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Pa. Lawmakers Unveil $500M Nuke Subsidy Bill

By Christen Smith

With two months to go before Exelon says it will pull the plug on Three Mile Island, Pennsylvania lawmakers unveiled legislation Monday to spend $500 million annually to subsidize the state's nuclear fleet.

The *Keep Powering PA Act* (House Bill 11) would add a nuclear power mandate to the 2004 Alternative Energy Portfolio Standards Act (AEPS). Prime sponsor Rep. Thomas Mehaffie (R), who was joined by 19 co-sponsors, said the bill "properly values the environmental benefits the nuclear power industry has been delivering to our state for decades."

"While the market is designed to price electricity on a day-to-day basis, it is the role of the legislature to set the long-term policies for this state," he said during a press conference on Monday at the Ironworkers Local 404 Union hall in Harrisburg. "The markets do not treat all clean sources of energy the same and they do not penalize polluters. As state legislators, we need to take a step back, recognize this and we need to take truly into account the cost of doing nothing."

3rd Tier

HB 11 would create a third tier of resources in the alternative energy portfolio from which companies must purchase at least 50% of their electricity by 2021: nuclear, solar, geothermal and low-impact hydropower. The first two tiers of the legislation include 16 resource types with targets of 8% and 10%. (See *Draft of Pennsylvania Nuke Subsidy Bill Leaked*.)

Continued on page 23

Senate ENR Committee Discusses Climate Change

By Michael Brooks

The hearing the Senate Energy and Natural Resources Committee held last week was perhaps less noteworthy for what was said than the fact it even happened.

Chaired by Sen. Lisa Murkowski (R-Alaska), committee members and panelists March 5 discussed the electricity industry's role in mitigating climate change. According to ranking member Joe Manchin (D-W.Va.), it was the first hearing the committee had held on climate change since 2012.

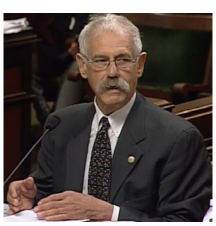
Continued on page 5

Calif. Officials: CCAs, Decarbonization Pose Reliability Challenges

By Hudson Sangree

California officials expressed concern last week that the state's push toward 100% clean energy and the rapid growth of community choice aggregators could imperil grid reliability if not carefully orchestrated.

The development is worrying enough that state regulators are considering creating a centralized process to ensure resources needed for long-term resource adequacy (RA) get sufficient financial support.



PUC President Michael Picker

Michael Picker, president of the California Public Utilities Commission, told lawmakers Wednesday that the state has moved away from its traditional model of vertically integrated utilities, with a few big owners of generation and wires also providing service to retail customers.

Now there are dozens of different load-serving entities delivering electricity to consumers. Not all of them can meet the basic legal requirement, enacted after the California energy crisis of 2000/01, that they have enough electricity available to meet demand on the year's hottest days, when demand soars, Picker said.

"Here's where we get into our uncharted and potentially dangerous territory," Picker told the State Assembly Utilities and Energy Committee. "We're neither here nor there.

"The cleanest way would be if we had vertically integrated utilities or we went to full competition where everybody picked their electricity provider and then you had discrete transmission and discrete distribution companies," he said. "That's what Texas and New York do. It works for them. [It's] not clear if it would work here, but it's also clear we're not going to go back to a vertically integrated system.

"So the question is, 'What do you do?'"

'One of the Things that Scares Me'

Picker made his comments at an *information-*

Continued on page 8

NECA RENEWABLE ENERGY CONFERENCE

Overheard at NECA Renewable Energy Conference 2019
(p.11)

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In this week's issue

TRANSMISSION SUMMIT EAST

Overheard at Transmission Summit East 2019

ARLINGTON, Va. — Transmission developers, planners and regulators gathered last week on the top floor of the Key Bridge Marriott, overlooking D.C. from across the Potomac River, for Infocast's annual Transmission Summit East. Panels and presentations covered a little bit of everything, from energy storage to cybersecurity.

Audience members listen on the top floor of the Key Bridge Marriott in Arlington, Va., during Infocast's Transmission Summit East on March 6. | © *RTO Insider*

Hoecker, Demarest Propose Interstate Tx Siting Bill

James Hoecker (left) and William Demarest | © *RTO Insider*

James Hoecker and William Demarest, both senior counsel at Kansas City-based law firm Husch Blackwell, proposed to the conference a legislative solution to the problem of getting high-voltage interstate transmission lines built.

The pair's proposal would essentially give FERC jurisdiction over siting interstate transmission projects, similar to how the Natural Gas Act gave the commission siting approval over gas projects, but with numerous caveats and exceptions that they said would preserve some state authority. Crucially, only projects that have facilities in multiple states would be subject to FERC approval. Intrastate transmission projects, unlike intrastate gas pipelines, would remain solely under the purview of the states.

Hoecker, a former FERC chairman, said demand for renewable resources is growing as states increase their portfolio targets. Currently, transmission developers must get approval from a "multiplicity" of regulatory agencies in each state their projects pass through, he said. But "if the momentum picks up for interregional and multistate forms of transmission, I think there'll be a growing drumbeat to somehow limit state authority in this area."

The desire to access cleaner generation will become a very powerful force in the transmission industry, Hoecker predicted. But without a good policy, "you could have states essentially getting steamrolled."

Demarest elaborated on that point, noting his years working for Rep. John Dingell (D-Mich.). When members of Congress "get on a course, they tend to take political, rather than economic ... solutions. They are frequently looking for *a* solution, and it need not be the best solution, because they delude themselves into believing that they can come back and address it and adjust it and fix it, which they never or rarely do." State regulators and industry need to find a solution before Congress imposes something they don't like, he said.

Under their plan, transmission rates for interstate service would be regulated by FERC, but any intrastate service rates would be regulated by each state the project serves. It also would not eliminate, nor allow FERC to eliminate, any state rights of first refusal for incumbent utilities to build intrastate projects. These projects would also not be subject to an "affecting commerce" standard, even though they're still part of interstate commerce.

RTOs would continue their role as planners, but RTO sponsorship would not be necessary. "RTOs, at least in my view, are political critters, often captive to certain stakeholders," Demarest said.

From left to right: panel moderator Rich Heidorn Jr., editor-in-chief and co-publisher of *RTO Insider*; Melissa Kemp, Cypress Creek Renewables; Steve Wemple, Con Ed; and Ray Hohenstein, Fluence. | © *RTO Insider*

Order 841's Impact on New York

New York is a very desirable market for the energy storage industry, but NYISO's proposed compliance with FERC Order 841 is somewhat

TRANSMISSION SUMMIT EAST

concerning, speakers said during a panel on the order's implementation.


Ray Hohenstein | © RTO Insider

"When we think about what drives the business case for storage ... by and large it is the need for capacity," said Ray Hohenstein, market applications director for storage developer Fluence. Peaking plants are retiring at a faster rate because of the state's increasing emissions targets. "New York is a state where if they get FERC 841 right, there could be a lot of energy storage that is making money."

The state's Public Service Commission has set a goal of 3 GW by 2030, with an interim target of 1.5 GW by 2025.

In its Order 841 compliance filing, NYISO said it would offer four modes for storage resources to participate: ISO-committed fixed, ISO-committed flexible, self-committed fixed and self-committed flexible. In the ISO-committed modes, suppliers would leave it up to NYISO to determine the most optimal dispatch times for their resources.

Last month, the Energy Storage Association filed responses to the grid operators' compliance filings. With NYISO, the group focused on what it called "rules that bias against self-management of state of charge."


Steve Wemple | © RTO Insider

Steve Wemple of Consolidated Edison, however, had an optimistic view on NYISO managing resources' state of charge. The ISO would "look at the beginning charge level and look forward and try to find the right pairs of charging and discharging to meet the bidder's economic desire ... so I think that's very positive."

Hohenstein agreed. "I think state-of-charge management is one of the keys to unlocking participation in wholesale markets in general. It actually is a really great development to have the ability to ... define your beginning and end-of-hour state of charge to ensure that you are available, for instance, if you have to provide a peak reliability service for part of the day. So it provides a lot more certainty."

As an example, he said a resource could tell the ISO that it was bidding into the frequency regulation market but it has to be fully charged by 6 p.m.


Melissa Kemp | © RTO Insider

Melissa Kemp, policy director at Cypress Creek Renewables, was skeptical of that. "I think if it were something that nuanced, we would not have a problem with it. My understanding of what they filed is that it's not that nuanced, and that it's more 'We need to control what you're doing here' and that there's a lot of concern from a lot of stakeholders in the ISO process [who] would like the option to select the ISO to control ... but that just simply turning over the ability to control the asset to the ISO is a great concern and kind of a nonstarter."

The 'Weakest Link' in Cybersecurity

A panel on cybersecurity focused on figuring out the most effective practices, which speakers said don't apply to every utility in the country.


Nick Wagner | © RTO Insider

Among the panelists was Iowa Utilities Board Member, and president of the National Association of Regulatory Utility Commissioners, Nick Wagner, who said criminal or hostile foreign hackers are probably not interested in taking down a rural, municipal cooperative in his state.

When asked about NERC critical infrastructure protection standards, Wagner said, "I think those are important beginning points. I don't necessarily [think] they should be a hard-and-fast rule that everybody should follow. One of the nice things about ... our grid today is a conglomerate of very different systems, which in itself is inherently secure. So if a person gets in a system of one utility, that doesn't necessarily mean that they'll be able to get into every system. ...

"Government does not move at the speed of industry. And it certainly does not move at the speed of hackers. So we will, from a standards standpoint, always be behind. And we want our utilities and our industry and our suppliers to move faster than that and be able to keep up with the threats that are out there," he said.

Instead, Wagner said, industry needs to focus on training employees to recognize hacking attempts. "People are the weakest link," he said. "Whether we like to admit it or not, we are the weakest link. ... I've gotten into the habit of, when I get an email from my family, I call them up and say, 'Did you send this email?' Because that's how sophisticated these hackers are getting."


Gladys Brown | © RTO Insider

Pennsylvania Public Utility Commission Chair Gladys Brown said that applies to state regulatory agencies as well. Agencies "have a wealth of information" that hackers would love to get their hands on, she said. Brown said that despite the robust training NARUC directs, even she has fallen for a phishing attempt, when she responded to an email from someone she thought was a state cabinet secretary. (Thankfully there was no link in the email to click.)


Ralph King | © RTO Insider

As part of the Electric Power Research Institute's training, the organization sends out its own phishing emails to test its employees, said Ralph King, cybersecurity program manager. And "if you actually click on a phishing email, you get to sit down with someone pretty high up in the company."

But King also warned that one utility company he worked with went too far in its training. "They had to back it off because all the employees, anything external, they deleted. And so they were missing a lot of emails."

King also said that many cyber experts think "the biggest threat in the next five years are insider threats. These could be malicious; they could be mistakes." Noticing unusual employee behavior — logging into a system in the middle of the night, logging into systems they're unauthorized to access, etc. — will be key to preventing disruptions. He told the story of another company he worked with that had an employee displaying "very odd behavior. And by looking for these things, we actually uncovered a serious health problem that they didn't know about. So it's not always malicious; it could be other things. But regardless of what it is, you want to be able to identify it."

"It may not impact the grid or the system overall, but it can certainly impact you as individuals and be a real pain to have to deal with some of that stuff," Wagner said. ■

— Michael Brooks

FERC & Federal News

Senate ENR Committee Discusses Climate Change

Continued from page 1

Compared to the House of Representatives, now in Democratic hands and holding almost weekly hearings on climate change, the GOP-controlled Senate has been nearly silent on the phenomenon. (See *House Democrats Put Climate Change Front and Center*.) That will change as Senate Democrats up their rhetoric and make it a central platform of their 2020 re-election campaigns, as The New York Times *reported* last week.

Last Tuesday's hearing, however, lacked partisan rancor. Instead, the few senators who attended and the panelists focused on increased investment in research and development of new technologies to make generating resources cleaner and more efficient.

This was in part because of the committee's jurisdiction: It does not oversee EPA nor does it have direct oversight of U.S. greenhouse gas emissions. Those are under the charge of the Environment and Public Works Committee.

"I think it's important to point out, we know here on the committee we have jurisdiction in certain areas," Murkowski said. "We do not have complete jurisdiction over climate change — we recognize that — but we do have a role to play in developing reasonable policies that can draw bipartisan support that I think will be a pragmatic contribution to the overall discussion."

But the homes of the committee's leaders also played a large role in what was discussed. Murkowski, who opened the hearing with a list of adverse effects being felt by Alaska — including *rapidly decreasing* Bering Sea ice and a more *challenging* Iditarod Trail Sled Dog Race — has broken away from her party in even discussing the issue. Manchin, who frequently sides with Republicans on the committee, criticized regulations as a solution, saying they disproportionately hurt rural residents and coal miners, like those in West Virginia.

"Therefore, the path to a climate solution must offer West Virginians opportunity — not additional economic burdens," Manchin said. "Chairman Murkowski and I share a deep concern for our rural communities and seek to use this committee as a means of identifying and legislating pathways to ensure our constituents have a role in the clean energy future."

Manchin said the use of fossil fuels to generate electricity is "not going away anytime soon" and noted China and India are increasing the use of coal. Kenneth Medlock, senior director at Rice University's Center for Energy Studies, put an exclamation mark on Manchin's point by noting China has 254 GW of coal-fired capacity under construction — more than the entire U.S. coal fleet.

"So ... when we think about CO_2 being a problem of the global commons, it really means we need to lead by example," Medlock said.

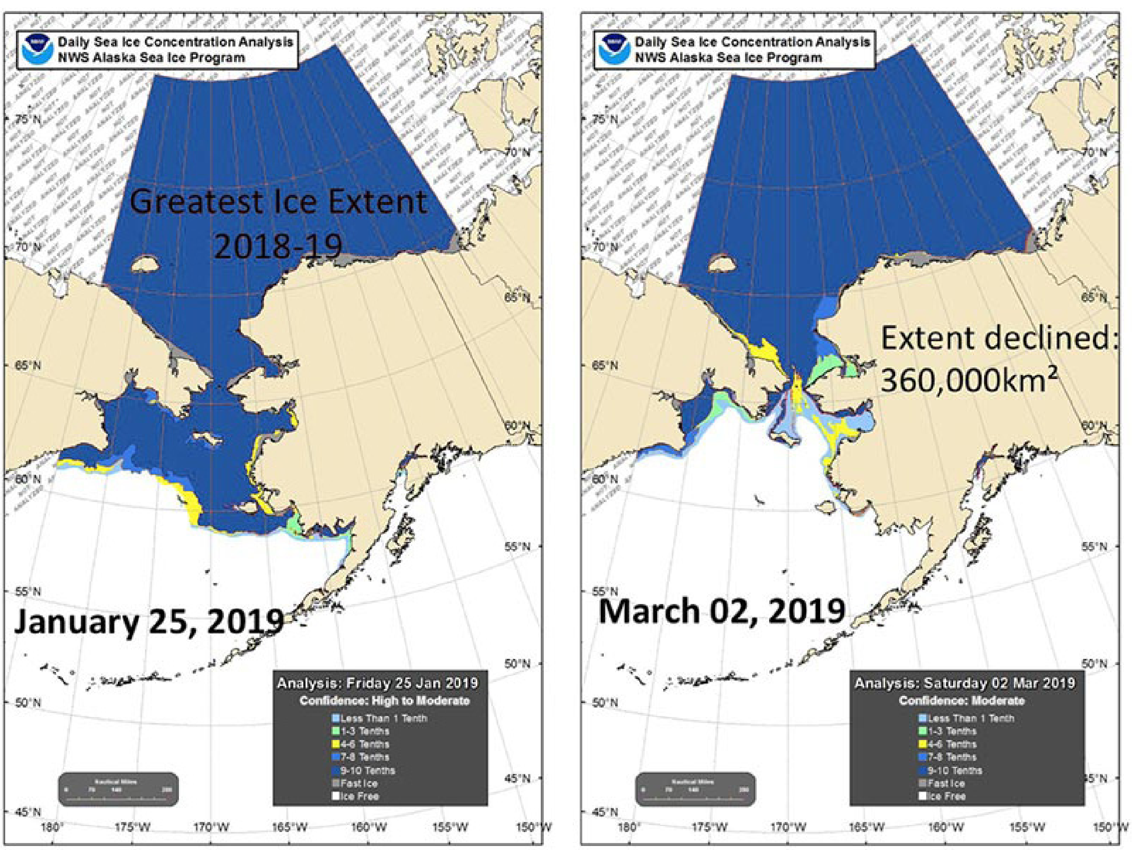
Manchin jumped in, asserting that the U.S. has led by example, mandating technologies such as scrubbers and low-NOx boilers. "They're not implementing any of those," he said.

Medlock replied his point was that the U.S. needs to lead in innovation, such as developing scalable carbon capture and sequestration (CCS), a technology seen as key to reducing emissions and even potentially reversing climate change. He noted federal R&D spending has been declining for the last 30 years "and that doesn't make any sense."

Susan Tierney, senior adviser at Analysis Group, said, "China is actually an unsung story on a lot of innovations," building advanced reactors and wind turbines.

"The U.S. needs to continue to advance technology leadership ... so we don't lose to them on these competitive technologies," she said.

Notably absent from the hearing was EPW Committee Chair John Barrasso (R-Wyo.), who last month reintroduced the Utilizing Significant Emissions with Innovative Technologies (*USE IT*) Act. The bill, which enjoys bipartisan support, would fund CCS R&D and create a board of experts to oversee projects under development. ■



Sen. Lisa Murkowski (R-Alaska) opened the hearing displaying this graphic, which shows the rapid decrease in Bering Sea ice, as a demonstration of the impacts of climate change. | *Rick Thoman, Alaska Center for Climate Assessment and Policy*

FERC & Federal News

Wheeler: EPA's Proposed Budget Cut 'Common-sense'

By Tom Kleckner

Andrew Wheeler at CERAWeek by IHS Markit | © *RTO Insider*

HOUSTON — EPA Administrator Andrew Wheeler on Monday defended the Trump administration's proposed 31% cut to his agency's budget, *saying* it's a "common-sense budget proposal."

