RTO Insider
Your Eyes and Ears on the Organized Electric Markets
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Annual FERC Reliability Conference Takes on Resilience

By RTO Insider Staff

WASHINGTON — FERC Commissioner Cheryl LaFleur, who has been attending the commission's annual reliability technical conference since her appointment in 2014, always opens the meeting by citing something special about each year's gathering.

At last week's conference, LaFleur noted it has been 50 years since NERC was formed following the 1965 Northeast blackout. "I was practicing piano when the lights went out in Boston," she recalled.

Issues cited in past years — including cybersecurity and improving NERC's

Continued on page 24

FERC's annual reliability conference last week came 50 years after NERC was founded in response to the 1965 Northeast blackout. | *© RTO Insider*

PJM Stakeholders Seek Capacity Rules FERC Will OK

By Rory D. Sweeney

VALLEY FORGE, Pa. — FERC wants PJM's capacity rules to be resolved by Jan. 4 and has dispatched staff to help the RTO and its stakeholders adhere to that timeline.

Matthew Estes, one of three FERC representatives attending last week's MRC. | *© RTO Insider*

Three FERC representatives attended Thursday's special session of the Markets and Reliability Committee on responding to the commis-

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Stakeholders Annoyed by NYISO Carbon Price Draft

By Rich Heidorn Jr.

NYISO's release of draft carbon pricing recommendations — and its refusal to immediately discuss the report — sparked annoyance and frustration among some stakeholders Monday.

The nine-page draft, released Aug. 1, summarizes discussions to date in New York's Integrating Public Policy Task Force (IPPTF).

But NYISO staff declined to discuss it at Monday's IPPTF meeting, which was scheduled for a briefing on the ISO's "Dynamic Change Case" — its GE MAPS analysis to refine estimates of how carbon prices will impact customer costs.

Before the briefing began, several stakeholders pressed ISO staff to answer questions about the draft recommendations. IPPTF Chair Nicole Bouchez, the ISO's principal economist, promised to schedule time for the discussion but said it would likely not occur before Aug. 27.

Attorney Kevin Lang, representing New York City, questioned language in the document that suggested the ISO was making decisions on issues that should be subject to a stakeholder vote. "It's not up to the NYISO to adopt things," he said.

"The draft is just a draft," Bouchez responded. "It was based on our best understanding of the discussions and a coherent proposal. We're definitely looking forward to input on any and all components."

Jay Brew, attorney for Nucor Steel Auburn,

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CAISO NEWS

Forecast Error Prompts CAISO CPM Procurement

By Robert Mullin

A forecasting error is prompting CAISO to procure a large volume of out-of-market resources for September under a special measure not invoked since the emergency shutdown of the San Onofre Nuclear Generating Station in 2012.

CAISO will solicit up to 1,434 MW of resources under its Capacity Procurement Mechanism, stakeholders learned during a call Thursday.

The procurement was prompted by the California Energy Commission's July 10 publication of a revised load forecast showing the ISO's balancing area will next month need 1,247 MW more in systemwide resource adequacy (RA) resources than originally projected, plus a 15% planning reserve margin.

Under CAISO's Tariff, the ISO can invoke CPM in response to a "significant event," defined as any "substantial event" or "combination of events" that "causes, or threatens to cause, a failure to meet reliability criteria absent the recurring use of a non-resource adequacy resource on a prospective basis." A load forecasting error qualifies as such an event, Delphine Hou, the ISO's manager of state regulatory affairs, said during the Aug. 2 call.

The CEC attributed the RA forecast error to its reliance on 2016 — rather than 2017 — energy demand data in its original 2018 monthly forecast. The forecast is provided to both CAISO and the California Public Utilities Commission for RA planning, which is managed by the commission.

The error was discovered because of discrepancies between the CEC forecast and the monthly peak forecast CAISO produces for Western Electricity Coordinating Council planning, which the ISO used this year for its flexible capacity needs assessment. The revised CEC forecast aligns with CAISO's projections, which had been benchmarked to 2017 load figures.

October a 'Concern'

While this month's CPM solicitation will focus only on procuring resources for September, Hou said the ISO will continue to evaluate the need to procure resources for October, which the revised forecast indicates has an even bigger RA need: 5,103 MW. Under CAISO rules, a CPM procurement has an initial term of 30 days, which can be extended by another 60 days if the "significant event" is likely to persist.

Pointing to the much larger October deficiency, NRG Energy Director of Market Affairs Brian Theaker asked, "Can you elaborate on what the ISO will be looking for and what conditions it will impose before making a decision as to whether to CPM for October?"

While October load will be lower, the ISO is "sensitive" to the possible continuation of Santa Ana winds during the month, fire concerns in Southern California and the impact of drought, she said. She also pointed out that some generators may begin entering maintenance outages during that month.

"So we want to at least see how September goes. … It is likely we will extend the significant event through October, but we wanted at minimum to get the word out for September," Hou said.

"Why are we hearing about [the error] now? It seems like we would've had this information back in January," said Nuo Tang, principal energy policy strategist at San Diego Gas & Electric.

Hou was diplomatic in her response.

"It took some time because we were having a lot of discussions with the CEC and the CPUC about how to think about the difference between the forecasts, and it was eventually recognized that because the original RA forecast seemed somewhat low for September. … Out of an abundance of caution, we really should sunshine this other forecast for CAISO to use under significant events," she said.

"I think what you're highlighting is that we don't vet the system RA forecasts," leaving CAISO stakeholders unable to compare the forecasts used for system RA and flexible capacity, Tang said. "Would that be a fair characterization?"

"Yes, that is fair, and in fact you pre-empted my very [next] line … which is [that] for future coordination, we're definitely working very closely with the CEC and CPUC to review the RA forecast for next year," Hou said.

Credit Where it is Due

Tang also asked why CAISO chose to invoke a CPM significant event instead of relying on exceptional dispatch, a shorter-term out-of-market procurement mechanism.

Hou said that CAISO officials were concerned that if they delayed procuring resources, generators without RA designations could end up selling to other buyers, including those outside the ISO, or go out on maintenance outages.

"What we landed on was that we would prefer to notify the market earlier to get more bids into the competitive solicitation process [in order] to have a deeper pool for the operators to be able to pull from, because this is a system issue. It's not going

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Comparison of 2018 monthly peak forecasts | *CAISO*

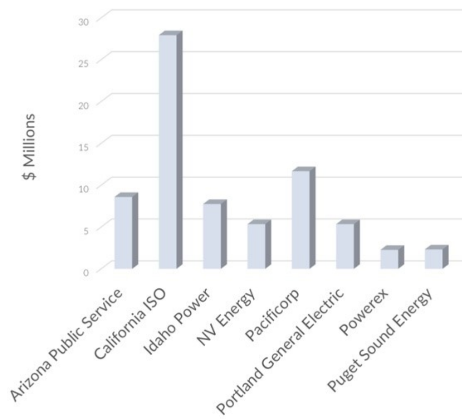
CAISO NEWS

EIM Benefits Surge to $71.2M in Q2

By Robert Mullin

The Western Energy Imbalance Market saw financial benefits soar to a record $71.2 million in the second quarter on surging exports of low-priced solar generation from California and the addition of new members Idaho Power and Powerex, according to a report from market operator CAISO.

Quarterly benefits were up more than 69% from the first quarter and 75% from the same period a year earlier. (See *CAISO, PacifiCorp Gain Most EIM Q1 Benefits*.) The EIM has yielded $401.7 million in gross benefits for its members since it began operation with PacifiCorp in November 2014, the ISO estimates.



Western EIM Q2 2018 financial benefits by member | *CAISO*

The CAISO balancing area reaped $27.9 million in EIM benefits last quarter, with net exports exceeding 1.9 million MWh, nearly 10 times the volume of the next biggest exporters, NV Energy and Arizona Public Service.

"The second quarter of 2018 saw an uptick in energy moving out of California through the EIM, as the system experienced high levels of renewable production at a time in the season when temperatures are still cool and electric demand is moderate," the ISO said in a statement.

PacifiCorp was the biggest beneficiary of CAISO's renewable surpluses, importing nearly 1.1 million MWh of low-cost power over the quarter and earning $11.67 million in EIM benefits, the second-largest share among market members.

Trailing the two biggest earners were APS ($8.6 million), wind- and hydro-heavy Idaho Power ($7.8 million), NV Energy and Portland General Electric ($5.4 million each), Puget Sound Energy ($2.3 million) and Powerex ($2.3 million).

The report once again shows CAISO as a significant exporter of power during spring. The ISO said the EIM's transfer capability allowed it to avoid curtailing 129,128 MWh of surplus renewable energy among its members during the quarter, up 93% from a year earlier. The avoided curtailments resulted in displacement of 55,267 metric tons of CO_2 emissions and increased the volume of renewable energy credits, although the benefits calculation does not include the value of RECs, the ISO said.

The report also illustrated the extent to which certain EIM areas function as paths for wheel-through transfers, meaning the BA area is neither the source nor sink for large volumes of power. During the second quarter, the NV Energy and APS systems handled 828,282 MWh and 321,667 MWh of transfers between CAISO and the PacifiCorp-East (PACE) area, respectively, while the relatively small PacifiCorp-West system facilitated 386,788 MWh of north-south transfers among California, the Pacific Northwest and PACE. By comparison, just 127,205 MWh of energy were wheeled through CAISO over the period.

"As part of the EIM Consolidated Initiatives stakeholder process, the ISO committed to monitoring the wheel-through volumes to assess whether, after the addition of new EIM entities, there is a potential future need to pursue a market solution to address the equitable sharing of wheeling benefits," the report notes.

A CAISO proposal to compensate EIM participants for wheel-through transfers last summer drew strong opposition from stakeholders concerned about the impact on the economic dispatch of generating resources. (See *EIM Members Wary of Need for Wheeling Charge*.)

The EIM's gross benefits represent either cost savings for serving load or increased profits from merchant operations within the participating BAAs. The benefits calculation nets out inter-BAA transfers that were scheduled ahead of the EIM's 15- and five-minute market runs to avoid attributing contracted flows to the market.

