO Chris Crane said there are regions, such as Commonwealth Edison's territory in Northern Illinois, that are 100% carbon free now.

"For Illinois to declare they want to be carbon free by 2030 to 2032, that's not a stretch. … And it's because of existing nuclear and the renewables that have been installed without the storage, without the advanced technology. But in other jurisdictions that would be much more difficult."

Crane said storage technology needs to advance beyond lithium-ion batteries before utilities can take full advantage of intermittent resources. "It's a ways away from [the] central station being [in] full demise," he said.

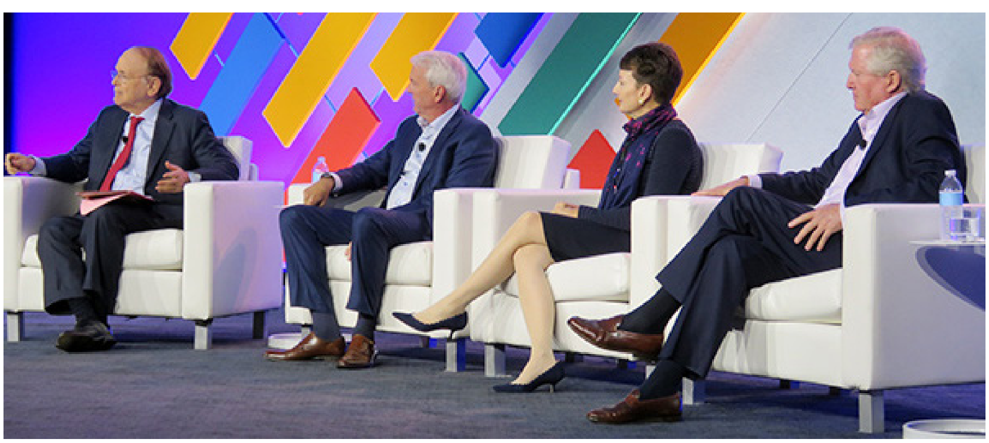
Duke Energy CEO Lynn Good said utilities must remain "the voice of reliability and affordability."

"We need to recognize that we don't have all the tools today to operate at scale to achieve a 100% renewable solution in four-season climates and heavy urban areas and areas that don't have a mix of renewable resources that certain geographies have," she said.

Xcel Energy CEO Ben Fowke said his company can help customers and communities reach 100% renewables with customized programs but that it will need more advances to reach Xcel's company-wide target of 100% carbon-free by 2050 and 80% by 2030.

Eventually, the grid will be saturated with renewables and short-duration batteries, he said.

"And at that point, we're going to [need] those carbon-free dispatchable resources. … Nuclear is one today. So, we're all about preserving our nuclear fleet. And I think the technologies that will get us that last 20% on our goal ... might come from hydrogen. It might come from the next generation of nuclear. It might come from carbon capture. It might come from something we don't even know — long-term storage for example."



From left: moderator Daniel Yergin; Ben Fowke, Xcel Energy; Lynn Good, Duke Energy, and Chris Crane, Exelon | © RTO Insider

Chef Says Adaptation is Recipe for Success

Chef José Andrés, the keynote speaker for the June 10 session, talked about how he and others provided more than 3.5 million meals in Puerto Rico following Hurricane Maria in 2017.

José Andrés | © *RTO Insider*

Andrés recalled how the effort grew "from one kitchen to 26 kitchens; from 20 friends [the] first day to 25,000 volunteers. We went from 1,000 meals a day the first day to more than 150,000 meals a day every day. We were delivering food in 935 places each day. … At the end, what seemed impossible became possible. What we did was adapt to every circumstance."

Andrés said his group was initially rebuffed when it asked the Army to deploy its helicopters to deliver the meals to remote locations. "The bosses here would not make it happen, but when I met with the guy who was running the helicopter he said, 'We'll find a way to deliver that food.' We needed to cross rivers without bridges. If I ask here, I never get it. If I ask the officer in charge of a unit of Humvees, boom! Those men and women would be there helping us cross the rivers. [When] we needed a boat to get to Vieques, if I ask over here, it would never happen. In the moment I met the Navy captain, all of the sudden, I had the boat to go every day to Vieques," Andrés said.

"You see the men and women are extraordinary people, the military and [the Federal Emergency Management Agency]. But we need to liberate them from rules and regulations that don't allow them to be successful. Because we are outside the system, we don't follow rules. We don't follow the plan. We continuously adapt."

Andrés also recalled for the EEI crowd his first visit to New York City, when he was a member of the Spanish Navy and his ship docked at 30th Street on the Hudson River. "Last month, I opened a *big restaurant* … 100 meters away from the dock I arrived on at 30th Street. Do I believe in the American dream? Yes, I do believe in the American dream."

Natural Gas: Bridge or Destination?

It wouldn't be an energy conference without a debate about natural gas's future. EEI's panel ("Natural Gas: A Bridge or a Destination?") featured an environmentalist, a representative of gas turbine manufacturer GE Power and two utility representatives.

Mark Brownstein, the Environmental Defense Fund's senior vice president for energy, said gas's future in a zero-carbon electric future

EEI 2019

will depend on the competitiveness of storage in supplementing intermittent sources and the gas industry's ability to eliminate CO_2 and methane emissions.

If the goal is to be net carbon zero by 2050, gas's future "has a lot to do with the level of investment in carbon capture and storage, either at the power plant or it may be in the context of ***producing hydrogen*** that is then run through combustion turbines," Brownstein said. "But either way, you have to have some way of capturing that CO_2. The future is really up to you guys."

Jerry Norcia | © *RTO Insider*

DTE Energy CEO Jerry Norcia said his company is doing its part to prevent methane emissions by replacing leaky cast iron pipe with plastic.

Diane Leopold, CEO of Dominion Energy's Gas Infrastructure Group, said the gas industry also needs to improve its physical and cybersecurity to match mandatory reliability standards for the electric industry. "So, we've been investing heavily, thinking of ourselves as the critical infrastructure to be able to be that backup ... to achieve these goals of higher electrification and increased penetration of renewables."

Brian Gutknecht | © *RTO Insider*

Brian Gutknecht, chief marketing officer for GE Power, said gas will continue to prosper as the cheapest dispatchable thermal energy technology, noting its energy density allows it to produce energy on 50 to 100 times less real estate than renewables.

Carbon capture "for us is the next tier," he said, adding that GE's gas turbines can burn 100% hydrogen. "Our customers are buying an asset that early on can accelerate decarbonization [by] burning natural gas, and over time, as the technologies advance, the role of gas is going to change, and our technology is able to change with it."

Brownstein said the 2015 leak at the Aliso Canyon storage facility, which took four months to plug, is an "object lesson."

"The methane emissions that came out of that facility ... basically [wiped] out all of California's climate progress for the course of that year, from all measures," he said. "California learned from that experience ... that battery technology was ready, willing and able to deploy to support the electric grid. So, the role that gas was playing in providing peak support in the summertime was taken up by batteries.

"The lesson is when the industry fails to take care of their equipment and emissions result, there are other competitors in the marketplace now ... able to take up that slack — so much so that California is really playing with the idea of closing that facility and other facilities like it entirely. The options that we have to deliver reliability and resilience ... are growing. It's not the case that natural gas has a corner on that market."

Gutknecht acknowledged that gas's role will change. "It will be doing more firming when renewables aren't available," he said. "Batteries are going to play a very important role for shorter duration ... storage. So, gas is left to play the longer duration role that may be required at times."

From left PSEG CEO Ralph Izzo; DC PSC Chair Willie Phillips; Asim Haque, PJM; and Sam Robinson, deputy chief of staff to Pennsylvania Gov. Tom Wolf | © *RTO Insider*

Addressing Climate Change: A View from the States

At a session on the states' view of climate change, former Ohio regulator Asim Haque, reflected on how his perspective has changed since ***joining*** PJM 12 weeks ago as executive director of strategic policy and external affairs.

Haque said the RTO has gotten whipsawed by stakeholders' decision in April to explore how to accommodate carbon pricing in its markets. (See "Carbon Pricing Talks Move Forward," ***PJM MRC/MC Briefs: April 25, 2019***.)

"On the one hand, you'll get folks within the environmental community who will say, 'It's about time.' On the other hand, you'll get perspectives — which I've already gotten — from states who will say, 'How dare you engage in policymaking?' This is the Catch-22 that the organization finds itself in."

Haque knew what he was getting himself into when he took the job, however.

"From an outsider's perspective, PJM is a very convenient punching bag," he said. "Politically it's so intelligent to utilize PJM in that fashion."

The 13 states and D.C. in PJM's territory have disparate views on climate policy, making it difficult to achieve any kind of consensus, Haque said.

The D.C. Public Service Commission is on one end of the spectrum, required to consider climate change in all decisions. "While states can move the ball ... it's a no brainer that federal action is necessary," D.C. PSC Chair Willie Phillips said.

With New Jersey planning to rejoin the Regional Greenhouse Gas Initiative and Virginia's governor ***considering it***, Pennsylvania is at risk of becoming the "donut hole" in RGGI, acknowledged Sam Robinson, deputy chief of staff for Gov. Tom Wolf (D). Republicans, who control Pennsylvania's House and Senate, ***contend*** such a move would require legislative approval.

Although the state hasn't taken steps to join RGGI, it "is the type of program we would consider," Robinson said. "It's something we're looking at."

Panel moderator Ralph Izzo, CEO of Public Service Enterprise Group, said the need for grid resilience will only increase in a world of electrification of transportation.

"If you think people are grumpy today when they can't charge their cell phone after a two-day outage, think of what the future will be like if they cannot drive their car after a two-day outage." ■

— Rich Heidorn Jr.

EEI 2019

An End to the Universal Service Model?

By Rich Heidorn Jr.

PHILADELPHIA — Has weather become so extreme that utilities should end the universal service model and stop serving at-risk locations?

Margaret Peloso | © RTO Insider

It's something that should be considered, Margaret Peloso, a partner in Vinson & Elkins' Environmental & Natural Resources practice, told the Edison Electric Institute 2019 meeting last week.

Peloso cited the National Oceanic and Atmospheric Administration's National Climatic Data Center, which found that between 1980 and 2018, the U.S. averaged 6.2 extreme weather *events* per year that resulted in $1 billion or more in damages (inflation adjusted to 2019). In 2014-18, the count of $1 billion events doubled to 12.6 per year, and in 2018 alone, there were 14 such events, including hurricanes, severe winter storms, floods and wildfires.

"We are seeing an increase in these really big, really high-dollar-value events," Peloso said. "When you start to look at our structures for disaster relief and how we socialize disaster costs, we're going to run out of money. And it raises the question: Who should pay for it?"

Peloso said the problem is a combination of climate change producing more severe events and more people living in high-hazard areas because of poor land use policies stemming from "misaligned" incentives. Local governments, which control zoning, benefit from an increased tax base and thus tend to be permissive and reluctant to risk litigation by denying landowners the right to build on their properties. And when there are losses from flooding or wildfires, much of the cost is externalized to the state and federal government.

In addition, research has shown that people underestimate risk and underinvest in insurance and risk mitigation, Peloso said.

"If you're really looking at managing the risks for your company, as the CEO, I think it's time to reconsider the universal service model and ask: Are there some areas that are just too exposed to natural hazards and risk to really be served?

From left: IDACORP CEO Darrel Anderson; Margaret Peloso, Vinson & Elkins; Ronald Brisé, Gunster; and Barnie Gyant, U.S. Forest Service | © RTO Insider

"We are seeing an increase in these really big, really high-dollar-value events. When you start to look at our structures for disaster relief and how we socialize disaster costs, we're going to run out of money. And it raises the question: Who should pay for it?"

— Margaret Peloso, Vinson & Elkins

"There's actually a small utility in California ... that couldn't get general liability coverage this year because of wildfires," Peloso said. The utility identified about 600 customers in high-risk areas. "They gave them all generators. And they said, 'We're going to shut your power off'" at times. (See related story, *Fire Season Starts in Calif. with Power Shutoffs*.)

"Let's try to move away from this paradigm ... of putting things exactly back where they [were]," she said. "Maybe that's not where we really want people to live."

Combining Efforts

Barnie Gyant | © RTO Insider

The consequences of the current policies are stark. After a wildfire is extinguished, "we're left with a landscape that's going to take, in many cases, several decades to recover," said Barnie Gyant, deputy regional forester for the U.S. Forest Service. "In some of the cases where we've had really large fires ... it will be 100 years before we have a forest again."

Gyant said government agencies need to work more closely with utilities and the owners of forest lands to coordinate preventive measures. In California, he noted, his department manages more than 60% of forested landscape and 20% of the landmass, giving it overlapping responsibilities with state and federal fish and wildlife agencies and utilities.

He cited the 2017 *memorandum of understanding* the Forest Service signed to improve coordination with Sierra Pacific Industries, which manages nearly 1.9 million acres of timberland in California and Washington. Other industrial landowners have signed the MOU since.

"Most everyone has five- or 10-year plans,

EEI 2019

but those plans are done in a vacuum. They're not connected," Gyant said. "When you look at the amount of money and resources those different entities have, I think we can make a difference with the fires in California. … We're not saying we're going to stop fires. But I do think we can be strategic in where we place our treatments to reduce the size of those fires, help protect communities and help protect infrastructure."

Peloso agreed, saying policymakers should resist "throwing dollars at things like management per mile as opposed to trying to be smart about where the highest risks are." Spending should be based on "where you get the most meaningful risk reduction instead of doing things [that] we think will generally reduce threats," she said.

Ronald Brisé | © *RTO Insider*

Resistance to Vegetation Maintenance

Former Florida Public Service Commissioner Ronald Brisé, now a government affairs consultant for Gunster, said utilities and regulators often meet resistance from local government over vegetation management efforts.

"Some cities will tell you … I'm going to sue you if you cut my trees," he said.

Some areas that suffered outages following Hurricanes Irma and Wilms "are the same cities [where] their citizens are reacting because of vegetation management."

Darrel Anderson | © *RTO Insider*

IDACORP CEO Darrel Anderson, who moderated the discussion, complained of having to deal with separate sets of rules for his company's operations in Idaho and Oregon.

"Most everyone has five- or 10-year plans, but those plans are done in a vacuum. They're not connected."

— Barnie Gyant, U.S. Forest Service

In Idaho, the company can use a soil sterilant to prevent vegetation growth around its poles, a technique he said is proven to reduce the impacts of fire on electric lines. "In Oregon, we can't do that unless we do a separate environmental study on each pole," he said. ■

Year	Number of Events	Total Cost (Millions)	Year	Number of Events	Total Cost (Millions)
1980	3	$37,005.90	2000	4	$11,594.40
1981	2	$2,842.50	2001	2	$16,844.60
1982	5	$12,583.70	2002	4	$19,466.10
1983	3	$20,721.90	2003	7	$31,321.10
1984	2	$2,612.60	2004	5	$75,090.50
1985	5	$13,706.50	2005	6	$222,567.40
1986	2	$5,413.50	2006	7	$19,494.90
1988	1	$44,008.50	2007	5	$15,411.80
1989	5	$31,993.10	2008	12	$77,393.70
1990	3	$10,453.90	2009	7	$13,971.30
1991	4	$15,982.80	2010	6	$15,319.70
1992	7	$65,774.30	2011	16	$78,081.90
1993	5	$52,962.50	2012	11	$129,784.40
1994	6	$13,478.70	2013	9	$25,104.10
1995	5	$26,407.00	2014	8	$18,930.70
1996	4	$17,836.30	2015	10	$24,199.20
1997	4	$13,881.40	2016	15	$49,570.60
1998	9	$29,525.40	2017	16	$315,675.40
1999	5	$20,020.90	2018	14	$91,845.90

Billion-dollar climate- and weather-related disasters in U.S., 1980-2018 | *NOAA National Centers for Environmental Information*

FERC/Federal News

FERC Probed on RTO Governance, Market Issues

Continued from page 1

commission finding its capacity market rules unjust and unreasonable — running the risk that FERC could force it to rerun the entire thing later. (See *PJM to Hold Capacity Auction in August*.)

Doyle noted PJM filed its revised rules in October, "so either a rule is going to be published right before August, which won't give participants enough time to adjust, or a decision will not be published, and participants will have to take part in an auction under rules that FERC has found to be unjust and unreasonable."

Chairman Neil Chatterjee assured Doyle that "we're working as diligently as we can."

"This is a vexing challenge," Chatterjee said, "because you have a situation where two things I think we all believe in — states' rights and the markets — are colliding. ... We're coming to a point where actions that states are taking to make decisions about their local energy futures are impacting the markets and trying to figure out how to sort through that while ensuring just and reasonable rates has proven to be very, very challenging."

"I am deeply, deeply troubled by the delay," Commissioner Cheryl LaFleur said. "I had dissented in the initial order because I thought it would put PJM in an impossible situation, and I'm afraid that's exactly what's come to pass. I've been using my world-class powers of nagging to be a nag about it, but so far we have not gotten an order out."

"I'm not sure how the auction can go forward without some clarity from FERC," Commissioner Richard Glick said.

| © RTO Insider

Speaking to reporters after the hearing, Glick said, "We should be working on this 24/7 because we owe it to [PJM] to provide some more certainty."

Rep. Frank Pallone (D-N.J.), chair of the full committee, called for "greater scrutiny of wholesale capacity markets. Frankly, the current state of affairs is a mess, especially in the PJM market, where New Jersey participates. PJM participants are currently left in the lurch of both an old and new capacity market design. ... It is vital that we figure this out immediately."

Subcommittee Chair Bobby Rush (D-Ill.) expressed concern that "consumer voices are often overlooked, ignored or cut out of the RTO process entirely." Pallone also noted "there has not been a comprehensive review by FERC of each RTO's stakeholder process to ensure compliance with the requirements of Order 719," issued in 2008.

U.S. Rep. David McKinley (R-W.Va.) speaks with Chatterjee before the hearing. | © RTO Insider

"This is something we continually hear from people around the country," Chatterjee replied. Reviewing Order 719 compliance "is one option, but looking with an eye towards ensuring consumers' voices are heard as they come up through the process is another manner in which to do this. I think particularly as new technologies come into play and we look to break down barriers to entry, we need to ensure these new voices have an opportunity to be heard at the RTOs and ISOs."

LaFleur agreed that "it's probably a good time for a relook."

LaFleur and Glick | © RTO Insider

FERC/Federal News

Call for Transparency

Rep. Joe Kennedy III (D-Mass.) said he was "increasingly concerned about the [RTOs] and their governing structures."

"My fellow citizens and I have no idea who makes decisions or how they are made at [the New England Power Pool] because unless you are a member, you can't even observe any meetings or proceedings, let alone talk about it publicly. Other RTOs benefit from governance structures that enjoy slightly more transparency. Still, I believe more has to be done." He asked LaFleur if the public should have more access, "even as a passive observer."

LaFleur noted a pending request for rehearing on press access to RTO meetings before she began to point to consumer advocates' participation in RTOs. Kennedy interrupted her, but LaFleur said she could not comment on the press issue.

U.S. Rep. Joe Kennedy III (D-Mass.) chats with LaFleur before the hearing. | © *RTO Insider*

FERC in April dismissed *RTO Insider's* complaint seeking rejection of rules proposed by NEPOOL to keep reporters from publishing what is discussed at the group's meetings. Consumer advocacy group Public Citizen filed a request for rehearing last month (*EL18-196*). FERC issued a tolling order June 7, giving itself more time to consider the request. (See *FERC Rejects RTO Insider Bid to Open NEPOOL*.)

Chatterjee and McNamee share a laugh with U.S. Rep. Morgan Griffith (R-Va.) before the hearing. | © *RTO Insider*

Glick jumped in. He also said he could not comment specifically on the rehearing request, but he explained that FERC rejected the complaint because it lacked jurisdiction, as press access does not affect NEPOOL's wholesale rates. But he said, "I agree with you, congressman, that transparency is a very important element of appropriate RTO functioning."