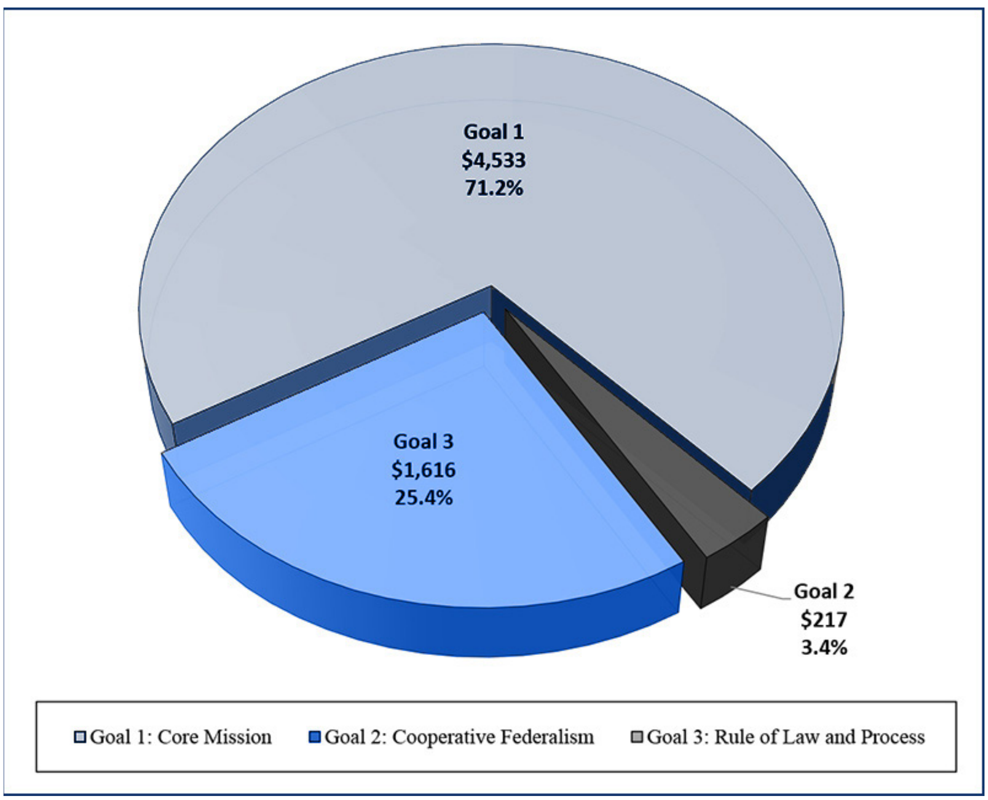
"We can accomplish our mission at that level," Wheeler said, following an appearance at CERAWeek by IHS Markit. "It takes out some of the more voluntary programs and duplicity [sic] in statutes and programs."

The 2020 budget would slash EPA funding from $8 billion to $6.1 billion. The reduction is similar to the administration's previous two budgets, neither of which Congress enacted. This budget is considered DOA with the Democrats now in control of the House of Representatives.

The White House said it wants to ensure clean air and water and chemical safety, while "reducing regulatory burden and eliminating lower-priority activities."

Wheeler highlighted a $50 million grant program EPA wants to establish for communities with aging school facilities, with the intention of creating safer and healthier environments.

The EPA says it wants to focus on investing in water infrastructure, efficiently cleaning up Superfund sites, strengthening protections from toxic chemicals and continued regulatory and permitting reforms.



EPA's enacted budget, FY 2019 ($ millions) | *EPA*

In comments to the CERAWeek audience, Wheeler called for the American energy industry to promote its environmentally-conscious process and procedures "that are better than anywhere else in the world."

"Our natural gas, oil, coal and fossil fuels are extracted in a more environmental-friendly manner here," he said. "That should be a selling point for anyone selling energy around the world to adopt our programs."

Wheeler was confirmed as the EPA's administrator last month, replacing scandal-ridden Scott Pruitt. He has been serving as acting administrator since July and worked at the agency from 1991 to 1995. (See *Wheeler Confirmed to EPA on 52-47 Vote*.)

"Some of the issues we were dealing with in 1991 are the same ones we're still looking at today," he said. "It's just become much more politicized over the last 30 years, which is a shame. We're doing a lot of things for the environment Republican administrations just don't get credit for."

Asked to explain the reason for that by moderator Daniel Yergin, IHS Markit's vice chairman, Wheeler said the environment has become a large campaign issue and "money-maker" for the political parties.

"I think that's what created the partisan divide in Congress," he said. ■

CAISO/WECC News

WECC Board Continues Focus on RC Transition

By Hudson Sangree

WECC held its quarterly board meeting and committee meetings March 5-6. | *WECC/Kirha Quick*

The Western Electricity Coordinating Council continued to deal with issues related to this year's reliability coordinator transition at its board of directors meeting in Salt Lake City on Wednesday.

Among the matters heard was an update from Peak Reliability CEO Marie Jordan on the wind-down of the company's operations this year as CAISO, SPP and BC Hydro prepare to take over RC functions across the Western Interconnection by the end of 2019. (See *Peak Reliability to Wind Down Operations*.)

Keeping key staff on board at Peak and maintaining high operational standards are among the top priorities, Jordan told WECC board members.

Another issue discussed was WECC's proposed process for requesting key data and information from the incoming RCs under *NERC Rules of Procedure* Section 1600. The planned move reflects the new operating conditions in a multi-RC environment rather than one exclusively overseen by Peak, WECC staff said.

"We've been working internally for about the past nine months to put this together in anticipation of moving to the multi-RC environment and want to make sure that WECC maintains its options for the receipt of information," WECC General Counsel Steve Goodwill said.

"Because a Section 1600 request would only apply to U.S. entities, not to our Canadian or Mexican partners [such as BC Hydro], we need a different mechanism to collect data from them," Goodwill said.

WECC had provided the draft Section 1600 request to incoming RCs and NERC, "totally informally but just for their review and comment before we started any formal process," Goodwill said. WECC incorporated their comments and changes, and in February it initiated a formal Section 1600 request, he said. The final draft was submitted to NERC and FERC last month for a 21-day comment period, followed by a 45-day period that started Friday for stakeholder comments.

The WECC board still must give final approval to the request. "We would like to have that in place by mid-June at the board meeting so that as the RCs go live, we can issue the data request to them," Goodwill said. CAISO will assume the RC role for its existing territory on July 1, "so that keeps us on the right timeline."

Peak Reliability Update

At WECC's last board meeting in December, speakers expressed concerns about the multiple turnover dates involved in the Western RC transition, each of which could provide opportunities for errors. (See *RC Transition Fraught with Pitfalls, WECC Hears*.)

WECC's board of directors meets in Salt Lake City. From left to right: Chair Kristine Hafner, President and CEO Melanie Frye, Gary Leidich and Richard Campbell. | *WECC/Kirha Quick*

After CAISO, BC Hydro will become the RC for most of British Columbia on Sept. 2. CAISO will then take over for many areas outside its footprint on Nov. 1, while SPP will take responsibility for other parts of the West on Dec. 3.

Another area of concern was the ability of Peak to hang on to essential staff members through the long transition.

After announcing it would get out of the RC business and end operations, Vancouver, Wash.-based Peak saw a number of employees depart, Jim Shetler, general manager of the Balancing Authority of Northern California and chair of Peak's Member Advisory Committee, told the WECC board in December. Some Peak employees in Washington and Colorado took positions with electricity entities in those areas, he said.

To stem attrition, Peak detailed the severance packages that employees will receive if they stay with the company until they're no longer needed, he said. With that, Shetler said, "the unplanned departures, I expect, will come down quite a bit."

Peak said in January that of its 169 staff members at the start of 2018, 23 had left by the end of the year. Peak's RC department declined from 42 staff members to 34 throughout 2018.

Jordan's presentation to the board seemed to partly confirm Shetler's prediction that the attrition would abate with increased transparency and communication with employees. Staffing levels in Peak's RC department have held steady since October, Jordan's presentation showed, though some engineering and IT employees continued to depart through February. ■

CAISO/WECC NEWS

Calif. Officials: CCAs, Decarbonization Pose Reliability Challenges

Continued from page 1

al hearing titled "The Metamorphosis of the Energy Sector: Maintaining Reliability and Affordability on the Road to Decarbonization." Panelists were asked to address the challenges facing California's grid as it pursues the legal mandates of SB 100 and other bills that set ambitious clean-energy goals — including a mandate that the state's LSEs deliver 100% zero-carbon electricity by 2045.

CCAs will require more than 5,700 new generation projects at a median size of 175 MW to meet those goals, Picker said.

"It's a challenge," he said. CCAs, many of which are startups, have customers but not the financial assets to get financing for generation projects, he said. To scale up quickly, you need "large companies with big balance sheets," he said.

Last year the PUC received an unprecedented 11 requests to waive RA requirements, most of which came from CCAs and electric service providers (ESPs), the latter of which sell directly to a limited number of nonresidential customers.

In the relatively small geographic pockets controlled by CCAs, there may not be enough transmission capacity to bring in power from outside on peak-demand days, so the CCAs must be able to purchase electricity from generators within their territory, Picker said. But many can't muster the financial resources to compete for those resources and must ask the PUC for waivers, he said.

"I consider that to be a weakness in the design," the PUC president said. "I think it's a big problem."

If a day arrives when a CCA has insufficient power to serve its customers, the problem could spiral out of control, he said.

"This is one of the things that scares me," he said. "You may be a small company, but your failure to provide electricity to your customers can cause a brownout that can escalate, and it can actually affect customers in somebody else's service area."

State Could Establish a Central Buyer

The state recently required CCAs to secure three-year RA procurement contracts, instead of annual contracts, and many are hoping the change will help the CCAs compete for reliability resources, Picker said. But if the situation doesn't improve by the end of this summer, "we may actually impose a central buyer," he said.

Picker said it's uncertain who might fill that role, but the state's big investor-owned utilities — Southern California Edison, Pacific Gas and Electric, and San Diego Gas & Electric — would be likely candidates.

"We know that we have to keep the grid whole, and we know that … three large central procurers have made it work," he said.

SCE's vice president of energy procurement, Colin Cushnie, urged lawmakers at the hearing to make the IOUs central buyers for the sake of grid reliability.

"We do think the central buyer framework should be adopted for local resource adequacy," Cushnie said. "We also believe that the IOUs, who are the reliability custodians of our grid, should be the ones designated to be those central buyers."

AB 56 — introduced in December by Assemblyman Eduardo Garcia, a Democrat who sits on the energy committee —would require the PUC and California Energy Commission to provide the legislature with a joint assessment of options for establishing a central statewide procurer of electricity for all retail customers by March 31, 2020. As currently written, Garcia's bill focuses on procurement of renewable and other "preferred" resources under state law, which include demand response and behind-the-meter generation.

CCAs Seek Joint Procurement

To some, the idea of a central buyer is anathema to efforts to establish local control of energy procurement and distribution.

Beth Vaughan, executive director of the California Community Choice Association, said the problems cited by Picker could be solved by CCAs banding together to buy electricity, as some have already done.

Four CCAs in Southern California are now purchasing as one entity, and Monterey Bay Community Power and Silicon Valley Clean Energy jointly put out a request for 280 MW of solar coupled with 340 MWh of battery storage for two projects in Kern and Kings counties, she said.

"There's a lot of experimentation going on in terms of joint procurement, in terms of being able to go out and procure those large sums of megawatts that President Picker referred to," Vaughan told the committee.

Rainy Days Get CAISO Down

CAISO Vice President Mark Rothleder

Mark Rothleder, CAISO's vice president of market quality and renewable integration, told the committee the state is still dependent on natural gas peaker plants and imports of out-of-state electricity to meet its evening ramps and peak demand days.

"As we transition to a low-carbon grid, the ISO may find meeting its demand when the renewable supply is not producing, such as evenings or stormy days, becoming more and more difficult," Rothleder said.

There are some days, he said, when CAISO's load is served almost entirely by renewable and zero-carbon resources, including nuclear and hydroelectric. Other days, however, solar output drops to 10 to 20% of its installed capacity, requiring the ISO to make up the difference. Behind-the-meter rooftop solar also falls away, meaning those households need thousands of extra megawatts.

That happened during four days in mid-January, he said.

Such a severe reduction in solar meant the ISO had to round up 14,000 MW of imported electricity, equivalent to the output of seven nuclear plants, he said. It was able to do so in January, but such large quantities of imported electricity are not always available, he said. There are times when the whole West is hot, and the interior West and desert Southwest have little electricity to spare.

"We need to secure that [imported electricity] if we're going to rely upon it," Rothleder told the committee.

The state's gas fleet is becoming more economically distressed because it's not being called on as much and faces competition from cheaper solar power, he said.

"If [gas plants] start retiring in large numbers, we won't have those resources available," he told lawmakers.

The challenge, Rothleder said, is maintaining the right set of resources and capabilities to ensure reliability.

"I am not suggesting we should shy away from the challenge," he said. "I'm saying we need to be thoughtful about meeting that challenge." ■

ERCOT News

ERCOT Summer Forecast: Record Demand, Alerts

By Tom Kleckner

ERCOT is forecasting record peak demand with increased potential emergency alerts this summer, given its historically low planning reserve margin of 7.4%.

The grid operator last week said it expects a summer peak of 74.9 GW, which would break the mark of 73.3 GW set just last summer. ERCOT has 78.2 GW of capacity on hand to meet that demand, according to its preliminary summer *seasonal assessment of resource adequacy* (SARA).

David Bellman | © *RTO Insider*

David Bellman, head of power for Houston-based Skylar Capital Management, told *RTO Insider* that the "surprising thing to note" is this year's projected peak is almost 3% higher than last year's predicted high of 72.8 GW, as well as being 1.6 GW higher than 2018's actual peak.

Bellman said the forward markets lost about $2/MWh on March 5, the day the SARA was released, and were trading at $138/MWh.

"The increase in peak demand and drop in resource adequacy means we expect emergency alerts to be issued this summer," Resource Adequacy Manager Pete Warnken said during a media call.

"Prior to each season, we consider a range of potential risks to determine whether there will be sufficient capacity to meet the expected peak load forecast," ERCOT CEO Bill Magness said in a *statement*. "In all of the scenarios studied, we identified a potential need to call an energy alert at various times this summer."

Declaring an energy alert during scarcity situations would free up the grid operator to tap into a variety of additional resources to meet demand. Those resources include demand response products, resources normally set aside to provide operating reserves, additional generation or imports from neighboring RTOs, and calls for voluntary conservation measures.

Dan Woodfin, ERCOT's director of system operations, said the grid operator has 900 MW of emergency response service available and another 1,300 to 1,800 MW of capacity from load-management programs.

The grid operator's reserve margin dropped from 8.1% to 7.4% with the December retirement of the Gibbons Creek coal plant. Warnken said 500 MW of summer capacity, much of it from wind and solar projects, has been delayed until late spring and early summer.

The final summer SARA report will be released in May and will reflect the expected summer weather conditions.

ERCOT also released its final *SARA* for the spring months (March to May), saying it has sufficient capacity (81.3 GW) to meet a forecasted spring peak of 61.6 GW. The system has added 577 MW of planned gas, wind and solar resources for the spring, with another 50 MW of wind and solar capacity expected to be available for the season's start. ■

March Seasonal Assessment of Resource Adequacy | *ERCOT*

ERCOT News

ERCOT Stakeholders Dig into Real-time Co-optimization

By Tom Kleckner

ENGIE's Bob Helton and ERCOT's Cheryl Mele | © *RTO Insider*

ERCOT stakeholders last week began taking a deeper look at real-time co-optimization (RTC), the market tool that procures both energy and ancillary services every five minutes to find the most cost-effective solution for both requirements.

Asked by Texas' Public Utility Commission to "reinitiate discussions" with stakeholders on the tool, ERCOT held a workshop on Wednesday. The PUC, which wants to see RTC "sooner rather than later," is working to hold its own workshop in early June and is soliciting stakeholder feedback on a list of related issues. (See "PUC, ERCOT Set Real-time Co-optimization Workshops," *Texas PUC Briefs: Week of Feb. 25, 2019*.)

Meanwhile, the member-led Technical Advisory Committee, which makes recommendations to the ERCOT Board of Directors, has been gathering member feedback on an RTC task force in advance of its upcoming March 27 meeting. TAC Chair Bob Helton, of ENGIE, said in an email to members that the committee's leadership would like to see the task force led by two co-chairs reporting directly to the committee.

"The task force would not be a voting body, and [its] leadership would report any recommendations to TAC, including any minority positions," Helton wrote.

The TAC will endorse the group's final structure, leadership and other details, with the board making the final decision.

"This is a good opportunity for our stakeholders to come together and work to ensure we design something that helps achieve our objectives and reflects the value of ancillary service," ERCOT COO Cheryl Mele said at a recent market summit.

Staff told stakeholders during the workshop that RTC will efficiently coordinate the provision of energy and AS in the real-time market and, similar to the operating reserve demand curve (ORDC), price AS shortages according to their defined demand curves.

Sai Moorty, ERCOT's market design and analysis principal, said the RTC process will be executed with each security-constrained economic dispatch run, yielding "better visibility of the constraints and the capabilities of the resources."

"As a result, the system can be operated more economically and reliably," he said. "This benefits loads by selecting the lowest-cost resources to provide energy and AS."