Idaho Power and Powerex began transacting in the EIM on April 5, days after the beginning of the second quarter. Sacramento Municipal Utilities District is slated to join the market in April 2019, followed by the Los Angeles Department of Water and Power, Salt River Project and Seattle City Light in April 2020.

Forecast Error Prompts CAISO CPM Procurement

Continued from page 3

to be as a restrictive as a local issue," she said.

Eric Little, manager of wholesale and GHG market design at Southern California Edison, asked if the ISO would reduce the 1,434-MW procurement if any LSEs show above their minimum RA requirements for the month.

Hou said the ISO had not yet performed that analysis, but that it would credit the system for any LSE overages.

"And then once you do that, when you start to cost allocate, will there be any reduction in bills for those LSEs that showed over, so they're only getting allocated for their portion of the additional CPM procurement performed by the ISO?" Little asked.

"It would credit against the total required amounts … but it would not be a credit against the cost allocation," Hou said.

"So all other LSEs get the benefit that the one LSE showed long?" Little asked.

"Yes," Hou replied.

Resources owners have until Aug. 25 to submit their offers to the ISO. Bidding is open to any RA eligible resources internal to the ISO balancing authority area. External, or "intertie," resources are excluded from participation.

ISO-NE NEWS

DC Circuit Upholds ISO-NE MOPR Exemption

By Michael Kuser

The D.C. Circuit Court of Appeals last week denied a petition by NextEra Energy and other industry players to review FERC orders allowing ISO-NE to exempt a limited volume of state-sponsored renewable resources from its capacity market's minimum offer price rule.

A three-judge panel concluded that the commission "engaged in reasoned decision-making to find that the renewable exemption to the minimum offer price rule results in a just and reasonable rate" and that "FERC did not abuse its discretion by denying the petitioners' request for a hearing" (17-1110).

The judges heard oral arguments on the case in April. (See *Court Questions FERC Change on ISO-NE Renewable Exemption*.)

Changing Circumstances

ISO-NE revised its Tariff in 2014 to allow up to 200 MW of qualifying new entrant renewable capacity to be exempt from the MOPR, beginning with the ninth Forward Capacity Auction covering the 2018/19 commitment period. The Tariff change included a carry-over rule allowing any unused portion of the 200 MW to carry forward for two additional auctions, up to a total of 600 MW.

Citing "changing market conditions," ISO-NE phased out its MOPR exemption in March 2018 while the case was under review.

Generators argued that the renewable exemption was unjust and unreasonable because it would undermine competitive entry and result in significant price suppression, an argument the commission rejected.

The court sided with FERC. "We defer to the commission's determination that the renewable exemption effectuates the market's primary purpose by sending the correct demand signals to new entrants and by protecting consumers from excessive rates."

Petitioners also argued that the commission's approval of the MOPR exemption conflicted with a previous decision to reject a categorical exemption to the rule, which was upheld by the D.C. Circuit.

But the court noted that in this case, the commission considered the price suppression associated with the uneconomic entry of a small quantity of renewable resources, rather than a categorical exemption, and in doing so "has performed an updated balancing of competing interests in the New England market."

The court also found that the commission explained how ISO-NE's sloped demand curve mitigates the price suppression and why its view on the renewables exemption had evolved.

The commission is not required to show that a previous rate was unjust and unreasonable in order to demonstrate that the revised rate is just and reasonable, the court said.

FERC has considered several MOPR exemptions in other markets, accepting some and rejecting others.

"This type of balancing requires an expert understanding of the market, which is well within the commission's realm of expertise. We see no reason to disturb the commission's balancing just because it came out in favor of the renewable exemption despite the potential for price suppression," the court said.

The petitioners also argued that the commission did not rationally link the magnitude of the exemption to any particular prediction of load growth or retirement. However, FERC explained that the 200-MW exemption was based on the best estimate of expected retirements and load growth, which was "estimated at 189 MW annually, plus an adjustment for the reserve margin required to meet the installed capacity requirement."

They further contended that FERC inappropriately raised its retirement rationale on remand, that uneconomic entry would continue after retirements are complete and that its experts found price suppression would occur even with retirements.

"But the commission is not required to protect against all price suppression ... [and] acted reasonably in concluding that retirements would help mitigate any price suppression," the court said.

"Accordingly, we defer to the commission's conclusion that the renewable energy exemption had only a limited potential for price suppression because of the implementation of the sloped demand curve, the prediction of a flatter supply curve, and predicted load growth and retirements."

ISO-NE NEWS

New England Clean Energy Legislative Roundup

By Michael Kuser

Left to right: Olivia Campbell Andersen, Renewable Energy Vermont; Kate Epsen, New Hampshire Sustainable Energy Association; Dan Bosley, New England Clean Energy Council; Amanda Winne, Environmental & Energy Technology Council of Maine. | © *RTO Insider*

BOSTON — This year's legislative sessions in New England produced clean energy developments ranging from Connecticut's "most important energy bill" in seven years, to Massachusetts taking "baby steps," to Rhode Island taking what might turn out to be a "regrettable pause."

Vermont even passed a bill requiring the installation of electric aircraft charging stations at state-owned airports.

One unresolved issue among most of the six states in the region relates to the siting of renewable energy resources, New England Clean Energy Council (NECEC) Executive Vice President **Janet Gail Besser** said Thursday at the group's annual legislative roundup, hosted by Boston-based law firm Pierce Atwood.

"Should there be different siting standards for renewables than for other kinds of development?" Besser said before the group's state coordinators provided an overview of new clean energy legislation in New England. "How do you preserve farmland and forestland and how do you have compatible uses of land?"

Connecticut Expands RPS, GHG Targets

Mike Martone, of law firm Murtha Cullina, said one new Connecticut law, SB9, "was hotly contested throughout the year... [and] was the most important bill this session and arguably the most important clean energy bill since Public Act 11-80 was enacted seven years ago," which established the state's Department of Energy and Environmental Protection.

The law revoked net metering guarantees that ensure rooftop solar owners earn retail prices for their excess electricity. (See *Connecticut Energy Bill Draws Mixed Reviews*.) It calls for the state's Public Utilities Regulatory Authority to set up a docket by Sept. 1 "to select the netting time between real time, one day or a fraction of a day, which is still going to be very problematic," Martone said.

But it also increased the state's renewable portfolio standard to 40% by 2030; extended the low- and zero-emission renewable energy credits program an additional year; and established a new tariff-based program for low- and zero-emissions projects, shared clean energy, and virtual net metering. The legislature also restored $10 million in energy efficiency funding to the 2019 state budget, Martone said.

Another new law (Public Act 18-82) establishes an interim target of reducing greenhouse gas emissions to 45% below 2001 levels by 2030, and updates Connecticut's Comprehensive Energy Strategy, the state's triennial plan to meet its energy needs, to include planning for climate change and a strategy to meet the new GHG target.

It also established the Connecticut Council on Climate Change, which is charged with coordinating the efforts on emissions among businesses, state and municipal agencies, and nonprofits.

Massachusetts on Track

Massachusetts concluded its two-year legislative session July 31 by passing a bill (H. 4756) to increase renewable energy usage and reduce high-cost peak hours. The bill includes a clean-peak standard, the first in the nation to promote the use of renewable resources to shave peak loads.

The bill, one of 175 energy-related ones considered in the session, also allows the Department of Energy Resources to solicit an additional 1,600 MW of offshore wind by 2035 and increases the state's energy storage target to 1,000 MW by 2025.

"I don't want to say we had a good two years, but we had a great 48 hours at the end of the session," said Dan Bosley of NECEC. "A lot of people were disappointed, but the more we looked, the more we realized we got a lot of our initiatives in this bill."

The legislation mandates that clean energy sources supply an additional 2% of the state's electricity each year, dropping to 1% in 2030 in order to "bring the business groups on," he said.

While the bill did not raise the cap on solar net metering, it did modify language related to the monthly minimum reliability contribution charge, which will compel everybody to refile with state regulators, Bosley said.

NECEC President **Peter Rothstein** called the bill "a step in the right direction," but the state's Sierra Club director, Emily Norton, said it represented "baby steps on clean energy legislation when what is needed are giant strides."

The environmental bond bill (H.4599) authorized $211 million to be spent on climate programs and state hazard mitigation, Bosley said. (See *New England Women Talk Climate Change, Resilience*.) That includes $10 million for a clearing house "to monitor, project and collate information so that we can do things that we want in an intelligent way," Bosley said.

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ISO-NE News

New England Clean Energy Legislative Roundup

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The bills have not been signed into law yet.

Rhode Island Pauses

Rhode Island had two landmark years for clean energy legislation in 2016 and 2017, and an exciting time this year in procuring 400 MW of offshore wind, but it was "not a banner year for legislation," NECEC Policy Analyst Jamie Dickerson said.

"I think it's going to shape up as a regrettable pause in what has otherwise been a tremendous three or four years of strong and steady growth," he said.

Legislation that failed to pass would have tweaked the state's renewable energy growth program to allow additional megawatts to be allocated to the residential solar, Dickerson said. In the 2017 program year, 6.5 MW were allocated for residential solar, and that capacity sold out in six months.

Other bills on the siting of renewables, harmful forest siting, capping energy efficiency program investments, and carbon pricing were either not taken up before the end of the session or referred to committee.

A substitute version of one bill, providing for independent review and verification of ongoing energy efficiency programs, was passed and signed by the governor, Dickerson said.

Northern New England

Kate Epsen, executive director of the New Hampshire Sustainable Energy Association, provided an overview of the conclusion of the Granite State's second year of a biennium session.

SB 321, signed into law in June, removed the requirement that members of a net-metering group use the same default supplier as the group's host, allowing residents to use both net metering and retail choice. "This is really helpful because it allows a lot of those larger end users who clearly shifted to competitive supply years ago, and don't want to go back, to also engage in rural renewable energy projects through net metering," Epsen said.