Kennedy then asked Chatterjee if the commission has considered reforms to RTO governance to ensure the public is better represented.

The chairman replied, "I agree with the concerns that you're raising," but "I'm not sure a one-size-fits-all approach could work here." ■

FERC/Federal News

Study Findings Clash on Value of Competitive Tx

By Amanda Durish Cook

A recent pair of dueling studies have drawn divergent conclusions about the merits of competitive transmission solicitations. The differences might have something to do with the reports' respective sponsors.

Both studies appear to be aimed at shaping the discussion around possible changes to FERC's Order 1000, the 2011 rulemaking that eliminated incumbent transmission owners' federal right of first refusal over regional projects and opened transmission planning processes to independent developers.

The first *report, released* by The Brattle Group in April, found electricity customers could save $8 billion over five years if competitive transmission planning processes expanded to cover 33% of all transmission investments, compared with just 3% today. That study was commissioned by independent transmission developer LSP Transmission Holdings, whose affiliates are developing three competitively bid transmission *projects* in MISO, PJM and NYISO.

But another study published by Concentric Energy Advisors on June 10 concludes there is no basis to expand the scope of competitive solicitations in RTOs and ISOs, claiming incumbent TOs' initial cost estimates for projects generally prove to be accurate. That study was prepared for Ameren, Eversource Energy, ITC Holdings, National Grid USA and Public Service Electric and Gas — all incumbent TOs in various RTOs.

The two studies come as FERC is signaling a move to re-examine Order 1000. FERC Chair Neil Chatterjee earlier this year acknowledged some industry stakeholders are complaining the rules are not working as intended, with proponents of competitive projects seeking a replacement and opponents hoping for a repeal. (See "Chatterjee: Focused on PURPA, Order 1000 Reforms," *Overheard at the NARUC Winter Policy Summit*.)

So far, the commission appears to be in the "replace" camp.

"As we think about addressing Order 1000, I believe we owe it to consumers to put our best effort forward toward spurring competition to work and getting the scope of competition right," Chatterjee told a gathering of state regulators in February.

Order 1000 Rethink?

But the numbers suggest competitive project developers continue to face barriers despite the aims of Order 1000.

Brattle's report showed that even seven years after FERC issued the order, 97% of RTO transmission investments are still made outside competitive processes. The study calculated that competitively bid projects only took about $540 million of the average $20 billion in annual transmission investment from 2013 to 2017, despite its finding that competitive projects typically result in cost savings of 20 to 30%.

Brattle took issue with the ongoing limitations faced by competitive developers.

"The tariffs that specify the rules for transmission planning for each region currently exclude the large majority of transmission investments from competitive processes," Brattle wrote. "We do not see compelling policy reasons for broad limits or having significant differences in criteria used in various regions that directly or indirectly exclude transmission projects from the competitive processes."

The report advocated federal and state policymakers move to expand the scope of competitive transmission investments to stimulate innovation and increase cost-effectiveness in an industry being transformed by new natural gas and renewable generation investments.

But Concentric contends Brattle's report doesn't paint a complete picture, maintaining the benefits of transmission solicitations are still unknown and Brattle's cost-savings estimates are flawed. Concentric also argues RTO competitive processes are "time- and resource-intensive," with solicitations involving more than one bidder taking anywhere from 113 to 1,498 days.

Concentric also questioned Brattle's assumption that incumbent TO projects typically exceed initial cost estimates by anywhere from 18 to 70%, calling that conclusion "false and inconsistent with the empirical evidence."

Instead, Concentric said it found incumbent TOs' final project costs only vary from initial investments by a "very modest" -2.9 to 7%.

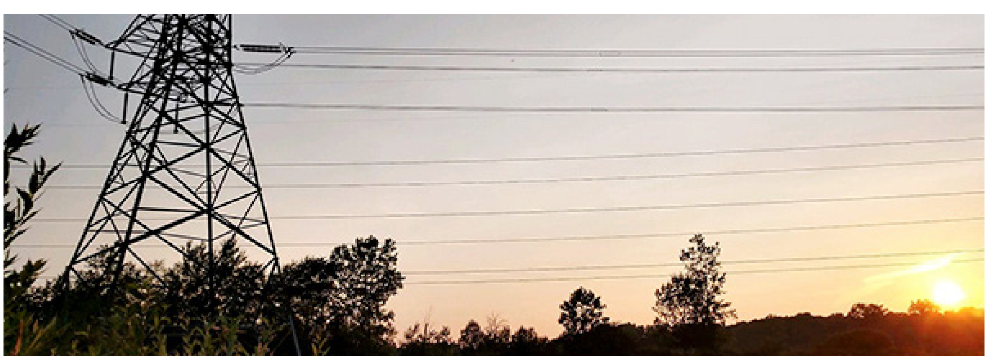
Concentric said there's "no credible support for the claim that current transmission processes limit customer savings, or that expansion of competition will yield meaningful additional savings."

"The Brattle report … uses a limited and unrepresentative sample size of incumbent TO projects to produce its average historical cost escalation estimates, which are significantly overstated," Concentric added. "Importantly, of the 15 [competitive] projects the Brattle report used to calculate its cost savings estimates, the final cost of the majority of the projects is currently unknown."

Concentric cautioned against any near-term moves to revise or replace Order 1000.

"If there is interest in expanding solicitations for transmission projects, we advise policymakers to wait until more of the projects selected through such solicitations have been placed in service. At such a time, more information will be available about the actual costs and operational performance of these projects and policymakers would be in a position to make better informed decisions about whether or not to expand such solicitations," Concentric said.

Jim Holodak, National Grid vice president of FERC and wholesale regulatory strategy, agrees with that last point. He said he's heard a variety of opinions about revisiting Order 1000, ranging from elimination or repeal to a series of slow modifications.



| © RTO Insider

FERC/Federal News

"We're suggesting we need more time before FERC opens it up," Holodak told *RTO Insider*.

He said multiple competitive projects should be completed before cost savings and benefit assumptions are made about them.

"You don't know what that project will cost until it finally goes into service. Then make that comparison," Holodak urged.

Concentric's study pointed out that even the cost caps promised by winning bidders for competitive projects are subject to "exclusions and exceptions." Holodak noted the caps can contain several exclusions related to siting, regulatory requirements and routing changes.

"There's a whole host of exclusions for cost caps. … At the end of the day, they're not taking on any more risk, and the project price for customers is not really capped" any more than for an incumbent TO project, Holodak said.

"It's as if you're buying a kitchen remodel based on an ad for a $10,000 kitchen, but you want to add granite countertops and other design features that increase the quote. It would be unreasonable to expect to hold the contractor to the original ad price," he said.

Holodak also argued the system's "resiliency and robustness" won't get the same attention if more project types are opened to competition. Complete competition on every level of transmission "is not the way to go," he said.

Brattle Responds

Brattle's conclusions couldn't differ more.

Johannes Pfeifenberger, one of the authors of the Brattle study, said he still stands by the position that Order 1000 is ready for expansion, even if there are few case studies so far.

"The reality is there are not a lot of competitive projects to study. But the experience with those 15 Order 1000 projects is that those projects were bid below initial cost estimates," Pfeifenberger said.

While Brattle is only beginning its review of the Concentric report, Pfeifenberger leveled several criticisms at Concentric's study methodology, saying the competing analysis incorrectly relied on updated cost estimates later filed by the incumbent transmission developers, not true initial cost estimates.

"Since the competitive bids are compared against the initial estimates when the bids come in, the initial estimates are the most appropriate information for comparison," Pfeifenberger explained.

Pfeifenberger also said the average 20 to 30% cost savings found in the Brattle study is consistent with the savings seen in other areas with transmission competition, including the U.K.; Brazil; Alberta, Canada; and the *Path 15* transmission project in California.

He also lightheartedly addressed the cost cap criticisms: "I would say that some cost caps are better than no cost caps."

Pfeifenberger also pointed out all transmission projects must undergo a process of identification and then study before approval. He said the planning process takes time, with or without bid windows and selection reports.

"The competitive process had only begun a few years ago, and these markets are still in the forming stage, and therefore the first few competitive projects take quite a bit of time to evaluate and approve. But these processes are improving and streamlining over time," Pfeifenberger said.

"If you can add six months [to the planning process] and save 20%, was that worth it?" he asked rhetorically.

But Holodak maintains early planning estimates at the conceptual design stage shouldn't serve as a study benchmark for cost savings, noting they often involve standard dollar-per-mile estimates and lack several design and engineering details unique to specific transmission projects.

"Nobody has ever suggested that's a model you should hold someone to. Brattle's suggestion that the preliminary planning estimate is a standard someone should be held to, we think it's completely without merit," Holodak said.

Brattle report co-author Judy Chang argued planning-level estimates could become more precise.

"It doesn't make sense that project costs will always escalate based on the initial estimates," Chang said. "That also means that nobody really cares about the initial estimate. The whole competitive process has induced these transmission owners to sharpen their pencils and really analyze costs they can control and bear the risk of costs coming in higher than they expect. This whole better cost containment is an innovative outcome of the competitive process. This is a benefit."

Pfeifenberger added that if planning-level estimates are made to be exceeded, then competitively bid projects would also consistently exceed those estimates. That's not the case, he said.

"Beyond trying to confuse the issue, Concentric has not addressed the fact that competitive bids have come in significantly below initial cost estimates while traditionally developed projects of similar type have come in above their initial cost estimates," he said. ■

FERC/Federal News

Overheard at EBA Northeast Annual Meeting 2019

Richard Glick | © *RTO Insider*

WASHINGTON — The Energy Bar Association's Northeast Chapter held its annual meeting last week in a small conference room within the offices of law firm Baker Botts. Members discussed the state of the offshore wind industry, RTO analyses of fuel security and the ongoing tension between markets and state policies. FERC Commissioner Richard Glick gave a keynote luncheon talk.

Here's some of what we heard Thursday.

Transmission for Offshore Wind

The Northeast has a combined goal of 21.9 GW in offshore wind procurements, a number only expected to grow as Maine and Delaware both consider their targets, and New Jersey contemplates upping its own.

Transmission planning on land is already challenging enough for RTOs. The nature of offshore wind facilities make planning their interconnections even more so.

John Marczewski, vice president of utilities and consulting for EN Engineering, gave an overview of the physical challenges. Each turbine in a wind farm connects to a collection substation in the ocean. "Substation engineers are not used to building electrical substations that sit on, effectively, what is an oil platform," he said. "A lot of design challenges [are] involved in that."

John Marczewski | © *RTO Insider*

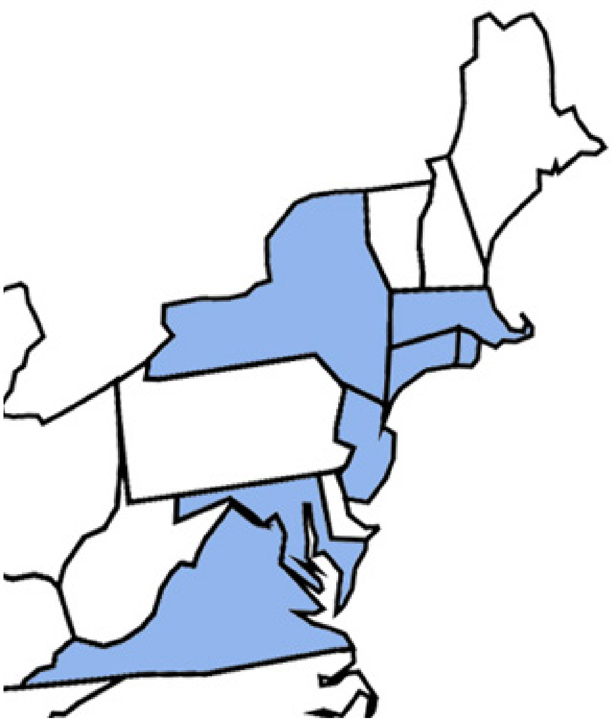
From the collection station, an underwater transmission line runs to a substation on land. The distance from the shore also presents design difficulties. An AC line is typically limited to 600 MW and 35 miles per circuit, so more circuits need to be added to transmit more power. Alternatively, designers could opt to use a DC line, but both the off- and onshore substations would need to be equipped with AC converters.

"It's very hard to actually get ... cables from platforms out in the ocean to these interconnection points," said Theodore Paradise, senior vice president of transmission strategy for Anbaric. "There isn't unlimited space across the ocean floor." He advised using HVDC systems, not only because adding more AC lines requires more trenching and thus harms the ocean environment, but because it's more expensive.

EBA CEO Lisa Levine opens the meeting. | © *RTO Insider*

Tackling Fuel Security

Matt White, ISO-NE's chief economist, reminded the audience of the RTO's chief



State	Goal (MW)	Procured (MW)
Massachusetts	3,200	800
Rhode Island	1,000	430
Connecticut	2,000	300
New York	9,000	130
New Jersey	3,500	0
Maryland	1,200	368
Virginia	2,000	12
Total	**21,900 MW**	**2,040 MW**

Offshore wind goals by state | *Anbaric*

FERC/Federal News

concern: During extended periods of extreme cold, natural gas pipelines become severely constrained, and building heating gets priority over fuel for electricity generation, resulting in about half the RTO's gas generators simply not being able to run.

"If you went to much of this country and told the system operator, 'Half your gas generators can't get fuel,' they would say, 'The lights are out,'" White said. "Today we're making this work — for now."

Like the rest of the U.S., renewable resources are growing in New England. "And if the renewables produced high levels of output all the time when the weather was cold, we'd probably have no problem," he said. But in the winter, the region is "latitudinally challenged" when it comes to solar, and wind output is highly variable.

White then went over the details of ISO-NE's proposal, ordered by FERC after it allowed the RTO to enter a cost-of-service agreement with Exelon to keep its 2,274-MW Mystic plant running. The proposal, due Oct. 15, was rejected by the New England Power Pool in March. In May, FERC agreed to hold a public prefiling meeting with the RTO, NEPOOL and the New England States Committee on Electricity. (See related story, *NEPOOL MC Debates Energy Security Models*.)

Glick: FERC Creating Legal Risks, Uncertainty

FERC commissioners remain entrenched in their positions on emissions, and they have yet to rule on PJM's capacity market proposal. Each issue is generating legal risks for natural gas infrastructure developers and the RTO, respectively, Glick said.

"The courts have twice now told us ... that when those [emissions] effects are reasonably foreseeable ... we have to consider that as well" in an environmental impact statement, Glick said, referring to the D.C. Circuit's 2017 Sabal Trail decision and a more recent decision earlier this month.

On June 4, a three-judge D.C. Circuit Court of Appeals panel *upheld* FERC's approval of a compressor station in Tennessee as part of Tennessee Gas Pipeline's *Broad Run Expansion Project*, though not without scolding the commission for failing to ask the company for data on downstream effects of the station.

The plaintiffs — local activists represented by former FERC attorney Carolyn Elefant — argued that the commission violated the National Environmental Policy Act by not considering those effects. But the court said it was forced to reject the complaint on procedural grounds, as the plaintiffs did not argue that FERC's failure to seek the data violated the law.

While FERC argued that asking for such information "would be an exercise in futility," the court countered that "We are troubled, as we were in the upstream-effects context, by the commission's attempt to justify its decision to discount downstream impacts based on its lack of information."

"What we're really doing to pipeline developers is we're creating an enormous amount of legal risk," Glick said. He noted that the 4th U.S. Circuit Court of Appeals has prevented the construction of the Atlantic Coast Pipeline because the U.S. Forest Service and National Park Service "essentially didn't cross their t's and dot their i's, and I think that's what we're doing here."

"At some point, the courts are going to be clear and say, 'Nope, FERC, we're sending that back to you; you have to consider it again.'"

Glick also elaborated on the comments he made on Capitol Hill regarding PJM's capacity proposal the day before. (See related story, *FERC Probed on RTO Governance, Market Issues*.)

FERC has found that PJM's current capacity market rules are unjust and unreasonable. If PJM runs its Base Residual Auction in August "under those same terms and conditions," Glick said, "my question is — and I don't know the full answer to this, but I think the courts would say, 'How could that auction be just and reasonable...?'

"We've done a great disservice, not only to PJM itself, but to a lot of the stakeholders who are either participating in the auction or are going to be impacted by the auction, because we've created a great level of uncertainty." ■

— Michael Brooks

Leaseholds in BOEM wind energy areas | *Anbaric*

CAISO/West News

Fire Season Starts in Calif. with Power Shutoffs

Hot Winds Fan Flames of Grass Fires

By Hudson Sangree

California's annual wildfire season kicked off last week with high winds, a heat wave and precautionary power shutoffs by Pacific Gas and Electric to thousands of customers.

A wind-driven blaze called the Sand Fire burned 2,500 acres of hilly terrain 60 miles west of Sacramento, and another fire scorched 1,800 acres of dry grasslands in rural Central California. Neither fire caused serious injuries or property damage, but they underscored the threat of wildfires as vegetation begins to dry out after an especially wet winter.

In response to the hot, windy conditions, PG&E *turned off power* for a day or two for about 1,700 customers in Napa, Solano and Yolo counties near the Sand Fire and for nearly 21,000 in the Sierra Nevada foothills of Yuba and Butte counties. Last year's Camp Fire, the deadliest and most destructive in state history, ravaged a large part of Butte and leveled the town of Paradise.

Southern California Edison and San Diego Gas & Electric have shut down power before when Santa Ana winds blew. (See *Fire Season Becomes Blackout Time in California*.)

PG&E first deployed its controversial Public Safety Power Shutoff program last October, nearly a month before the Camp Fire started Nov. 8 — though it did not use the measure in Butte just before that fire ignited.

Members of the California National Guard search debris after the deadly Camp Fire, which led PG&E to institute emergency power shutdowns days later. | *California National Guard*

Power shutoffs are now part of the utilities' annual wildfire mitigation plans approved by the California Public Utilities Commission. (See *California Regulators OK Utility Wildfire Plans*.)

A Portland, Ore.-based utility announced Thursday it was adopting a similar measure, suggesting that intentional shutoffs may spread beyond California. The Pacific Northwest has seen its share of devastating wildfires in recent years.

"This measure would only be taken as a last resort to help ensure customer and community safety," Pacific Power said in a *statement*. The utility, a subsidiary of PacifiCorp, serves about 764,000 customers in Oregon, Washington and an area of Northern California near the Oregon border.

The *National Interagency Fire Center* (NIFC) in Boise, Idaho, predicts an active wildfire season in California, the Great Basin and the Pacific Northwest this year because of a "robust grass crop" from winter rains.

"As we go forward into June, those grasses that we see across the landscape are going to dry and cure out … and we'll see an increase in fire activity especially across California," said Bryan Henry, assistant program manager of predictive services at the NIFC.

Temperatures soared above 100 degrees Fahrenheit in inland areas during last week's heat wave. CAISO issued its first "flex alert" of 2019 by calling for residents to voluntarily conserve electricity during peak demand in the late afternoon and evening, when air conditioning use spikes and solar arrays power down.

"Because of widespread heat, the ISO anticipates energy demand reaching a peak of 42,800 MW this evening," CAISO said in a June 11 news release. "Also, two units with a total generation of 1,260 MW are offline due to mechanical failures. The Flex Alert is being called in response to the high electricity demand and the reduced generation."

California, which last year mandated greater dependence on renewable energy sources going forward, offset the spike in demand largely with natural gas peaker plants, according to CAISO. ■

FERC Leery of SCE's Rate Hike for Wildfires

Utility Wants 'Extraordinary' ROE Increase for Liability Risk

By Hudson Sangree

Investigators found that Southern California Edison power lines sparked the Thomas Fire, which killed two people in December 2017 and led to a mud flow that killed 21 more. | *U.S. Forest Service*

Southern California Edison's request for a huge transmission rate adjustment based on potential wildfire liability got a tepid reception from FERC last week (*ER19-1553*).

The commission tentatively accepted the increase, per its customary procedure, but postponed any change for the maximum five months and set it for an evidentiary hearing, while encouraging the utility and protesters to settle. Protesters in the case include the California Public Utilities Commission, whose recommendations FERC largely followed.