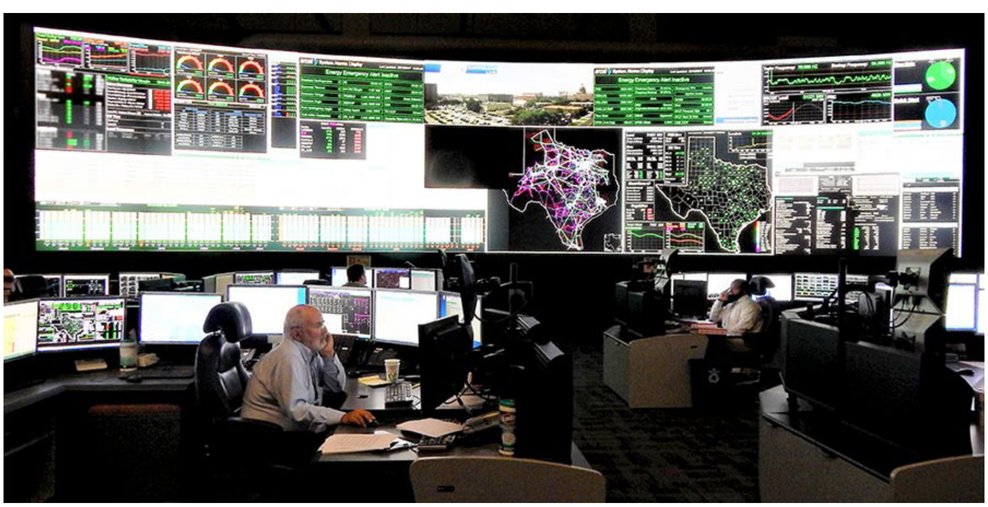
Unlike the ORDC, the SCED engine will apply a demand curve for each AS product, establishing offer-based prices for energy and AS types in the real-time market, staff said. The defined AS demand curve will set AS shortage conditions, and ORDC price adders will no longer exist.

"Real-time co-optimization will definitely impact temporary price spikes we've seen outside the ORDC," NRG Energy's Bill Barnes said at the same summit. "Demand curves for ancillary service … ensure we're sending proper price signals during times of scarcity."

ERCOT grid operations have not yet identified a reliability need to define a local reserve product, staff said, noting the RTC design will co-optimize the required reserves.

The PUC, which has opened a project for RTC (*48540*), is considering whether to allow financial-only AS offers.

Staff have said it will take four to five years and about $40 million to implement the RTC process and software. ■



ERCOT's Operations Center | © *RTO Insider*

ISO-NE News

NECA RENEWABLE ENERGY CONFERENCE

Overheard at NECA Renewable Energy Conference 2019

Declining Costs, Increasing Customer Demand Drive Deployment

AUBURNDALE, Mass. — Commercial demand is supplanting state policy as the driving force behind deployment of renewables, whose costs are declining in every category, participants at the Northeast Energy and Commerce Association (NECA) Renewable Energy Conference heard last week.

Judy Chang | *© RTO Insider*

"You will see, maybe not so much yet in New England, but you will see across North America, customers are buying renewable energy," Brattle Group principal Judy Chang said Thursday.

States drove renewable energy adoption in the very beginning, "but now we're really seeing customers, particularly large commercial and industrial customers, directly signing up contracts for renewable generation — and some of those come with storage," Chang said.

"Change" is the watchword, according to Stephen J. Rourke, ISO-NE vice president for system planning, who said he's seen more change in the past year than in his whole 40 years in the industry.

"One way to get a sense of what's headed our way next, when you think about the resources that are going to come forward, is to look at the [interconnection] queue," Rourke said. "If you followed our queue from roughly 2005 to 2017, we had 12,000 to 14,000 MW in our queue, three-quarters of it natural gas. The rest of it was wind and a little bit of something else.

"If you look right now, we have over 20,000 MW of generation in our queue, and 85% of it is either wind, solar, batteries, hydro, biomass or fuel cells," he said. "The 15% that's left over is natural gas, so what resource developers are saying to us ... is these are the resources that are coming forward ... and this has changed dramatically since just 2017."

Big Projects for Big Goals

Richard Stuebi, president of Future Energy Advisors, said that renewables accounted for 10% of New England's generation in 2018, so that if the region and New York want to achieve their ambitious environmental goals, "we need to start doing it now."

From left to right: ISO-NE's Stephen J. Rourke addresses the NECA Renewable Energy Conference on March 7 with Richard Stuebi, Julia Bovey, Jason Burwen and Judy Chang. | *© RTO Insider*

Richard Stuebi | *© RTO Insider*

Moderating a panel discussion, John Dalton, president of consultancy Power Advisory, asked whether the 100% carbon-free or renewable power goals in Massachusetts and New York were attainable at all.

Doreen Harris | *© RTO Insider*

"Large-scale renewables like solar and wind are a primary reason the state is able to achieve these lofty goals," said Doreen Harris, director of large-scale renewables for the New York State Energy Research and Development Authority. "The last two years alone have brought about incredible cost reductions and competition from these resources. In 2017 and 2018, New York awarded agreements for long-term contracts for 46 different large-scale projects, and at prices over 20% less than those received just two years ago."

Gov. Andrew Cuomo in January vaulted New York ahead of other states by pledging to secure 70% of electricity from renewables by 2030 and to achieve carbon-free electricity by 2040, while nearly quadrupling its offshore wind energy goal to 9 GW by 2035. (See *New York Boosts Zero-carbon, Renewable Goals*.)

New York is in the midst of reviewing 18 proposals from four developers responding to its first offshore wind solicitation issued last November seeking 800 MW or more of offshore wind. The state expects to award contracts in April, Harris said. (See *Four Bidders Vie for NY Offshore Wind Project*.)

Harris noted the "very interesting areas of regional overlap" among the lease areas capable of serving multiple markets from New Jersey north to New York, Connecticut, Rhode Island and Massachusetts.

"Big 100% renewable or carbon-neutral goals are attainable; it's just a matter of how much you're willing to spend to get there," Chang said.

Emily Green, staff attorney with the Conservation Law Foundation, said Maine Gov. Janet Mills' new renewable energy goals of 80% by 2030 and 100% by 2050 are attainable.

Emily Green | *© RTO Insider*

"Clearly it's a very aggressive goal, calculated to fulfill Gov. Mills' campaign pledge

ISO-NE News

NECA RENEWABLE ENERGY CONFERENCE

to establish Maine as a leader on clean energy," Green said. "If you look at the technical potential in the state of Maine, our solar developers would really like to tell us that the state is 33% sunnier than Germany, the global leader in solar development. In terms of offshore wind, we rank seventh in terms of technical potential, so I think the resources are there."

Transmission Issues

David Wilby | © *RTO Insider*

David Wilby, president of Maine-based consulting firm Wilby Public Affairs, said that if asked to rank the challenges to developing large-scale renewables, "I'd rank the top three as transmission, transmission, transmission."

Dalton asked about the potential for regional cooperation in developing offshore wind transmission.

Transmission is "an existential issue" for onshore wind, Wilby said, but getting regional cooperation for offshore wind transmission, though not easy, "probably could be done in a limited way."

"In some cases, we just have to do better together as stakeholders as part of ISO New England and New York ISO," said Melissa Kemp, director of policy for the region for Cypress Creek Renewables.

"Right now, something like over 50% of distribution-level solar projects and storage projects in Massachusetts are on hold," Kemp said. "There's absolutely no clarity about how those will be studied; there's been no process set up ahead of time for ISO-NE transmission coordination with the distribution-level companies. That's just not OK ... that's a crisis."

Melissa Kemp | © *RTO Insider*

Offshore wind comes with its own set of transmission challenges, and New York "is seeking a bundled product in the sense that we're looking for generation and transmission, and we're paying for it in one associated contract," Harris said.

"The proposals that we received, in several cases the leaseholder actually partnered with a transmission company for delivery into New York," Harris said. "It might have been conceivable to think about radials when you're talking about 2,400 MW of offshore wind, but when you're thinking about 9,000, obviously that's a very different ballgame from the perspective of scale and points of interconnection." (See *Vineyard, Anbaric Team on 1,200-MW Offshore-Tx Proposal*.)

Storage and Hybrid

Jason Burwen | © *RTO Insider*

Distributed storage will continue to be a significant part of the region's installation base, said Jason Burwen, vice president of policy for the Energy Storage Association.

"You're going to see a significant fraction of deployment coming onto distribution systems ... and the duration of these assets getting longer," Burwen said.

The story, he said, is the decline in costs, precipitous and somewhat unprecedented in the history of energy technologies at bulk scale, with 8 to 10% declines in installed costs from year to year.

All the storage in the country amounted to 1,200 MWh in 2017, while today a single facility planned to go online in California next year will have the same 1,200-MWh capacity, Burwen said.

"That gives you a sense of how the order of magnitude of the amount of storage coming onto the system is changing, as well as the size of these projects," he said.

Aside from its known benefits of providing flexibility and balance on the grid, "you're going to see storage used for congestion avoidance and curtailment avoidance, and that becomes particularly important at much higher levels of renewables, whether that's in more localized systems for congestion, or on a more system-wide basis for the curtailment issue," he said.

"Adding storage to our assets across the country is the lowest-hanging fruit," Kemp said. "In the Northeast ... the first and easiest entry point has been the distributed market ... relatively straightforward, predictable revenue streams for adding storage to various sizes of distributed assets."

But there is still work to do on the wholesale market side, Kemp said, citing the ISO/RTO filings in December on Order 841 implementation to allow for greater market participation by storage resources. (See ***RTOs/ISOs File FERC Order 841 Compliance Plans***.)

"There are a lot of problems there," Kemp said. "I think Order 841 from FERC symbolically looks great, but ... we're not there yet. In New York, there's discussion about dispatch, whether that has to be controlled by the ISO because of software constraints. ... ISO-NE is in some ways simpler because they have the Pay-for-Performance."

The Pay-for-Performance program took effect last June to replace the RTO's Winter Reliability Program, increasing financial incentives for resource owners to make investments to ensure reliability and responsiveness during periods of scarcity. ■

— Michael Kuser

From left to right: Juliet Caplinger, Jon Mancini, Becky Gallagher, Kathy Castro, Brianna Brand and Emily Green. | © *RTO Insider*

ISO-NE News

ISO-NE Steady on Fuel Plan Despite NEPOOL Rebuff

By Michael Kuser and Rich Heidorn Jr.

The New England Power Pool Markets Committee last week rejected ISO-NE's interim proposal for compensating generators for fuel security. But the RTO plans to file the plan with FERC with or without stakeholder endorsement, it said Monday.

The proposal, which would cover capacity commitment period 14 (2023/24) and 15 (2024/25), received only 42% support, short of the 60% threshold to recommend it to the Participants Committee.

[Editor's Note: This account of the meeting is based on the committee actions *notice* posted after the two-day session March 5-6. Like most NEPOOL meetings, it was closed to the public and the press.]

ISO-NE spokeswoman Marcia Blomberg said the RTO will seek a vote on its proposal at the NEPOOL Participants Committee meeting Wednesday and plans a FERC filing by the end of the month regardless of the outcome. "In its advisory role, NEPOOL provides input on ISO proposals, and the ISO has filed proposals in the past when we haven't had the full support of NEPOOL," she said via email. "The ISO always evaluates NEPOOL's input, but I can say that we are working toward a filing on the interim compensation proposal."

ISO-NE said the *plan* — which it estimated could cost more than $100 million over the last winter reliability program — is intended to prevent otherwise economic resources from retiring because they are not fully compensated for their winter energy security attributes. It would trigger when gas availability is low and system conditions were tight.

Under a two-settlement structure, resources would be paid or charged for deviations between the inventoried energy purchased in a forward position for the entire winter season and the spot settlement rate — representing energy maintained during each trigger condition.

The plan is intended to be an interim measure until the RTO completes development of a market-based compensation scheme for energy security, which will not be filed before retirement bids are due for Forward Capacity Auction 14 this month.

Amendments also Rejected

The committee also rejected efforts by the Union of Concerned Scientists (UCS), PSEG Energy Resources & Trade and energy services firm Energy New England (ENE) to amend the ISO-NE proposal.

ENE *argued* that the RTO's proposal "far exceeds" its stated goal of retaining resources for fuel security reliability and preventing uneconomic retirement bids, saying its "resource eligibility is too broad and extends beyond target resources."

The company recommended limiting compensation to oil, natural gas, demand response and electric storage, "resources capable of improving winter energy security by providing incremental reliability benefits." ENE said its proposal would reduce the cost of the program by about $50 million.

The 440-MW Merrimack Station in Bow, N.H., is New England's largest remaining coal-fired power plant.

ENE's amendment received only 48% support, winning backing from most End Users and Publicly Owned Entities but overwhelmingly opposed by the Generators, Suppliers, Alternative Resources and Transmission sectors.

The PSEG amendment would have set the inventoried energy base payment rate on April 30 immediately prior to the delivery period.

"It is widely recognized that setting the energy base payment rate for the winter delivery period over four years prior to when the contracts are expected to be obtained increases the likelihood that the rate will be inconsistent with market conditions when resources are expected to go to market to obtain those contracts," PSEG's Joel Gordon said in a *memo* to the committee. "If the rate is too low, the program will fail to procure the additional fuel security needs of the system. Conversely, if the rate is too high, the overall cost of the program will be greater than otherwise required to achieve its objectives."

It failed with 42% support, with strong backing from Generators and strong opposition from End Users.

Abigail Krich, president of Boreas Renewables, was to present on behalf of the UCS a *proposal* guaranteeing that energy actually provided would receive the same compensation as inventoried energy.

Krich's presentation said that renewable resources that provideenergy during cold weather are also essential to reliability but that they would not be compensated like fossil fuel plants because they have no "inventoried" energy. The UCS proposal, which would have amended *Tariff Section I.2.2* and *Appendix K* of Market Rule 1, failed on a show of hands.

Energy Efficiency Exemption Impact

The Markets Committee also rejected a proposal by the New England Power Generators Association (NEPGA) to address a disconnect in the calculation of Pay-for-Performance penalties during scarcity conditions in off-peak hours. The proposal was introduced by NEPGA member Dynegy Marketing and Trade.

Because of an exemption ordered by FERC, energy efficiency resources are subject to ISO-NE's PfP requirements only during DR on-

ISO-NE News

peak and seasonal-peak hours. That became an issue on Labor Day 2018, when EE resources were treated as if they had hit the stop-loss limits, resulting in $9.7 million in settlement imbalance charges to other capacity resources, according to NEPGA.

The association said because most EE resources are in Massachusetts and Connecticut, the cost of the exempted performance obligations should be allocated to the states based on their shares.

NEPGA's proposal received less than 35% support, winning majorities from only the Generation, Supplier and Alternative Resources sectors.

An alternative *amendment* by Vermont Energy Investment Corp. (VEIC) fell just short of approval with 58.4% support, strongly backed by End Users, Publicly Owned Entities and Transmission and strongly opposed by Generation, Suppliers and Alternative Resources.

VEIC's proposal was *presented* by Synapse Energy's Doug Hurley, who said the balancing ratio (BR) used to compute penalties removes EE from the numerator but not from the denominator during non-peak hours.

Hurley said the proposal would revert the mutual insurance pool to its original intent of covering resources that reach stop-loss limits. "The BR for any interval would be calculated based upon those resources that are subject to payments or penalties in that interval, as the FERC order intended," he said.

In a related matter, the committee agreed to ask the Demand Resources Working Group to consider how EE resources' performance could be established in all hours and what standards and reporting mechanisms are necessary to make the change. The committee acted on a *problem statement* that noted the lack of a consensus on EE performance measurements in off-peak hours.

New Ancillary Services and Multi-day-ahead Market

The meeting also featured a presentation on the introduction of three categories of new ancillary services to be procured in the day-ahead market and an update on the previously introduced multi-day-ahead market (M-DAM).

ISO-NE Principal Analyst Andrew Gillespie was scheduled to *present* the committee with conceptual details, as well as a timeline for a FERC filing by Nov. 15, in line with the RTO's January *request* for a four-month extension to file a plan. The delay request is currently pending before the commission (EL18-182).

The presentation to the committee acknowledges the RTO has "heard a number of questions and concerns about the length of the market horizon, primarily how this may not align with participants' hedging strategies."

The Massachusetts attorney general's office commissioned London Economics International (LEI) to prepare an *alternative* to the RTO's M-DAM proposal, which LEI found "conceptually and operationally complex" and said would "require substantial administrative costs."

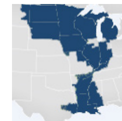
Complete revamping of the day-ahead market into an M-DAM is an unproven mechanism and may not meet all the RTO's goals, LEI concluded, proposing instead a "forward stored energy reserve" ancillary service.

The advisory firm contends that while the RTO's proposal might increase revenues for some power plants and prevent inefficient retirement, the resulting higher energy prices may lower net cost of new entry, which would suppress capacity market prices and potentially accelerate retirement.

Calpine was scheduled to *present* its case for a "forward enhanced reserves market" (FERM), with analyst Rebecca Hunter arguing all problems that fall within a planning horizon time frame are left unsolved without a forward price signal. (See "Market Reaction," *New England Talks Energy Security, Public Policy*.)

The FERM would have no offer cap, but awards to resources with capacity supply obligations would be incremental to the clearing price. In addition, FERM resources would have daily day-ahead must-offer obligations in winter months only. The construct would allow participation from resources without a supply obligation, such as energy-only resources that only plan to be available for peak days in the winter. ■

MISO News



MISO, Stakeholders Debate Merits of Seasonal Auction

By Amanda Durish Cook

CARMEL, Ind. — MISO last week revived the idea of implementing a seasonal capacity auction as part of its multipronged resource availability and need (RAN) initiative but promised to gather more data on resource flexibility before defining long-term solutions.

Seasonal Auction Revival

Davey Lopez | © *RTO Insider*

MISO planning adviser Davey Lopez said he's observed a shift from stakeholders criticizing a two-season capacity auction to becoming open to analysis of possible benefits, including better capacity availability and price signals. Lopez also said stakeholders indicate the most support for a four-season construct. However, stakeholders still support holding a single auction rather than performing auctions in different seasons, he added.

But whether that single auction would be conducted simply with seasonal inputs, encompass four separate seasons or be four auctions performed simultaneously remains to be seen, Lopez said. MISO said it will work on seasonal design elements through the end of the year.

"I think by the end of the year we'll have at least some results on here's what a seasonal auction would look like and here's what the results will be," Lopez said at a March 6 Resource Adequacy Subcommittee meeting.

But representatives from Xcel Energy, DTE Energy and Madison Gas and Electric said they still favored MISO's erstwhile monthly auction design. The RTO switched from monthly voluntary auctions to an annual voluntary capacity auction in 2013.