On the other hand, Gov. Chris Sununu vetoed SB 446, which would have raised the net metering cap to 5 MW from 1 MW and set the price at the default rate, which changes every six months. The Senate already has the two-thirds majority needed to override the veto on Sept. 13, "Override Day," she said.

"The veto was unfortunate, for the Republican governor had a lot of cover, with many Republicans favoring it, so this veto happened for about five people in one company," Epsen said. "That's how local some of these relationships can get."

In Maine, Gov. Paul LePage in his two terms since 2010 has vetoed more bills, 642, than all other Maine governors in the past century combined, said Melissa Winne, executive director of the Environmental & Energy Technology Council of Maine.

All energy-related bills, save one, either died in committee, died in special session or were vetoed. The exception was a bill, enacted without the governor's signature, that extends Maine's participation in the Regional Greenhouse Gas Initiative through 2030.

Olivia Campbell Andersen of Renewable Energy Vermont highlighted H.676, a law eliminating state fees for rooftop solar and removing mandatory setbacks for solar parking lot canopies, as well as a law that maintained net metering for up to 500 kW.

"Utilities have made it very clear that they would like to have net metering only go up to 150 kW," Andersen said.

MISO NEWS

MISO Moving to Combat Shifting Resource Availability

By Amanda Durish Cook

MISO last week laid out how it will tackle changing resource availability and needs in its footprint ahead of the release of a white paper on the issue.

The RTO told stakeholders it will focus on four key areas: resource accreditation, the annual capacity auction, outage scheduling and its own expectations for resource availability.


Jeff Bladen | © RTO Insider

MISO Executive Director of Market Development Jeff Bladen said the project will aim to determine how the RTO can more efficiently turn committed capacity into available energy in a climate of diminishing reserve margins and growing use of intermittent resources.

"[This] is about making sure we can meet operating needs every hour of every day," Bladen said during an Aug. 3 Reliability Subcommittee meeting. "This is becoming more critical as we see a narrowing gap between load and resources, which have increased the occurrence of emergency operations throughout the year."

The four areas entail:

- Studying characteristics of different resources to learn how to best incentivize them to create more flexible availability systemwide.
- Evaluating the current Planning Resource Auction design. MISO said it will examine how it can best procure adequate resources throughout the planning year and reexamine how it accredits resources.
- Ensuring that MISO's outage process matches expected resource output with resource commitments. Bladen said MISO will look into how it can get more information on outages and the risk of outages, and examine how it can better model the risk in its planning process. The RTO says "a significant number" of unit operators change the start dates of outages within a month of the originally scheduled outage.
- Aligning resource expectations and obligations with availability. For this, Bladen said MISO will ask what availability should be expected of resources; whether current emergency operating procedures are adequate; and whether resources provide the RTO enough information on their availability times. Bladen said MISO will focus especially on load-modifying resources, whose performance has been lacking during emergency declarations. (See "LMR Performance in January," *MISO Mulls Additional Emergency Communication*.)

MISO's Steering Committee will assign the issues to various stakeholder groups after next month's release of a white paper explaining the issues in more detail.

Bladen said he expects MISO and stakeholders will work on implementing recommendations as they develop the project through late 2020.

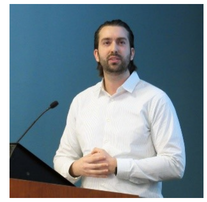
In response to a question from WPPI Energy economist Valy Goepfrich, Bladen said MISO might be open to altering its loss-of-load study to reflect a departure from planning for a summer peak, but that such a move would not solve the issue entirely because the study and resulting reserve margin is a "blunt instrument."

Bladen also said he was deliberately not suggesting a rule similar to PJM's Capacity Performance. While CP may come up as MISO and stakeholders discuss solutions, the RTO instead wants to emphasize incentives so that the "capacity we're counting on — and has arguably already been paid for by ratepayers — is available to us."

New Notification System

As it debates how to address changing resource availability, MISO will this month roll out a new notification type to give members more warning of forecasted capacity shortages.

The new capacity advisory, which MISO plans to use when all-in capacity is forecast to be less than 5% above operating needs, is meant to be an intermediary step before declaring a maximum generation alert.


Phil Van Schaack | © RTO Insider

Manager of Unit Commitment and Dispatch Phil Van Schaack said the new advisory is strictly an informational communication and does not carry any operational instructions. However, the new notice does request that unit operators update their data and availability in the MISO system.

Van Schaack said the additional notification would be especially useful for weekends and going into Mondays, when generation assets tend to be more sparsely staffed.

"This is for when we want people to get looking at things when they're ordinarily not looking at things," Van Schaack said.

After stakeholders asked for more real-time electronic communication of tight operating conditions, MISO declared a maximum generation alert on a Friday in mid-May for predicted Monday conditions that did not materialize. With hindsight, some stakeholders said declaring the alert may have been overly cautious. (See *MISO Mulls Additional Emergency Communication*.)

Under the new approach, MISO will send a capacity advisory communication to members when it foresees tight operating conditions in advance.

"Everyone wanted proactive information, but they oppose restrictions or impacts to operations," Van Schaack said. "The capacity advisory addresses stakeholder requests for transparency of forecasted conditions without impact to operations."

The Indiana Utility Regulatory Commission's Dave Johnston asked how the new notification will differ from MISO's current hot weather alerts.

"The intent is more to say that 'this is a capacity issue' and 'please review some of the data that you've submitted.' I would say there's some overlap, but for the hot weather alerts, we need about 99 degrees in Little Rock or so," Van Schaack said.

MISO staff said they would have sent out the capacity advisory a few times this summer had the process been in place.

MISO NEWS

FERC Rejects MISO Plan for External Capacity Zones

By Amanda Durish Cook

FERC last week rejected MISO's proposal to create external zones for its annual capacity auction but left the door open for the RTO to submit a revised version of the plan in the future.

Under the proposal, MISO would have altered its Planning Resource Auction to include external resource zones based on neighboring balancing authority areas. In cases of price separation, the RTO would also distribute historical supply arrangement credits from excess auction revenues as a refund to external resources with long-term and consistently used historical supply agreements.

The proposal also included two new external resource subcategories: border external resources and coordinating owner external resources, which would be modeled and priced according to the existing local resource zone with which the resource shared a direct electrical connection. MISO had said that both types of resources are comparable to its internal resources and can meet physical and operational criteria that allow them to continue to be treated as if they were inside a local resource zone. (See *MISO Closing in on External Capacity Zones*.)

MISO had hoped to implement the new external zones by the 2019/20 planning year.

| MISO

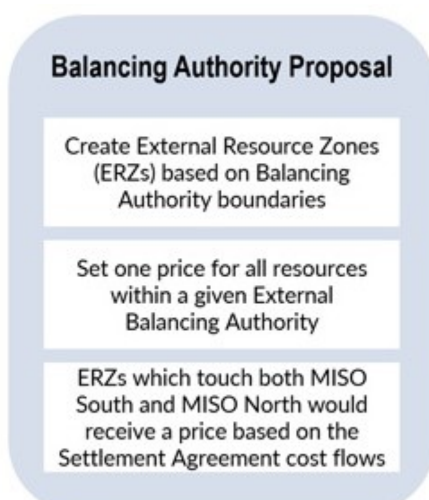
But in its Aug. 2 ruling, the commission took issue with two provisions of the proposal, both introduced in response to a deficiency letter in May (ER18-1173). (See *FERC: MISO External Capacity Zone Plan Deficient*.)

The first provision would have allowed an external resource bordering more than one local resource zone to choose which zone to participate in during the auction. The second would have permitted holders of evergreen contracts — supply contracts that include extension or renewal options written prior to MISO's capacity construct — to receive historical supply arrangement credits collected from excess auction revenues to cover price separation. FERC said both provisions were unreasonable.

No Zone Toggle

FERC's order said it was problematic for MISO to allow resource owners to toggle between zones in search of the best capacity prices.

"MISO's proposal provides resource owners with new optionality that could lead to uneconomic behavior. For instance, a market participant could decide to move a lower cost capacity resource from one local zone to another in order to increase the likelihood that an affiliated higher-cost capacity resource clears in the local zone from which the capacity resource was moved. The ability to effectively move capacity resources from one local zone to another is not contemplated by the Tariff's market power and mitigation provisions."



MISO also proposed allowing internal capacity resources that border more than one local resource zone the option to choose their zone of participation, providing the "same flexibility" as similarly situated border external resources. The RTO said it contains 20 eligible internal resources and only one border external resource, the Joppa Power Plant in southern Illinois, with ties to multiple local zones.

But FERC said that rather than allowing market participants to select local zones, MISO could divide the resource's capacity credit between the zones it borders using historic or forecasted system flows. The RTO could also propose a new system that determines how capacity credit is assigned to a resource that borders multiple local zones, the commission said.

Evergreen Contracts

FERC also determined that MISO should not make evergreen contract extensions eligible for excess auction revenues, saying the option would "embed inefficiencies into MISO's resource adequacy construct for an indefinite period of time."

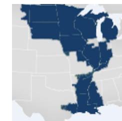
"LSEs with evergreen contracts could continue to extend those contracts indefinitely to avoid the locational price signal that MISO's locational resource adequacy construct was designed to provide," the commission said.

Rejection in Full

FERC said it rejected the filing in full because MISO had instructed it to evaluate the contract as a cohesive whole. In its filing, MISO had said the elements "were created as a complete and balanced package based on discussions and adjustments made during the stakeholder process" and "are intended to be an integrated set of elements to improve MISO's existing resource adequacy construct and should not be viewed in isolation."

The RTO plans to discuss the proposal during an Aug. 8 Resource Adequacy Subcommittee meeting.

MISO NEWS



DC Circuit Upholds Surcharges for Presque Isle SSR

By Amanda Durish Cook

Presque Isle power plant | *Michigan Technological University*

The D.C. Circuit Court of Appeals last week upheld a 2016 FERC order that reallocated most costs for the Presque Isle system support resource agreements to consumers in Michigan's Upper Peninsula.