FERC said its preliminary analysis indicated SCE's proposed 2019 transmission revenue requirement could be unjust and unreasonable — and may provide the utility "substantially excessive revenues."

SCE is seeking a whopping 17.62% return on equity, which includes the 11.12% base ROE the utility requested last year plus a 50-basis-point incentive adder for CAISO participation, along with an additional 600-basis-point cushion to account for the costs of wildfire liability. If approved, the new rate would boost SCE's annual transmission revenues by nearly $290 million.

SCE said in its April 11 *filing* its proposal was based on "dramatic material changes to SCE's regulatory and financial conditions that have occurred" since the utility filed its currently effective formula rate in October 2017.

Those changes include massive and deadly wildfires in SCE's service area and the potential for multibillion-dollar costs based on California's strict liability standard for utility-sparked fires, known as inverse condemnation. (PG&E, which intervened in the case, faces similar circumstances and filed for bankruptcy in January due to wildfire liability.)

"Beginning in December 2017, several wind-driven wildfires impacted portions of SCE's service territory and caused substantial damage to both residential and business properties and service outages for some of SCE's customers," SCE wrote. "California has unique inverse condemnation laws. These laws provide that an electric utility will be held strictly liable for property damages and legal fees if its facilities are the substantial cause of a fire regardless of fault and even if the utility was fully compliant with all applicable rules and regulations and acted reasonably."

"As a result of these laws and recent fires, SCE is exposed to significant potential wildfire damage claims," the utility said. "In 2017, the California Public Utilities Commission issued a decision holding that it could preclude a utility from recovering these court-assigned costs if it finds the utility was not prudent, even if the source of the alleged imprudent conduct was not directly the cause of the fire."

FERC, which has oversight of SCE as a transmission owner, and the CPUC, which regulates the utility's distribution system, have different standards for cost recovery, SCE pointed out. The difference could be a costly one.

'Atypical' Risk

State investigators determined SCE equipment started the 282,000-acre Thomas Fire in December 2017 that killed two people and led to mudslides that killed 21 more in Ventura and Santa Barbara counties. The California Department of Forestry and Fire Protection (Cal Fire) has listed the official cause as "line slap," whereby electrical conductors contact each other or adjacent components. (See *Edison Takes Partial Blame for Wildfire in Earnings Call*.)

The Woolsey Fire in November 2018 killed three residents, destroyed 1,500 structures and burned 97,000 acres in Los Angeles and Ventura Counties. Its cause remains under investigation, though lawsuits have blamed SCE. The fire began near an SCE substation where a nearby circuit experienced problems shortly before the fire started, the *Los Angeles Times* reported.

In its filing with FERC, SCE argued its conventional base ROE does not reflect "extraordinary wildfire liability risks." The utility submitted testimony concluding an ROE allowance of 600 basis points added to its base ROE would match the size and insurance cost of the wildfire problem.

"SoCal Edison states that authorizing such an amount on top of the base ROE would provide additional investor returns needed to account for the severe wildfire risk SoCal Edison faces," FERC wrote.

In its protest to FERC, the CPUC called SCE's proposed increase "extraordinary" and noted SCE's request "touches upon similar issues in proceedings pending before the CPUC."

"SCE's filing would result in a retail revenue requirement of $1.328 billion, compared to the current revenue requirement of $1.038 billion," the CPUC wrote. "SCE's proposed rate increase is primarily tied to a proposed return on common equity of 18.4%, an unprecedented proposal [that] would create a windfall to SCE investors, at an unacceptable cost to SCE's captive customers, in violation of the Federal Power Act. This proposed formula will result in unjust and unreasonable rates in 2019 and beyond and should be rejected."

The CPUC said it calculated the higher rate based on an ROE of 17.12%, a 50-basis-point incentive adder for membership in CAISO and

CAISO/West News

project-specific adders ranging from 75 to 125 basis points.

"The enormous increase in the rate of return request is due primarily to a 600-basis-point adder ascribed to the legal issue in California of 'inverse condemnation' and the wildfire liability risk it imposes on California utilities," the California regulator said. "The CPUC does not object to SCE raising this issue, but it does object to the magnitude of the proposed risk premiums, which stems from SCE's departure from accepted cost of capital methods used to develop that estimate.

"The wildfire liability issues in California, including state law on inverse condemnation, are complex and do create atypical utility risk," the CPUC wrote. "It may be the case that a reasonable treatment of this risk as part of rate of return should be considered. That said, the proposed 600-basis-point adder is unreasonably large, violates the upper end of the zone of reasonableness (for an electric utility proxy group, which is FERC practice) and is not consistent with the available financial metrics for SCE and its parent Edison International."

The CPUC said SCE had overstated its risk. Though its credit rating fell due to fire liability, it remains in investment-grade territory, and its stock price has been relatively stable, the CPUC contended. "The presently observed risk indicators for SCE are not as dire as portrayed by company witnesses," it said.

'Utility Imprudence'

Protesters Public Citizen and The Utility Reform Network, both nonprofit public interest groups, advanced similar arguments.

"SCE misrepresents the liability regime in California, and the utility is not at risk for wildfire liability absent a finding that it was imprudent in managing its system [under the prudent manager standard]," they said. "FERC should not condone utility imprudence by insuring the company against its own negligence. Moreover, SCE has raised these very same issues in its recently filed cost of capital proceeding at the California Public Utilities Commission.

"Since any alleged financial risk due to wildfires depends on California-specific factors and policies, and any such risk is caused primarily by ignitions on to the distribution system, this commission should refuse to rule on such issues or authorize increases in ROEs for transmission investments and instead should allow the California PUC to evaluate these claims," the groups argued.

The Thomas Fire left a massive burn scar across coastal Southern California. | *NASA*

FERC said it hopes the parties will settle prior to a hearing.

"While we are setting this matter for a trial-type evidentiary hearing, we encourage the parties to make every effort to settle their dispute before hearing procedures are commenced," FERC wrote. "To aid the parties in their settlement efforts, we will hold the hearing in abeyance and direct that a settlement judge be appointed." ■

CPUC Concerned About New PG&E Board Members

Safety Qualifications, Time Commitment Questioned

By Hudson Sangree

The California Public Utilities Commission on Thursday asked for more information on Pacific Gas and Electric's new corporate directors, with some commissioners expressing doubts about their safety expertise and ability to fully focus on their jobs.

The latest effort — in which the CPUC adopted an administrative law judge's *proposed decision* — is part of the commission's ongoing investigation into the safety culture at PG&E, a company blamed for catastrophic wildfires and a deadly pipeline explosion in 2010. (See *CPUC Expands Probe into PG&E Practices After Deadly Fire*.)

During the CPUC's *meeting* in Sacramento, President Michael Picker said he'd met with Jeffrey Bleich, the new chair of utility PG&E, and intended to meet soon with Nora Mead Brownell, chair of parent company PG&E Corp. Bleich, an attorney, is a former ambassador to Australia, and Brownell is a former FERC commissioner.

"While both of these individuals have very impressive resumes, it's not immediately clear from their record that they have the appropriate qualifications for the task at hand," Picker said. "In addition, they may not have enough time in the day, given their other commitments, to dive into the full governance of PG&E.

"The corporate governance of PG&E really demands the whole attention of qualified people and not just the splintered attention of otherwise well-meaning people," he said.

Brownell serves on at least one other board and co-founded an energy consulting business, according to PG&E's web site. *Bleich* serves on two other corporate boards and chairs the Fulbright Foreign Scholarship Board, it says.

Neither could immediately be reached for comment.

PG&E said in a statement that its new board members, named in April, "possess the important qualifications — including and especially safety expertise — to lead PG&E going forward."

The "PG&E Corp. board's Nominating and Governance Committee explicitly added safety expertise to the variety of experience and skills we require for our directors," it said. "The directors include industry leaders who have dedicated their careers to safe and reliable utility service — including as federal and state regulators, and as board members and executive officers of other energy companies."

Picker, backed by three of his fellow commissioners (one was absent), said the CPUC needs to "dig deeper" into the board to "find out who's making decisions, how qualified they are and whether we have the right leadership at PG&E." ■

CAISO/West News

Judge Urges Appeals Court to Decide PG&E v. FERC

Same Bankruptcy Judge Ruled FERC has no Authority over PPAs

By Hudson Sangree

Generators worried that Pacific Gas and Electric will try to reject billions of dollars in power purchase agreements during its bankruptcy proceeding said they will appeal a federal judge's recent order telling FERC it has no authority over the agreements.

NextEra Energy, Calpine and Consolidated Edison Development filed *notices of appeal* with the U.S. Bankruptcy Court in San Francisco on Thursday. They want FERC to have concurrent jurisdiction with the court over the PPAs.

Judge Dennis Montali | *Commercial Law League of America*

The generators' filing came the day after Judge Dennis Montali certified the matter for direct appeal to the 9th U.S. Circuit Court of Appeals, saying it "is very much a matter of public importance," involving what is likely the largest utility bankruptcy in U.S. history, and ought to be decided quickly.

"Also of great importance, though not directly related to the rejection issue, are billions of dollars in claims arising from the tragic wildfires that occurred principally in 2017 and 2018 in Northern California for which [PG&E bears] substantial liability," Montali wrote in a *memorandum* for the appeals court.

The fires include the fatal wine country fires of October 2017 in Napa and Sonoma counties and the Camp Fire, the deadliest in state history, which killed at least 85 people in November 2018 and destroyed the town of Paradise.

"In some cases [PG&E's] liability is a result of [its] direct actions and in others because of … strict liability under California's inverse condemnation laws," the judge said. "These wildfires are the principal publicly stated reasons why the debtors filed for bankruptcy." (See *PG&E Wants to Undo Contracts, Revamp Biz in Bankruptcy*.)

Power Play

On June 7, Montali had issued another memorandum saying "FERC must be stopped" from undermining the bankruptcy court's oversight of contracts PG&E might seek to reject during Chapter 11 reorganization.

Montali said FERC has no authority over the $42 billion in PPAs signed by the utility or its parent company PG&E Corp., despite the commission's assertion that it shares jurisdiction in the matter with the court. (See *'FERC must be Stopped,' PG&E Bankruptcy Judge Says*.)

The FERC decisions "discussed here were not the actions of a power regulator carrying out its statutory duties to police rates, terms and conditions of power contracts, and enforcing the filed-rate doctrine," Montali wrote. "To be blunt, they were unauthorized acts of the power regulator executing a power play (to use a hockey term) to curtail the role of the court acting within its authorized and exclusive role in these bankruptcy cases. Those decisions cannot be applied or honored here."

Exelon's Antelope Valley Solar Ranch in the desert near Los Angeles is one of the largest solar photovoltaic projects in the world and one of the renewable generation facilities potentially affected by PG&E's bankruptcy. | *U.S. Department of Energy*

Montali emphasized that FERC does not have concurrent jurisdiction — "or any jurisdiction" — over the authorization of any rejections of PPAs. "Debtors do not need approval from [FERC] to reject any of their power purchase contracts," he said.

In response to petitions by NextEra and Exelon, FERC declared in January that it shares authority over PG&E's wholesale PPAs with the bankruptcy court. (See *FERC Claims Authority Over PG&E Contracts in Bankruptcy*.) In May, it rejected a rehearing request by PG&E, saying the wholesale PPAs "implicate the public's interest in the orderly production of plentiful supplies of electricity at just and reasonable rates" and so fall under FERC jurisdiction. (See *FERC Denies PG&E Rehearing Over Contracts Dispute*.)

PG&E asked Montali to tell FERC not to meddle in its bankruptcy proceedings, which he did, and requested an injunction against FERC, which he said was unwarranted.

"There is no need to enjoin anyone or any action now," he wrote in June.

Montali has said all along that he thinks the 9th Circuit needs to decide the competing viewpoints of federal authorities and that he wanted to expedite that process.

"The central issue of whether a bankruptcy court alone may grant or deny a motion to reject a PPA as an executory contract, or whether FERC has a say in the question by virtue of its claimed 'exclusive jurisdiction' [over wholesale PPAs], has not been addressed by any reported 9th Circuit decision or by the United States Supreme Court," Montali wrote.

The case involves up to 400 contracts for power, the rejection of which "will give rise to substantial damage claims because rejection constitutes a breach under current bankruptcy law," the judge said. "How those damage claims will be treated under any Chapter 11 reorganization plan will inevitably be interrelated with how the wildfire-related claims will be treated.

"If FERC has a say in the rejection decision because its authority is upheld as 'concurrent' with this court's, an extremely complicated situation will be rendered all the more complicated and time-consuming, possibly delaying further the ultimate resolution, settlement and payment of those wildfire and contractual claims," Montali said. ■

ERCOT News

ERCOT Board of Director Briefs

Staff Prep Directors for Summer Expectations

A tag team of ERCOT executives last week reviewed the grid operator's summer preparations at the Board of Directors' last meeting before the big heat. Judging by the few questions from the board, the presentation was well received.

Staff have said they expect to use emergency measures this summer to meet a record forecasted peak demand of 74.9 GW. ERCOT has available capacity of 78.9 GW and a reserve margin of 8.6%. (See *ERCOT: More Capacity, but Emergency Ops Still Expected*.)

Dan Woodfin, senior director of system operations, *told the board* that ERCOT expects to "implement energy emergency alerts several times this summer." He said the alerts would allow it to take advantage of the extra 2 to 3 GW of resources available "only in those limited situations."

The grid operator does not expect any "wide-area reliability concerns," Woodfin said. He said Far West Texas may see some congestion from oil and gas and solar development, and areas in the Texas Hill Country and the Rio Grande Valley could experience congestion as well.

The ERCOT system could get a boost if *weather forecasts* predicting cooler temperatures than the summer of 2018 — when the grid operator set a new peak demand of 73.5 GW — prove accurate. Senior Meteorologist Chris Coleman said it's "unlikely" to be as hot as last summer, pointing to the ninth-wettest year on record for Texas.

"Wetness tends to suppress heat, to some extent," Coleman said. He is projecting almost half as many 100-degree days in various Texas cities than last year (five to 14 in Austin, compared to 41 in 2018).

Kenan Ögelman, ERCOT's vice president of commercial operations, *reminded the board* of two Public Utility Commission-mandated changes to the operating reserve demand curve (ORDC), which provides a price adder when generation is scarce.

The grid operator will now blend 24 different ORDC curves, based on season and hour blocks, into one curve that aggregates all the data. This will raise adders above 2 GW of reserves during the summer months, but lower them in the winter, Ögelman said.

The PUC also directed ERCOT to shift the

The June ERCOT Board of Directors meeting

ORDC curve by 0.25 standard deviations, which Ögelman said will create a higher adder for any level of reserves above 2 GW.

IMM Market Report: Load Continues to Climb

The ERCOT Independent Market Monitor's 2018 State of the Market report says the wholesale market performed "competitively" last year, but it also includes some future warning signs.

In briefing the *report*, which was filed at the PUC on June 5, IMM Director Beth Garza told the board that load is increasing in all four ERCOT load zones, led by a 15.4% increase in average real-time load from 2017 in the West zone, which includes the petroleum-rich Permian Basin. The average load in the North zone, home to Dallas and Fort Worth, increased 6.5% over 2017, and it was up 5.3% for the ERCOT system.

"There's substantial load growth everywhere. There's no other word to describe it," Garza said.

She said the additional load amounts to a 2.2-GW increase each hour, noting, "That's like two new combined cycle [generating units] to serve load every hour."

Given the ever-increasing load, Garza said, "In 2022, the existing fleet is no longer sufficient to serve peak load."

As it is, the IMM report said system shortages increased in 2018, with about 17 hours of prices above $1,000/MWh. The Monitor expects the trend to continue in 2019.

"What seem like very low reserves may just be the new normal," the report says. "Given the overall size of the system and projected growth, a more robust reserve margin may no longer be required to cover load forecast errors and mitigate generator availability risks."

The report also said with distributed generation playing an "increasingly important role in ERCOT, the risk associated with generator outages should decrease."

Overall, ERCOT's average prices climbed to $35.63/MWh, a 26% increase from 2017. Higher natural gas prices helped drive the increase, up 8% to $3.22/MMBtu.

The grid operator's real-time market experienced a 30% increase in congestion costs, which totaled $1.26 billion. The IMM said a costly, localized constraint in Far West Texas was the primary culprit.

The report offers three recommendations to improve the reliability commitment process and resulting pricing:

- Evaluate and improve the reliability deployment price adder, which the IMM says is producing results "inconsistent with its original intent."
- Explore options to consider commitment costs for RUC-committed units.
- Eliminate the opt-out option for RUC-committed resources.

"Continuing to have the opt-out option is an

ERCOT News

IMM Director Beth Garza presents an overview of the 2018 State of the Market report.

incentive to withhold capacity," Garza said. "In our decentralized market, where we count on people to make their own best decisions, the incentives in front of us lead to a situation where people are incented not to commit."

Magness Reviews Legislative Session

During his regular *CEO's report*, Bill Magness briefed the board on the Texas 86th Legislative Session, which ended May 27 and included a significant right-of-first-refusal bill. (See *Texas ROFR Bill Passes, Awaits Governor's Signature*.)

Senate Bill 1938 gives incumbent utilities the first shot at building transmission projects in the state. The bill, which went into effect immediately after Gov. Greg Abbott signed it May 16, will require ERCOT to modify its transmission planning process to no longer designate transmission provider endpoints.

A second law already in effect — *SB475*, signed June 7 — creates a Texas Electric Grid Security Council composed of Magness, PUC Chair DeAnn Walker and a designee of Abbott. Magness said Walker will chair the council, which will begin meeting later this year.

SB936, signed June 10 and effective Sept. 1, requires ERCOT and the PUC to contract with an entity to serve as the commission's cybersecurity monitor. It will be funded by the grid operator's system administrative fee, Magness said.

Magness also celebrated a two-year delay in the grid operator's sunset review, which also applies to the PUC and the Texas Office of Public Utility Counsel (OPUC). The review has been pushed back to 2024/25.

"While we always welcome sunset reviews, we're happy for it to be in 2024 and 2025," he cracked.

ERCOT's positive year-end variance to budget has slipped slightly, from $34 million to $33.2 million, still boosted by a large gain in interest income ($18.7 million), Magness said.

Telemetry Data Blamed for Market Event

Ögelman told the board that a May 30 market event that briefly resulted in $9,000/MWh prices was the result of the security-constrained economic dispatch system receiving bad telemetry data.

"This happens," Ögelman said. "Normally for very short durations, but it doesn't hit the SCED. This hit the [market] run."

The telemetry data indicated about 5,000 MW of resources wanted to move down during an interval, he said, and when the market didn't respond quickly enough, the SCED engine used regulation up to get the ramp it thought it needed. Energy on the power balance penalty curve, used by ERCOT to price ancillary services such as regulation up, hit $9,000.01/MWh for about 2.5 minutes before operators, sensing something was wrong, reran SCED and corrected the data.

The blip resulted in settlement prices of as much as $1,500/MWh in some load zones for one 15-minute interval, Ögelman said.