MidAmerican Energy's Greg Schaefer said the monthly auction was a lot of work that yielded unclear price signals.

"Rather than leaping from once per year to 12 times per year, let's try something intermediate," Schaefer urged.

But some stakeholders say price signals are no better in MISO's current capacity situation.

"With the current annual construct, we don't have a price signal ... we have a price that is essentially zero," Coalition of Midwest Power Producers' Mark Volpe said.

Many stakeholders said MISO must come prepared with study results that show a seasonal capacity auction will solve potential capacity shortfalls.

"From our perspective, the case has yet to be made, and the analysis has yet to be exhausted," WPPI Energy's Steve Leovy said. He also argued that MISO shouldn't proceed with a seasonal auction unless the RTO's loss-of-load expectation (LOLE) study shows risks outside the summer season.

MISO Independent Market Monitor Michael Chiasson said the current annual capacity market design prohibits some resources unavailable in the summer from entering the market at all.

"So those are essentially lost resources from a capacity value perspective. This sort of flexibility should increase the number of capacity resources. ... That will make our market a lot deeper ... and more economically efficient," Chiasson said.

"Assuming that the LOLE can be edited, [we still] need to be careful about summer and winter compared to the spring and fall," Minnesota Public Utilities Commission staff member Hwikwom Ham said, emphasizing that MISO should still recognize that summer and winter risks will continue to be more pronounced than those in spring and fall.

"I need to remind people we're in a planning reserve sharing group. And if we go to seasonal accreditation, what's the point of being in the MISO?" Consumers Energy's Jeff Beattie said. "The bottom line is we need to show value in this; otherwise we're going to ... be in a 'Groundhog Day' situation," Beattie said in reference to MISO's proposed, three-year forward capacity auction design that was *rejected* by FERC in early 2017.

Beattie noted that Consumers is relying on MISO's reserve sharing characteristics while its Ludington pumped storage facility is on an extended outage for major upgrades. He said when the facility returns, Consumers will repay the reserve-sharing debt with nearly 2 GW in storage capacity.

Consumers has said MISO moving to a two- or four-season construct would be "a step back" in the RTO's value to stakeholders unless it also devises a method for monthly true-ups, similar to NYISO's practice.

"A seasonal construct with a minimum of two seasons with forward monthly true-ups has been proven to be FERC-acceptable for many years," Consumers said in comments to MISO.

Mississippi Public Service Commission consultant Bill Booth asked how a seasonal auction construct would impact MISO's annual must-offer requirements for resources.

"It may be a little premature to talk about must-offer requirements ... but I think, yeah, we'd have to address the must-offer requirement in some form or fashion," Lopez said.

MISO Director of Resource Adequacy Coordination Laura Rauch said the RTO may find it needs a higher percentage must-offer requirement but a lower overall megawatt requirement for fall, when outages spike and weather becomes volatile.

"There will be impacts across the board that we'll have to analyze," Rauch said.

Lopez said outages in particular will be a consequential variable for a seasonal auction. He also said MISO will have to examine seasonal auction inputs, including the loss-of-load target, planning reserve margins, local reliability requirements and capacity import and export limits. Resources, including wind and solar generation, would also need accreditations that vary by season.

Lopez said MISO will likely devise hypothetical seasonal inputs and study them against annual auction values based on a summer peak.

Data on the Way

MISO this week committed to more internal study on its system to gather more data to support future long-term RAN solutions, including the possible seasonal capacity auction.

Dustin Grethen | © *RTO Insider*

At a March 7 Market Subcommittee meeting, MISO market design adviser Dustin Grethen said the RTO will conduct an analysis to provide "visibility into availability and flexibility."

"So a lot of buzzwords there," Grethen said, smiling. "We're really going to be digging deep into availability and flexibility. What are the system needs and

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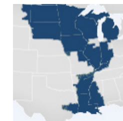


characteristics that MISO has? ... We need to make sure we have good empirical evidence for the things we're proposing."

MISO said it will assess multiple years of hourly, real-time location-specific values for load, reserves and net-scheduled interchange. It will use those data sets to look into changing needs for energy, ramp and reserves in MISO regions and in load pockets throughout the year. Grethen said MISO will also examine its past forecasts and the "final disposition" of all megawatts that were potentially available to meet system needs. The goal is to quantify MISO's uncertainty and resource flexibility, he said.

Grethen also said stakeholders have made "many calls" for MISO to develop a multiday market forecast as part of the RAN project. He said MISO will have to complete its data-gathering and future discussion before such an addition is made. Discussions on a multiday forecast are currently on hold until early 2020, according to the RTO's Market Roadmap list of possible market changes.

Xcel Energy's Kari Hassler asked MISO to not assume in its new analyses that coal and nuclear resources continue in their must-run capacities, as incentives to continue operating such generation are vanishing.

"Please don't assume that all of your must-run resources will continue to run that way," she told Grethen, who took notes.

"Waiting for data is not the answer. Volatility is a given; uncertainty is a given. We have to work under that assumption instead of waiting for data. To me, that's a very dangerous proposition," the Minnesota PUC's Ham said.

Ham also said as long as distributed energy resources aren't visible to MISO, its data collection will continue to be incomplete. He said MISO should aggregate DERs and let them into the market in order to alleviate some uncertainty.

Grethen said MISO hasn't been sitting on its hands waiting for data and pointed to its three "stopgap" Tariff filings aimed at freeing up 5 to 10 GW of capacity this spring. MISO has two near-term filings awaiting FERC action as part of the short-term piece of the three-phase RAN project, one to subject demand response to annual capability testing and one to impose new generator accreditation penalties for planned outages taken with fewer than 120 days notice and during "low-margin, high-risk periods." (See *Stakeholders Seek Slowdown on MISO RAN Project*.) The RTO last month got FERC's nod on a Tariff filing meant to ensure load-modifying resources are available as promised. (See *MISO LMR Capacity Rules Get FERC Approval*.)

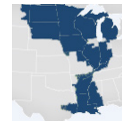
History on Repeat?

As part of RAN, MISO is also mulling modeling both nonoptimized planned outages and resource lead times in its annual LOLE study, and an investigation into how resources are accredited before the 2020/21 Planning Resource Auction. MISO's current LOLE doesn't account for either variable. Lopez also said MISO will continue to evaluate its capacity accreditation for the PRA over the next several months.

However, MidAmerican's Schaefer said he didn't see why MISO was considering modeling sub-optimized scheduled outages in the LOLE when it has a Tariff filing out for FERC approval aimed at improved scheduling.

"It doesn't make sense that we're telling FERC we can do better. ... We just can't blindly tell FERC that history will repeat itself when we're telling FERC that history won't repeat itself," Schaefer said. ■

MISO News



LSE Load Forecast Documents Incomplete, MISO says

By Amanda Durish Cook

Michael Robinson addresses the RASC. | © *RTO Insider*

CARMEL, Ind. — In an assessment of this year's load forecast Wednesday, MISO told its load-serving entities they could do more to support their individual forecasts with documentation.

MISO adviser Michael Robinson began the annual load forecast *review* with an anecdote that Lake Superior was days away from freezing over completely.

"Every 30 or 40 years it typically does this," Robinson said. "Assuming no forced outages and instantaneous replacement," it would take one Zamboni 693 years to resurface the lake, he said.

"It hasn't taken us that long to assess the load forecast, but it has taken us some time," Robinson joked.

He said that while all of MISO's 140-plus LSEs submitted demand forecasts, supporting documentation was often incomplete.

This year, MISO posted a template of information to emphasize the kinds of information and documentation it expects.

"Last year when we did this, we weren't happy with the initial response we got from LSEs and the documentation supporting the coincident peak demands," Robinson said.

Despite the written expectations, Robinson said LSEs again provided spotty documentation supporting their forecasts. MISO this year conducted a random sampling of 11 LSEs with peak demand under 1 MW and 17 LSEs greater than 1 MW, representing 48.5% of the RTO's peak demand. It said it found "many instances where information was initially missing."

"Well over half of our LSEs have given us insufficient information on the first go-round," Robinson said. "We need to do better next year."

However, Robinson said once MISO got the requested information, it resulted in only minor revisions to the load forecasts.

MISO this year *expects* a coincident peak load of nearly 122 GW systemwide and a 135-GW planning reserve margin; the RTO says it has about 172 GW of totaled installed capacity to cover it.

This is the last year MISO will use its historic load forecasting method. For its 2020 Transmission Expansion Plan, the RTO will rely on a blended forecast that will have Purdue University's State Utility Forecasting Group and consulting firm Applied Energy Group work with 20-year forecasts provided by LSEs. (See "MISO Under New Load Forecasting Method," *MISO Planning Week Briefs: Feb. 12-13, 2019*.)

Capacity Auction Nearing

MISO will post final Planning Reserve Auction load forecast data on or about March 18 and plans to hold a conference call on the final data March 20. (See *MISO Preliminary PRA Data up Slightly from Early Prediction*.)

This year's capacity auction offer window will open at 12:01 a.m. on March 26 and close at 11:59 p.m. on March 29. Results will be publicly available on April 12.

LMR Registration Steady Despite New Requirements

The number of load-modifying resources *registering* for this year's auction is in line with last year, MISO's Eric Thoms reported. The RTO registered 809 LMRs representing 11.7 GW for the 2019/20 planning year. Traditional behind-the-meter generation (BTMG) totaled 340 resources at 3.6 GW, and demand response totaled 280 resources at 7.3 GW. The total also includes 189 intermittent BTM resources at 913 MW.

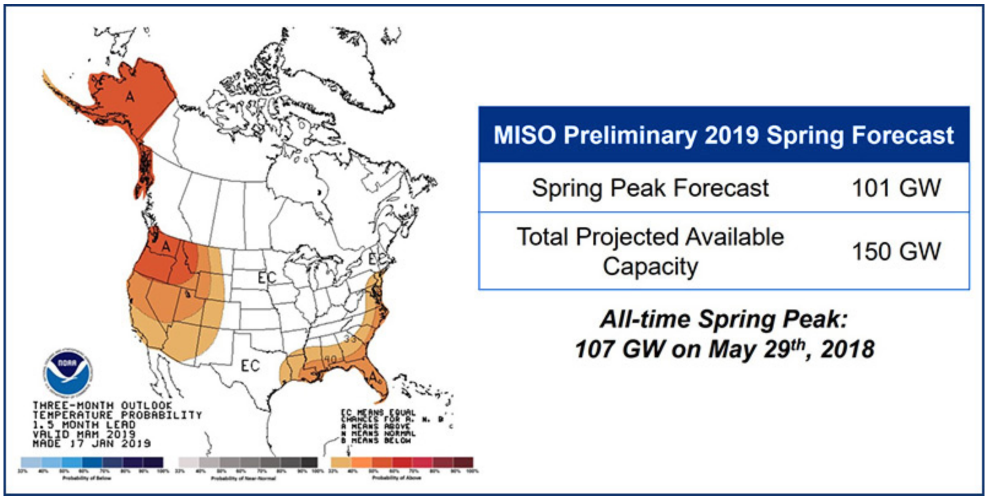
According to MISO's count, 48% of traditional BTMG and DR LMRs have a lead time of fewer than two hours, while about 27% have a lead time of between two and six hours. Slightly less than 25% have a notification requirement of six or more hours.

About 81% of the traditional BTMG and DR reported availability for more than nine months out of the year. This is the first year that LMRs had to provide firmer and more clearly documented commitments regarding their availability before participating in the PRA. In years past, MISO LMRs were only required to be available for dispatch in the summer months. (See *MISO LMR Capacity Rules Get FERC Approval*.)

During the registration process this year, MISO created a bulk LMR registration template to allow market participants could register several LMRs at once, after the RTO noticed owners of multiple LMRs were experiencing a time-consuming process, Thoms said. Because MISO's Tariff filing was intended to ensure that LMRs are available as promised, resource owners this year had an extended registration deadline. (See "LMR Registration Confusion," *MISO Preliminary PRA Data up Slightly from Early Prediction*.) ■

MISO News

MISO Expects 'Modest' Spring Risk



NOAA spring prediction | *NOAA, MISO*

CARMEL, Ind. — MISO foresees a "modest probability" it will declare a systemwide maximum generation event this spring.

The RTO last week said such a scenario would culminate from both high loads and forced outages, and it stressed that the need for emergency procedures will be "impacted by the availability of resources," such as wind generation, capacity imports, stranded capacity and load-modifying resources.

MISO predicts a 101-GW peak this spring and says it has 150 GW of resources, including load-modifying resources, available to cover demand and outages. Last spring, total outages in MISO in April neared 50 GW, the highest level in the last five years.

The National Oceanic and Atmospheric Administration forecasts average temperatures in MISO Midwest and higher than normal temperatures in MISO South during the season.

Speaking at a March 7 Market Subcommittee meeting, MISO Manager of Probabilistic Resource Studies Ryan Westphal said the forecast indicates a good chance of a "normal spring for the north part of the footprint."

MISO has projected it has a probable 103.3 GW worth of generation capacity in March, 95.2 GW in April and 105.1 GW in May.

Westphal said MISO expects May to have the highest chance of systemwide maximum generation event procedures.

MISO's all-time record spring peak occurred last year on May 29 when unseasonably hot weather prompted a 107-GW peak load. (See "Volatile Spring," *MISO Players Probe Causes of Increasing Emergencies*.)

Meanwhile, in preparation for summer, MISO will hold readiness drills for members to review emergency operation procedures on April 18, April 25, May 2, May 9, May 16 and May 23.

MISO will also hold its annual summer readiness workshop on April 23. ■

— Amanda Durish Cook

MISO News

NextEra Gains Incentive for Hartburg-Sabine Project

By Robert Mullin

FERC last week authorized NextEra Energy Transmission (NEET) Midwest to recover all "prudently incurred" costs related to the company's investment in the Hartburg-Sabine Junction 500-kV project in East Texas, MISO's second-ever competitively bid transmission project (*ER19-775*).

The commission's granting of the abandoned plant incentive ensures NextEra will be covered for 100% of its investment if the project is canceled for reasons outside the company's control.

The Hartburg-Sabine project will consist of a new 23-mile 500-kV transmission line, four short 230-kV lines and a new Stonewood substation that will connect the longer line with the existing Hartburg substation. The project is designed to relieve congestion issues and import limitations along the Texas-Louisiana border.

MISO awarded the project to NextEra last November following a competitive bidding process in which the company's proposal scored 97 out of a possible 100 points, beating out 11 other competitors. (See *NextEra Wins Bid to Build MISO's 2nd Competitive Project*.) NextEra's proposal capped total project costs at $114.8 million, less than MISO's $122 million estimate, and demonstrated a 2.2-1 benefit-to-cost ratio.

Under its FERC-approved formula rate, NextEra is already entitled to a 50-basis-point adder for RTO participation and a mechanism for later recovery of pre-commercial and formation costs along with a carrying charge. In its request for the abandoned plant incentive, NextEra noted the Hartburg-Sabine project is still subject to multiple layers of review, including those by the U.S. Fish and Wildlife Service, Federal Aviation Administration and EPA, as well as those by several Texas state and county agencies.

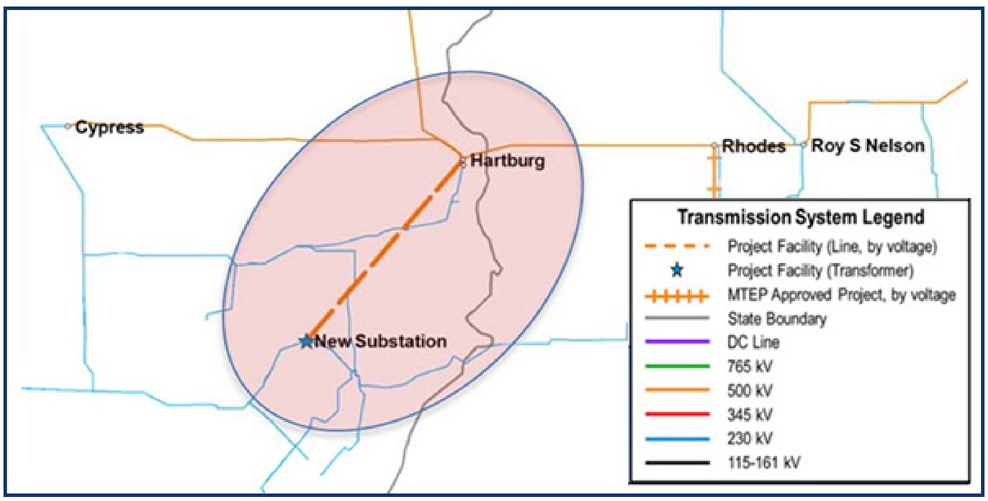
NextEra pointed to other nonregulatory risks confronting the project.

"In this regard, NEET Midwest states the project was included in the 2017 [MISO Transmission Expansion Plan] primarily because of the economic benefits to be derived from the project," the commission wrote. "However, NEET Midwest points out that under the MISO Tariff, significant changes in those anticipated benefits could result in MISO reconsidering and potentially canceling the project."

The company said it has no rate base or other revenue stream that could potentially offset any costs sunk into the project.

In approving the incentive, the commission noted it has previously found reliability and congestion-relieving projects selected through a regional transmission planning process are entitled to the rebuttable presumption established under *Order 679*, which requires an applicant to show "there is a nexus between the incentive sought and the investment being made."

"We find the total package of incentives, including the previously granted incentives, as modified as part of the selected proposal, is reasonable because it addresses the risks and challenges associated with the development of the project," the commission said. ■



Hartburg Sabine map | *MISO*

MISO News

MISO Prototyping Short-term Reserve Product

By Amanda Durish Cook

CARMEL, Ind. — MISO will prototype its proposed short-term reserve product to demonstrate cost and benefits to its members.

The move comes in part at the behest of stakeholders, who want more information on the availability of resources that might provide the reserves; the cost and reliability impacts of a reserve product; and how the product would interact with out-of-market commitments, according to MISO Market Design Adviser Bill Peters.