The court denied in full petitions from a group of Michigan officials and load-serving entities, which included the state's Public Service Commission and attorney general (15-1098). They argued that FERC's reallocation of the SSR costs amounted to retroactive ratemaking. (See Michigan Groups Contest Presque Isle Cost Allocation.)

But the court said FERC was within its authority to order refunds to customers "who paid too much, funded by surcharges on customers who paid too little."

"The reallocation at issue here does not constitute an impermissible retroactive rate increase," the court said. "FERC reasonably determined that the prior rate methodology was unjust and unreasonable, and its reliance on certain evidence in reaching this conclusion was appropriate. Having … determined that a different methodology would comply with cost-causation principles, FERC had authority to order refunds and corresponding surcharges."

The court added that while FERC is limited in power over the filed rate doctrine, its "remedial authority is otherwise expansive."

The decision means Upper Peninsula ratepayers will bear nearly all SSR costs for the coal-fired plant. Under the original 2014 agreement, those costs were allocated across the American Transmission Co. zone on the Michigan-Wisconsin border, with Upper Peninsula ratepayers paying 8% and Wisconsin ratepayers responsible for the rest.

Following a complaint by Wisconsin's Public Service Commission that the state was paying for most of the SSR but not receiving the majority of the benefits, FERC allowed MISO to shift 98% of the costs to LSEs in the sparsely populated Upper Peninsula. That change in part stemmed from NERC's 2014 decision to separate the Upper Peninsula from Wisconsin into its own local balancing authority.

FERC at the time said it was unjust to allocate SSR costs on a *pro rata* basis to all LSEs in the ATC zone, despite historical practice. It said the costs must instead be allocated to LSEs that require the operation of the plant for reliability purposes. The Michigan LSEs and regulators countered that there was no new evidence or change in circumstances to justify changing ATC zone allocations.

The court was not persuaded by the Michigan argument. It pointed out that ATC was the only MISO zone subject to such a pricing zone methodology, with LSEs in other zones paying for reliability resources in proportion to their reliability needs: "For the rest of the MISO area, the Tariff provided only that reliability costs were allocated to the LSEs 'which require the operation' of reliability resources. In other words, SSR costs for all non-ATC service areas were allocated to the LSEs that actually benefited from the reliability resources."

The court was also not swayed by the argument that FERC improperly relied on a preliminary MISO load-shed study in its reallocation decision.

"FERC's recognition that more accurate data was necessary does not undermine its reliance on the preliminary study at the time of the complaint, or on the final data once the study was complete," the court said. At any rate, the court said, the Michigan groups did not demonstrate that the old *pro rata* calculation was superior.

Cloverland Electric Cooperative, one of the Michigan petitioners affected by the surcharges, said through its attorney that it was disappointed with the decision.

"We … believe it expands FERC's authority to assess retroactive surcharges beyond anything we have seen before. It also undermines the court's rule about accepting *post hoc* rationalization of earlier FERC orders," attorney Christine Ryan said in an email to *RTO Insider*.

MISO NEWS

FERC Seeks Details on MISO Dispute Resolution Plan

By Amanda Durish Cook

MISO's proposal to put time limits on its alternative dispute resolution process with RTO members is still missing key details, FERC said last week.

In a deficiency letter issued July 30, the commission asked MISO for multiple specifics on its plan to set limits on the amount of time members have to initiate alternative dispute resolution measures with the RTO over market settlements (ER18-1648).

The process is used in place of a lawsuit or FERC complaint when parties seek to negotiate contractual disputes over settlements. The RTO's Tariff doesn't contain provisions that "categorically bar settlement disputes raised after a long time," according to MISO.

MISO has proposed giving members a limit of 90 days to request either an informal or formal alternative dispute resolution and 120 days for the RTO and members to resolve settlement disputes. MISO itself would have two years from the operating day in question to make resettlement corrections. Resettlement outside of the two-year cutoff would require MISO and the participant to seek a Tariff waiver with FERC.

The RTO's May proposal provides for a two-year limit for adjustment of "any billing, invoice or settlement statement with respect to any transmission service under the Tariff" and "any settlement statement with respect to any market activity or other service under the Tariff" involving "a system or software error of the transmission provider."

But FERC asked MISO to define the terms "system error" and "software error." It ordered it to define the meaning of "readily discoverable, one-time MISO errors" and asked if the RTO foresees any short-term errors that are not "readily discoverable."

MISO will also need to clear up when the 90-day time frame begins and if an "extended delay in the resolution of a settlement dispute or [an alternative dispute resolution] dispute by MISO" could possibly limit the resettlement of incorrect billings under the two-year limit.

FERC inquired about a hypothetical situation raised by MidAmerican Energy in its comments on the proposal, which said that MISO could violate its two-year correction deadline if a monthslong error is discovered and the resettlement period needs to extend to before the operating day or invoice date in question. The commission asked if MISO planned to file an amendment to allow for resettlement for more than two years for such a scenario.

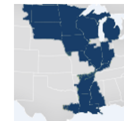
The commission also questioned language in the proposal saying MISO "may make an appropriate adjustment" in "cases involving a system or software error of the transmission provider."

"The word 'may' suggests that MISO is under no obligation to make the 'appropriate adjustment' even if a system or software error results in a Tariff customer paying an incorrect amount. Please explain why it is appropriate for MISO to have this discretion," FERC said.

Lastly, the commission ordered MISO to clarify whether the alternative dispute resolution process will apply to both market settlement disputes and transmission service disputes. FERC said certain sections of the proposal indicated it would apply only to market settlement disputes.

MISO lengthened the cutoff periods from the original proposal after stakeholders earlier this year expressed concerns they would need longer than 30 days to research and raise settlement disputes and longer than one year to make settlement corrections. (See *MISO Considering Time Limits on Dispute Resolution*.) MISO did not propose to place a dollar limit on resettlements. The RTO was aiming to have the deadlines imposed in July.

MISO NEWS



FERC OKs MISO-PJM Double Charge Fix for Pseudo-ties

By Amanda Durish Cook

FERC has allowed MISO and PJM to implement the first of a two-phase fix to remedy the RTOs' double-charging of congestion fees on pseudo-tied generation.

The commission last week approved amendments to the RTOs' joint operating agreement addressing market-to-market (M2M) settlement and day-ahead coordination of pseudo-tie transactions (ER18-136-003, ER18-137-003).

Effective Aug. 1, the RTOs will calculate day-ahead LMPs "that reflect the real-time usage of the pseudo-tied resource," FERC said. To model generator pseudo-tie impacts, the RTOs will calculate flowgate impacts based on amounts offered in the day-ahead market. The two will also modify settlement procedures to account for market flows and associated M2M congestion payments.

Until now, the RTOs have reflected the costs of relieving a binding flowgate in both their LMPs.

FERC agreed with the RTOs that the proposal "represent[s] an improvement over current practices" and will eliminate most of the overlapping congestion charges.

Separately, the commission also approved PJM's Phase 2 revisions, which will modify its Tariff to provide for rebates for deviations from day-ahead commitments and remove the remaining overlapping congestion charges not addressed by Phase 1 (ER18-1730).

FERC required MISO to make periodic informational filings on the status of its Phase 2 efforts.

MISO and PJM worked throughout 2017 to remove the overlapping congestion charges soon after the first of several complaints about the issue were filed with FERC. (See *MISO, PJM Pursue Pseudo-Tie Double-Charge Relief*.)

MISO reports 754 MW pseudo-tying into the footprint and about 2,142 MW pseudo-tying out.

Possible Interregional Projects

Meanwhile, the RTOs are working on two studies that could identify both small-scale and large-scale interregional transmission projects.

MISO and PJM are conducting a two-year coordinated system plan study to identify more expensive seams projects called interregional market efficiency projects (IMEPs) and a shorter-term study to identify smaller targeted market efficiency projects (TMEPs). (See *MISO, PJM Plan 2 Studies for Seams Projects*.)

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NYISO NEWS

Stakeholders Annoyed by NYISO Carbon Price Draft

Continued from page 1

said he also had questions about the recommendations, citing as an example, "basic principles that were applied by NYISO staff" regarding the allocation of carbon residual payments.

"I think the NYISO should be aware of the effect it has on the market — even something with a 'draft' recommendation," added Seth Kaplan of EDP Renewables. "Be aware that you guys are producing turbulence out in the market as you float these things."

"Nicole, we asked you not to do this. We said that it's premature to put out recommendations," interjected Lang. "You rejected that and said, 'No, we have to do it.' For the NYISO to now put out a series of draft recommendations and then not schedule anything to discuss them and just have them sitting there is inappropriate."

"Thank you for your feedback," Bouchez responded evenly. "We'll look for continued discussion and get something scheduled."

The task force is not scheduled to meet Aug. 13, and the Aug. 20 meeting is tentatively earmarked for presentations by two stakeholders, Bouchez said, making Aug. 27 the first time the recommendations could be discussed.

Report Builds on Straw Proposal

NYISO said its report builds on the April 30 straw proposal on a potential design for incorporating the social cost of carbon (SCC) into the ISO's wholesale markets and subsequent stakeholder discussion.

The ISO proposed implementing the SCC without a transition mechanism and said internal suppliers participating in the wholesale markets will self-report their carbon emissions or their estimated emissions to the ISO weekly, subject to true-ups.

It rejected a proposal by some stakeholders that the ISO estimate emissions and have suppliers report final emissions. "This approach was not adopted because suppliers are better positioned to accurately estimate their emissions than the NYISO," the report said.

Still under review by the ISO is whether the carbon impact on each component of the locational-based marginal price (LBMP) needs to be determined and how to prevent what the ISO called "double payments" for the same carbon reductions. The ISO cited stakeholder concerns that some resources may receive both state renewable energy credits and the ISO's carbon charge.

EDP's Kaplan took issue with the ISO's statement, saying it "sort of assumes the REC payments are a carbon payment, which a lot of us would say is not true. So simply embedding it as an assertion … before a discussion [with stakeholders] is troubling."

The ISO also has not decided on how to handle external transactions, saying it "is considering whether the external proxy bus LBMPs should be posted without the carbon effects rather than establishing a settlement mechanism that applies a carbon charge to imports and a credit to exports."