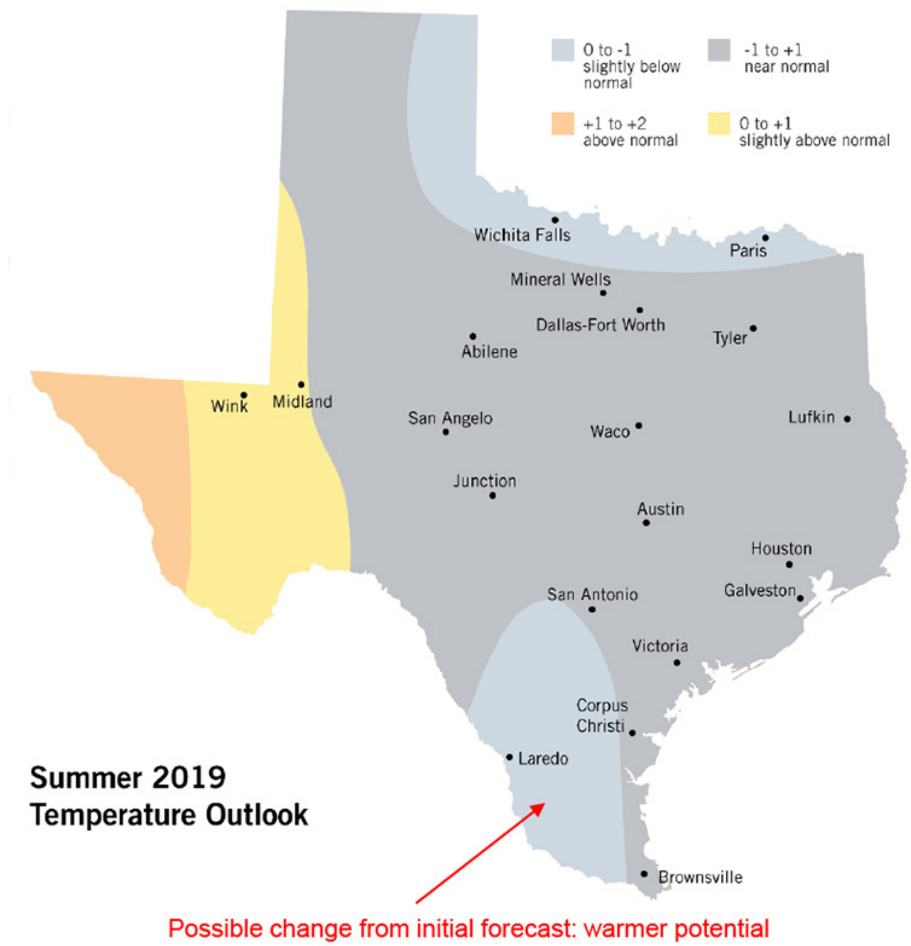
Staff investigated the event but determined it didn't warrant a price correction, according to ERCOT's Protocols.

"Incorrect telemetry coming from outside ERCOT is not something we run corrections for," Ögelman said. Telemetry data are owned by the resources, not the grid operator.

He said staff would look into strengthening its telemetry data and follow up with stakeholders to evaluate alternatives.

TAC Vice Chair Coleman Leaves for CPS

Technical Advisory Committee Chair Bob Helton said the committee will "bring on" a new vice chair before the next board meeting, replacing longtime member Diana Coleman, who has left OPUC to take a position at CPS



| ERCOT

ERCOT News

Energy, San Antonio's municipal provider.

Coleman had served as the TAC's vice chair since 2018, when Helton moved up from vice chair to chair to replace Adrianne Brandt when she also left for CPS.

Board Approves Budget, Change Requests

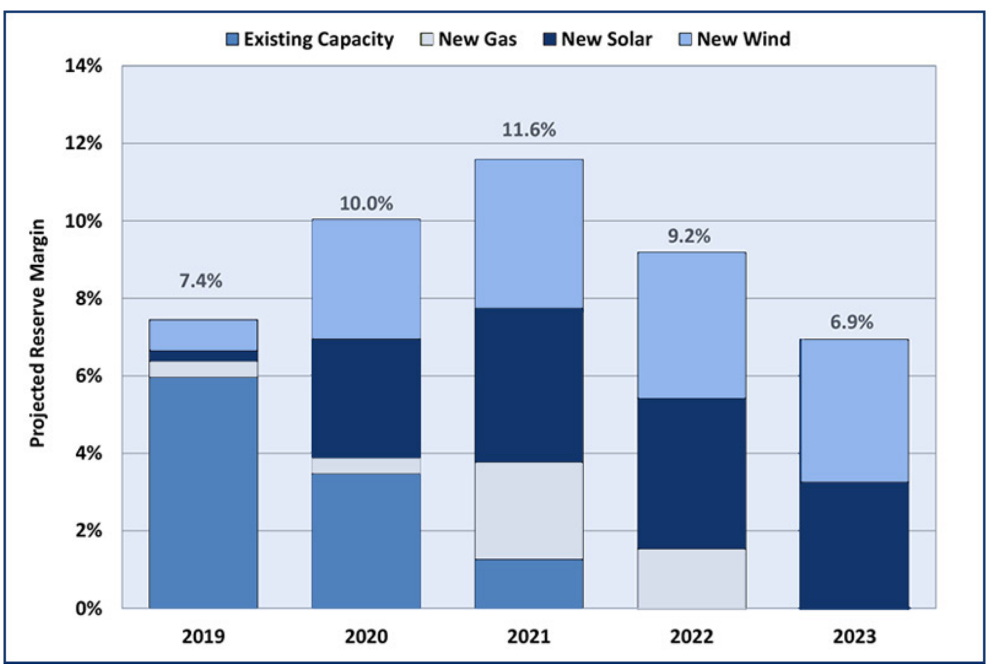
ERCOT's system administrative fee will remain at 55.5 cents/MWh through 2021 as a result of the board's unanimous approval of the *2020/21 biennial budget*. The fee has remained level since 2016.

The board approved $268.3 million and $275.2 million for operating expenses, project spending and debt-service obligations for 2020 and 2021, respectively.

The board also approved seven Nodal Protocol revision requests (NPRRs), a change to the Nodal Operating Guide (NOGRR), two new Other Binding Documents (OBDRRs), two Planning Guide additions (PGRRs) and a system change request (SCR) on its consent agenda:

- *NPRR885*: Adds new language to address the solicitation and operation of must-run alternatives, as directed by the PUC (Project *46369*). The commission ruled that a resource entity must file a notification of suspension of operations at least 150 days prior to the date on which it intends to cease or suspend operations; within the 150-day notice period, ERCOT must determine whether the resource is needed for reliability.
- *NPRR896*: Outlines the process to evaluate the cost-effectiveness of procuring reliability-must-run service or one or more must-run alternatives.
- *NPRR921*: Replaces all instances of the "all-inclusive generation resource" and "all-inclusive resource" terms with "generation resource and settlement-only generator (SOG)" and "generation resource, settlement-only generator and load resource," respectively. Eliminating the all-inclusive generation resource enables ERCOT to more narrowly tailor the requirement's applicability to a reasonable scope.
- *NPRR923*: Updates the weather-sensitivity process by allowing transmission and/or distribution service providers an additional 30 days to complete the investigation and execution of requests to revise electric service identifier (ESI ID) load profiles.
- *NPRR924*: Moves the Independent Market Information System Registered Entity Application for Registration form into a section of the Nodal Protocols that houses similar forms.
- *NPRR926*: Removes the 90-day period between subsynchronous resonance (SSR) study approval and initial synchronization, clarifies that the SSR mitigation plan is part of the SSR study and adds an ERCOT review process that gives the grid operator 30 days to review the SSR study. The change also gives ERCOT 45 days to implement any required SSR monitoring after the study's approval.
- *NPRR929*: Adds new criteria for determining whether a point-to-point (PTP) obligation with links to an option bid is eligible to be awarded based on the resource's current operating plan (COP) status at the node where the bid sources. Bids will not be eligible for awards if they source at a resource with a COP status of "OUT" or "OFF" and the resource is not offered into the day-ahead market.
- *NOGRR185*: Uses the terms created in *NPRR889* (RTF-1 Replace Non-Modeled Generator with Settlement Only Generator) to replace the terms "all-inclusive generation resource" and "all-inclusive resource" in the NOG.
- *OBDRR013*: Changes the current single-value voltage categories of 345, 138 and 69 kV used to define generic transmission shadow price caps for N-1 constraint violations to accommodate Lubbock Power & Light's transmission equipment, which does not fall into the three existing categories. The ranges are: greater than 200 kV ($4,500/MW), 100 to 200 kV ($3,500/MW) and less than 100 kV ($2,800/MW).
- *OBDRR015*: Sets the value of lost load (VOLL) equal to the systemwide offer cap, which changes the high cap to the low cap should the peaker net margin exceed its threshold within an annual resource adequacy cycle.
- *PGRR069*: Uses terms created by *NPRR889* to replace "all-inclusive generation resource" and "all-inclusive resource" in the Planning Guide. The PGRR also clarifies the applicability of the generation interconnection or change request process to different generators, based on NPRR889.
- *PGRR070*: Aligns the Planning Guide with NERC Reliability Standard TPL-007-2 (Transmission System Planned Performance for Geomagnetic Disturbance Events) by identifying responsibilities for performing studies needed to complete benchmark and supplemental geomagnetic disturbance vulnerability assessments.
- *SCR799*: Enables ERCOT to provide transmission service providers its current month, 60-day and 90-day outage study cases in the system operations test environment on a monthly basis. ■

— Tom Kleckner

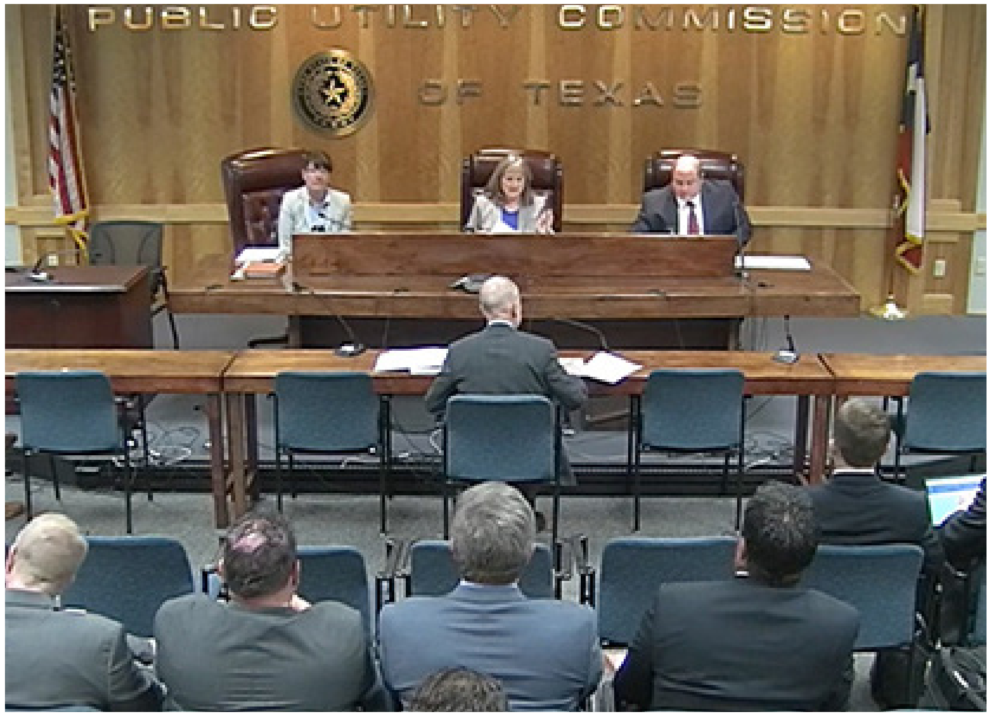


Projected planning reserve margins | *Potomac Economics*

ERCOT News

Texas PUC Briefs

Commissioners Approve CCN for Oncor-AEP 345-kV Project



The Texas PUC's June 13 open meeting

The Texas Public Utility Commission last week approved a certificate of convenience and necessity for a 345-kV transmission project that cuts through an active petroleum field in West Texas' Permian Basin (Docket *48785*).

During their open meeting Thursday, the commissioners agreed to tweak a previously *proposed order* by an administrative law judge.

The CCN allows Oncor and AEP Texas to build 345-kV double-circuit transmission lines, ranging in length from 44 to 59 miles, and at a cost of $98 million to $126 million. The line is part of the $336 million Far West Texas transmission project, approved by ERCOT in 2017. (See *ERCOT Board Approves West Texas Transmission Project*.)

During the meeting, PUC Chair DeAnn Walker and Commissioner Arthur D'Andrea discussed Walker's *addition of language* allowing Oncor and AEP to make a "minor deviation" from the route if they receive landowners' permission and they do not cause an "unreasonable" increase in cost.

Walker said she normally omits the language from orders. However, it gives the developers flexibility in dealing with drilling wells that take only months to begin producing.

"I think when Oncor gets out there, there's going to be something they have to address," Walker said. "If Oncor gets out there and finds something they can't do, or they feel they don't fall within the language, I'm fine with them filing a request for an expedited decision. I don't think we should go to a full CCN to get them an answer."

D'Andrea agreed with granting exceptions to transmission facilities in areas with petroleum development and suggested a rulemaking to address the process.

AEP Texas Securitization OK'd

The commission approved a request from AEP to securitize $369.2 million in system restoration costs as a result of Hurricane Harvey in 2017 (Docket *49308*).

In an ex parte communication to Walker, financial planner Saber Partners *argued* that AEP's proposed servicing fee of 10 basis points was inconsistent with the state's Public Utility Regulatory Act that mandates a "lowest transition charge." Staff examined 72 recent similar transactions and determined AEP's request was consistent with those ranges and with the PURA.

Commissioner Arthur D'Andrea

PUC Fines Oncor, Intervenes at FERC

In other actions, the PUC:

- Approved a settlement agreement against Oncor for inaccurate telemetry. The utility agreed to pay an administrative penalty of $75,000 (Docket *49454*).
- Voted to join regulators from Indiana, Mississippi and Missouri in intervening in LS Power's complaint with FERC against MISO's economic planning process (*EL19-79*). The company charges that the RTO's planning process fails to provide a clear path for regionally beneficial economic enhancements that do not currently qualify as market efficiency projects, resulting in unnecessary congestion costs. ■

— Tom Kleckner

ISO-NE News

NEPOOL MC Debates Energy Security Models

By Michael Kuser and Robert Mullin

ISO-NE floated a portion of its long-term market proposal to address fuel supply constraints, and five stakeholders presented their own concepts at the June 10-12 meeting of New England Power Pool's Markets Committee.

The RTO faces an October deadline to file a market design with FERC that permanently addresses the regional fuel supply issue — specifically winter scenarios when natural gas supplies are limited.

In March, the RTO filed an interim *proposal* with the commission to address winter energy security for the commitment periods covered by Forward Capacity Auctions 14 (2023/24) and 15 (2024/25). That plan would "provide incremental compensation to resources that maintain inventoried energy during cold periods when winter energy security is most stressed" (*ER19-1428*). (See *ISO-NE Filing, Whitepaper Address Energy Security*.)

The interim proposal consists of five core components, including a two-settlement structure, a forward rate, a spot rate, trigger conditions (such as extended cold snaps) and a maximum duration for compensation. But some stakeholders have found the plan to be unduly complex, with the Massachusetts attorney general contending it represents the most dramatic change to the energy and ancillary services markets since their inception.

Keeping it 'In Market'

ISO-NE's proposed long-term solution looks to be no less complex — and transformative — than its short-term one. Senior Market Designer Andrew Gillespie's *presentation* last week focused on just a portion of the plan — a proposal to create day-ahead ancillary services products intended to ensure that in-market processes begin to cover more of the RTO's next-day operating requirements.

"Meeting these requirements via 'in-market' awards improves resources' incentives to arrange energy supplies facing uncertainty," the presentation said.

ISO-NE's proposal calls for the creation of an hourly energy call option: option sellers would offer resources in hope of clearing in the day-ahead option market. As the buyer of the option, the RTO would specify an option price for each hourly interval before submission of option offers, which would occur in concert with submission of hourly energy offers. A resource could submit offers for both options and energy for the same hours, subject to limitations based on its physical parameters.

A resource with a cleared day-ahead option would then have an option position open for a given interval, which would be "closed out" at the real-time LMP for that interval.

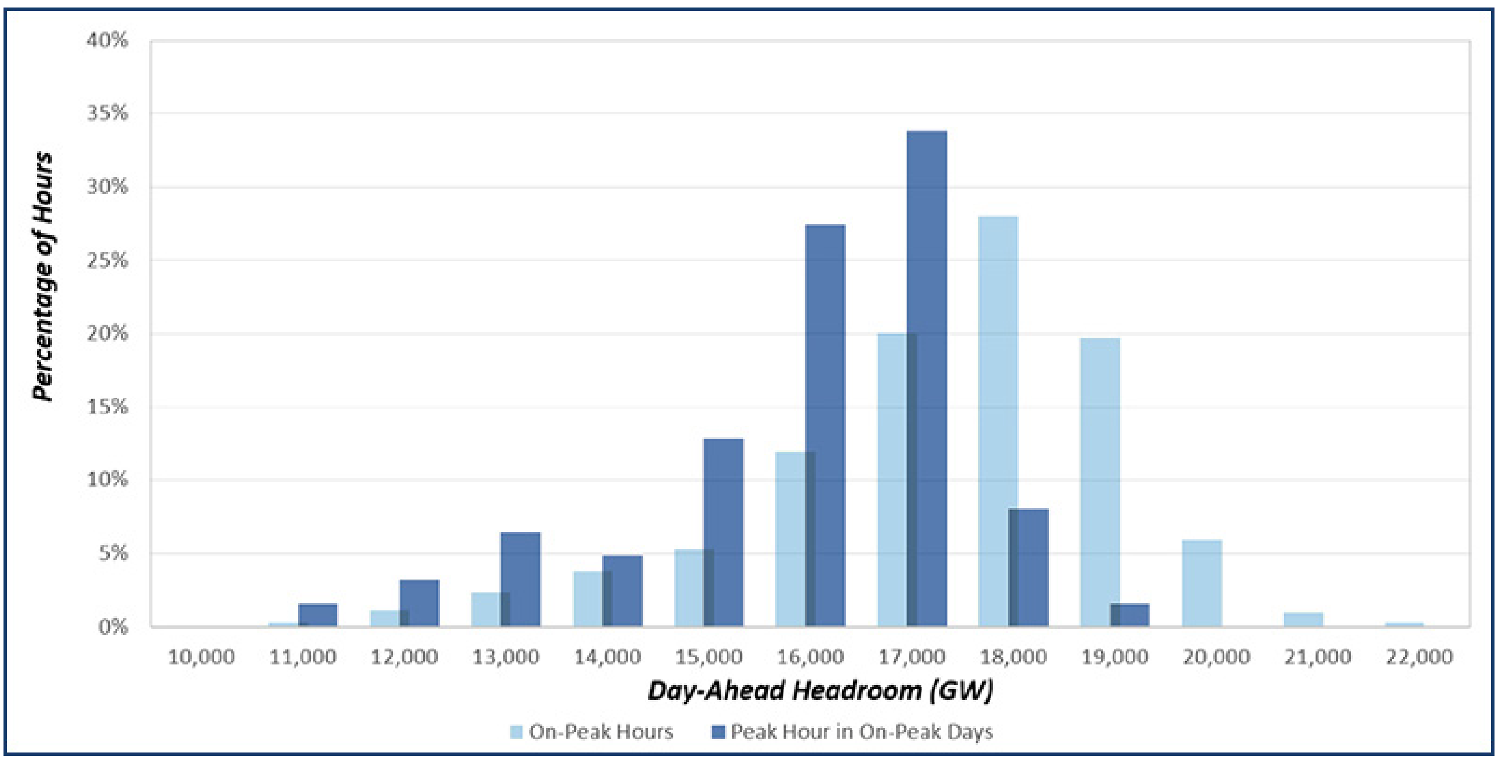
"If the real-time LMP is greater than the strike price, the unit will be debited an amount equal to the product of the option quantity and the difference between the real-time LMP and the strike price," the presentation explained.

The resource would also be credited for real-time energy and reserves supplied at applicable real-time prices.

ISO-NE expects that the total volume of call options it procures will meet day-ahead ancillary services requirements.

"These amounts would be based, at a minimum, on the procedures currently applied by the ISO in developing a reliable next-day operating plan," ISO-NE said.

From a supplier's perspective, Gillespie's



Day-ahead headroom is the difference between the sum of day-ahead schedule amounts and the sum of real-time economic maximum values for the winter on-peak hours. | *ISO-NE*

ISO-NE News

presentation points out, the option is on real-time energy — not a specific real-time ancillary service; regardless of why the option was awarded, it will still be settled against the real-time LMP.