MISO has said it hopes to roll out the product in mid-2021, supported by its soon-to-be-replaced market platform. (See *New MISO Platform Headed to the Cloud*.)

The product would be designed to furnish capacity within 30 minutes. The RTO has said it will be especially helpful in MISO South, which has less than 500 MW of offline capacity available within that time frame.

However, Robert Francis, speaking on behalf of the Entergy Operating Companies, questioned whether MISO South's load pockets even have an adequate number of offline resources to support the 30-minute response time.

"One concern is that there may not be sufficient online and offline resources in the load pockets to enable the proposed product to work as intended," Francis said in *comments* to MISO. "Of the load pocket units that are typically online during periods of system stress, are these units historically dispatched at levels that they would lend themselves to the [reserve] product?"

Peters said the reserve product will better compensate available resources while "incenting new capability for offline response." He said there won't be a minimum target amount of such reserves.

MISO Director of Market Design Kevin Vannoy said the short-term reserves would differentiate themselves from the current contingency reserves by addressing either an excess of flow on the regional dispatch transfer constraint or restoring normal operating conditions in a load pocket following the loss of a generator sooner to avoid violations of contracts and reliability standards.

"This is a method of making sure we're able to replenish contingency reserves following a contingency. To date, we've been flush, but we're finding" that reserves are thinning, Vannoy said. He added that the short-term reserve's price signal will attract more generation willing to furnish reserves.

MISO has published a *conceptual design* of short-term operating reserves where online resources and offline resources can either register as a supplier or provide availability through hourly offers in the day-ahead and real-time markets. It plans to clear the resources according to opportunity costs, offer prices and a demand curve when insufficient amounts of the reserve exist.

Restoration Energy, Uninstructed Deviations and Tx Settlements

MISO plans to form a task team later this month to begin discussions on how it should price restoration energy — energy delivered to restore the system in the event of the real-time market ceasing to function. The RTO and stakeholders revived the idea of a plan to compensate restoration energy last year. (See *Old Analysis Could Guide MISO Restoration Pricing Effort*.)

It will also begin holding weekly conference calls Thursday to answer questions about its new uninstructed deviation threshold. The new threshold calculates a generator's uninstructed deviation with a tolerance based on the minimum of five times the real-time ramp rate or 12% from the average set point instructions. Generators in MISO are currently flagged after they deviate by more than 8% from dispatch signals over four consecutive intervals. (See *MISO Plans for New Uninstructed Deviation Rules*.)

Lastly, MISO has delayed the introduction of its new transmission settlements system until spring. The new system was slated to go live March 1, but the RTO decided it required more test runs before rollout.

John Weissenborn said MISO decided to delay the new system "to allow testing and validation from market participants." He said it will schedule a follow-up conference call in the middle of March to evaluate testing progress and discuss implementation. ■

Bill Peters | © *RTO Insider*

PJM News

Capacity Market Sellers Anxious over Uncertain PJM Auction Rules

By Christen Smith

VALLEY FORGE, Pa. — Capacity market sellers expressed anxiety Wednesday over PJM's "parallel path" for its upcoming Base Residual Auction, urging staff to consider delaying the auction until FERC clarifies the minimum offer price rule (MOPR).

Stu Bresler, PJM senior vice president of operations and markets, said the RTO is asking capacity sellers to adhere to BRA *timelines* under current rules as a preventative step in case the commission provides no additional guidance before the auction, which has already been delayed to Aug. 14.

FERC last summer granted PJM's request to delay the auction in response to the commission's June ruling requiring the RTO to revamp its MOPR to address price suppression from rising state subsidies for renewable and nuclear power (*ER18-2222*). (See *FERC OKs Delay of PJM Capacity Auction*.)

PJM filed its proposed MOPR changes Oct. 2 and said a FERC ruling by March 15 would keep the August schedule on track (*EL18-178, ER18-1314, EL16-49*).

But at Wednesday's Market Implementation Committee, PJM's Jeff Bastian said the RTO had no indication when a ruling would be made.

Bastian then walked stakeholders through the upcoming deadlines in what he called its "parallel path" to the August auction, for delivery year 2022/23. The document called for sellers to confirm whether they will be offering resources with "actional subsidies" by March 17 — a deadline stakeholders said was unreasonable.

Staff said they believe only the MOPR will be subject to change in the pending ruling. But they acknowledged the auction might need to be pushed back again if the ruling is not issued soon.

"I would concede that at some point we would get to where it would be impossible to proceed and we would have to look at delaying the auction," Bresler said. "I don't have a specific date I can give you at this point.

"I think any delay has some kind of a consequence, so that's why we are trying to avoid it," he continued. "We wouldn't want to go past next May's auction, obviously. Anything in between has a certain level of negative consequences with it, but I think it gets worse as we go through time."

Stakeholders balked at the plan, insisting it contradicted the arguments made in PJM's original delay waiver that its market suffers without certainty.


Jason Barker, Exelon | *© RTO Insider*

"It's hard, as sellers, to know what to provide for MOPR," said Jason Barker of Exelon. "This new path no longer allows us as sellers to evaluate FERC's new conditions. This is going to be problematic for market sellers. You guys realize that and wrote it in your Tariff waiver request. Now we seem to be slavishly following a schedule and not the needs balanced in the FERC order."

Adrien Ford of Old Dominion Electric Cooperative echoed Exelon's sentiments and complained about the persisting uncertainty across PJM's markets.

"I don't feel like there is a single market I can give an update [to colleagues] on with any certainty," she said. "Then to add this on top of it? I just think it's going to be really problematic for capacity market sellers."


John Horstmann, Dayton Power & Light | *© RTO Insider*

John Horstmann of Dayton Power & Light pressed PJM for more time.

"This could be life and death for your unit," he said. "You've heard from a number of stakeholders how there's going to be huge impacts. And yet you want us, without any real Tariff, to comply with all these data submissions because they might be enforced. Of course, they might not. 'Oh yeah, and we want it in a week and a half.' Where's the reasonableness in that?"

"What we appear to be doing is asking people to make irreversible decisions based on rules that may change," said Joe Bowring, PJM's Independent Market Monitor. "It sounds like PJM's theory is move forward with existing rules and just be prepared for changes." ■

PJM News

AWEA Balks at PJM Plan on Wind, Solar Capacity

By Christen Smith

VALLEY FORGE, Pa. — The American Wind Energy Association on Thursday said that PJM's proposal to change how wind and solar capacity values are calculated does not account for the technologies' performance improvements over the last decade.

Jerry Bell, PJM | © RTO Insider

After a year of stakeholder discussions, PJM staff will ask the Planning Committee in April to endorse *calculations* based on effective load-carrying capability (ELCC), which measures the additional load that a group of generators can supply without a reduction in reliability. Jerry Bell, of PJM's resource adequacy department, presented the Manual 21 *changes* during the March 7 PC meeting.

PJM's five-step process for delivery year 2022/23 begins with an average of the ELCCs for each year since 2012/13. The RTO determined that the composite ELCC is 4,181 MW, 21% of the 19,910 MW of nameplate wind and solar capacity projected for 2022/23.

After calculating the ELCC's for the two generation types separately, PJM then prorated the shares between wind and solar, resulting in capacity factors of 12.3% and 45.1%, respectively. (See "PJM Pushes Change in Wind, Solar Capacity Measurements," *PJM PC/TEAC Briefs: Feb. 7, 2019*.)

PJM would assign the ELCCs to existing individual units based on their output during the top 10 daily peak load hours in the 10 most recent delivery years. Future units will get the class average credit unless they request a project-specific calculation.

AWEA Proposals

Travis Stewart, Gabel Associates | © RTO Insider

Representing AWEA, Gabel Associates' Travis Stewart told the PC that the RTO's proposal understates the current fleet's capacity value by giving equal weight to all years in the sample.

Stewart said federal data shows wind capacity factors increased from 30.2% to 42.5% between 2009 and 2016, while solar's capacity factors increased from 20.8% to 26.8% between 2010 and 2016. PJM's equal weighting ignores the fact that older, less productive projects represent a small share of the current fleet, AWEA says.

"When PJM attaches an ELCC average to the entire renewable generation fleet, it fails to account for the individual generator's share," Stewart said.

The association proposed two *options* for remedying its concerns:

- Option 1: Find the average ELCC for each renewable project vintage across all historical years, and then calculate the ELCC for the current fleet by weighting according to each vintage's share of the current fleet.
- Option 2: To account for Option 1's potential to mask the underlying renewable performance trend, AWEA proposes building a larger dataset by combining each year's renewable output profile with corresponding load patterns to calculate an average ELCC. The trendline of ELCC change across years could then be used to weight PJM's results under its current method to recreate what ELCC performance in prior years would have been with the current fleet.

Patricio Rocha Garrido, PJM | © RTO Insider

Patricio Rocha Garrido, of PJM's resource adequacy department, said staff have "some issues" with AWEA's second option.

"We want to capture the relationship between wind output and load. … Once you start mixing outputs from one year with load shapes from another year, then that relationship gets totally missed," he said. "You achieve your goal of increasing sample size, but you totally lose that correlation."

Next Steps

PJM will present a first read of the manual changes at the March 21 Markets and Reliability Committee meeting before seeking an endorsement in April. The discussion will likely rehash stakeholder concerns over the handling of capacity interconnection rights (CIRs). (See related story, *Showdown Set on PJM Must-offer Exceptions*.)

John Brodbeck, EDP Renewables | © RTO Insider

"We purchased a lot of these CIRs through upgrades. … [PJM is] making a change here; this is not us retiring units," said John Brodbeck of EDP Renewables. "This is not the good Lord knocking a whole bunch of towers down. This is a decision to rerate units by PJM and that has a different impact than anything else. We don't like to see our assets taken away."

PJM's ELCC formula represents a shift in thinking for the RTO, which had been pushing an alternative method using average values. The new methodology is more representative of the incremental value of adding a new unit to the existing fleet, PJM's Tom Falin said in February.

The Manual 21 changes include a new section devoted to obtaining, maintaining or losing CIRs, as well as sections devoted to installed capacity calculations and testing requirements.

New rules on testing within temperature bounds will take effect June 1 with rules on simultaneous testing and the ELCC effective for delivery year 2022/23. Wind and solar units losing CIRs would be notified before Jan. 1, 2025.

Notably, the testing window for generators remains June 1 through Aug. 31 after stakeholders expressed concerns over an earlier proposal from PJM to instead start in July. (See "Skepticism of Gen Capability Changes Continues," *PJM Operating Committee Briefs: June 5, 2018*.)

PJM wants MRC endorsement by the April meeting so that unforced capacity (UCAP) values for wind and solar can be posted by May 1 for use in the 2022/23 Base Residual Auction in August. They would not affect UCAP values from prior auctions. ■

PJM News

Pa. Lawmakers Unveil $500M Nuke Subsidy Bill

Continued from page 1

Pennsylvania Rep. Thomas Mehaffie (R) introduces House Bill 11. | *Facebook*

Mehaffie said his bill would provide consumer protections through capped pricing and the prevention of "double dipping" across programs. He estimated the bill would cost $500 million — one-eighth of the $4.6 billion in annual costs he claims would result should all five nuclear plants in the state shut down: $788 million in higher electric prices; $2 billion in lost state GDP; and $1.86 billion in costs associated with carbon emissions and harmful criteria air pollutants, including SO_2, NO_X and particulate matter.

"For the state legislature to ignore the challenges facing these plants, it would be one of the most irresponsible and irreversible decisions we've made in a generation," he said.

The Pennsylvania Rural Electric Association and several union officials endorsed the bill, as did Exelon, which has threatened to shutter TMI later this year if lawmakers fail to act by May. (See *Exelon: Need Pa. Action by May to Save TMI*.)

David Fein, Exelon Generation's senior vice president of state governmental and regulatory affairs, urged support for the bill in an emailed statement on Monday, saying it "will put Pennsylvania on a path to a clean energy future [and] preserve 16,000 good-paying jobs."

Exelon successfully lobbied for nuclear subsidies in New York and Illinois after threatening to close plants experiencing financial strain. Exelon manages the largest nuclear fleet in the country, with three facilities located in Pennsylvania alone. (See *Seeking Subsidy, Exelon Threatens to Close Three Mile Island*.)

Criticism

Critics argue the plan awards undeserved subsidies and have questioned generators' claims of hardship.

"The notion that if we do nothing, nuclear power plants will simultaneously shut down and prices will be impacted is disingenuous at best — Exelon, FirstEnergy Solutions and Talen Energy are making too much money to justify shutting down," said Steve Kratz, spokesman for Citizens Against Nuclear Bailouts, a coalition of power generators and energy, business and manufacturing associations, in an email Monday. "What does Rep. Mehaffie know that industry experts — who have all testified that competition and reliability aren't a problem — do not?"

He noted that Exelon *applied* in July to extend the license of its Peach Bottom Units 2 and 3 through 2054. The group also cited research by the Kleinman Center for Energy Policy at the University of Pennsylvania that projected the subsidies would increase Pennsylvania's electric rates by $981 million annually.

"Adding already profitable nuclear power plants to the AEPS is a bailout that would significantly increase consumer electricity prices, eliminate consumer choice and fundamentally change the way Pennsylvania's competitive energy markets operate," Kratz said.

He also pointed to data from PJM's Independent Market Monitor, whose most recent State of the Market report noted improved earnings for the RTO's nuclear fleet. Although a "significant proportion" of nuclear plants did not cover annual avoidable costs in 2016 and 2017, the Monitor *reported* that nuclear plants benefited from substantially higher LMPs and forward prices in 2018.

A coalition of environmental groups — including the Sierra Club, Natural Resources Defense Council, Clean Air Council and Conservation Voters of Pennsylvania — said the bill also locks the state into propping up aging and expensive nuclear plants at the expense of more efficient renewable technologies.

"Pennsylvania's policymakers ought to be working to significantly scale up clean, safe and affordable renewable energy from wind, solar, geothermal and low-impact hydropower," the group said. "Building a clean energy economy around renewable energy in tandem with a declining, enforceable limit on carbon pollution from power plants will reduce emissions significantly in Pennsylvania as well as create jobs and protect health and the environment."

Supporters of the bill argue, however, no plan for a cleaner Pennsylvania succeeds without nuclear power — which they say generates 93% of the state's zero-carbon electricity. Mehaffie said one nuclear plant produces more power than all of the state's wind and solar assets combined. Nuclear generation supplied about 42% of Pennsylvania's net generation in 2017, compared with 4.5% for renewables, according to the Energy Information Administration.

"If we lose one or more of these plants, then we might as well forget about all the time and money we've invested into wind and solar," Mehaffie said. "It's the only baseload power supply being created without any carbon emissions. If our state wants to move forward with a cleaner environment, there is simply no way possible to get there without our nuclear power plants being open."

Gene Barr, president and CEO of Pennsylvania's Chamber of Business and Industry, said the nuclear mandate unnecessarily walls off 70% of the market, potentially forcing the state to import power — a reversal of the state's role as an energy exporter.

"The General Assembly must be aware of the possibility that FERC will soon direct the grid

Continued on page 30

PJM News

PJM MIC Briefs

First Read on Change to FTR Forfeiture Calculations

VALLEY FORGE, Pa. — The PJM Market Implementation Committee on Wednesday heard a first read on a *proposed change* to the calculations for financial transmission rights forfeitures.

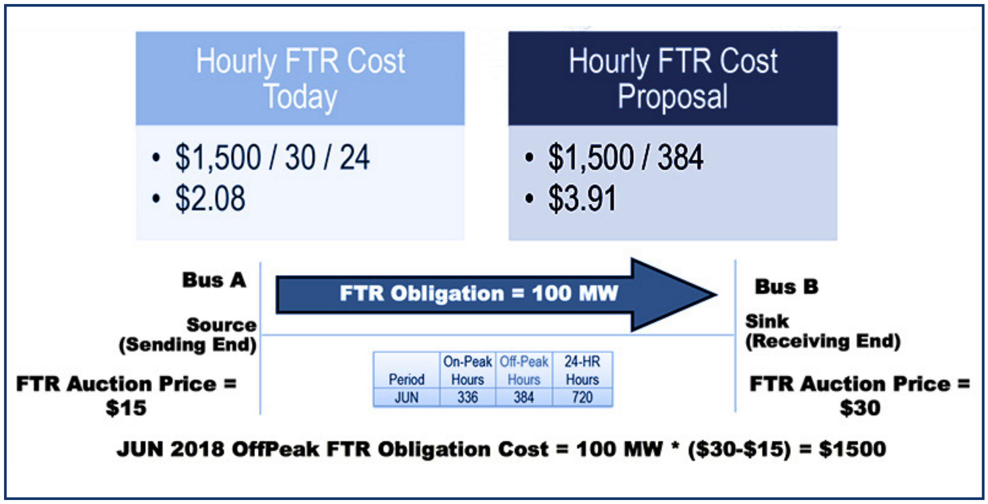
Brian Chmielewski, manager of market simulation, said PJM and the Independent Market Monitor agreed the current forfeiture rules should be adjusted because they do not distinguish between on-peak and off-peak FTRs.

Chmielewski said the issue was discovered in January but that the RTO determined its code is aligned with the Operating Agreement and Manual 6 and that no rebilling was necessary.

FTR forfeitures are intended to discourage traders from cross-market manipulation — for example, placing increment offers or decrement bids to cause congestion on paths where they hold FTR positions.

Holders subject to forfeiture are credited for the hourly cost of the FTR. Under current rules, a $1,500 off-peak FTR for June 2018 would be credited an hourly cost of $2.08, equivalent to $1,500 divided by 720 hours (30 days x 24 hours). Under the proposed change, the FTR cost would be divided by only 384 off-peak hours, increasing the credit to $3.91.

PJM plans a vote on the changes at the April MIC, with first read at the April meeting of the Markets and Reliability Committee and an effective date in the third or fourth quarter.



Current and proposed FTR forfeiture formula | *PJM*

Incremental Auction Revenue Rights Funding

Chmielewski also presented the first read on a *problem statement* and *issue charge* to address a risk to FTR market revenue funding. The initiative concerns the awarding of incremental auction revenue rights (IARRs) — ARRs created by the addition of required transmission enhancements, merchant transmission or customer-funded upgrades.