It also noted the "robust stakeholder discussion" over how carbon charges will be allocated to loads, outlining four proposals without expressing a preference for one.

Questions on Analysis

ISO officials also faced tough questions during the briefing on the Dynamic Change Case.

Lang questioned how the ISO will adjust the results of the MAPS analysis regarding the assumed location of renewable resources.

"Wind is being sited in particular areas because of cheap land, wide open spaces and good wind," said Lang.

He asked what the ISO's basis was for assuming that developers would move projects into other areas, such as Rockland County or New York City, solely because of higher LBMPs. Bouchez said the ISO is not projecting wind development in the city.

"It is reasonable to assume — and I've talked to a number of developers — as to whether or not higher LBMPs in different locations would affect their choice to develop a project or not. And the answer has always been yes, because they're looking to all the inputs to the project."

Lang said it appeared the ISO was using a "very *ad hoc* approach, without any kind of methodology" and asked that NYISO discuss its methodology before performing the analysis.

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NYISO NEWS

Stakeholders Annoyed by NYISO Carbon Price Draft

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Bouchez promised to research the issue with the experts working on it and report back. But she could not promise an explanation would come before the analysis is conducted. Officials said the first results from the analysis should be available about Sept. 10.

Mike Mager, representing Multiple Intervenors, a coalition of large industrial, commercial and institutional energy customers, said his client is unlikely to support carbon pricing without more certainty about how the state Public Service Commission will allocate residual payments to customers and between residential and non-residential accounts.

"We're trying to get comfortable with [the concept of] carbon pricing," Mager said. "Are you telling us we're going to vote on something and have no idea whether the PSC is ever going to let [all of the carbon residuals even] flow back to end-use customers or flow [them] back in an equitable manner? We would automatically oppose that. I think you're going to get a lot of concern from other parties too. ...

A simulation of EverPower Wind Holdings' Cassadaga wind farm, which was approved by the New York State Board on Electric Generation Siting and the Environment in 2016. | *Environmental Design & Research*

"I view it similarly to the whole issue of how is the carbon price set? How is it updated? When is it updated? What's the method for updating it? These are all huge gaps in the proposal that [are] going to need to be fleshed out before something's ready to be voted on, in my opinion. Otherwise you're going to get a lot of votes in opposition due to the extreme uncertainty."

Bouchez said a vote is unlikely before the second quarter of 2019 and that the ISO will begin its normal stakeholder process once the task force concludes its work.

"So we're going to, at that point, spend a lot of time talking about exactly what we mean and how do we do this and how do equations for different things work and what does the Tariff look like. So that at that point we'll be really nailing down a lot of the details but also potentially talking about different options," she said. "So, I think there's lots of opportunities to have those detailed discussions."

DC Circuit Rejects PJM Tx Cost Allocation Rule

By Rory D. Sweeney

PJM and FERC must reconsider how they allocate the costs of high-voltage transmission projects developed to satisfy individual utilities' planning criteria, the D.C. Circuit Court of Appeals ruled Friday (17-1040, 17-1041).

Old Dominion Electric Cooperative, Dominion Energy Services and Virginia Electric and Power Co. 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.

Dominion had initiated both projects in July 2013 as part of its FERC Form 715 criteria, which allow utilities to set planning criteria for their zones that go beyond NERC or RTO requirements. At the time, PJM's rules required that half of the cost of high-voltage projects be assessed on a *pro rata* basis to all 24 utilities in the RTO based on customer demand, with the remainder allocated to zones based on benefits, as determined by a distribution factor (DFAX) analysis.

Dayton Power & Light objected to using the 50% *pro rata* allocation for Dominion's initial Elmont-Cunningham project.

PJM then proposed a Tariff amendment that would prohibit cost sharing for projects proposed to satisfy TOs' own planning criteria. FERC initially rejected the proposal, saying it violated Order 1000 and was inconsistent with the commission's earlier finding that high-voltage transmission lines provide "significant regional benefits that accrue to all members of the PJM transmission system." (See *FERC Rejects PJM Cost Allocation on Dominion Project*.)

After a technical conference, however, the commission reversed its decision, ruling that projects such as Elmont-Cunningham belonged in a new category of projects included in the Regional Transmission Expansion Plan for coordination but not selected for cost allocation. The commission then used the amendment to reject regional cost sharing for the Elmont-Cunningham and a subsequent Cunningham-Dooms project. (See *FERC Does 180 on Local Tx Cost Allocation in PJM*.)

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

'Severe Misallocation' of Costs

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

"FERC's reasoning would replace a cost-allocation formula about which FERC had expressed no concerns with another one that is less accurate overall, as well as grossly inaccurate with respect to high-voltage projects, in return for no countervailing regulatory benefit," the court said.

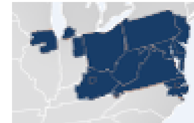
Because FERC has already acknowledged the regional benefits of high-voltage infrastructure, it "could hardly say that trying to distinguish between high- and low-voltage facilities was not worth the trouble." By holding to a principle of cost causation, "FERC must make some reasonable effort to match costs to benefits," the court said. "The cost-causation principle focuses on project benefits, not on how particular planning criteria were developed."

"We fail to see how a categorical refusal to permit any regional cost sharing for an important category of projects conceded to produce significant regional benefits can be reconciled with the background [cost-causation] principle," the court added. "We are sensitive to the concern, pressed by Dayton and the other *amici* supporting FERC, that individual utilities should not have free rein to impose unjustified costs on an entire region by unilaterally adopting overly ambitious planning criteria. However, nothing we say here prevents PJM or its member utilities from amending the Tariff, the Operating Agreement or PJM's own planning criteria to address any problem of prodigal spending, to establish appropriate end-of-life planning criteria or otherwise to limit regional cost sharing — as long as any amendment respects the cost-causation principle."

The court remanded the three orders back to FERC for further review.

"The legal or economic merit of Dominion's particular end-of-life planning criteria, and the appropriateness of the Elmont-Cunningham and Cunningham-Dooms projects under those criteria, remain open issues on remand," the court said.

PJM NEWS



PJM Stakeholders Seek Capacity Rules FERC Will OK

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PJM's Adam Keech addresses the committee. | © *RTO Insider*

sion's June 29 ruling rejecting PJM's "jump ball" capacity filing.

Office of General Counsel attorney Matthew Estes, one of the three FERC representatives, stressed that they were non-decisional and therefore not speaking to or for the commission. He advised all stakeholders to address the commission directly with their interests by filing comments in the docket.

"We're happy to give our input, but that's not going to get to the commission," he said.

He described the representatives' role as "historians" who could explain what they understand the current situation to be and to provide insight into what stakeholders might consider proposing because it would be "helpful to the commission to have things they can realistically consider."

FERC rejected both of PJM's proposals to revise its capacity market (ER18-1314), partially granted a 2016 complaint led by Calpine (EL16-49) and initiated a Section 206 proceeding for a "paper hearing" on an alternative approach in which the RTO would expand its minimum offer price rule (MOPR) to all subsidized resources (EL18-178). (See *FERC Orders PJM Capacity Market Revamp*.)

Comments prior to the hearing are due on Aug. 28. FERC said that it hoped to issue a final ruling by Jan. 4, 2019, in time for the 2019 Base Residual Auction.

The size of the task led several stakeholders to file for extensions on the Aug. 28 deadline. But PJM staff said they plan to provide comments by the deadline and still accept input from stakeholders. Thursday's meeting, along with a follow-up scheduled for Aug. 15, are intended for that purpose.

"That doesn't leave a whole lot of time for extension. I know people want more time," Estes said.

PJM plans to file a proposal that would follow FERC's suggestion of combining an expanded MOPR with a unit-specific fixed resource requirement (FRR). The MOPR would have few exceptions and would include units receiving out-of-market payments, such as state subsidies for nuclear units. Such units could then use the FRR option to be removed from the capacity auction, if they can take with them an "appropriate corresponding quantity of load."

Four Proposals

PJM solicited comments from stakeholders as part of developing its proposal and was surprised to receive four other proposals among the 19 responses. At Thursday's meeting, representatives of the four proposals outlined their ideas.

Calpine has advocated for a "strong" MOPR with no exceptions, the company's Sarah Novosel said, but recognizes that other stakeholders don't agree.

"We're ready to work on an accommodation, but we think there's a better accommodation than FRR," she said, suggesting an approach like ISO-NE's Competitive

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FERC OKs MISO-PJM Double Charge Fix for Pseudo-ties

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The windows for submitting interregional project ideas opens Nov. 1 for PJM and Jan. 1 for MISO. Analysis on the project proposals will take place next year. MISO and PJM have yet to approve an IMEP.

At an Aug. 1 Interregional Planning Stakeholder Advisory Committee conference call, MISO and PJM staff said they would be ready to share this year's TMEP study results during the October IPSAC. PJM interregional engineer Alex Worcester said the two are investigating 19 facilities — down from an original 61 — that have each amassed more than $1 million in congestion charges in 2016 and 2017 combined.

"Very soon here, we'll be reaching out to the equipment owners of the 19 facilities flagged for further study to identify the limiting equipment and what the potential solutions might be," Worcester said.

In September, MISO and PJM will begin testing the potential upgrades to see if they solve congestion.

PJM NEWS

PJM Stakeholders Seek Capacity Rules FERC Will OK

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Auctions with Sponsored Resources.

LS Power proposed combining the MOPR with a "resource specific requirement" that would be similar to the FRR but remove load based on where the resource's generation is "electrically delivered" rather than its physical location. It would subject the load and generation that remains in the auction to increased reliability requirements. Those costs would be borne by the resource electing to leave the auction.

Panda Power Funds offered an alternative to FRR that would identify and mitigate subsidized resources and allow those that don't clear the auction an opportunity to buy capacity commitments in a second auction phase.

| © RTO Insider

Consultants Rob Gramlich of Grid Strategies and James Wilson of Wilson Energy Economics presented a proposal developed for the Sierra Club, Natural Resources Defense Council, D.C. Office of the People's Counsel and American Council on Renewable Energy.