The RTO commissioned Analysis Group to provide some context on how the proposed changes might affect energy market outcomes. Company principal Todd Schatzki on Wednesday said its *study* concluded that the proposed improvements could change the way market participants make resource decisions and change economic offers in ways that improve energy security.

Gillespie also noted that the RTO is reviewing a stakeholder suggestion to develop its proposed Multi-Day Ahead Market (M-DAM) separately, after the rest of the energy security improvements are filed with FERC in October.

Massachusetts AG: Simpler, More Physical

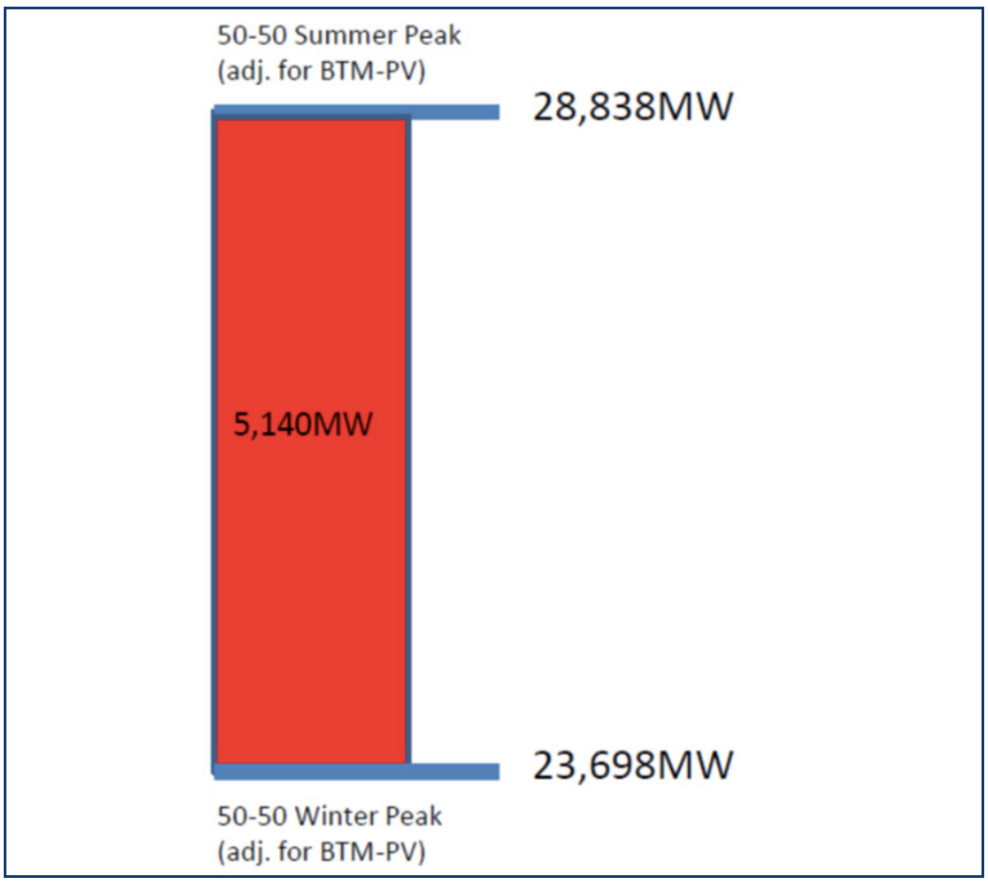
In a *proposal* prepared by London Economics, the Massachusetts attorney general's office recommended a simple auction format of sealed bids with a uniform clearing price.

Marie Fagan of London Economics described the Forward Stored Energy Reserve (FSER) proposal as a limited amount of insurance for a limited challenge; she said details on the timing of the auction and other matters would be discussed at the July 8-10 MC meeting.

The pros of a uniform clearing price? Each bidder that clears the auction is paid the same price as the highest-cost clearing bid. Bidders can also submit low bids at short-run marginal cost (SRMC) for low-cost (infra-marginal) plants, ensuring they will be chosen.

But the proposal acknowledged one potential negative outcome of a uniform clearing price — that a bidder could engage in portfolio bidding, raising the bid price over SRMC for plants it expects to be marginal.

London questioned whether ISO-NE's proposal will be effective from a reliability or cost perspective. It said the FSER is a simple and smaller-scale alternative to the RTO's complex scheme, helping preserve the market signal when supplies are tight.



Based on FCA 13-related values, being resource adequate at the summer peak may not assure enough gas storage to be resource adequate at the winter peak. | *FirstLight*

NextEra: Reserve Products

NextEra Energy Resources *proposed* the creation of replacement energy reserve (RER) and generation contingency reserve (GCR) products to be purchased by ISO-NE in the day-ahead market.

NextEra's Michelle Gardner emphasized that both RER and GCR would be physical products, not financial call options, and as such could increase real-time energy prices when fuel reserves are low.

"Resources that sell the call options would have incentives for next-day fuel arrangements," NextEra said of ISO-NE's proposal. "However, the extra incentives are weak at best. They depend on assumptions about lumpy offers and risk aversion. One simply cannot expect a strong response absent a fundamental change to real-time demand."

If done incorrectly, a seasonal forward market is likely to depress energy market prices and provide the wrong incentives, NextEra said. A physical RER, coupled with the right forward incentives, is key, it said.

Calpine: More Precise; More Cautious

Calpine — which has long suggested that the RTO acted in haste in not allowing the market time to work through its energy security issues — presented an energy security *concept* dubbed Forward Enhanced Reserves Market, which would procure fuel-secure capacity for the winter months three years prior to the obligation year.

Rather than qualify resources based on their ability to contract for stored fuel or readily-used stored energy, Calpine proposes that suppliers bid at auction for a total minimum or maximum amount of megawatt-hours they will commit to offer off of stored fuel during an *Operating Procedure 21*, which is activated when the RTO declares an energy emergency event.

Rebecca Hunter, Calpine senior analyst for government and regulatory affairs, said the benefits of its market design include: fuel security through a diverse pool of resources; timely transition of the evolving resource mix; investment in the existing fuel infrastructure; and market design changes in critical winter months only.

Energy Market Advisors: Use Today or Save for Later?

Brian Forshaw presented a *concept* by Energy Market Advisors, which has concluded that ISO-NE's market suffers from:

ISO-NE News

- Misaligned incentives: Resources lack incentive to procure and maintain energy supplies that may be needed in the future.
- Operational uncertainty: The system may not have sufficient energy available to withstand extended supply losses during winter.
- Inefficient schedules: Energy supplies can be depleted prematurely even when stored energy may be more valuable in the future.

Forshaw's presentation posed the hypothetical question of whether the RTO should "use stored energy today or save it for later when it may be more valuable?"

"How we answer this question has significant (and differing) impacts for resource owners, system operators and electric consumers," the company said, concluding ISO-NE should primarily focus on addressing those problems as quickly and efficiently as possible. Forshaw cautioned the RTO against implementing M-DAM and seasonal forward procurement at the same time as day-ahead enhancements, contending that would significantly complicate stakeholders' development, and FERC's evaluation of such significant changes.

FirstLight: Filling Buckets

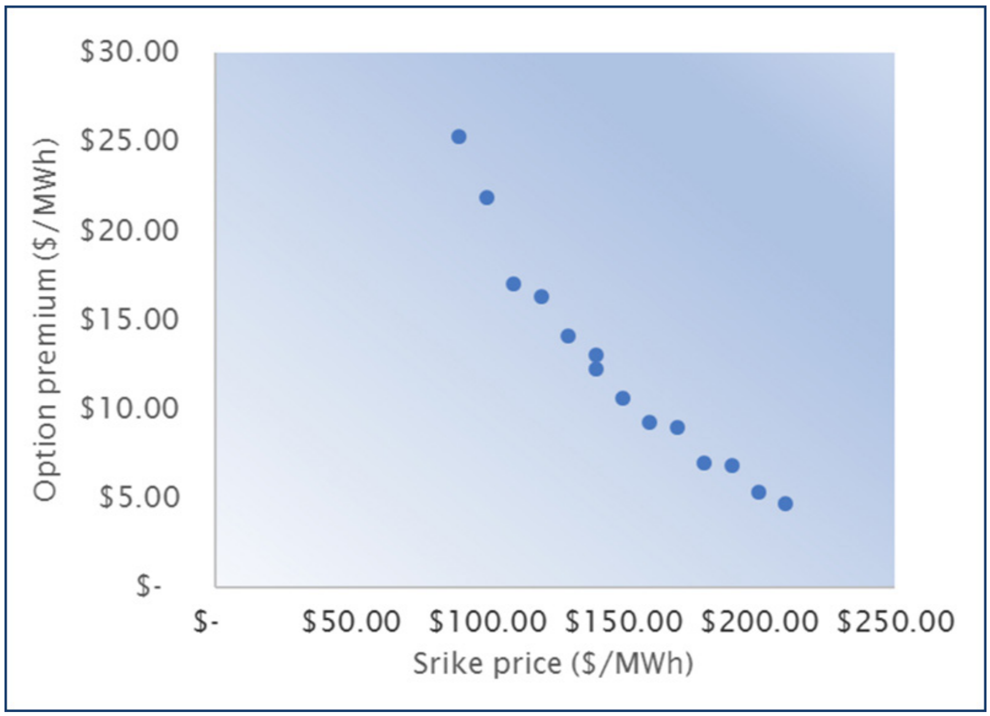
Tom Kaslow of FirstLight, owner of the largest pumped hydro facility in the region, presented his firm's *concept* for defining energy security, which asks the RTO to "connect the dots" between fuel security and resource adequacy by ensuring that the latter is backed by sufficient fuel storage. Kaslow's presentation posed the question in terms of generator fuel tanks, which he termed "buckets": How many buckets need to be filled, he asked, against how many can be filled?

"If the aggregate gas-only generator winter capability exceeds the region's capability to access gas to support simultaneous generation at such resources, their actual reliability support to meet winter peak load is less than their aggregate megawatts of capability," the presentation said.

FirstLight recommends ISO-NE "establish the highest level of aggregate winter gas-only capability that can be simultaneously fueled at winter peak demand" and give capacity credit to gas-only resources that have firm transportation rights or contracted priority to take LNG during winter.

"Limit qualified gas-only winter capacity on the rest of the gas-only fleet to the level of such generation that can simultaneously operate," FirstLight urges.

By assuring that each procured megawatt can be fueled, FirstLight says, ISO-NE can avoid sending inaccurate market signals at times when winter capacity is actually not in surplus. At the same time, it will provide efficient longer-term signals for resources to install dual-fuel capability, contract for pipeline transportation or obtain priority access to LNG, it said. ■



The Massachusetts attorney general's office prefers a simple auction wherein bids vary depending on bidders' independent evaluations of costs and other factors, as well as the strike price the bidder wants to offer. | *London Economics*

MISO News

Supply Future Looking Brighter, OMS-MISO Survey Shows

By Amanda Durish Cook

CARMEL, Ind. — A key annual capacity report issued by MISO and the Organization of MISO States predicts the RTO is now unlikely to face a near-term shortfall in generation — a welcome reversal of last year's more worrisome findings.

Credit the change to expectations for flat demand and the promise of ample resource additions.

The *survey* released Friday forecasts a generation surplus of about 3 to 6 GW in 2020, though the RTO says "continued action will be needed to ensure sufficient resources are available going forward." Last year's survey forecasted a possible 0.1-GW shortfall in 2020.

Unsurprisingly, OMS and MISO say the future through 2024 could bring a "range" of resource amounts, but the survey no longer predicts any regional shortfalls in generation before 2022.

Using this year's 16.8% planning reserve margin as a baseline, the survey predicts a 1- to 4-GW surplus in 2021. By 2022, that excess dwindles to 1 to 3.4 GW. The range of possibilities in 2023 and 2024 varies the most, with the forecast indicating anything from a 1.3-GW shortfall to a 7-GW surplus in 2023, and a 2.3-GW shortfall to another 7-GW surplus in 2024.

MISO said more than 97% of its load-serving entities and additional non-LSE market participants responded to the survey.

Last year's survey showed MISO's footprint could see anything from a 7.5-GW surplus to a 4.5-GW shortfall from 2020 to 2023 and predicted spare capacity ranging from 0.6 to 6.6 GW this year. (See *OMS-MISO Survey Reveals Dimmer View of Future Supply*.) The newest survey results are also a far cry from the 2016 iteration, where MISO said a generation shortfall was possible in 2018.

But during a call Friday to discuss the results, MISO staff cautioned that the 2019 survey results will differ from future realities. MISO Executive Director of Resource Planning Patrick Brown stressed that capacity deficiencies could occur "if no action is taken."

MISO said certain Midwestern zones could develop the greatest resource adequacy risks, including Southern Illinois' Zone 4, Indiana and western Kentucky's Zone 6, and Lower Michigan's Zone 7. MISO said it foresees "lower resource commitments" in those areas in 2020 and beyond, including a possible 0.2- to 0.7-GW deficit in downstate Illinois and a potential 0.9-GW shortage in Lower Michigan in 2020.

But a possible capacity shortfall isn't an immediate concern even in those areas, Brown said.

"Zones with deficiencies don't automatically have a resource adequacy risk as they can use surplus resources outside of their zone … taking advantage of MISO's footprint diversity. … They do have the option to import capacity into their zones to meet their local needs," Brown said.

Brown also said those areas have ample time to adjust to ensure appropriate capacity.

Contrary to OMS-MISO results, the Michigan Public Service Commission has said that state will have sufficient capacity in place to meet obligations through 2022, he noted.

As with prior reports, MISO's demand growth rate is set to decline again, with the five-year annual rate adjusted to 0.2%, down from a 0.3% projection in 2018.

"Fewer resources are needed to serve load," Brown said.

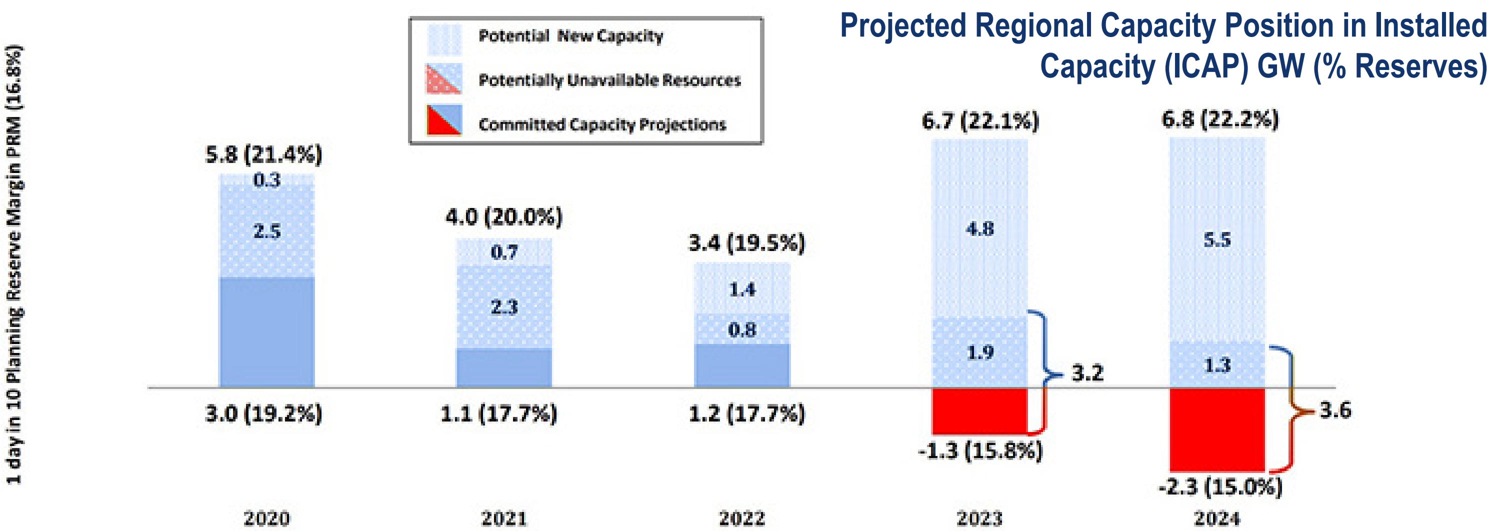
MISO has only expected "modest" changes in peak load over the next five years, *anticipating* a 4.4-GW variance in expected system peak, with electric vehicles adding about 1 GW in demand by 2023. The RTO doesn't expect its current approximate 120-GW peak predictions to be "radically different" within five years, market design team member Dustin Grethen said at a June 6 Market Subcommittee meeting.

As of May, MISO's generator interconnection queue *consisted* of 640 projects totaling 100.7 GW, nearly 30 GW of which (210 projects) are solar generation.

Brown also said this year's survey shows significant amounts of generation retirements, with "a mix of wind, solar storage and gas" as well as load-modifying resources lined up in the interconnection queue set to replace them. MISO does expect emergency declarations to become more frequent as a result, he said.

The RTO plans to post and discuss the survey results in more detail, including a zonal breakdown, at its July Resource Adequacy Subcommittee meeting. ■

Projected Regional Capacity Position in Installed Capacity (ICAP) GW (% Reserves)



2019 OMS-MISO survey results | *MISO*

MISO News

Berkeley Study: Up to 12 Million EVs in MISO by 2040

By Amanda Durish Cook

Blue Indy car sharing in Indianapolis | © *RTO Insider*

CARMEL, Ind. — MISO will one day see a proliferation of electric vehicles. Just don't expect them to begin plugging in en masse before millennials begin hitting midlife crises.

The region served by MISO can expect to see significant EV penetration of anywhere from 1 million to 12 million vehicles by 2039, according to a Lawrence Berkeley National Laboratory impact *study* prepared for the RTO.

MISO policy studies engineer Aditya Jayam Prabhakar opened his presentation on the study Wednesday before the Planning Advisory Committee with an anecdote describing how his neighbor on one side of his home had recently purchased a red Tesla model, while his other neighbor is also considering buying a Tesla.

"I'm going to be addressed as the guy between two Teslas," Prabhakar joked.

But he said the story illustrates that "what was once was out of reach is now becoming attainable."

If EV adoption revs up — and "MISO turns into San Jose" — the RTO could see as many as 36 million EVs in the footprint Prabhakar said. But that's an extremely unlikely case, he pointed out.

"There's obviously a very high range," Prabhakar said.

The likeliest range of future EVs, he said, lies somewhere among the study's "low," "base" and "high" case scenarios of 1.6 million, 4 million and 12 million vehicles, respectively, by 2039. To come up with its estimates, Berkeley used a combination of MISO and state-level data, 2018 *projections* from Boston University researcher Peter Fox-Penner and figures from the U.S. Energy Information Administration.

The MISO footprint currently contains only about 70,000 to 80,000 EVs, Prabhakar said.

"That's a very small number compared to where we could be in the future," he said.

The study shows that if left uncontrolled, EV charging stands to steadily increase peak loads and the ramps needed to accommodate those peaks. However, if EV charging is controlled, it can deliver "significant load shaping grid services," MISO said.

Controlled charging can occur in one of two ways, the study explained. Under "unidirectional" control, the flow of power to the vehicle can vary over the course of a charging session based on a timer, price signal or other set of rules based on grid conditions. "Bidirectional" control offers all those same features, while additionally allowing power to flow from the vehicle to the grid, helping to alleviate grid stress during periods of peak consumption.

MISO also noted that managed EV charging can help mitigate the daily load troughs and morning and evening ramps that increased renewable use can exacerbate.

In the extreme, 36 million vehicle case, uncontrolled EV charging "dominates loads throughout the day" and could add about 40 GW to load by mid-2038. MISO's average summer load last year was 86.6 GW.

"Preparing for EV impacts and their charging is a really great thing to start thinking about," Prabhakar said. "This is uncharted territory in terms of what can happen; there's so much that can happen."