IARRs are granted to the customer only if the transmission improvement provides additional capacity that makes the request feasible. PJM guarantees that awarded IARRs are at least 80% of studied IARR megawatts.

Chmielewski said underfunding of interregional IARRs could occur because MISO's rules cannot guarantee future firm flow entitlements (FFEs) to PJM for upgrades built for IARR requests. Any portion of the FFEs for an affected coordinated flowgate that is less than 80% of the IARR megawatt total will result in inadequate FTR revenues, the RTO has found.

The MIC will vote on the initiative at the April meeting. PJM wants stakeholder work completed by Aug. 1 to allow implementation of the new rules for the 2020/21 planning period.

Gas Contingencies Update

PJM will take its rejected gas contingencies proposal back to the MRC on March 21 for stakeholder input on what a new plan might look like, PJM's Thomas DeVita told the MIC.

On Feb. 19, FERC rejected PJM's proposed process for generators to seek recovery for costs resulting from fuel-switching instructions from the RTO (*ER19-664*). (See *FERC Rejects PJM's Gas Pipeline Contingency Proposal*.)

PJM's filing would have allowed generators to request cost recovery across nine categories, such as overrun charges and exceeding maximum daily quantity.

The proposal would have allowed crediting of non-penalty switching costs prior to commission approval, subject to refund, while penalty costs would be credited only after commission approval.

FERC described PJM's definition of "penalty" — costs that are designated as such in the pipeline or local distribution gas company tariff — as "unreasonably narrow and unsupported." The commission said situations that trigger penalties by some pipelines are called switching costs by others.

The commission also said PJM must add events that trigger fuel-switching directives in its Tariff because they "significantly affect rates, terms and conditions."

PJM staff said Wednesday it was "somewhat telling" that FERC rejected the order without prejudice, leaving the door open for the RTO to tweak the proposal for resubmission.

March 6 Day-ahead Results Rerun

PJM told members it had to rerun the results of its day-ahead market for March 6 but that the changes were minor.

The bidding period was extended by a half-hour because of "challenges" getting up-to-congestion bids into Market Gateway, PJM's Tim Horger said. Staff had to make some manual transfers of data, which resulted in about 10% of UTCs not being transferred properly.

"The impact was minor. I understand that's relative to participants as to what minor would be," Horger said. He said unit commitments for physical generation did not change, although the dispatched megawatts may have. The revised results were posted Wednesday afternoon.

Load Management Testing Requirements

Members approved by acclamation a *problem statement* and *issue charge* on load management testing requirements.

PJM News

PJM said the RTO's current testing rules are based on limited demand response (LDR) requirements made obsolete by Capacity Performance.

LDR applied only to summers, non-holidays and weekends, while CP requires the resource on demand year-round. Likewise, CP events can now last up to 15 hours — versus just six under LDR — and lack LDR's cap of 10 reductions a year.

The Demand Response Subcommittee is expected to take 12 months to investigate the issue and recommend potential changes. Any rule changes would require revisions to the Reliability Assurance Agreement and several manuals, PJM's Jack O'Neill said. (See *PJM DR Subcommittee to Review Capacity Test Requirements*.)

OASIS

PJM's Chris Advena provided a first read on the *update* of the Open Access Same-Time Information System (OASIS) tool, which he said has been unchanged since 1990.

Advena said the changes are administrative and cosmetic, including product name changes, additional fields and the automation of annulment request evaluations, a process currently done via email. The MIC will be asked next month to endorse related changes to the regional transmission and energy scheduling practices.

The new tool also will reflect changes to the business practices of the Neptune, Hudson and Linden VFT merchant transmission facilities.

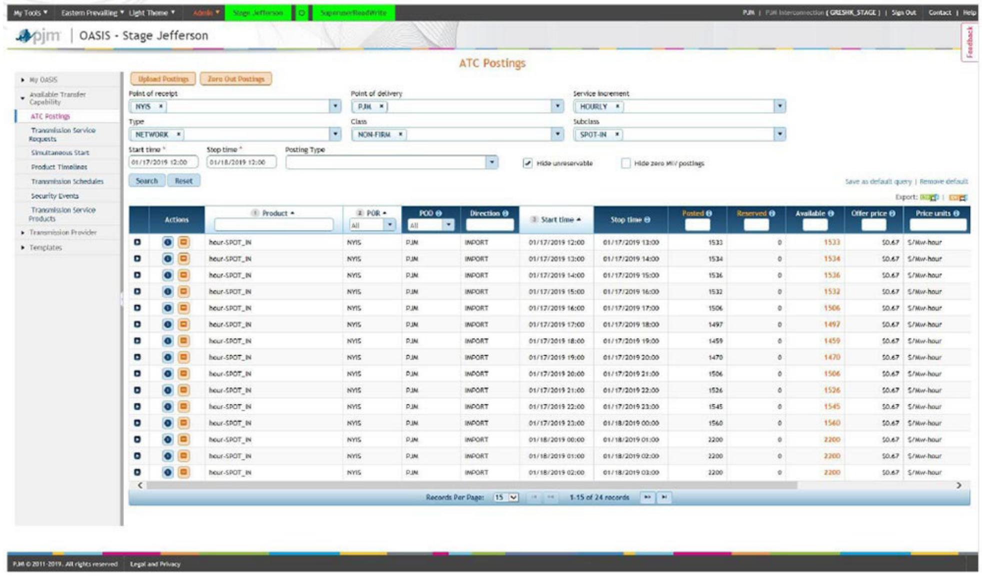
Early Look at Redesigned Homepage

PJM has posted a *beta version* of its redesigned home page available for visitors to test and provide feedback before its scheduled rollout at the end of March. RTO officials also gave stakeholders a *sneak peek* at the redesign during meetings last week.

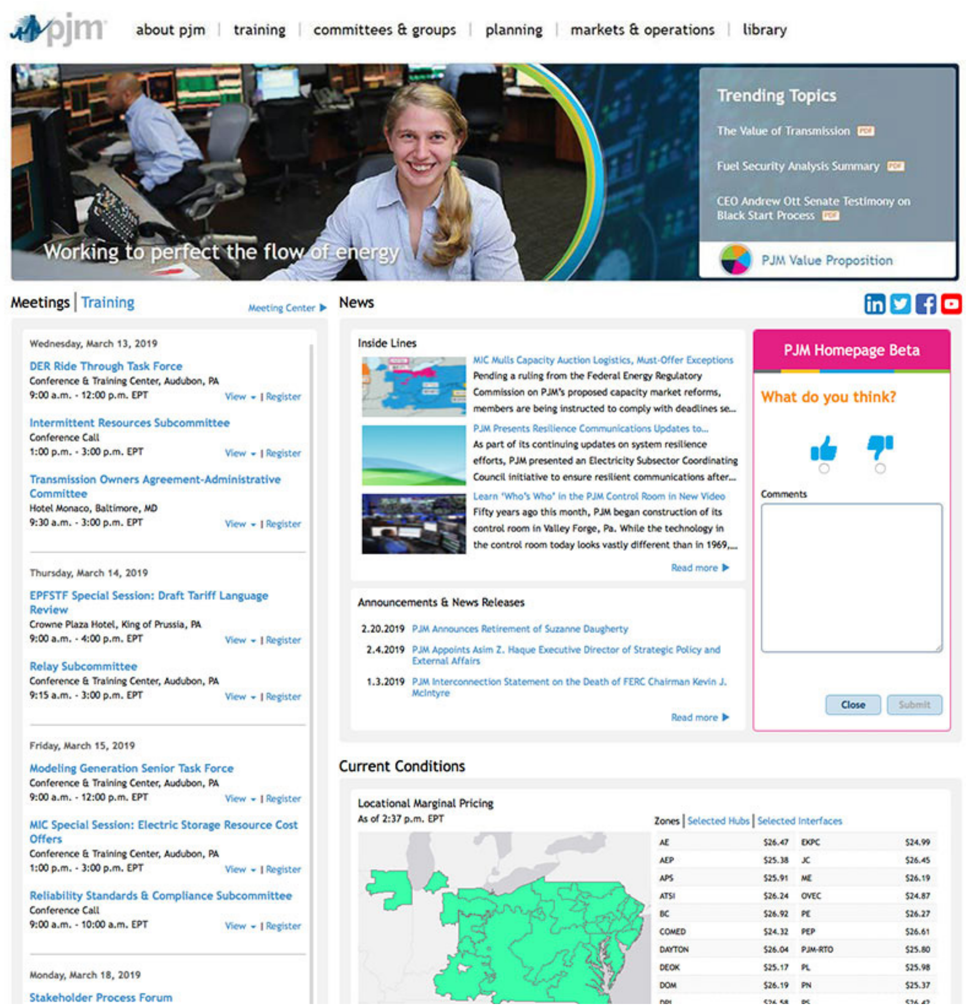
The new design is intended to highlight "more dynamic and up-to-date content," including announcements and real-time grid conditions, PJM said. The new homepage also includes a new section for filings and orders, streamlines meeting and training information, and includes a reorganized and expanded footer with links and contact information.

Questions and comments can be sent to *webfeedback@pjm.com*.

—Christen Smith and Rich Heidorn Jr.



New OASIS screen | *PJM*



PJM home page beta | *PJM*

PJM News

PJM Operating Committee Briefs

VALLEY FORGE, Pa. — PJM's Operating Committee breezed through a light agenda during its March 5 meeting.

Frequency Response Performance Underwhelms

The number of generators providing primary frequency response (PFR) in 2018 fell short of PJM's expectations, according to the RTO's most-recently analyzed *data*.

Event Time	Count of Units (with expected response)	Sum of Gen (MW) expected response	Sum of Gen (MW) actual response	Count of Units Online (includes all online units)	Sum of Gen (MW) actual response for all units	A- B Frequency Delta (as measured by BAL-003)	MW/0.1Hz Response for Gen	Expected MW/0.1Hz Response for Gen
01/27/2018 16:17:41	144	165	130	390	218	-0.044	295	375
04/07/2018 08:36:00	136	93	46	395	64	-0.056	82	166
06/30/2018 09:44:57	205	297	153	536	290	-0.038	403	782
09/13/2018 09:46:14	142	282	110	450	175	-0.048	229	588
09/20/2018 08:41:49	166	98	73	443	129	-0.048	152	204

Count of units that provided PFR by % of response compared to expected response. Only units expected to respond are in evaluation. | *PJM*

Danielle Croop, PJM senior engineer of operations and analysis, told the committee that PFR-capable generators didn't respond as anticipated during five low-frequency events selected for evaluation throughout the year, at times providing less than half the megawatts the RTO expected.

"These five events are the only ones that met the [PJM] criteria for 2018," Croop said. "There's usually about 25 or 30 events that meet [NERC's] BAL-003, so you can see how narrow the evaluation selection is."

At last October's OC meeting, PJM shared frequency response data from 13 BAL-003 events between December 2017 and April 2018 that showed similar results. (See "The Right Metric on Frequency Response," *PJM Operating Committee Briefs: Jan. 8, 2019*.)

PJM assesses generator performance during events in which the system frequency goes outside a +/-40-MHz deadband for 60 continuous seconds and the minimum or maximum frequency reaches +/-53 MHz. (See "Utilities Question Primary Frequency Response Calculation," *PJM Operating Committee Briefs: Feb. 5, 2019*.) The five events fitting into the narrower criteria occurred on Jan. 27, April 7, June 30, Sept. 13 and Sept. 20.

While generators provided 130 MW of the anticipated 165 MW during the January event, available energy dipped to 50% or less of what PJM expected during the April 7, June 30 and Sept. 13 events.

Brock Ondayko of AEP Energy refuted PJM's expectation for more output, calling it "incorrect." He said PJM's existing dispatch software often oversimplifies a resource's anticipated PFR capability because it doesn't account for physical operational hold points.

"Until PJM modifies [its] dispatch software to take into account how resources actually operate and then subsequently begins to preposition capable units to respond, 'expected' numbers really need to be taken with a grain of salt," he said in an email March 5. "While I sympathize with PJM's dispatch issues and understand the limitations of [its] current estimates, my continuing to bring up the topic/issues for what has seemed like years has never stopped PJM from continually sharing what must be considered suspect data, without disclaimers."

Croop defended the numbers during the meeting, noting more accurate data will come from analysis of individual generators — to which Ondayko agreed.

"This is not absolute … but it's a good line in the sand to see if we are getting the PFR we are expecting or not," Croop said. "I think more intricate details will work through at the generator evaluation level."

Ondayko requested PJM consider accounting for future PFR sources and those scheduled for retirement, referencing FERC Order 842 requirements.

"It would give us a better sense of how successful the FERC order is going to be or not going to be," he said.

Stakeholders Ponder Meeting Changes

As the schedule for upcoming OC meetings fills up with obligations from new and continuing task forces, stakeholders pondered getting an earlier start.

Committee Chair Dave Souder suggested starting April's meeting at 8:30 a.m. to account for agenda items related to non-retail behind-the-meter generation business rules. Stakeholders approved a problem statement and issue charge revising the existing manual language during last week's meeting. (See "PJM Continues Review of Non-retail BTM Generation Business Rules," *PJM Operating Committee Briefs: Feb. 5, 2019*.)

"I think the 8:30 start time is a little early," said Sharon Midgley of Exelon. "And the beginning of the meeting is sometimes important, particularly if there are any controversial endorsement items."

Jim Benchek of FirstEnergy agreed an earlier start time would prove difficult for stakeholders commuting and instead suggested staying an hour later.

Souder proposed implementing a working lunch for future OC meetings, to which no stakeholders voiced any objections. He said PJM's Dave Anders also suggested moving meetings to Thursday mornings beginning in 2020 so staff could have more time to provide accurate and updated reference materials. Planning Committee meetings would occur Tuesday mornings instead. ■

— *Christen Smith*

PJM News

Showdown Set on PJM Must-offer Exceptions

By Christen Smith

Sharon Midgley, Exelon | © *RTO Insider*

VALLEY FORGE, Pa. — Members of the PJM Market Implementation Committee on Wednesday set up a showdown over whether the RTO can force capacity resources into energy-only status for failing to meet Capacity Performance requirements.

About 61% of MIC voters endorsed an Exelon proposal that would allow capacity resources to voluntarily switch to energy-only status but would not allow PJM to force such a switch. Eighty-five percent also said they preferred the Exelon rules over those proposed by PJM and approved by the MIC in November. The votes made the Exelon proposal eligible to be considered by the Markets and Reliability Committee next month.

Both proposals, which would require changes to Manual 18 and the Tariff, will receive first reads at the March 21 MRC meeting. However, the November proposal will be voted on first at the April 25 MRC meeting because it was previously approved by the MIC, winning 79% support. The Exelon proposal will only get a vote if the November proposal fails to clear the necessary two-thirds sector-weighted threshold.

MIC members Wednesday also preferred Exelon's proposal over a joint ***plan*** from PJM and the Independent Market Monitor that received only 35% support, below the 50% threshold for consideration by the MRC. About 49% preferred the PJM-IMM plan to the November proposal.

Remand

The original MIC-endorsed plan was remanded back to the committee in December after the MRC agreed further discussions were needed. It would require existing capacity resources not offered in three consecutive auctions to change to energy-only status. Capacity interconnection rights (CIRs) of such resources would be terminated one year from the switch to energy-only, unless the rights holder submits a new generation interconnection request within that year using those same CIRs.

The PJM-IMM proposal would have added to the November proposal a requirement that any resource receiving a must-offer exception file a plan showing how it will become able to satisfy CP requirements in order to retain capacity status. The requirement would be effective with the 2023/24 delivery year.

Resources would be granted exceptions for no more than two auctions. (See ***PJM MIC to Vote on Alternative Must-offer Exception Rules***.)

Pat Bruno, PJM | © *RTO Insider*

"Both [the original proposal and PJM-IMM addition] have a requirement for units with CP must-offer exceptions to go energy-only after a certain amount of time," PJM's Pat Bruno said. "The main difference between the two is the way that they would be required to go energy-only and how soon that would take effect."

Exelon said it did not support a mandatory switch to energy-only because stakeholders were not in consensus on the issue, which raised equity issues over resources' potential loss of CIRs. Intermittent resources are exempt from must-offer rules.

"We were able to support the compromise approach previously endorsed by the MIC," Sharon Midgley, senior manager of wholesale market development for Exelon, said Wednesday. "Exelon does not support the PJM-IMM alternative proposal. We have concerns with the mandatory process and concerns with the CIR inequities between traditional generation resources and renewables."

'Unlevel Playing Field'

Other generation owners agreed with Exelon's objections.

"If you have renewable resources that aren't offering into auctions ... they should probably forfeit CIRs for all the same reasons," said David "Scarp" Scarpignato of Calpine. "Allowing energy-only wind resources to have CIRs and to say generators of other types aren't allowed to is a completely unlevel playing field. It's more than problematic. It's contrary to the Operating Agreement."

David "Scarp" Scarpignato, Calpine | © *RTO Insider*

Consultant Roy Shanker agreed that PJM should subject renewables to the same requirements as traditional resources.

"If we can hold the CIR without being CP based on an exemption, then they get to do that," he said. "To Scarp's point, then they, just like everybody else, should be expected to forfeit CIRs under the same conditions. We passed the hurdle a long time ago that those definitions of capacity resources within CP being different going forward. They go hand in hand. To me, there's no reason to partition between anyone."

John Brodbeck of EDP Renewables argued companies like his pay for interconnection upgrades and receive CIRs in return. "When you pay for something, you want to own it," he said.

Load interests, however, said generators' focus on who owns CIRs muddles the issue. Carl Johnson of the PJM Public Power Coalition said some legacy generators stand to lose CIRs for which they never paid.

"Some may have [paid], many have not," he said. "As topology has changed, a lot of legacy generators did not pay for them. Loads have." ■

PJM News

PJM PC/TEAC Briefs

RTEP Removal Discussions Scheduled

VALLEY FORGE, Pa. — PJM last week scheduled two meetings in the coming weeks to discuss rules for removing projects from the Regional Transmission Expansion Plan.