Gramlich said it is "very close" to PJM's proposal and "greatly expands" the current MOPR, but it also makes the process "as usable as possible" for states, who "can't take advantage of [the FRR] right away."

Joe Bowring, PJM's Independent Market Monitor, warned that the unit-specific FRR results in price suppression if the subsidized resource would not clear in the auction without FRR — and could affect clearing prices either up or down if it would have cleared.

Estes confirmed that FERC had not required an FRR to be part of any proposal, nor has it ruled on whether self-supply units should get a MOPR exemption. He advised stakeholders to file their requests along with substantiation that goes beyond assuming the way things have been traditionally should continue because "FERC found the way it's always been to not be just and reasonable."

PJM's Jen Tribulski agreed with Estes' analysis on FERC's FRR proposal.

"We don't view it as a strict mandate, but we do view it as the commission looks at it as a viable option to accommodate state actions," she said.

Calpine also agreed.

"I think it's clear that we at Calpine do not believe that the partial FRR was a mandate, just a suggestion. We think they're open to other alternatives as well," Novosel said.

SPP NEWS

Board of Directors/Members Committee Briefs

Board Approves NDVER Conversion, Ponders Virtual Trades

OMAHA, Neb. — SPP's Board of Directors last week approved a Tariff change requiring non-dispatchable variable energy resources (NDVERs) to register as dispatchable variable energy resources (DVERs), prompting a discussion on the value virtual trades offer the markets.

Staff said the Tariff change (MWG-RR272), which will require resources to reduce their output when instructed, will improve SPP's ability to manage congestion and lead to an increased convergence between day-ahead and real-time prices.

However, several directors wondered aloud whether the measure would lead to unintended consequences. Virtual transactions are driven by market inefficiencies, so the more efficient the market, the less value in virtuals.

Director Bruce Scherr noted that staff cited as one benefit an expected reduction in profits for virtual traders.


Bruce Scherr | © RTO Insider

"I never really understand whether we are encouraging or discouraging the participation of virtuals in our market," he said during the board's July 31 meeting with the Members Committee. "I think we flip and we flop on that. It's never been clear to me whether we find virtual participation a positive or a negative."

Fellow Director Graham Edwards pointed out virtuals are a small part of SPP's market and asked, "If we start driving the virtuals out, is there a negative?"

SPP's Market Monitoring Unit said in its most recent market assessment that virtual transactions as a percent of load increased to 17% this spring, compared to 10% in 2017.

"There are times when virtuals can be a help, there are times when virtuals can be parasitic," responded Keith Collins, the MMU's executive director. "In this scenario, if they are benefiting as a result of something that is a result of modeling inconsistency, are they really adding a benefit or value to the market? Yes, they are making money, but they're making money on consistent modeling differences."

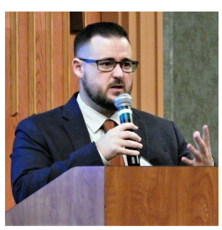
Collins said virtuals can make the day-ahead market more efficient when load is under-scheduled.

"The value here [with RR272] is switching from virtuals to other resources and reducing uplift payments everyone around this table is paying," he said.

Resources must convert by Jan. 1, 2021, or the 10-year anniversary of its original commercial operation date, whichever is later. Qualified facilities under the Public Utility Regulatory Policies Act and run-of-river hydro projects incapable of following dispatch instructions are exempt.

The Tariff change passed the Markets and Operations Policy Committee earlier in July, after having been rejected during the committee's April meeting. (See *SPP Markets and Operations Policy Committee: July 17-18, 2018*.)

Staff's analysis of RR272's economic effects found the change would improve congestion management and convergence of real-time and day-ahead prices. The analysis projects about $15,000 in additional monthly real-time energy payments to converted NDVERs and about $20,000 in additional revenue to other resources.


Gary Cate | © RTO Insider

"The more dispatchable resources we have, the easier it is to solve congestion," said Gary Cate, SPP's manager of market design. "NDVERs are generally located in areas where they are one of the few that are dispatchable. Opening them up allowed us to get rid of those breaches … by a fairly significant amount."

Liberty Utilities, Omaha Public Power District (OPPD) and Walmart opposed the measure, which also received a pair of abstentions.

"This is an after-the-fact rulemaking scenario, where we're required to upgrade equipment on older facilities," said OPPD's Joe Lang. "We're concerned about the oppressive nature of this on wind power and setting precedent for other generation. The EPA has new-source-review requirements that properly limit the applicability of new rules on older facilities that give us concerns about walking down this path."

The Wind Coalition's Steve Gaw, who didn't have a vote, said his group is "very supportive" of market efficiency, but he also expressed his concerns about RR272's wording. He pointed to ambiguity as to when the conversions should take place for non-SPP generator interconnections and the excessive burden it places on the conversion of certain older wind farms.

"There are two issues of substance," Gaw said. "One, whether or not SPP should be directly stating the conversion costs should be on the interconnection customer, as is stated in the new language. And two, the lack of any kind of exception for resources that have a substantial cost to convert."

In written comments, the coalition said the conversion of fixed-speed (Type 1) and variable-slip (Type 2) turbines "can amount to millions" in capital expenditures.

SPP, MISO Resolving Jan. 17 Issues

CEO Nick Brown told stakeholders during his president's report that SPP has reached an agreement with MISO on "specific operating procedures pursuant to our operating agreement" that arose during a Jan. 17 severe-weather event staff refer to as "The Big Chill."

Colder-than-normal weather and generation shortfalls in MISO South led to MISO exceeding its regional dispatch limit on transfers between its northern and southern footprints across SPP's system. The ISO made emergency energy purchases from Southern Co. before operations returned to normal.

"I, for one, get extraordinarily nervous when there is a disagreement or misunderstanding between our operators," said Brown, who noted the meetings are continuing.

He said SPP added three new members during the previous quarter, bringing its membership to 97. The newest members include the Crocker Wind Farm, Walmart

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SPP NEWS

Board of Directors/Members Committee Briefs

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and NextEra Energy Transmission Southwest. Walmart joined as the RTO's first large retail customer, a segment that has existed since 2003.

Brown also said that halfway through SPP's fiscal year, the RTO has over-collected $8.4 million from members. Revenues are up because the number of completed interconnection studies and network services billing have both exceeded projections, Brown said.

An over-recovery this year will reduce rates in 2019, when this year's actuals are reconciled with budgeted figures.

Board, Members Honor SPP RE Leadership

SPP RE President Ron Ciesiel stands as he is honored by CEO Nick Brown (left). | *© RTO Insider*

The board and members recognized SPP Regional Entity Trustees Mark Maher and Steve Whitley and RE President Ron Ciesiel with resolutions and applause following a final report. Dave Christiano, the trustees' chair, was not present, spending his time instead in Ecuador following his passion for botany.

Maher said the RE successfully transferred 825 GB of data and more than 687,000 files to the Midwest Reliability Organization, SERC Reliability Corp. and NERC. The RE ended all compliance monitoring and enforcement activities for its 122 registered entities on June 29, with the MRO and SERC taking over those duties. (See *SPP RE Ending Compliance Monitoring, Enforcement Activities*.)

The trustees will hold a conference call Aug. 30 to officially terminate the RE's regional delegation agreement.

Stakeholders Look at Changing Admin Fee's Recovery

MOPC Chair Paul Malone said John Olsen of Evergy will chair the task force charged with developing a new rate structure allowing SPP to recover its administrative costs from energy transactions. (See *SPP Stakeholders to Study Admin Fee Changes*.)

The Schedule 1A Task Force is holding its first meeting Aug. 8 at the Dallas/Fort Worth International Airport. It is expected to report back with recommendations in January.

Stakeholders Add 3 to Members Committee

Members approved three new representatives to the Members Committee during a special meeting of the committee: Northwestern Energy's Bleau LaFave (Investor Owned Utilities), NextEra Energy Resources' Holly Carias (Independent Power Producer) and Walmart's Chris Hendrix (Large Retail Customer).

LaFave's term ends in 2019, those of Carias and Hendrix in 2020.

Members also approved removing from the bylaws references to the RE, while incorporating a *de minimis* investment requirement. FERC's Orders 888 and 2000 bar grid operators, staff and non-stakeholder directors from holding financial interests in any market participant and require them to maintain independence from "any entity whose economic or commercial interests could be significantly affected by the RTO's actions or decisions."

Board Approves $47M in Near-term Projects

As part of its consent agenda, the board unanimously approved the Integrated Transmission Planning process' 2018 near-term assessment portfolio, a package of 13 projects in six states with an estimated total investment of $47 million.

The portfolio is expected to resolve 101 reliability needs resulting from increased load in the Texas Panhandle and announced generation retirements along the Kansas-Missouri border. Notices to construct will be issued by Aug. 21, staff said.

The projects include a new 345-kV, 50-MVAR reactor at City Utilities of Springfield's (Mo.) Brookline substation, originally identified as an interregional project with Missouri's Associated Electric Cooperative, Inc. (See *SPP: No Need for Joint Study with AECI in 2018*.)

Six previously approved projects, expected to cost $85 million, were removed from the assessment because they were no longer needed.