"I think EVs are a question of not if, but when," Wabash Valley Power Association's Matt Dorsett said. "What are the next steps for MISO? It's certainly on our radar, and I think it's coming quicker than we'd like."

Prabhakar said the RTO can begin adding more sophisticated EV load shapes in planning models. He said previous attempts to model future EV use boiled down to simple energy use increases.

"This is a more engineering-based approach," he said, referring to the load-shaping approach.

Veriquest's Dave Harlan asked whether MISO would also consider that, by 2040, several generators could have already installed storage that would already serve to flatten load.

Prabhakar agreed potentially disruptive technologies like storage and EV charging should be considered together.

Multiple stakeholders also asked MISO to keep an eye on burgeoning, ultra-fast technology that can fully charge a vehicle within minutes, placing extra demand on the grid. ■


Tesla charging station in Carmel, Ind. | © *RTO Insider*

MISO News

MISO Floats MTEP Time Trade-off

Proposal Would Put Focus on 2021 Futures Retool

By Amanda Durish Cook

CARMEL, Ind. — MISO is toying with the idea of foreshortening its 2020 Transmission Expansion Plan (MTEP) process in order to maximize time spent on the 2021 cycle of transmission projects.

The RTO last week said it wants stakeholder approval to stop work on the four 15-year future scenarios used in the 2020 MTEP (requiring it to instead rely on an older version of futures) and to forego the usual planning studies in favor of smaller, specialized studies to identify projects.

MISO Planning Manager Tony Hunziker said the idea is to finish MTEP 20 work early to provide more time to completely retool the future scenarios in time for the 2021 cycle.

"Throughout this process, there's been this building momentum and increased interest in starting MTEP 2021 futures as early as possible," Hunziker told stakeholders at a Planning Advisory Committee meeting Wednesday.

Stakeholders asked if the 2020 plan would still contain an Appendix A, the annual list of transmission projects recommended to the Board of Directors for review and approval.

"There would certainly be an Appendix A and the usual reliability projects. This would more impact economic projects," Hunziker said.

If MISO stops work on MTEP 20, it won't have the usual Market Congestion Planning Study for the cycle.

"In its place, we could do a couple targeted economic studies," Hunziker suggested. "We haven't completely thought through everything yet. We wanted to put this out there and judge stakeholders' interest."

He assured stakeholders that MISO wouldn't skip economic transmission planning for the year; it would just come in a different form.

"We're still very committed to the economic planning process," Hunziker said.

He said moving forward with MTEP 20 futures development would "tie staff up until mid- to late summer."

"If we continue down the path of completing MTEP 2020 futures, it's going to slide down the time that we can start on the 2021 futures," Hunziker said.

Stopping work on MTEP 20 would pull staff's focus entirely to developing MTEP 21 futures, he said. Staff have previously promised stakeholders an extensive rework of the four futures that guide the annual transmission planning process in time for 2021.

MISO had been using the same set of futures with only minor edits for the last three years to evaluate transmission projects. The RTO developed the futures in collaboration with stakeholders with long-term use in mind. (See *MISO: Minimal Change to 2019 Tx Planning Futures*.)

In April, MISO said it would boost renewable generation estimates in each of the four 15-year future scenarios, bumping minimum penetration levels from 15 to 35% of the generation mix to 20 to 40%. (See *Renewables Outlook to Get Boost in MTEP 20 Futures*.) However, MISO's pivot puts that proposal in doubt, with Hunziker saying it could either keep or discard the larger renewable assumptions.

In halting further efforts on MTEP 20, MISO would likely begin 2021 futures discussions in July and schedule four special workshops in fall to gauge stakeholder expectations around a new set of futures.

"Either way we go, we'll start the MTEP 2021 futures discussion early," Hunziker said, adding that MISO would begin discussions on MTEP 21 with or without a MTEP 20 work stoppage by September. MISO usually begins futures development in January of each year for the upcoming year's transmission planning cycle.

A Hijacking?

Some stakeholders pointed out the move would give MISO 27 months to develop futures, risking that enough time could pass for the freshly developed futures to themselves become stale. But Hunziker said the first few months would be spent on how to improve the process and settle on what new data should inform the scenarios.

Clean Grid Alliance's Natalie McIntire asked how the move would affect MISO's annual interregional transmission planning efforts with SPP and PJM. She said that because MISO no longer builds a joint model with its neighboring RTOs, it should keep up with grid modeling.

MISO staff said they weren't yet sure how the new course of action would interact with next year's interregional planning.

Tony Hunziker | © *RTO Insider*

"I'm really surprised and concerned by this," McIntire said. "It's concerning that a small number of stakeholders can hijack the process," suggesting that only a few influential members were in favor of truncating MTEP 20.

However, Xcel Energy's Drew Siebenaler thanked MISO for proposing a "pared-down" MTEP 20. He said the move would give the RTO the time necessary to evaluate several new state and company renewable targets, new resource retirements and recent zero-carbon commitments for use in its futures.

"Who says we're going to have that kind of clarity in five months?" consultant Roberto Paliza challenged. "I just don't see that we'll have a new set of futures that are radically different."

"We're just about done with the MTEP 20 discussion here," McIntire said. "The whole idea that we would get rid of a big part of MTEP 20 … I don't think that extra two months [for MTEP 21 futures] is going to be that significant."

But Hunziker pushed back on that assertion, saying his staff don't have time to properly facilitate both MTEP 20 futures and studies and early preparations on MTEP 21. He asked for more comments on the issue by June 28. ■

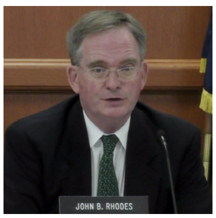
NYISO News

NYPSC Dings Utilities for 2018 Reliability, Safety

Extreme Weather Resulted in more Outages than in 2017

By Michael Kuser

Four of New York's major utilities will collectively see their revenues reduced by more than $7 million for failing to meet certain reliability and customer service requirements last year, state regulators revealed last week.



John B. Rhodes

The New York Public Service Commission on Thursday reviewed reports on utility performance in electric reliability, gas and electric safety and customer service in 2018 (Cases 19-E-0169, 19-E-0246 and 19-M-0307). "While most utilities are doing a good job providing safe and reliable service, four utilities have fallen short of our expectations in certain areas, and we will continue to act aggressively to ensure utilities improve performance," PSC Chair John B. Rhodes said. "Additionally, as a result of this analysis, it is clear that utilities must be ready to address more frequent and powerful storms."

The utilities being dinged for their performance include New York State Electric & Gas, Central Hudson Gas & Electric, Orange and Rockland Utilities, and National Grid's Long Island gas operation.

Major storms last year accounted for more than 80% of the total customer-hours of electric service interruptions and 36% of the overall number of customers affected. New York experienced 36 separate major storm events in 2018, with the five largest occurring between March 2 and May 20, said Mary Ferrer, of the Department of Public Service's Office of Electric, Gas and Water.

Last year ranks third in customer-hours of interruption in the last 20 years, behind Hurricane Irene and Tropical Storm Lee in 2011 and Hurricane Sandy in 2012.

Last year saw more customer-hours of interruption when including major storms than calendar year 2017; however, excluding major storms, the statewide interruption frequency and duration performance for 2018 declined compared to the previous year and the statewide five-year average, primarily because of fewer outages from equipment failures and tree contacts, Ferrer said.


The PSC held its regular monthly session in New York City on June 13.

'Right Kind of Oversight'

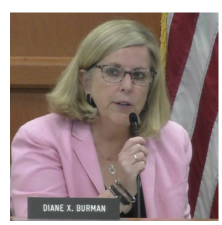
The commission relies on two primary metrics to measure electric performance: the System Average Interruption Frequency Index (SAIFI), and the Customer Average Interruption Duration Index (CAIDI). By compiling the interruption data provided by the individual utilities, the average frequency and duration of interruptions can be reviewed to assess the overall reliability of electric service statewide.

NYSEG had its worst performance last year since 2007 with an average duration of 2.17 hours, above the target of 2.08 hours. Central Hudson's frequency performance of 1.50 did not meet the target of 1.38.

The duration and frequency target failures mean NYSEG shareholders will see a negative revenue adjustment of $3.5 million and Central Hudson shareholders will see a negative revenue adjustment of $2 million, the commission said.


Benjamin Dunton

All the utilities complied with safety standards in 2018. Manual stray voltage testing performed on approximately 1 million utility facilities statewide identified 396 stray voltage situations, more than in 2017, though incidences of the more severe category over 4.5 V declined. Most such incidents on utility-owned facilities stem from street lighting, DPS staff member Benjamin Dunton said.



Diane Burman

In response to a question by Commissioner Diane Burman about why the more serious stray voltage readings were down from the previous year, Dunton said, "More awareness on the part of people doing construction work and digging."


Sonny Moze

DPS staff member Sonny Moze delivered the report on customer service quality, which found that most utilities met or exceeded the standards for customer service for 2018, with the exception of O&R,

NYISO News

which failed to meet its target for calls answered by a representative within 30 seconds.

"This is the right kind of oversight," Rhodes said of the customer service report. "I appreciate that O&R is responding to the evidence and will appreciate it even more when their performance improves to the standard that we expect."

O&R's shareholders will be required to pay $450,000 for the performance shortcoming.

"I do think it's important that we have more meat on the bone when it comes to the 30 seconds for calls answered," Burman said. "The utilities point out why it's taking longer to answer the call, so we might need to work on that." O&R, for example, cited higher-than-normal call volumes.

Barring ESCOs?

The PSC also announced steps that could prohibit five energy service companies (ESCOs) from further marketing and enrolling new customers in New York. Only one of the five companies, Atlantic Power & Gas, currently has any customers.

"I think it's important to identify that we are looking at potential violations of the Uniform Business Practices [adopted for ESCOs], and really relating to filings that haven't come, and there are no customers there," Burman said. "Two of them have voluntarily discontinued practicing in the state because they failed to report to us. The other two are orders to show cause, but again there are no customers involved."

The commission has the authority to regulate ESCOs' access to utility distribution systems, including the power to require them to meet price caps set at utility prices.

The PSC directed that Atlantic explain why the commission should not ban it from operating in New York or take other remedial action (Case *16-M-0618*).

In March 2017, the commission ordered Atlantic to cease marketing to and enrolling customers. On March 4, DPS staff identified apparent violations of the order.

Atlantic does business in the service territories of Central Hudson, Consolidated Edison, and National Grid's KeySpan Gas East and Brooklyn Union Gas. It has 30 days to counter the DPS findings.

Further, the commission also directed that Clear Choice Energy, Amerigreen Energy, Bluesource Energy and Got Gas? — none of which has customers — explain why they should not be barred from operating in New York for failing to file their annual compliance filings.

Sayre Farewell

Gregg C. Sayre

Rhodes read a resolution of appreciation for Commissioner Gregg C. Sayre, likely attending his last session as commissioner, as the New York State Senate is soon to vote on Gov. Andrew M. Cuomo's nomination of Tracey Edwards, a Long Island Democrat, to a seat on the PSC. State law sets a maximum of five members of the commission, of which only three can be members of the same political party.

The PSC currently has four members: three Democrats and one Republican. ■

PJM News

PJM MIC Briefs

FTR Settlement Start Date Set

Jen Tribulski | © *RTO Insider*

VALLEY FORGE, Pa. — The 90-day clock for stakeholders to work out how PJM will unwind $100 million worth of financial transmission rights settlements will begin this Wednesday, PJM legal counsel Jen Tribulski told the Market Implementation Committee last week.

The update comes after FERC issued an order June 5 that encouraged conflicting parties to hammer out disagreements ahead of a scheduled paper hearing under the guidance of a settlement judge, who will report progress on the discussions to the commission at the 45- and 90-day marks (*ER18-2068*). A one-time extension may be granted for 30 days, FERC said. (See *FERC: PJM Settle Disputes Before GreenHat Hearing*.)

The order also granted PJM's motion for clarification on its denied petition to waive its liquidation rules, which has complicated the RTO's efforts to minimize the damage of the default and potentially increases costs to members by $300 million. (See *FERC Orders PJM to Unwind GreenHat Settlements* and *PJM: FERC Order Could Boost GreenHat Default by $300M*.)

"During the settlement proceedings, all issues are on the table," Tribulski said. "It doesn't have to be just the six [issues PJM raised in its request for clarification]. If we go to hearing, it's limited to just the six issues."

Stakeholders expressed a mix of confusion and frustration over the ruling, with most unsure of what's left to settle considering many were in agreement with PJM's initial waiver request.

"The real problem is FERC just making the wrong decision and setting us down a path that PJM said is untenable," said Carl Johnson of the PJM Public Power Coalition. "You asked them to clarify their own rules, so I think it's unrewarding that FERC is going to ask us to fix it among ourselves."

PJM's Market Implementation Committee met on June 12. | © *RTO Insider*

5-Minute Dispatch Problem Statement Endorsed

Stakeholders gave near-unanimous support for the Independent Market Monitor's *problem statement* to review processes for real-time security-constrained economic dispatch (RT SCED) and market pricing that PJM uses to send dispatch signals to generators and calculate LMPs. (See "Monitor Presents Updated 5-Minute Dispatch Problem Statement," *PJM MIC Briefs: May 15, 2019*.)

Siva Josyula | © *RTO Insider*

Siva Josyula of Monitoring Analytics said a publishing price delay on April 8 — as well as a July 10, 2018, low area control error (ACE) *event* and corresponding Manual 11 revisions — call into question the transparency of PJM's RT SCED processes.

Education about RT SCED will begin in the MIC next month.

Electric Storage Participation Rule Changes

PJM presented more manual *revisions* for electric storage participation rules in compliance with FERC Order 841.

In Manual 11: Energy & Ancillary Service Operations, section 2.3.4B was added to explain how electric storage resources (ESRs) would participate in the markets, including clarification that the resources can sell in the energy, capacity and ancillary markets if they are technically capable of providing those services. It also provides information on dispatch and pricing, bid parameters and clarifies that stored megawatt-hours are billed at LMPs as wholesale. Staff also added definitions for defined modes and the opt-in and opt-out processes and updated ESR hourly limits.

In Manual 18: PJM Capacity Market, staff updated the definition of capacity storage resource to include ESRs that participate in the reliability pricing model or are "elsewhere treated as capacity in PJM's markets such as through a fixed resource requirement capacity plan." Revisions also clarify that ESRs may not receive peak load contributions for energy they sell back to the grid.

Laura Walter, a senior lead economist for PJM, said the purpose of the revisions — and many more anticipated in other manuals — is to open up markets for ESRs and ensure parameters allow such resources to operate effectively.

PJM's ESRs include approximately 5,000 MW of pumped hydro and 310 MW of battery storage, she said. The resources will be allowed to offer into both the day-ahead and real-time markets and will be modeled as continuous resources with the ability to self-manage their own state of charge.

PJM will seek MIC endorsement at the July 10 meeting. ■

— Christen Smith

PJM, Monitor Subpoenaed in 2010 UTC Scam Case

By Christen Smith

PJM and its Independent Market Monitor must turn over a trove of documents stemming from allegations of market manipulation against now-defunct Coaltrain Energy over its profits on up-to-congestion (UTC) trades collected in 2010.

The U.S. District Court for Southern Ohio *subpoenaed* both parties on June 4 for records supporting complaints to FERC that the trading group profited by $4.2 million using an "over-collected loss strategy" that diverted more than $8 million in marginal loss surplus allocation (MSLA) payments between June and September 2010.

FERC and Coaltrain's former staff — including leaders Shawn Sheehan and Peter Jones, and traders Jeff Miller, Jack Wells and Robert Jones — have been locked in a lengthy and expensive court battle over the commission's demand for $42 million in fines and disgorged profits as penalty for the bad behavior.

Coaltrain is one of at least three firms accused by FERC of market manipulation for profiting on line-loss rebates from what the commission called risk-free UTC trades in PJM. (See *Traders Deny FERC Charges; Seek Independent Review*.) The company maintains it didn't manipulate the market; its trading strategy wasn't deceptive; and it didn't engage in wash trades or try to affect market prices.

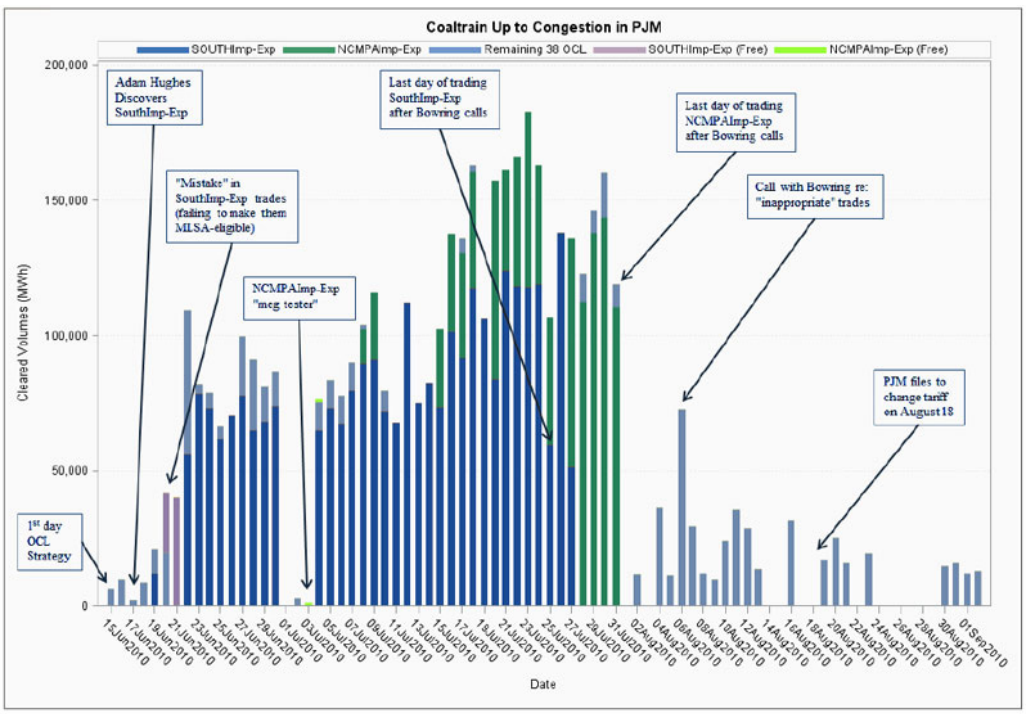


Chart illustrates the time period over which Coaltrain Energy engaged in its over-collected losses (OCL) strategy, illegally earning it payments from PJM's marginal loss surplus allocation program. | *FERC*

FERC also alleged Coaltrain's use of employee-monitoring software gave investigators evidence of the company's trading strategy. FERC said Coaltrain employees at first claimed they had forgotten about the software — Spector 360 — when the Office of Enforcement initially asked, and then they repeatedly delayed giving up the data. Sheehan and Jones allegedly didn't have the program installed on their computers, effectively concealing their actions. (See *FERC: Spy Software Provide Evidence of UTC Scam*.)

Now, the court wants the Monitor and PJM to hand over all communications regarding Coaltrain from Jan. 1, 2010, through Sept. 30, 2010 — including phone calls, emails, studies, simulations, calculations and even the 2009 State of the Market Report.

The Monitor said in a June 4 email to PJM stakeholders the court order forces it to reveal confidential member information. Those opposed to the release must alert the IMM no later than June 28, the Monitor said. ■

PJM News

PJM Operating Committee Briefs

New Chair Come July

VALLEY FORGE, Pa. — PJM's Darlene Phillips will take over the Operating Committee in July after current Chair Dave Souder starts his new role as executive director of systems operations.

Phillips is currently the senior director of strategic policy and external affairs and joined PJM in August 2015. She served in several leadership roles for MISO for more than 10 years and is a graduate of the University of Michigan and Indiana University's Robert H. McKinney School of Law.