Aaron Berner, PJM | © *RTO Insider*

Aaron Berner, PJM's manager of transmission planning, told the Planning Committee on Thursday that the RTO crafted a *problem statement* for a holistic review of the process in response to stakeholder concerns over rules for removing supplemental projects.

The initiative could result in changes to Manual 14B. Staff, he said, are otherwise "unconcerned" with existing manual language.

He said meetings scheduled for March 22 and March 29 will focus on educating stakeholders about PJM's past project cancellations — a process that is currently handled on a case-by-case basis resulting from a reduction in load forecasts or because developers are unable to get state siting approval.

"We should look to solidify rules that are consistent among the three project types: baselines, network upgrades and supplementals," Berner said. "They are all modeled the same."

Sharon Segner, LS Power | © *RTO Insider*

The issue arose after Sharon Segner, vice president of LS Power, proposed an *amendment* to Manual 14B: PJM Region Transmission Planning Process specifying that a transmission owner's supplemental project "will generally be removed from the RTEP" following a final order by a state siting agency rejecting the project. Supplemental projects are proposed by TOs and are not required for compliance with PJM's reliability, operational performance or economic criteria. (See *PJM Rebuffs Stakeholders on Supplemental Projects*.)

At Segner's request, the Markets and Reliability Committee last month agreed to delay a vote on revised transmission planning rules for 60 days to accommodate further discussion on the language. (See "Transmission Replacement Vote Deferred Until April MRC," *PJM MRC/MC Briefs: Feb. 21, 2019*.)

"Certainly, we don't object to having a broader discussion" at the March 22 meeting, she said Thursday. "We request the specific issues we listed for discussion in the delay motion to be part of the agenda for the March 22 meeting."

Ed Tatum, American Municipal Power | © *RTO Insider*

Ed Tatum, vice president of transmission for American Municipal Power, said he was confused by the problem statement. He said there are many improvements AMP would recommend to the modeling process for adding or removing facilities, but that doesn't seem to be what PJM wants to tackle.

"This is really more of PJM's position on the MRC's direction than a problem statement," he said. "Stakeholders raised concerns that PJM should simply acknowledge that it has the same discretion to supplemental projects as it does to all other projects," he continued. "It's important to have a good understanding of the types of projects PJM has already removed from the plan."

PC Chairman Ken Seiler said staff will "tighten up" the language of the problem statement based on stakeholders' comments and present a revised draft at the March 22 meeting.

PJM Readies Package on Market Efficiency Rule Changes

PJM presented the first read on proposed rule changes developed by the Market Efficiency Process Enhancement Task Force.

Brian Chmielewski, PJM's manager of market simulation, said the *package* that staff will present for a vote at the PC's April 11 meeting changes how often the RTO will re-evaluate projects and shifts the long-term submission window and timing of the mid-cycle updates.

Chmielewski said the task force agreed PJM will not re-evaluate any projects once a certificate of public convenience and necessity (CPCN) has been issued or — in the case of states without such a process — once construction has begun. Under current rules, PJM reviews the costs and benefits of economic-based transmission projects annually to ensure they remain economical.

Both the costs and benefits of market efficiency projects costing more than $20 million will be re-evaluated annually if they lack CPCNs or are not subject to such requirements. Projects under $20 million will not be re-evaluated if the updated costs do not cause the benefit-cost ratio to fall below 1.25 based on the original benefits.

Segner said LS Power supported the language, noting her comfort level came with PJM's qualifiers for how the process changes under different state regulatory requirements.

"Essentially, if you are in a state that needs a CPCN, the state grants it or they don't, and the re-evaluation stops at that point," she said. "If your permits are more municipality-driven … the test for states that don't have a CPCN process is physical construction because the focus of stopping the re-evaluation is tied to the construction at the physical site."

PJM attorney Pauline Foley agreed and said the distinction between the two divergent processes "puts us in a lot better place than we are today regarding when re-evaluation can cease."

The task force also proposed shifting the long-term window back two months to January-April from November-February to align it with MISO's processes. If approved, both RTOs would post economic drivers in January.

The mid-cycle model refresh would be made in late April to allow project proposers extra time to analyze their projects under the revised case prior to a final submission.

The changes were the result of the task force's "Phase 2" discussions.

Staff will seek PC and MRC approval of the changes in April, with Members Committee endorsement of Operating Agreement revisions scheduled for May. PJM wants the new rules effective Aug. 1 for the 2020/21 long-term window.

Chmielewski said the task force is considering a third phase of discussions after failing to reach consensus on two other proposals:

- Evaluating regional targeted market efficiency projects to address historical congestion using the same criteria as used in interregional TMEPs; and
- Changing the 1.25 benefit-cost threshold to measure energy benefits separately from capacity benefits.

PJM News

Revisions from Order 845

PJM says it has met, or is close to meeting, changes required by FERC's Feb. 21 ruling clarifying Order 845.

In Order 845-A, the commission ruled on 12 requests for rehearing or clarification of the 2018 rulemaking intended to improve the transparency and timeliness of the generator interconnection process. (See *'Boring Good' Rulemaking Seeks to Clean up Order 845*.)

PJM's Susan McGill briefed the PC on four Tariff or manual *changes* it has finalized and said an additional six changes will be presented to the PC in April. The RTO faces a May 22 deadline for its compliance filing.

Among the changes will be new definitions and clarifications and a new Tariff section for nonbinding dispute resolution procedures including interconnection customers.

Offshore Interconnection Rights Meetings Begin in April

PJM will commence a *series* of stakeholder meetings on offshore wind development and merchant transmission beginning April 16.

Suzanne Glatz, PJM's director of infrastructure planning, said the first meeting will consist of education about the RTO's current process, followed by three months of exploration into alternative options before returning to the PC in August for endorsement of proposed changes.

Last month, the committee approved a problem statement to consider granting merchant transmission developers capacity interconnection rights (CIRs) for offshore wind. (See "PC Moves Forward on Offshore Interconnection Rights," *PC/TEAC Briefs: Feb. 7, 2019*.)

Current rules allow merchant transmission developers to obtain transmission injection and withdrawal rights for DC facilities or controllable AC facilities connected to a control area outside the RTO. Under the problem statement, stakeholders will consider allowing merchant transmission developers to request CIRs, or equivalents, for non-controllable AC transmission offshore.

$15M Project to Solve High-voltage Alarms in Dayton Zone

Berner told the Transmission Expansion Advisory Committee on Thursday that PJM and Dayton Power & Light planners have identified a $15 million *solution* to address excessive high-voltage alarms in the utility's zone. The utility has logged approximately 19,000 alarms over the last two years.

The alarm-to-minimum-load-hour ratio nearly doubled between 2017 and 2018, Berner said, with 327 alarms over the two years at 345-kV buses.

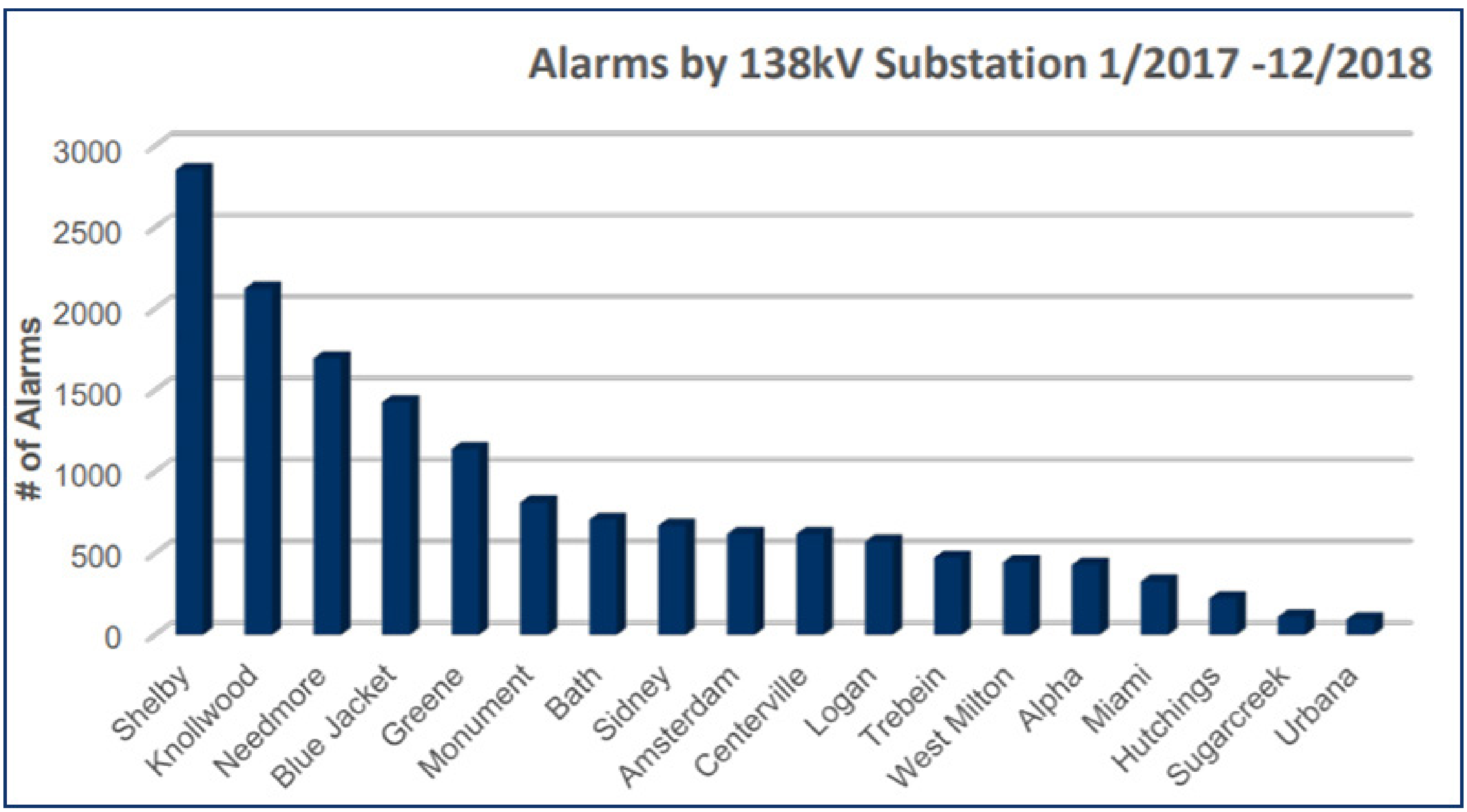
PJM said the problem is attributable in part to plant retirements, which have left the zone with only peaking plants.

The RTO said that after exhausting all typical operating procedures, Dayton is frequently forced to switch out equipment to avoid long-term damage from high-voltage exposure — a practice it finds unsustainable and ineffective.

The solution will be the installation of three 100-MVAR reactors with a projected in-service date of Dec. 31, 2021. They will be located at the 138-kV Miami, Sugarcreek and Hutchings substations.

End-of-life Project for Loudon-Dulles Junction

Dominion Energy plans to rebuild a 4.4-mile-long section of the 230-kV #2008 line between Loudon and Dulles Junction in Virginia to eliminate corroding towers.



Alarms by 138-kV substation, January 2017 to December 2018, for Dayton Power & Light | *PJM*

PJM News

PJM said removing a section of the line would cause 241 MW of load to be on radial and 311 MW of load to be dropped by a failed breaker contingency at the Reston substation.

Line #2008 will share the towers of line #2173, double-circuit structures that currently have an empty arm.

Dominion also plans to retire the 8.44-mile-long line #156 from Loudoun to the Bull Run substation and cut and loop a 230-kV line into the substation to prevent thermal violations. Three 230-kV breakers would be added to accommodate the upgrade.

The plan also removes two 230-kV transformers and a 115-kV capbank at the Loudoun substation; removes a 115-kV capbank at the Bull Run substation; and removes a 230-kV line switch from line #295 at the Bull Run substation.

The project is expected to be in service by the end of 2023.

Separately, Dominion canceled a $2.7 million project to add three 500-kV breakers at the Mt. Storm substation after the manufacturer indicated existing breakers are capable of 44 kA.

LS Power's Segner said PJM should evaluate whether the Loudon-Dulles Junction project would address any regional needs and should be subject to the Order 1000 competitive process.

She cited the August 2018 D.C. Circuit Court of Appeals ruling ordering FERC and PJM to reconsider how they allocate the costs of high-voltage transmission projects developed to satisfy individual utilities' planning criteria. The court ruled in a case prompted by Old Dominion Electric Cooperative, Dominion Energy Services and Virginia Electric and Power Co., which had challenged FERC's approval of a PJM Tariff revision that resulted in the RTO assigning all the costs for two transmission projects proposed by the companies to the Dominion zone (*17-1040, 17-1041*). (See *DC Circuit Rejects PJM Tx Cost Allocation Rule*.)

The commission has not acted on the remand order.

"Because the matter is remanded to FERC, we need to wait and hear what FERC is going to say on this issue," PJM's Foley responded. "So, we're on hold. … When the commission finally addresses this issue, we will implement what it decides."

Dominion, ATSI Supplemental Projects Presented

Dominion gave the TEAC a *presentation* on several supplemental project needs:

- A new Paragon Park substation to support existing data center load and a new data center campus in Loudoun County with a total load in excess of 100 MW;
- A third, 84-MVA distribution transformer at the Poland Road substation in Loudoun County to address customer load growth and contingency loading for the loss of one of the existing two transformers; and
- The replacement of the aging Chesterfield Tx#9 and Peninsula Tx#4 224-MVA, 230/115-kV transformers.

Dominion also presented proposals to:

- Install a 1200-A, 40-kAIC circuit switcher and associated equipment to feed the fourth transformer at the BECO substation in Loudoun County ($750,000); and
- Interconnect the new Buttermilk substation with line #2152 (Cumulus-Beaumeade) and line #2170 (Roundtable-Pacific), and install line switches, circuit switchers and bus work for the new transformers ($11 million).

American Transmission Systems Inc. *presented* a plan to rebuild 1.5 miles of the Perry-Ashtabula-Erie West 345-kV tap line as a double circuit at a cost of $23.7 million. The current three terminal lines are prone to misoperations with lengthy fault locating analyses and restorations. The company said the existing transmission relay communication equipment is approaching its end of life and is difficult to maintain and repair. ■

— Christen Smith and Rich Heidorn Jr.

Pa. Lawmakers Unveil $500M Nuke Subsidy Bill

Continued from page 23

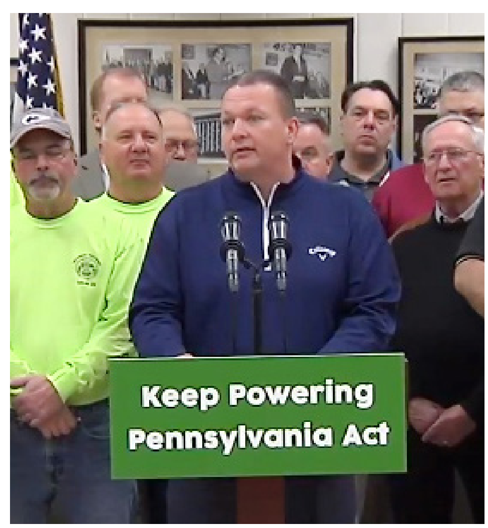
operator to deduct the value of these state subsidies out of market payments, leaving the state in an even worse position — significantly higher energy costs with no tangible benefit," he said.

MOPR Ruling

Last June, a FERC order concluded that increasing state subsidies for renewable and nuclear power were suppressing PJM capacity prices. The commission's 3-2 ruling required PJM to expand the minimum offer price rule (MOPR) to cover all new and existing capacity receiving out-of-market payments, including renewable energy credits and zero-emission credits for nuclear plants. The MOPR currently covers only new gas-fired units. (See *Little Common Ground in PJM Capacity Revamp Filings*.)

Stu Bresler, PJM's senior vice president of markets and operations, *testified* before both the House Environment Resources & Energy Committee and the Consumer Affairs Committee on Monday that the success of the RTO depends upon its ability to evolve with technology and consumer demand. However, stakeholders' recent focus on refining capacity market rules has left PJM's reserve and energy markets ignored, he said.

"It is imperative that the resources called upon by PJM to maintain system reliability are appropriately valued for the services they provide, and today's reserve and energy pricing rules fall short of that mark," he said. "By setting energy and reserve prices to levels that accurately reflect system conditions both during normal conditions and most importantly when reserve quantities become tight, resources operating to protect reliability collect revenues for the capability to respond when needed most." ■



Joe Gusler, president of the Central PA Chapter of Building and Construction Trades Council, speaks in favor of House Bill 11. | *Facebook*

SPP

FERC Blocks GridLiance Oklahoma Tx Acquisition

By Robert Mullin

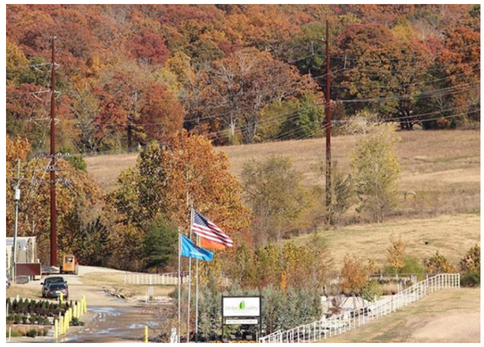
FERC on Wednesday rejected GridLiance High Plains' plans to acquire transmission assets from Oklahoma-based People's Electric Cooperative, finding the company failed to prove the transaction would not have an adverse impact on rates (*EC18-122*).

The proposed deal would have seen GridLiance take over 55 miles of 138-kV lines and a substation from People's, which provides electricity to about 15,000 members across 11 Oklahoma counties and operates a 4,500-mile distribution and transmission network.

Completion of the transaction was subject to FERC accepting GridLiance's proposal to earn an annual transmission revenue requirement on the assets by moving them under the company's commission-approved rates in SPP. The co-op is not a member of the RTO.