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SPP NEWS

Board of Directors/Members Committee Briefs

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Consent Agenda Includes 11 Revision Requests

The consent agenda also included a recommendation that Oklahoma Gas & Electric's Jerry Peace fill a vacancy on the Finance Committee; a new baseline cost estimate for Southwestern Public Service's 115-kV loop rebuild in West Texas; approval of NorthWestern Energy's sponsored upgrade of a new 115-kV line in Aberdeen, S.D.; charter changes to the Model Development and Reliability Compliance working groups; and 11 revision requests:

- CTPTF RR279: Modifies the competitive project proposal process to allow a re-evaluation request before awarding a notice to construct.
- MWG RR177: Clarifies references to NERC standards in the Integrated Marketplace's protocols and the Tariff's Attachment AE, the marketplace's governing rules to eliminate confusion over whether entities are performing obligations for market reasons or compliance with NERC standards. The change also modifies the attachment's definition of operating reserve to that defined in the Tariff.
- MWG RR266: Allows any resource to elect to be a combined ownership resource through the modeling option. Those that choose this option will be run through the market-clearing software as a single resource, with post market revenue allocations dispersed to each share based on designated ownership percentages.
- MWG RR277: Corrects language in Attachment AE to accurately reflect the settlement formula for the auction revenue rights daily amount by reversing the sequence of the source and sink.
- MWG RR304: Streamlines the process by which frequently constrained areas are re-evaluated, to make adjustments in a timely manner.
- MWG RR306: Minimizes potential gaming opportunities identified by the MMU. The change allows market-committed resources that have a minimum run time extending beyond initial reliability unit commitment or day-ahead commitment periods to be eligible for make-whole payments after their initial commitment period.
- MWG RR310: Adds three reporting requirements to comply with FERC Order 844: zonal make-whole payment reports, resource-specific make-whole payment reports and operator-initiated commitment reports. Also requires public posting of transmission constraint penalty factors; the circumstances in which violation relaxation limits (VRLs) could set prices; and procedures for temporarily changing VRLs in the Tariff.
- ORWG RR309: Removes section 7.3.1 (FAC-011-3 System Operating Limits Methodology) from SPP's planning criteria and places it in a separate document for reliability coordination purposes.
- RTWG RR278: Corrects Attachment O's Addendum 1 to include only current and applicable interregional coordination agreements and an update link to the joint operating agreement with MISO.
- RTWG RR314: Adds clarifying language to the ITP manual addressing ambiguity in the base reliability and short-circuit model builds.
- RTWG RR315: Removes references to the RE from governing documents.

— Tom Kleckner

SPP NEWS

RSC Briefs

RSC, OMS to Take Crack at Interregional Issues

OMAHA, Neb. — State regulators from the SPP and MISO footprints are banding together to take on seams issues created by what one industry expert calls "RTO gerrymandering."

Commissioners sitting on SPP's Regional State Committee and MISO's Organization of MISO States (OMS) met last week to begin developing a joint RSC-OMS working group to improve market coordination and tackle problems the grid operators and their stakeholders haven't been able to resolve.

"It's a conversation we've been having off and on since May," said RSC Chair Shari Feist Albrecht, who also chairs the Kansas Corporation Commission. "We want to contribute a state regulator's point of view to the discussion here, and to provide advice and guidance."

OMS Chair Ted Thomas, who chairs the Arkansas Public Service Commission, and Minnesota Public Utilities Commissioner Matt Schuerger met with RSC regulators before the committee's regular quarterly meeting. Albrecht said the commissioners discussed defining the problems and establishing goals going forward.

"It made sense to work together," she said. "State commissions have regulatory and cost-allocation authorities. We should have a responsibility in this area."

"We need to work together… and not bang heads," Thomas said during an OMS Executive Committee conference call in June.

SPP and MISO have been unable to agree to any interregional projects since FERC issued Order 1000 in 2011. The grid operators have said the cost of building joint models and financial and voltage thresholds inhibit their ability to come together on projects across the seams.

The RTOs agreed last month to work on improving their interregional process. They will study potential joint projects within their own regional models and have also added new benefit metrics, such as the avoided cost of other projects. (See *MISO, SPP Loosen Interregional Project Requirements*.)

"If there are problems, what are they? You can't solve problems if you don't try," said Albrecht, noting that MISO and PJM work well across their seam. "We don't have a sense of history or the background behind [seams issues]. Whatever they are, they're not unsolvable."

Stakeholders on both sides of the seam have expressed their frustration over the RTOs' inability to get interregional projects approved. The Wind Coalition's Steve Gaw, one of the more outspoken critics of the process, said he is pleased by the RSC and OMS efforts.

"RTOs were formed in part because of the savings that result from reducing the costs of seams between utilities," Gaw said. "Today we have a seam between MISO and SPP that stretches across multiple states. The states, through the regional committees, are well positioned to examine whether significant cost savings for consumers and reliability improvements could be made between RTOs."

Patrick Lyons, N.M.; Geri Huser, Iowa; Kristie Fiegen, S.D.; Chair Shari Feist Albrecht, Kan.; and Dennis Grennan, Neb. | © *RTO Insider*

Ironically, it's the shape of the SPP-MISO seam itself that has contributed to the problem. Economist Rob Gramlich, president of Grid Strategies, said without "rationally configured RTOs," seams issues have become larger than they should be.

"FERC has allowed oddly shaped RTOs — and the states and utilities have played a part in that — but they won't work without effective seams management," Gramlich said, referring to the shapes as "RTO gerrymandering."

"It's helpful for state regulators in both regions to help resolve seams problems for their mutual benefit," he said. "Clearly, SPP and MISO are talking to each other and trying to work things out. They've made a number of improvements, but somebody needs to be holding them accountable and moving the process forward."

SPP General Counsel Paul Suskie, staff secretary for the RSC, said the grid operator is "encouraged" by the commissioners' engagement and greater understanding of seams issues. "It's especially valuable when it comes to building seams projects, considering commissioners' critical roles in cost allocation and siting authority," he said.

Ag Study Safe Harbor Limit Stays Unchanged

The RSC unanimously accepted the Cost Allocation Working Group's recommendation to not conduct a larger study on the aggregate study's safe-harbor waiver criteria, following the CAWG's first limited review. The committee also agreed that the CAWG should conduct a second limited annual review in 2019.

The committee agreed last year to conduct a limited study of the aggregate study, which assesses the projects necessary to satisfy transmission service requests to move energy around the SPP system, as well as who pays for those projects. Transmission upgrades under the safe harbor limit are base-plan funded through the RTO's highway/byway approach. (See "RSC Leaves Safe Harbor Limit Unchanged," *SPP Regional State Committee Briefs: July 24, 2017*.)

The safe harbor cost limit will remain unchanged at $180,000/MW.

— Tom Kleckner

SPP NEWS

SPP Ramps up Western RC Effort

By Tom Kleckner

OMAHA, Neb. — SPP met last week with Western entities that have expressed interest in its reliability coordinator (RC) services, further evidence the RTO is intent on becoming a serious player in the Western Interconnection.

The grid operator hosted the first meeting of its new Western Interconnection Reliability Coordination Working Group (WIRCWG) Aug. 2 in Westminster, Colo. It said the WIRCWG (suggested pronunciation: work-wig) will eventually become a forum for Western customers and other stakeholders of the RTO's RC services "to engage in matters of RC-related governance and strategy."

COO Carl Monroe said SPP hopes WIRCWG's initial meetings and a "transparent, open-door policy that welcomes questions and concerns from any interested party" will demonstrate "our dependability and customer-focused attitude in the West, where we understand our potential customers may still be feeling us out."

"SPP has more than 75 years of experience as a regional grid operator, and we've built a reputation as a reliable, effective and relationship-based organization among our members, market participants and other contract customers," he said in a press release.

SPP has already scheduled an Aug. 14-15 meeting at its corporate headquarters in Little Rock, Ark., restricted to entities who have signed a letter of intent (LOI) for RC services. The grid operator says it has received 28 LOIs from Western entities, representing 200 TWh of net energy for load. SPP announced in June that it intends to provide RC services in the Western Interconnection by late 2019. (See Westward Ho: SPP Plans to Become RC in West.)

CEO Nick Brown told stakeholders last week that SPP is intent on establishing agreements with the companies and is following the necessary certification steps "to serve in this capacity."

"Certainly, we have a good track record of incorporating folks in our RC services," Brown said, referring to the 2009 and 2014 additions of Nebraska utilities and the Integrated System, respectively. "Our primary goal is to use the expertise we have, and to reach out to other entities and reduce the overall operations costs to our members. We very much expect that to be the case here."

SPP said that while service agreements are still being negotiated, WIRCWG meetings will help those interested to learn about SPP and have a say in its service offerings in the West. It said 53 attendees were present in Westminster, a number that included members of the RTO's Operating Reliability Working Group, which met before the WIRCWG meeting. It declined to give a breakdown of the 53 attendees.

Once the group is formally created, future meetings will be posted in advance and it will function like all other SPP working groups, an RTO spokesperson said.

"We're eager to meet with potential customers, work with them to develop systems and processes to address their distinct needs, and begin a new chapter in the evolution of the power grid in the West," said Bruce Rew, SPP's vice president of operations.

With Peak Reliability's recent decision to end its operations as early as Dec. 31, 2019, SPP and CAISO are now competing to offer RC services across the West. (See Peak Reliability to Wind Down Operations.)

CAISO last month received its first public commitment from an RC customer, the Balancing Authority of Northern California, a joint powers authority that provides balancing services for six California publicly owned utilities, including the Sacramento Municipal Utilities District. (See CAISO Board OKs Rate Plan, RMR Change.) The ISO has said that most Western balancing authorities have signed LOIs for its services. (See Most of West Signs up for CAISO RC Services.)

The Western Electricity Coordinating Council, which is responsible for the region's bulk electric system compliance monitoring and enforcement, has asked its BAs and transmission operators to confirm which RC they will be using by Sept. 4.

SPP is still interested in integrating the Mountain West Transmission Group into its market, work that has been overshadowed by the competition for RC services and Xcel Energy's April announcement that it was leaving the Rocky Mountain group. The RTO's executives told stakeholders last month they expect to hear from the remaining participants in September, once they redo their cost-benefit studies.