Souder's promotion comes after a leadership shake-up following CEO Andy Ott's retirement, effective June 30. (See *PJM CEO Ott to Retire*.) He will take over the role for Ken Seiler, who will become vice president of planning and be responsible for the oversight of the System Planning Division, which includes transmission planning, interregional planning, interconnection analysis, interconnection projects, infrastructure coordination and resource adequacy planning.

Tornadoes Knock Out Tx Lines

PJM said a wave of tornadoes on Memorial Day and throughout the last week of May left about 80,000 customers without power around Dayton, Ohio.

Half the customers were restored within 12 hours, staff said, but several transmission lines remain inoperable because of storm damage. PJM expects the lines will be under repair through the end of June.

Energy Storage Revisions Get First Read

Revisions to PJM manuals for energy storage mandates got a first read during last week's OC meeting. PJM staff said the changes follow directives from FERC Order 841.

First up were changes to *Manual 14D: Generator Operational Requirements*, including Operating Agreement definitions of energy resource, capacity resource, energy storage resource (ESR) and capacity storage resource. Language was also added to clarify applicability of manual requirements to generation and storage resources. Sections 4.1.7 and 4.2.3 were revised to include telemetry of state of charge for ESR model participants and specific metering requirements. Staff also added a definition for generating facility per FERC's compliance filing for Order 845.

In *Manual 36: System Restoration*, PJM revised the exception to critical cranking power to include non-hydro energy storage resources and updated the participation model to allow ESRs to participate in all markets where technically feasible.

In *Manual 40: Training and Certification Requirements*, sections 3.2.4 and 3.2.6 were updated to account for small generation resource dispatchers and lower the megawatt threshold for training requirements to accommodate ESRs. Language was also changed to reflect ESRs are assumed to be more than participants in ancillary markets.


Laura Walter | © *RTO Insider*

Laura Walter, a senior lead economist for PJM, said the purpose of the revisions — and many more anticipated in other manuals — is to open up markets for ESRs and ensure parameters allow such resources to operate effectively.

PJM's ESRs include approximately 5,000 MW of pumped hydro and 310 MW of battery storage, she said. The resources will be allowed to offer into both the day-ahead and real-time markets and will be modeled as continuous resources with the ability to self-manage their own state of charge.

The manual revisions will return to the September OC for final endorsement to give stakeholders time to provide additional feedback.

Nuclear Plant Interface Coordination Updates

PJM wants to *update* Manual 39 with new sections and clarifying language for its nuclear plant interface coordination procedures.

The revisions include new language in sections 2.7, 3.6 and 3.7 that address coordination of remedial action schemes and load-shedding schemes. They also cover the deactivation and retirement process for nuclear units and the regulatory requirements of that process, as well as the coordination between reliability coordinators when a non-PJM member is identified by a nuclear plant generator operator as a transmission entity.

PJM's Operating Committee met on June 11. | © *RTO Insider*

Attachment B will also be renamed to "Plant Specific NPIRs." Endorsement is scheduled for the July OC.

Emergency Operations Updates

Staff added multiple section *changes* to Manual 13: Emergency Operations to align with the new Markets Gateway functionality for resource limitation reporting to be implemented on Aug. 1.

Sections 1.1, 2.3, 3.1-3.5 and 5.2 have been revised to reflect the following:

- Terminology for "fuel-limited" units has changed to "resource-limited" to clarify applicability of reporting requirements.
- Units are considered resource-limited if they have less than 72 hours of remaining runtime at maximum capacity, limited by primary/alternate on-site fuel, emissions, demineralized or cooling water or other consumables.
- Resource-limited units are to report resource limitations via the new Markets Gateway page.
- Natural gas-fired units with fuel limitations are not considered resource-limited and are excluded from resource limitation reporting via the Markets Gateway.
- References to the Supplementary Status Report (SSR) for reporting resource limitations have been removed and replaced with instructions for using the new Markets Gateway page.

In Section 6.4, clarifications were made to

PJM News

address procedures when PJM has declared conservative operations or hot/cold weather alerts:

- Fuel-limited gas-fired units are not to be placed in maximum emergency but should remain available to ensure PJM tools "economically schedule" the gas-fired units, unless PJM dispatch directs them to be placed in maximum emergency dispatch status.
- Dual-fuel units — gas/other on-site fuel — should be placed in maximum emergency status when non-fuel resource limitations restrict runtime to less than 16 hours for combustion turbines and 32 hours for steam turbines. When fuel is limited, they should be placed in maximum emergency status only when natural gas is unavailable and their on-site fuel inventory is less than 16 hours for CTs and 32 hours for steam.

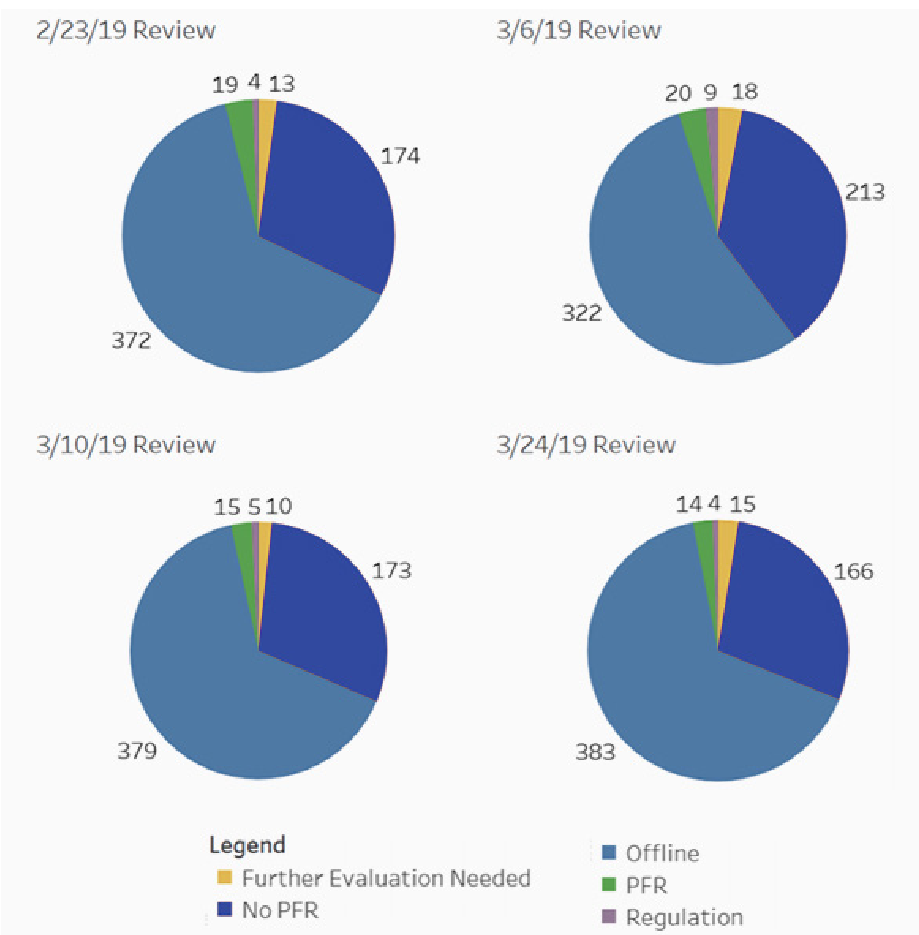
The changes were made to align with existing language in the OA for designating fuel-limited resources as maximum emergency.

First PFR Evaluation Reveals Low Participation

Most online resources don't provide primary frequency response (PFR), a PJM *analysis* concluded.

PFR is the ability of generators to automatically change their output in five to 15 seconds when the grid's frequency strays above or below 60 Hz. As more renewables enter the resource mix and coal plants retire, the grid can become more susceptible to these frequency swings, threatening system reliability.

Danielle Croop, a senior engineer in PJM's generation department, said 583 units with capacities of 50 MW or greater were evaluated for PFR across five events in late 2018 and early 2019. The selected events for analysis met one of three qualifications: frequency goes outside the +/- 40-mHz deadband, frequency stays outside the +/- 40-mHz deadband for 60 continuous seconds or minimum/maximum frequency reaches +/- 53 mHz.



Few PJM resources provided primary frequency response when called upon on four dates reviewed in February and March. (Number of units is listed for each category of response.) | *PJM*

No more than 20 resources provided PFR during the selected events, PJM data show. More than half remained offline and another third did not respond, Croop said. When pressed as to whether the analysis meant generators were performing poorly, she said only that clearly more follow-up is needed to fully understand why units did not respond as anticipated.

"I will say there is a concern here because we looked at 583 units, and the majority of them are not responding," she said.

BTM Generation Rules Preview

PJM will soon bring rule *changes* for non-retail behind-the-meter generation (NRBTMG) to the OC for endorsement.

NRBTMG refers to resources used by municipal electric systems, electric cooperatives or electric distribution companies to serve load. They do not participate as supply resources in PJM markets but can be netted against their wholesale load to reduce transmission, capacity, ancillary services and administrative fee charges.

PJM's rules on such resources resulted from a 2005 settlement agreement (*EL05-127*), before development of the RTO's capacity market and CP constructs. NRBTMG resources can be called upon during the first 10 maximum generation emergencies annually, while CP resources are required to perform during all performance assessment intervals (PAIs). BTM operators that fail to perform face reduced netting benefits. In 2006, the grid operator identified about 400 MW of NRBTMG.

Terri Esterly, PJM's senior lead engineer for capacity market operations, said *manual changes* are ready for stakeholder review. The revisions grew out of a problem statement and issue charge that showed PJM can't accurately account for how much NRBTMG contributes to the grid, particularly with the growth of solar and other distributed resources. (See "PJM Continues Review of Non-retail BTM Generation Business Rules," *PJM OC Briefs: Feb. 5, 2019*.)

Updates to Manual 13 show the phrases "maximum generation emergency action" and "deploy all resource action" have been identified as triggers to load NRBTMG. Updates to Manual 14D Appendix A include revisions to the business rules to clarify the reporting, netting and operational requirements of NRBTMG. ■

— Christen Smith

PJM News

PJM PC/TEAC Briefs

PC Chair Change

VALLEY FORGE, Pa. — PJM Planning Committee Chairman Ken Seiler said the new executive director of systems operations, Dave Souder, will replace him as committee chair in July.

Souder currently heads the Operating Committee. Seiler is becoming PJM's vice president of planning. (See related story, "New Chair Come July," *PJM Operating Committee Briefs: June 11, 2019*.)

Seiler's promotion came during a leadership shake-up with the announcement of CEO Andy Ott's retirement, effective June 30. (See *PJM CEO Andy Ott to Retire*.)

RTEP Poll

PJM scrapped plans to take a nonbinding poll in the meeting about its regional transmission planning language *revisions*, deciding instead to email open-ended questions to members in hopes of generating more accurate feedback.

Aaron Berner, manager of transmission planning, said after more than six meetings with stakeholders, staff believe they are "close" on tweaks to Manual 14B that address how and when supplemental projects are removed from the Regional Transmission Expansion Plan.

Staff will email two questions to PC members regarding whether they believe the posted manual changes "are on the right track" and what further revisions still need to be made. Results will be presented at the Markets and Reliability Committee meeting June 27. (See "RTEP Removal Language on Track for June MRC Vote," *PJM PC/TEAC Briefs: May 16, 2019*.)

The decision was made after stakeholders expressed confusion over how the results of the nonbinding poll would be interpreted. Some felt uncomfortable signaling approval without complete consensus on the language. A few transmission owners remain diametrically opposed to the entire effort and consider existing manual language sufficient as is, possibly skewing PJM's perception of how willing stakeholders are to adopt changes. (See *PJM Rebuffs Stakeholders on Supplemental Projects*.)

PJM Developing Hybrid Fee Structure

Stakeholders will soon see PJM's proposal for a hybrid-fee structure for transmission *project cost-containment analyses*, Manager of Infrastructure Coordination Mark Sims said.

Currently, the RTO charges nothing for cost-containment reviews of projects $20 million or less. Projects up to $100 million cost $5,000 to review, and larger projects incur a $30,000 fee. Sims said the new formula may include a flat fee, plus itemized study costs.

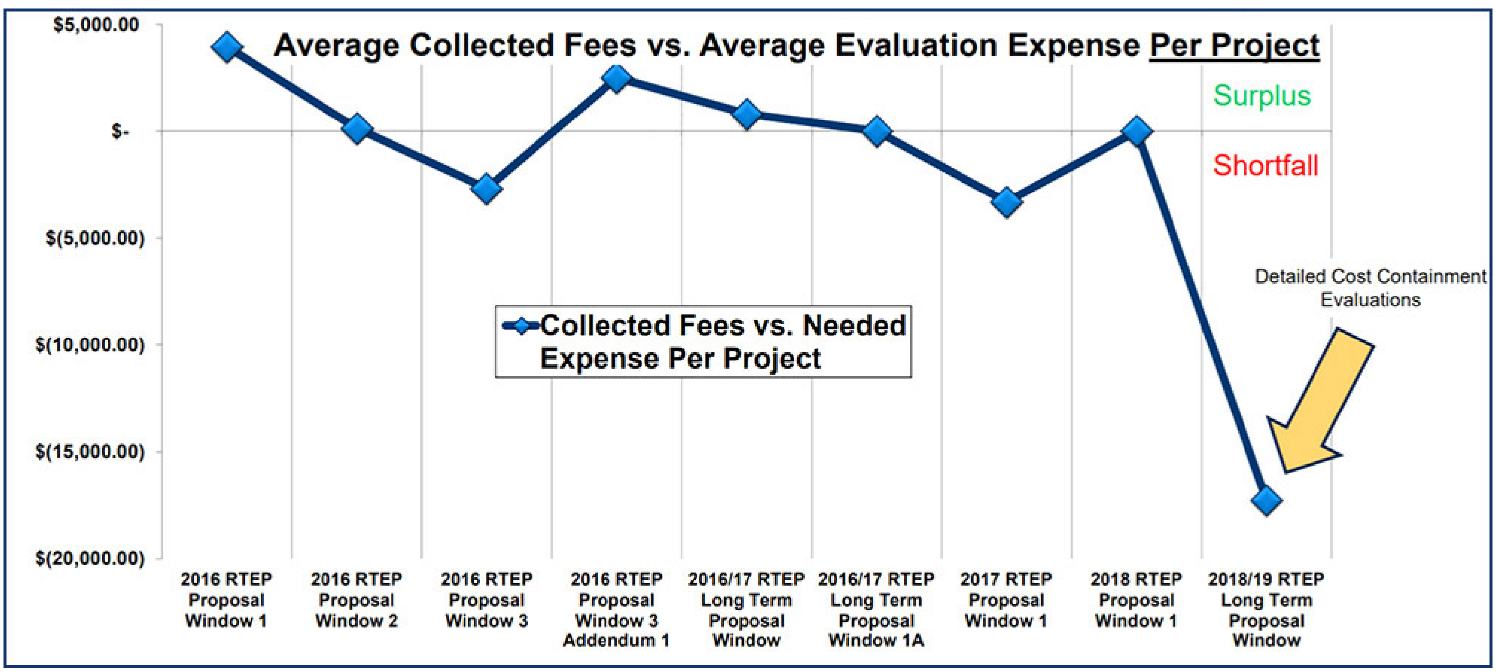
Projects considered the most competitive will accumulate more itemized costs, Sims said, while those considered less viable could pay nothing additional beyond the flat fee.

"The way we are headed, we think, is to keep some flat fee structure plus detailed studied costs," he said. "It will be somewhere between that zero and $30,000."

Sims told the PC last month that PJM's old tiered approach, approved in 2014, doesn't account for the increased cost of the new comparison framework that involves an independent consultant's review and legal and financial analyses. (See "New Fee Structure for Cost Containment Needed," *PJM PC/TEAC Briefs: May 16, 2019*.)

Generation Interconnection Rules Endorsed

The PC endorsed *revisions* to Manual 14G to update PJM's generation interconnection process and clarify the site control requirements. The changes expand rules for demand response in section 1.7 and refers on-site generators used to reduce load that participate as DR to Manuals 11 and 18 for further guidelines. The portion of such generators that inject power past the point of interconnection follow the interconnection process outlined in Manual 14G.



PJM's collected project proposal fees versus actual analysis expenses | *PJM*

PJM also proposes a minimum site control term of three years — two years for projects of 20 MW or less — commencing on the first day of the new services queue in which the customer submits its request. Extensions must have been exercised by the developer when site control evidence is given to PJM if the initial term is less than the required minimum.

Despite some misgivings about site control extensions expressed during the May PC, stakeholders endorsed the revisions with only one abstention and zero objections. (See "Generation Interconnection Requests Update," *PJM PC/TEAC Briefs: May 16, 2019*.)

Market Efficiency Process Enhancement Task Force Charter

The PC endorsed the updated *charter* for phase 3 of the Market Efficiency Process Enhancement Task Force.

Both the PC and the Markets and Reliability Committee approved phase 3 of the task force last month. Under its new charge, the group will explore possible alternatives to regional targeted market efficiency projects and consider changing the 1.25 benefit-cost threshold to measure energy benefits separately from capacity benefits, as well as other concerns raised with benefit-cost calculations. (See "Market Efficiency Process Enhancement Task Force Gets Phase 3," *PJM PC/TEAC Briefs: April 11, 2019*.) The group will make recommendations to the PC by Dec. 12.

Reserve Requirement Study Assumptions

PJM's *assumptions* for its reserve requirement study earned unanimous support at the PC.

The capacity benefit margin — the amount of transmission import capability reserved to capture the reliability benefit of emergency sales — modeled in the study will be 3,500 MW. PJM will also use a load forecast error factor of 1% and base load models on assessment work performed by staff and reviewed by the Resource Adequacy Analysis Subcommittee.

PJM's Planning Committee and Transmission Expansion Advisory Committee met June 13. | © *RTO Insider*

Staff will use the PRISM model to develop a cumulative capacity outage probability table for each week of the year except the winter peak. During the winter peak, staff will create a table based on RTO-aggregate outage data collected between 2007/08 and 2018/19 to better account for the risk caused by the large volume of concurrent outages observed during the winter peak week.

The results of this study will be used to determine the forecast pool requirement for the 2020/21, 2021/22, 2022/23 and 2023/24 delivery years. A final report will be presented to the PC in September.

Dayton, Dominion, AEP Solutions

Dayton Power & Light, Dominion Energy and *American Electric Power* presented proposed supplemental projects during the Transmission Expansion Advisory Committee.