In making its case for the acquisition, GridLiance contended the rate impact would be small: about $2.7 million, based on a $14.9 million net book valuation of the assets. It said "non-quantifiable" benefits would offset those costs.

In rejecting GridLiance's request, the commission acknowledged that the transaction "on its face" resembled those of similar proposals it had approved in the past. Like GridLiance, the buying party in each of those deals acknowledged the acquisition would increase rates for transmission customers, "which the commission has acknowledged 'is not unexpected' when the transaction involves 'ownership changes from a not-for-profit utility to a for-profit business with a different capital structure, tax obligations and the need to earn a return,'" the commission wrote, citing a previous decision.



People's Electric Cooperative line in Oklahoma | *People's Electric Cooperative*

In each of those transactions, applicants contended that the rate increases were justified by the non-quantifiable benefits of transmission company ownership and therefore not "adverse."

But in Wednesday's decision, the commission pointed out that its approvals were based on the specific facts at play in each request. GridLiance, the commission said, failed to back up its promised benefits, or show that they would offset the proposed rate increases.

FERC questioned GridLiance's claim that the acquisition would increase reliability for retail customers receiving service over People's transmission system, noting that only 47 MW of load are being served by the transmission feeds being acquired.

"Without further evidence as to the reliability benefits of the transaction, we cannot find that the benefits of increasing the reliability of service to this relatively small amount of retail load is sufficient to offset the rate increase resulting from GridLiance's acquisition of the assets," the commission said.

The commission also rejected GridLiance's contention that the transaction would provide the non-quantifiable benefit of promoting transmission company ownership of facilities.

"This argument simply restates the general holding of the commission's cases described above without explaining how GridLiance's ownership of the assets provides benefits that offset the projected rate increase," FERC said.

The commission also rebuffed GridLiance's claim that its ownership would improve operations and efficiency in SPP, pointing out that while the lines could be made more reliable if looped into the RTO's system, they would still be primarily serving the same small volume of industrial load. "GridLiance has failed to demonstrate how placing the assets under SPP's control would maximize the use of the assets, minimize the need for new transmission or provide new avenues for transmission expansion," the commission said.

Finally, FERC rejected GridLiance's argument that the acquisition would further the commission's goal of increased RTO participation among publicly owned utilities.

"Here, the addition of 55 miles of transmission facilities whose only use is to deliver power to industrial customers does not materially add to the size or scope of SPP, nor has it been shown to provide other material benefits to SPP," the commission concluded. ■

SPP

SPP Briefs

RTO Says Day-ahead Market Has Saved Participants $2.7B

SPP celebrated the fifth anniversary of its wholesale market by noting it had produced the nation's lowest electricity costs, saving market participants $2.7 billion, and exceeded initial projections for annual net savings.

In making its case, SPP cited a 2018 FERC *market report* that listed its average year-to-date monthly day-ahead prices in October at $29/MWh. The Southeast region came in second at $31/MWh.

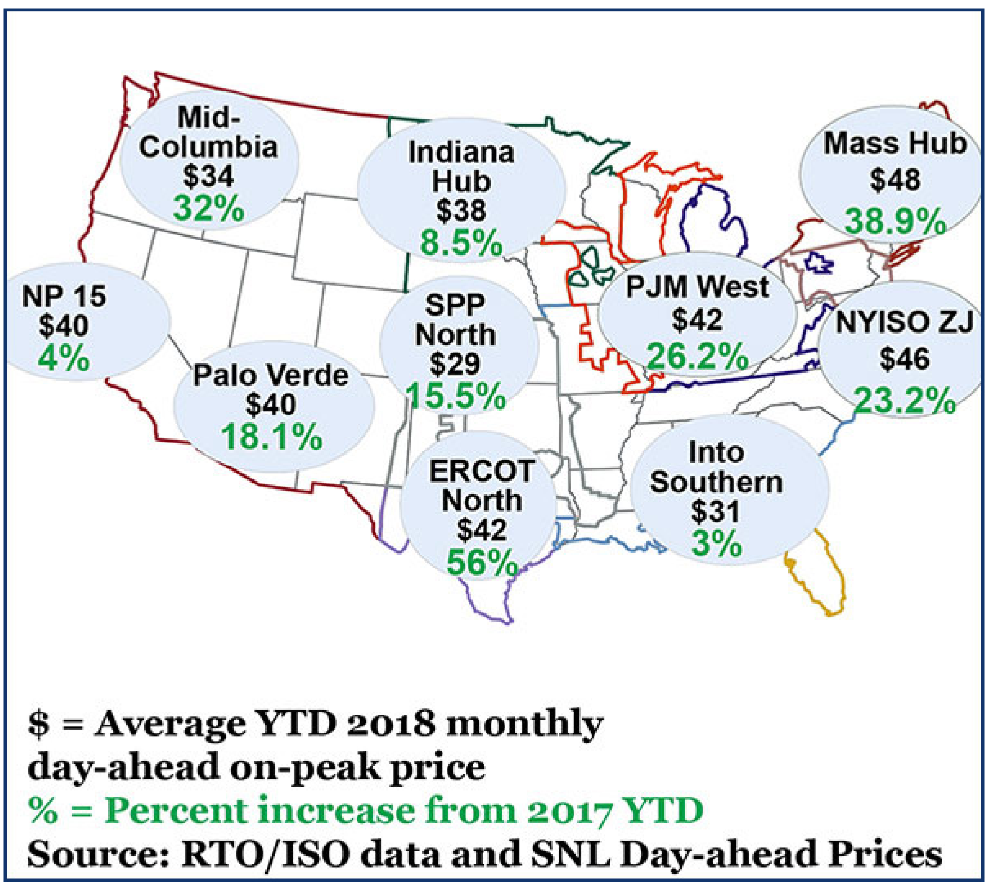
SPP had projected the Integrated Marketplace would yield $100 million in annual net savings to market participants when it was brought online in March 2014. Instead, it said, the markets have "dramatically outperformed expectations" by producing an average of $570 million in annual savings from lowered production costs, reductions to excess capacity requirements and other efficiencies.

"Our market has continually proven itself to be one of the wisest investments our members have made," SPP CEO Nick Brown said in a *statement* referring to the market's economic and reliability benefits. "It has also set us up for continued success well into the future."

The Integrated Marketplace added day-ahead generation dispatch, congestion management and real-time balancing solutions to SPP's market offerings. At the same time, the RTO consolidated the 16 balancing authorities (BAs) in its 14-state footprint to coordinate next-day generation, increasing access to lower-priced renewable energy and energy reserves.

SPP said wind energy made up 3% of its annual energy production (6 of 176 GWh) in 2008. Last year, the RTO produced 276 GWh of energy, with wind accounting for 23% of that figure. It has seen a peak wind penetration level of 64%.

"A decade ago, serving even a quarter of our load with variable, renewable generation wouldn't have been possible, but today it is almost a daily occurrence," Vice President of Operations Bruce Rew said.



2018 RTO/ISO Spot Power Prices ($/MWh) | *FERC*

Conservative Operations Alert Ends

SPP ended two-and-a-half days of conservative operations last week after successfully meeting high demand, despite subzero temperatures in the northern portion of its footprint. The RTO issued the conservative operations alert about midnight March 3, lifting it shortly after noon March 5.

Spokesman Derek Wingfield said SPP was able to mitigate the loss of 2.5 GW of generation from derates and failures to start in the cold weather, primarily in the southern part of the footprint.

SPP saw peak loads, all in the 7 a.m. hour, of 41.1 GW on March 4; 40.6 GW on March 5; and 39.3 GW on March 6. The RTO hasn't met demand that high since September 2018.

Temperatures in Bismarck, N.D., dipped to -15 degrees Fahrenheit on March 3, before rising to 22 F on Wednesday.

SPP, Members Prep for Summer in Arctic Temps

Temperatures were 18 F on March 5 as SPP staff and market participants gathered in Omaha, Neb., for — ironically enough — a workshop on summer preparedness.

Staff said a new summer peak is unlikely. SPP expects average heat during the early summer months across its footprint, with a 33 to 40% chance of above-average temperatures in later months. It also gave a 33 to 40% chance of above-average precipitation in early summer months, with average precipitation later in the season.

SPP's all-time peak demand of 50.6 GW came in July 2016. Demand in 2017 was 50.5 GW, dropping to 49.7 GW last summer.

Staff reviewed with members last summer's performance, when the only critical moments came during the shoulder months. SPP issued a hot-weather alert in May and a level 2 emergency energy alert in September, both during periods of above-average heat and low wind.

"We have tight capacity issues because we try to run a tight ship," SPP's Jon Langford said.

Staff is working on its 2019 summer assessment, using power flow and voltage stability analyses. ■

— Tom Kleckner

Company Briefs

Hoecker Retires from WIRES

Transmission trade association WIRES last week announced the retirement of Executive Director **James Hoecker**. A former FERC chairman and currently senior counsel at Husch Blackwell, Hoecker helped found WIRES in 2005 and, according to the organization, "will support the group until the end of 2019."

"WIRES is deeply grateful for the guidance and expertise that Jim Hoecker has provided to our organization throughout the years," group President Brian Gemmell said. "Taking the steps to ensure that our country has a robust electrical transmission grid is no small task, and Jim more than rose to the challenge."

"We started WIRES because it was the one sector of the electricity industry for which no one advocated," Hoecker said. "The grid was an afterthought, despite its importance as critical infrastructure. Judging by the number of groups and policymakers now focused on grid modernization, that has changed. WIRES is ready to move to the next level. I am terrifically grateful to have represented WIRES and its progressive member companies for so long."

More: *WIRES*

PG&E Seeking Court Approval to Pay $235M in Bonuses

PG&E Corp. last week sought a judge's approval to pay $235 million in bonuses to thousands of employees despite its bankruptcy.

The money is intended to provide incentives to workers and will not be distributed if the company doesn't meet safety and financial goals, PG&E said in a court filing. The bonus program has been restructured with its Chapter 11 case in mind and puts a greater emphasis on safety performance, the company said.

The utility scrapped its plan to pay $130 million in bonuses for 2018, determining the payments were inappropriate given the wildfires that year and the company's deteriorating financial situation. Attorneys for wildfire victims had objected to the awards. An employee union argued that the decision was unfair to workers. The new bonus figure is for work in 2019.

More: *The Associated Press*

Vistra Launches Retail Service in 3 States

Vistra Energy last week announced that it is launching a new retail electricity brand, Brighten Energy, in Illinois, Ohio, and Pennsylvania.

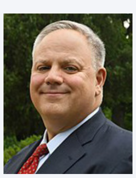
The company will open retail sales offices in Oak Brook, Ill.; Columbus, Ohio; and King of Prussia, Pa. According to Vistra, Brighten will "supply renewable energy to socially conscious consumers looking for an affordable way to make a difference."

Vistra is also expanding its newly acquired Dynegy retail business in Pennsylvania. The moves follow its announcement last month that the company will acquire retailer Crius Energy.

More: *Vistra Energy*

Federal Briefs

Trump Formally Nominates Bernhardt for Interior



President Trump last week submitted the nomination of acting Interior Secretary **David Bernhardt** to be the official department head to the Senate, a month after announcing his intent to do so.

Sen. Lisa Murkowski (R-Alaska), chair of the Energy and Natural Resources Committee, *said* she "will schedule a hearing and seek to move his nomination forward as expeditiously as possible." The nomination came just a few days after Murkowski told reporters she had no idea why Bernhardt's paperwork hadn't been sent over to the Senate. "Why do we not have it? What is up with that?" she said.

More: *The Hill*; *Politico*

Trump Budget Slashes DOE, EPA Spending for Border Wall

President Trump's fiscal 2020 budget blueprint released on Monday would cut funding for the Department of Energy's Energy Efficiency and Renewable Energy Office by 70%, while EPA would see a 31% cut.

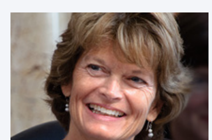
The $4.7 trillion proposal includes $8.6 billion for a wall along the U.S.-Mexican border, as well as increased funding for the Defense Department.

The document lacks details on individual programs that normally come as part of the president's request. The rest is expected later this month. Most analysts said the budget would be quickly dismissed by Congress. (See related story, *Wheeler: EPA's Proposed Budget Cut 'Common-sense'*.)

More: *Washington Examiner*; *Bloomberg*

Murkowski, Manchin Call for 'Pragmatic' Climate Solutions in Op-ed

In an editorial published in *The Washington Post* on Friday, Sens. **Lisa Murkowski**



(R-Alaska) and Joe Manchin (D-W.Va.) called for the U.S. to pursue "pragmatic policies" to combat climate change instead of focusing on "drastic, unattainable measures."

"If the United States is going to lead by example, we must continue to lead the world in the development of new and improved technologies," the leaders of the Senate Energy and Natural Resources Committee wrote. "We believe the time for sensationalism is over. And we are seeking ideas that will bring people together, rather than drive them apart."

The op-ed echoes statements the senators made at a hearing on climate earlier last week. (See related story, *Senate ENR Committee Discusses Climate Change*.) Though not mentioned at the hearing nor in the op-ed, their statements are seen as in response to the Green New Deal.

More: *The Washington Post*; *The Hill*

State Briefs

ARKANSAS

Senate Passes Bill Boosting Solar Net Metering

The state Senate last week passed a bill that would allow third-party financing for customers who install solar panels and raise limits on the size of solar arrays that can operate under net metering.

Supporters say the bill, sponsored by **Sen. Dave Wallace (R)** could potentially double or triple home and business solar installation in a state with plenty of sunshine but relatively few solar projects. "Solar energy means more jobs in Arkansas," Wallace said during remarks on the Senate floor. "This bill is a step in the right direction."

The bill moves on to the House Insurance & Commerce Committee, which could take it up as soon as this week.

More: *Arkansas Business*

CONNECTICUT

Dominion Scrambling for Millstone Contracts Ahead of Friday Deadline

Dominion Energy last week said it is working to complete negotiations with state utilities for the purchase of electricity from its Millstone nuclear power plant before a March 15 deadline.

"There is a March 15 deadline for Dominion to submit a retirement bid to ISO New England," Dominion spokesman Kenneth Holt said. "We are working to complete negotiations prior to that date."

After three years of working with politicians and regulators on a plan to keep the plant in service, the state in December selected Millstone for a contract to purchase a little over half of its output for 10 years. The price of that contract, however, was not firm, so Dominion said it is negotiating with the state and two local utilities.

More: *Reuters*

MARYLAND

Enviros Urge Support for Pipeline Water Certification Legislation

Environmentalists came to the State House last week to urge support for bills that would require the state to conduct water quality certification reviews for natural gas pipelines, as it is authorized to do under Section 401 of the Clean Water Act.

The bills are sponsored by **Del. David Fraser-Hidalgo (D)** and Sen. Bobby Zirkin (D) in their respective houses of the General Assembly. They are in part a response to efforts by Columbia Gas Transmission, a subsidiary of TransCanada, to build a pipeline under the Potomac River near Hancock. The Maryland Board of Public Works in January denied an easement and permission to build the pipeline under the Western Maryland Rail Trail, effectively blocking the project for now.

"This bill is designed to do one thing and pretty much one thing only," Fraser-Hidalgo said, "and that is, that if a natural gas pipeline … is going to be put in inside the state of Maryland, through our waterways, that we need to do our own testing … our own research, and make sure that if this is going to happen, that this is indeed in the best interest of the citizens of the state of Maryland."

More: *The Herald-Mail*

MISSOURI

Kansas City Council Pledges to go Carbon-free by 2021

The Kansas City Council last week adopted a resolution directing the city manager to negotiate with Kansas City Power & Light and procure all electricity for municipal operations from carbon-free sources by the end of 2020.

The council also ordered 90% of all eligible municipal buildings of 25,000 square feet or more to achieve Energy Star certification by the end of 2023. It also ordered that at least

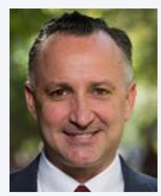
50% of the city's new bus and passenger sedan purchases in 2021 to 2016 are all-electric or plug-in-hybrid-electric vehicles.

The resolution cites Mayor Sly James' commitment to meet the targets set by the Paris Agreement on climate change, from which the U.S. has said it would withdraw in 2020.

More: *Kansas City*

NEVADA

Bill Would Require more Frequent Emissions Reporting



Sen. Chris Brooks (D) last week introduced a bill that would require the Department of Conservation and Natural Resources to more frequently issue reports on the state's total greenhouse emissions, as well as identify policies and possible regulations that would help lower emissions in the state.

The bill would require the state to issue a statewide emissions report yearly, as opposed to the current requirement that it be published every four years. It also would require the report to identify ways to reduce emissions and to track the state's progress on emission reductions compared to 2005, the highest year on record for emissions in the state.

It also would require the report to make a "qualitative assessment" as to whether the emission-reduction policies identified by the state support a long-term goal of zero or near-zero emissions by 2050.

More: *The Nevada Independent*

NEW MEXICO

Senate Passes Clean Energy Bill After Lengthy Filibuster

The Senate last week voted 32-9 to pass a bill that would replace the state's carbon-emitting generation with clean-energy resources over the next 25 years.

Before that, however, Sen. William Sharer (R) filibustered for nearly four hours, accusing the bill's backers of pushing to close the San Juan Generating Station despite opportunities to keep the plant open using cleaner technology. In addition to the clean energy standards, the bill would allow fixed-rate bonds to be issued to help Public Service Company of New Mexico recover the costs associated with closing the coal-fired plant. The legislation is supported by Gov. Michelle Lujan Grisham, several environmental groups and PNM.

The filibuster led to the interruption of an annual charitable basketball game, as seven senators that had left to play were summoned back to the Senate chambers in T-shirts and shorts.

More: *Albuquerque Journal*

WYOMING

Gordon Signs Coal Plant Bailout Bill

Gov. Mark Gordon last week signed into a law a measure that aims to keep the state's coal-fired power plants online and in business by requiring utilities to try to sell the plants first before decommissioning them.

If a new company buys a plant, the utility that sold the plant will be required to buy back the power, even if a cheaper source is available.

More: *The Associated Press*