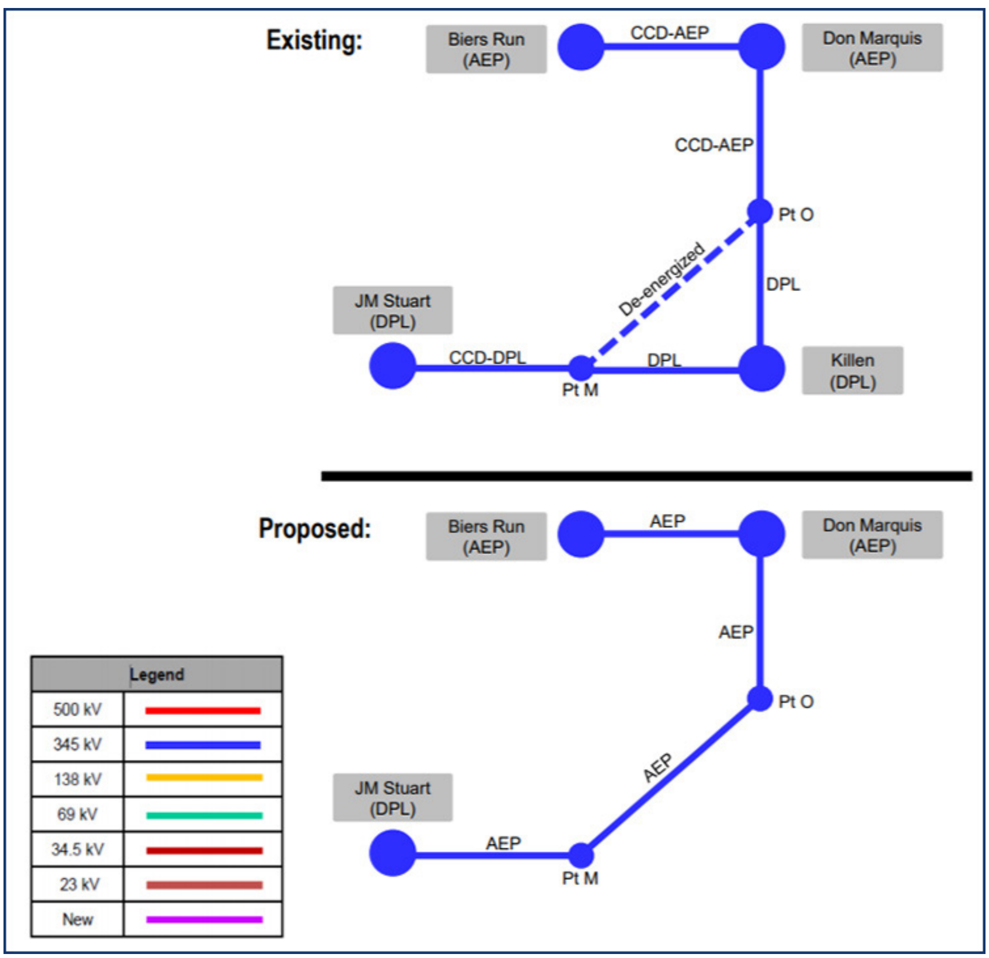
Dayton said AEP will re-energize a dead section of the Stuart-Marquis 345-kV line to bypass the now-defunct Killen substation near Wrightsville, Ohio. The $200,000 project will consist of Dayton installing guy stub poles for tension on the open section of the 345-kV loop.

A cheaper solution, Dayton said, would be to de-energize the Killen substation, update relay settings on the Stuart end of the line, install new tie-line meters and work with AEP to complete end-to-end relay testing for a cost of $100,000.

AEP estimates its share of the work — re-energizing the line, upgrading relay at the Don Marquis station and retiring intercompany metering — will cost approximately $1 million.

Dominion proposes installing a 3,000-amp, 50-kAIC circuit breaker to feed a requested new transformer at Chickahominy substation in Charles City County, Va., for an estimated cost of $750,000. ■

— Christen Smith



Dayton Power & Light and American Electric Power presented a solution to transfer power from the retired Killen substation near Wrightsville, Ohio. | *AEP*

PJM News

Battle over FTR Reform Shaping up in PJM

By Christen Smith

A battle over the future of the financial transmission rights market looms for PJM as stakeholders dig into the causes behind the GreenHat Energy default and consider ways to prevent such an event from ever happening again.

In one corner, the Independent Market Monitor, the Organization of PJM States Inc. (OPSI) and some RTO staff believe reforms should extend beyond credit and risk management policies to the FTR market structure itself, as suggested in the PJM-commissioned review of the conditions that allowed the situation to unfold. (See *Report: 'Naive' PJM Underestimated GreenHat Risks*.)

In the other corner, stakeholders and staff argue the FTR market structure remains sound and is vital to keeping costs low for consumers because it allows market participants to appropriately hedge congestion risk. Their interpretation of the independent probe concludes that failures in PJM's credit and risk management practices and unresponsive leadership allowed this small, unknown trading company to amass the largest portfolio of FTRs in RTO history in just a few short years — more than doubling the positions held by the second-largest market participant that had been building its folder for at least a decade.

The Energy Trading Institute stands in favor of keeping FTRs around. In a *white paper* released Wednesday, the policy group urged the PJM Board of Managers to ignore overtures from the Monitor and OPSI to reform the market, insisting the groups are just trying to distract from the real causes of the default.

"What matters for consumers is getting the lowest price possible in the competitive retail markets or standard offer/default service auctions where consumers actually lock in the cost of their electricity," said Noha Sidhom, ETI executive director. "By eliminating or reducing FTRs, OPSI and the Market Monitor would significantly increase the risk premium needed by retail service providers to serve customers in their specific locations."

PJM Monitor Joe Bowring said Monday that modifying the existing structure — including increasing auction frequency, reducing the number of paths to auction and eliminating long-term FTRs — would help return the FTR market "to its fundamental purpose."

"The current path-based FTR market is inconsistent with LMP and the payment of congestion in a network system," he said. "Congestion is simply the difference between what load pays and generation receives as a result of transmission constraints."

In particular, Bowring noted the generator-to-generator path to auction could be eliminated because LMP provides appropriate price signals and the right incentives for location and operation of generating units.

"All congestion belongs to load because load is the source of all congestion revenue," he said. "Generators do not pay congestion. Generators appropriately receive LMP at their location. FTRs were not designed to ensure that generators receive a higher price than their LMP."

Sidhom counters that only the "granular and diverse" nature of FTR products provide market participants with enough confidence to protect themselves against congestion risk and diversify their portfolios. Eliminating paths to auction will distort prices and raise risk premiums, she said.

"Limiting the availability of such paths for purchase in the FTR market will limit the load-serving entity's ability to more exactly target and prevent its exposure to that constraint," she writes in the ETI white paper, noting that the generator-to-generator path has proved invaluable to the growing share of wind and solar resources coming online. "If you eliminate a generator-to-generator path, the wind generator would be forced to face the financial exposure of its FTR against a load node, zone or hub, when wind output is low. This would be a far less effective and riskier hedge for the wind plant."

Bowring argued current market design forces load to accept whatever prices FTR buyers offer, which leaves them collecting about 80% of the congestion revenue owed to them — a share that drops even further for long-term FTRs. He recommends that PJM first assign congestion revenue to load and then allow LSEs to sell these rights as FTRs at an agreed-upon price.

"PJM can decide how to structure that auction," he said. "As with the current FTR auctions, any participant could buy such FTRs including generators and speculators."

Deeper Review

In a May 24 *letter* to the board, OPSI President Michael Richard supported a deeper review of FTR market structure, noting that current rules "lack adequate financial protection for load." The organization declined to comment on the contents of the ETI white paper.

Chairman Ake Almgren said in a June 7 response *letter* that the PJM board shares OPSI's view of the importance of reviewing FTR products, but he noted it's beyond the purview of the recently formed Financial Risk Mitigation Senior Task Force. (See *PJM Stakeholders OK Risk Management Task Force*.) He said the board instead expanded the charter of the Audit Committee to include direct supervision of risk management and that PJM continues to "actively recruit" for a senior level executive to lead the process.

"The task force is charged with assessing credit risk mitigation and management and not general market design," he said. "However, we expect the task force will consider whether credit risk can be appropriately mitigated by steps to simplify existing FTR products and increase the frequency of FTR auctions."

The task force began work last month to consider changes to credit and risk management requirements, market rules, membership qualifications and the stakeholder process in response to an independent probe of the default that uncovered structural flaws. PJM wants stakeholders to form solutions and make recommendations for Tariff and Operating Agreement revisions to the Markets and Reliability Committee and board by the end of year.

"We are committed to examining whether our current FTR product offerings present risk management challenges that outweigh the overall benefits," Almgren concluded. "However, at the same time, we cannot delay taking actions that might offer near-term opportunity to mitigate immediate risk exposure. Before embarking on broader market design changes, PJM will retain experts, as we have in the past, and our Market Monitor will be an integral part of that process."

PJM spokesperson Jeff Shields said Monday that RTO management agrees with several of ETI's points and disagrees with others, though the board will respond "in the near future" and consider stakeholder feedback when deciding what reforms to recommend to FERC.

"As is typically the case with letters to the board, the issues in play are contentious, with strong feelings on all sides of the debate," Shields said. "PJM and its membership are underway with a comprehensive assessment of better ways to mitigate and manage FTR credit risk." ■

FERC Orders Fast-start Rules for SPP

By Tom Kleckner

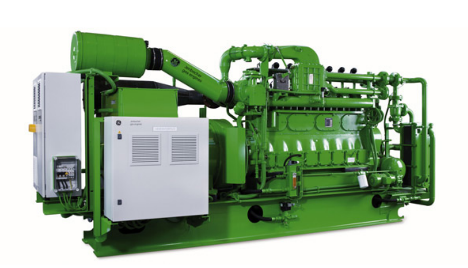
FERC last week directed SPP to make Tariff changes to allow fast-start resources to set clearing prices, saying its current rules are not just and reasonable (*EL18-35*).

The order wraps up investigations of several RTOs the commission began in December 2017 under Federal Power Act Section 206 and directs SPP to eliminate inflexible operating limits and other rules that the commission said are preventing prices from reflecting the marginal cost of serving load. (See *FERC Drops Fast-Start NOPR; Orders PJM, SPP, NYISO Changes*.)

FERC found SPP's quick-start pricing practices to be unjust and unreasonable because they do not allow prices to reflect the marginal cost of serving load. It directed the RTO to make six Tariff changes that the commission said would result in acceptable rates:

- Modify the real-time energy market clearing process to execute the cost-minimizing dispatch solution followed by a pricing run; remove a screening run; and remove the option for enhanced energy offers that incorporate amortized commitment costs in the incremental cost curves.
- Modify the pricing logic so that commitment costs of quick-start resources (including all such resources even if they have not registered as quick-start resources) are reflected in prices, in both the day-ahead and real-time markets.
- Include in the definition of quick-start resources a requirement that those resources have a minimum run time of one hour or less.
- Allow for relaxation of all quick-start resources' economic minimum operating limits by up to 100%, such that the resources are considered dispatchable from zero to their economic maximum operating limit in setting prices.
- Apply quick-start pricing treatment to both registered and unregistered quick-start resources.
- Include the quick-start pricing practices in the Tariff.

OG&E's Mustang Energy Center features gas-fired quick-start units. | *OG&E*



Jenbacher 2 reciprocating engine | *GE Power Generation*

FERC said the changes will result in SPP "having a pricing mechanism that is similar to the pricing mechanisms in other RTOs/ISOs." It noted that the RTO said it would be required to develop new pricing systems and software to gain compliance with the order, but it expected additional information to be entered into the record when "details on mitigation contained in the Tariff revisions are filed on compliance."

The commission's investigation led it to conclude SPP, PJM and NYISO did not adequately allow fast-start resources to set LMPs, resulting in prices that were not just and reasonable and that muted investment signals. In April, it issued a similar order that applied to PJM and NYISO. (See *FERC Orders Fast-start Rules for PJM, NYISO*.)

FERC found SPP's approach to pricing quick-start resources to be "inconsistent with minimizing production costs." It directed the RTO to submit a compliance filing by Dec. 31. ■

SPP Reaps $1.65M in April M2M Payments

SPP collected another $1.65 million in market-to-market (M2M) payments from MISO in April, pushing the total to $62.5 million since the two RTOs began the process in March 2015.

SPP staff told the Seams Steering Committee on June 11 that 33 temporary flowgates were binding for 585 hours, resulting in more than $934,000 in M2M bills. It was the 25th month in the last 31 in which M2M distributions have flowed in SPP's direction.

Eight permanent flowgates were binding for 142 hours, accounting for more than $720,000.

— Tom Kleckner

Company Briefs

American Public Power Association Names 2019-2020 Officers

Decosta Jenkins, president and CEO of Nashville Electric Service, was installed as chair of the American Public Power Association's Board of Directors at the group's National Conference in Austin, Texas, last week

Jolene Thompson — executive vice president of member services and external affairs for American Municipal Power and executive director of the Ohio Municipal Electric Association in Columbus, Ohio — is chair-elect for 2019-2020. Colin Hansen, executive director of Kansas Municipal Utilities in McPherson, Kansas, is vice chair.

More: *American Public Power Association*

SCE&G Customers up to $146M After Judge Finalizes Settlement

A South Carolina judge finalized a legal settlement tied to the failed V.C. Summer nuclear project last week, splitting somewhere between $121 million and $146 million among current and former South Carolina Electric & Gas customers.

The order ends a lengthy legal battle between the utility and several high-powered law firms that sued on behalf of SCE&G's electric ratepayers.

The lawsuit largely centered on the more than $2 billion SCE&G charged its customers for two reactors in Fairfield County before the nuclear project was canceled in July 2017.

More: *The Post and Courier*

Walmart, US Solar Sign Deal for 36 Community Solar Gardens

Walmart has signed off on a new deal to subscribe to 36 of US Solar's community solar gardens located across Minnesota.

The gardens, each with a generation capacity of 1 MW, will provide energy to Walmart locations in 13 separate counties. The first gardens have completed construction, while the remainder are targeted to be online by the first half of 2020.

Community PV in Minnesota allows businesses, public entities and residents to subscribe to an off-site solar garden without having to site solar directly on their property.

More: *PV-Tech*

Federal Briefs

US Solar Market Sees Best Q1 in History

The U.S. installed 2.7 GW of solar photovoltaics in the first three months of 2019, making it the most solar ever installed in the first quarter of a year. With the strong first quarter, Wood Mackenzie Power & Renewables forecasts a 25% growth this year compared to last and expects more than 13 GW of installations this year.

The largest share of installations came from the utility PV segment, with 1.6 GW coming online, making up 61% of PV capacity installed. The report notes that with 4.7 GW of large-scale projects under construction, 2019 is on track to be a strong year for utility PV, with 46% growth over 2018 expected.

The residential market experienced annual growth as well. According to the report, the U.S. saw 603 MW of residential solar installations during the first quarter, up 6% annually.

More: link *Wood Mackenzie*

FERC Report: US Renewable Capacity Surpasses Coal

Total Available Installed Generating Capacity

	Installed Capacity (GW)	% of Total Capacity
Coal	257.48	21.55%
Natural Gas	531.08	44.44%
Nuclear	106.99	8.95%
Oil	39.77	3.33%
Water	100.44	8.41%
Wind	98.62	8.25%
Biomass	16.10	1.35%
Geothermal Steam	3.83	0.32%
Solar	38.54	3.23%
Waste Heat	1.32	0.11%
Other*	0.78	0.07%
Total	1,194.95	100.00%

The total installed capacity of renewable resources in the U.S. surpassed that of coal in April, according to FERC's monthly energy infrastructure *update*.

As of April, the total available installed generating capacity of coal stands at 257.48 GW, while renewables — solar, wind, hydro, biomass and geothermal steam — were at 257.53 GW.

Individually, coal is still the U.S.' second most used resource. Gas reigns as king, sitting at 531.08 GW, or 44.44% of the country's total capacity.

More: *CNN Business*

US Escalates Online Attacks on Russia's Power Grid

The U.S. is stepping up digital incursions into Russia's electric power grid in a warning to President Vladimir Putin and a demonstration of how the Trump administration is using new authorities to deploy cybertools more aggressively, current and former government officials said.

In interviews over the past three months with *The New York Times*, the officials described the previously unreported deployment of American computer code inside Russia's grid and other targets as a classified companion to more publicly discussed action directed at Moscow's disinformation and hacking units around the 2018 midterm elections.

Advocates of the more aggressive strategy said it was long overdue, after years of public warnings from the Department of Homeland Security and FBI that Russia has inserted malware that could sabotage American power plants, oil and gas pipelines, or water supplies in any future conflict with the U.S.

More: *The New York Times*

State Briefs

KENTUCKY

PSC: Electric Vehicle Chargers not Subject to Regulation

The Public Service Commission has ruled that electric car charging stations are not utilities and do not need to be subject to regulation.

The ruling is intended to remove any ambiguity over the legal status of charging stations. The commission says it should also pave the way for more stations to be installed in the state, which currently has 94.

More: *The Associated Press*

MAINE

Governor's Vetoes of CMP Bills Survive Override Votes in House

Gov. Janet Mills on Wednesday vetoed two bills aimed at creating obstacles for Central Maine Power's proposed 145-mile New England Clean Energy Connect transmission project. She said the bills would give towns disproportionate power over a project with statewide benefits and would discourage private investment by upsetting established regulatory and permitting procedures.

The next day, the House of Representatives failed to override Mills' vetoes. One bill would have required electric utilities to obtain approval from local governments before using eminent domain to take private land for transmission line projects. Supporters in the House failed to garner the two-thirds majority needed to overturn the bill's veto (79-64). A second measure would have required an electric utility to receive approval from two-thirds of the municipalities through which a transmission line project passes. The veto override vote for this bill failed 75-68.

More: *Kennebec Journal and Morning Sentinel*

NEW JERSEY

Murphy's Energy Master Plan Includes Nuclear

Gov. **Phil Murphy** last week unveiled his long-awaited energy master plan, calling for more investment in renewable energy, such as solar and wind, and putting support behind nuclear energy to lower the state's

contribution to global warming.

The 108-page draft lays out an ambitious plan to convert the state's electricity production to 100% clean energy by 2050. To achieve that, the state would ambitiously install offshore wind and solar energy, and support nuclear energy.

About 95% of electricity generated in New Jersey comes from natural gas-powered plants and nuclear facilities. Murphy has made some moves toward renewable energy, most recently setting a goal of 3,500 MW for offshore wind generation by 2030.

More: *North Jersey Record*

NORTH CAROLINA

NCUC Approves Sale of Duke Energy Hydro Projects at $40M Loss

The Utilities Commission last week approved Duke Energy's sale of five small hydropower plants in the Carolinas to Northbrook Energy while denying the state utility customer advocate's request to review $17.4 million the utility spent on the plants since 2015.

The commission approved the sale of the projects for $4.75 million, at a loss of about $40 million. Duke "has determined that divestiture of the facilities is more economical than continued ownership and maintenance ... resulting in net savings to customers over time," the commission said.

The South Carolina Public Service Commission must also approve the sale. Assuming all approvals are received and conditions of the sale are met, Duke expects the deal to close by early this fall, according to the company.

More: *Charlotte Business Journal*

NORTH DAKOTA

PSC Denies NextEra Siting Permit for Burke County Wind Farm

The Public Service Commission last week unanimously rejected NextEra Energy Resources' application for a wind farm siting permit in the state's northwest corner following opposition from state and federal wildlife agencies.

Regulatory filings showed federal and state agencies charged with protecting wildlife have long been concerned with the wind farm's location. A state Game and Fish Department official said the developer "could not have picked a worse spot in the state." The U.S. Fish and Wildlife Service welcomed NextEra's moves to reduce the project's size and contract from a grassland-rich area, but it recommended against the location in the end.

NextEra sought to build a 23,000-acre, 200-MW wind farm in Burke County that would have consisted of up to 76 turbines.

More: *The Bismarck Tribune*

OREGON

Controversial Cap-and-Trade Bill Heads to House

Climate change legislation rolled through the Joint Ways and Means Committee last week on a 13-8 party line vote and now heads to the House of Representatives, where it figures to be fiercely debated yet again.

House Bill 2020 calls for a decrease in greenhouse gas emissions to 80% below 1990 levels by 2050. To get there, the bill would require companies in the utility, transportation and industrial sectors to buy emission allowances in a state-run auction or on a secondary market to cover each metric ton of pollution their operations emit.

As the state reduces the supply of allowances, they will get more expensive, increasing fossil fuel prices and incentivizing business and consumers to reduce their consumption and related emissions.

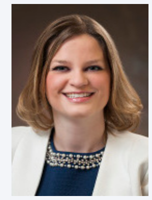
But transportation fuels remain the only industry that has not been offered free emission allowances. Gas prices are projected to rise by 22 cents a gallon in 2021 and have become a principal rallying cry against the bill.

More: *The Oregonian*

WISCONSIN

Bill Would Create Public Funding for Renewable Energy Startups

Democratic lawmakers are pushing legislation to form a new state development authority designed to kick-start the state's clean energy economy.



The bill, introduced last week by Rep. **Katrina Shankland**, would create a Wisconsin Renewable Energy Development Authority, which would be authorized to issue grants and loans to state-based businesses or residents engaged in producing energy, fuels or other products from renewable resources.

The bill would appropriate an as-yet-undetermined amount and authorize WREDA to issue up to $500 million in tax-free bonds, though the state would not be on the hook for the debt.

More: *La Crosse Tribune*