Western Interconnection Balancing Authorities (38)

- AESO - Alberta Electric System Operator
- AVA - Avista Corporation
- AZPS - Arizona Public Service Company
- BANC - Balancing Authority of Northern California
- BCHA - British Columbia Hydro Authority
- BPAT - Bonneville Power Administration - Transmission
- CFE - Comision Federal de Electricidad
- CHPD - PUD No. 1 of Chelan County
- CISO - California Independent System Operator
- DEAA - Arlington Valley, LLC
- DOPD - PUD No. 1 of Douglas County
- EPE - El Paso Electric Company
- GCPD - PUD No. 2 of Grant County
- GRID - Gridforce
- GRIF - Griffith Energy, LLC
- GRMA - Sun Devil Power Holdings, LLC
- GWA - NaturEner Power Watch, LLC
- HGMA - New Harquahala Generating Company, LLC
- IID - Imperial Irrigation District
- IPCO - Idaho Power Company
- LDWP - Los Angeles Department of Water and Power
- NEVP - Nevada Power Company
- NWMT - NorthWestern Energy
- PACE - PacifiCorp East
- PACW - PacifiCorp West
- PGE - Portland General Electric Company
- PNM - Public Service Company of New Mexico
- PSCO - Public Service Company of Colorado
- PSEI - Puget Sound Energy
- SCL - Seattle City Light
- SRP - Salt River Project
- TEPC - Tucson Electric Power Company
- TIDC - Turlock Irrigation District
- TPWR - City of Tacoma, Department of Public Utilities
- WACM - Western Area Power Administration, Colorado-Missouri Region
- WALC - Western Area Power Administration, Lower Colorado Region
- WAUW - Western Area Power Administration, Upper Great Plains West
- WWA - NaturEner Wind Watch, LLC

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FERC & FEDERAL NEWS

FERC Rejects Bid to Boost QF Output

By Rich Heidorn Jr.

FERC on Friday rejected CMS Energy's plan to boost a 60-MW qualifying facility to 263 MW, saying the change is too large to qualify for recertification under the Public Utility Regulatory Policies Act (EL18-123, QF87-481-002).

The company sought to recertify as an existing cogeneration QF its T.E.S. Filer City Station facility in Manistee County, Mich. The facility has two boilers that can burn coal, tire-derived fuel and waste wood and creates 60 MW of electricity that is sold to CMS subsidiary Consumers Energy. It also provides about 50,000 pounds per hour of process steam to the facility's thermal host, a paper mill owned by Packaging Corporation of America.

CMS proposed replacing the solid fuel boilers with a natural gas-fired combustion turbine and heat recovery boiler to be used with the existing steam turbine that would produce approximately 263 MW of net electrical output while providing the same thermal output to the mill. The company said a smaller turbine and boiler would not provide enough waste heat to efficiently operate the existing steam turbine and serve the mill.

The 2005 Energy Policy Act modified PURPA, requiring that any new cogeneration facility demonstrate that its "thermal energy output … is used in a productive and beneficial manner," and that its electrical output be used fundamentally for industrial or other permitted uses "and is not intended fundamentally for sale to an electric utility."

To implement the changes, the commission in Order 671 created a "fundamental use test," allowing the thermal output from a replacement cogenerator to be considered to be "used in a productive and beneficial manner" if at least 50% of the total energy output (the electric, thermal, chemical and mechanical output) is used for industrial or other permitted purposes.

Order 671 said that an existing QF does not become a new facility "merely because it files for recertification. However, we caution that changes to an existing cogeneration facility could be so great (such as an increase in capacity from 50 MW to 350 MW) that what an applicant is claiming to be an existing facility should, in fact, be considered a 'new' cogeneration facility at the same site."

FERC said CMS' proposed changes are too significant to qualify for recertification as an existing facility.


T.E.S. Filer City Station cogeneration facility | *Tondu*

"The increase in net capacity from 54 MW to 263 MW constitutes so substantial an increase in capacity that … it cannot be considered the same facility that was previously certified," the commission ruled. "Rather, the converted facility, as proposed, is a 'new' cogeneration facility."

The commission said CMS had not provided information demonstrating that it meets the fundamental use test. "Accordingly, on the record before us, we cannot certify the facility, if converted as proposed, as a cogeneration QF. T.E.S. Filer is free to file such information with the commission by either submitting a self-certification or applying for a commission certification of QF status."

Dissent by LaFleur

Commissioner Cheryl LaFleur dissented.

"I do not read [Order 671] as requiring any significant increase in megawatt output to be treated as a change so great as to consider a facility a 'new cogeneration facility at the same site,'" she said. "The record here shows that the conversion was designed to meet the needs of the thermal host, and that the increased megawatt output is simply a byproduct of meeting that existing need with a modern, efficient gas turbine. I believe those facts are the pertinent ones for determining here whether the changes are 'so great' as to warrant denying recertification."

LaFleur noted that PURPA requires the commission's rules to encourage cogeneration facilities. "Unfortunately, interpreting Order No. 671 in a manner that requires rejection in this instance may in fact discourage other cogeneration resources from updating and optimizing their systems, for fear of no longer maintaining their QF status. I do not believe that outcome is justified on this record."

Separately, FERC approved CMS' request for a declaratory order confirming that its power purchase agreement with Consumers will remain exempt from Federal Power Act Sections 205 and 206 after the PPA is amended to reflect the upgrades to the facility (EL18-124, QF87-481-003). "Assuming for the sake of this discussion that T.E.S. Filer is a QF, sales made pursuant to the PPA, as amended … will continue to be exempt from commission oversight pursuant to FPA Sections 205 and 206."

FERC & FEDERAL NEWS

FERC Rejects Liability Limit in NorthWestern Transmission Pact

By Rich Heidorn Jr.

Billings refinery | *ExxonMobil*

FERC last week rejected NorthWestern Energy's attempt to limit its liability for service interruptions to an ExxonMobil oil refinery in Montana, saying the provision was discriminatory (ER18-1715).

The utility had attempted to include the limitation in an unexecuted network integration transmission service agreement for ExxonMobil's Billings refinery, saying it was needed because of the facility's size, its "sophisticated equipment" that is "particularly sensitive" to loss of power, and that its continuous 24/7 operation lacks a backup power source.

The liability provision stated that neither party would be liable for "consequential, special, indirect or incidental damages whether arising in tort or contract, including a breach or alleged breach" of the agreement.

In 2016, ExxonMobil sued NorthWestern in state court, seeking $92.4 million in damages and lost profits over two power outages at the refinery that the oil company said resulted from NorthWestern's negligence. The case was settled in December 2017 but terms were not released.

NorthWestern said the service interruptions — a 96-minute outage in 2014 and a 53-minute outage in 2016 — were caused by faults on its 50-kV radial lines feeding the refinery. It said the outages were triggered by problems on the distribution system of the city of Billings' sewer plant. ExxonMobil's suit alleged the utility was negligent because protective relays on its 50-kV lines were not coordinated with the relay system at the sewer plant.

FERC agreed with ExxonMobil that the liability provision was unduly discriminatory because NorthWestern was not seeking to impose such limits on other transmission customers, including three other oil refineries it serves in Montana.

"A transmission provider seeking commission acceptance of a non-conforming agreement bears a high burden to justify and explain that the non-conforming aspects of the agreement are not merely 'consistent with or superior to' a *pro forma* agreement but are necessary," FERC said.

The commission rejected NorthWestern's argument that ExxonMobil expected perfect, uninterrupted service. "ExxonMobil's lawsuit against NorthWestern was not based merely on service interruptions, but the allegation that NorthWestern had 'negligently failed to exercise reasonable care in designing, constructing, installing, managing, maintaining, inspecting and operating its electrical facilities and equipment,'" the commission said.

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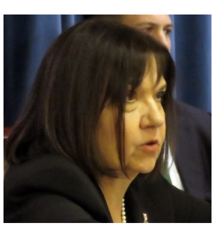

Cheryl LaFleur | *© RTO Insider*

efficiency — were joined in this year's hearing by concerns over inverter-based resources, the wind-down of Peak Reliability and the impact of gas shortages on resilience. Commissioner Neil Chatterjee chaired the session for Chairman Kevin McIntyre, who was unable to attend. Chatterjee was joined by LaFleur and Commissioners Robert Powelson and Richard Glick (AD18-11).

NERC CEO Debuts

Jim Robb | *© RTO Insider*

It was the FERC debut for new NERC CEO Jim Robb, who joined the organization four months ago from the Western Electricity Coordinating Council. Robb said his initial focus has been implementing the risk-based philosophy that NERC and the Regional Entities (REs) established over the last several years "and really embedding that in all the activities we undertake."

A second priority, he said, is "consistent implementation" of NERC's programs across the regions. "It's clearly a challenge. It's clearly an issue that industry wants to see us get better at." He vowed to focus on the big issues and "try not to be distracted by the trivial."

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Time for a Gas Standard?

Robb also described his organization's work on fuel assurance, the subject of a NERC technical conference in early July. Robb said it is time to shift from recognizing the challenges caused by the increasing reliance on natural gas and identify actions that can "synch" the operating practices of the gas and electric industries to make them "compatible and harmonious."

NERC's reports, such as its November 2017 special reliability assessment on risks to the grid from severe gas disruptions, are one tool, he said. (See NERC: Natural Gas Dependence Alters Reliability Planning.)

"We're not close-minded to the possibility of a suite of standards, if indeed they're required. I think at this point in time we haven't made that leap that we think we need to go to the step of creating a fuel-specific standard — that we can address this through some of the existing processes that we have," Robb said. "But it's clear that industry wants more guidance around what they should be studying and what sort of corrective actions they should be contemplating."

That was exactly the ask of Peter Brandien, ISO-NE's vice president of system operations. "It would be helpful for us if there was some sort of guideline or something agreed upon by the industry on how to look at energy security and what are the attributes or the pass/fail criteria you should be looking at," he said.

Cybersecurity Rules for Pipelines?

Glick asked witnesses whether there are sufficient cybersecurity rules for gas pipelines. In June, Glick and Chatterjee penned a joint op-ed calling for mandatory reliability standards for natural gas pipelines like those FERC and NERC enforce on the grid. They noted that Transportation Security Administration has only a half-dozen employees overseeing pipeline security and relies on voluntary cybersecurity standards.

Berkshire Hathaway Energy CEO William Fehrman, who testified for the Edison Electric Institute, said NERC's Critical Infrastructure Protection (CIP) standards "were very effective in developing a culture of security" in the industry.

"I do think that similar approaches should be made on gas pipelines. Whether or not there needs to be a standard I think is debatable, but I certainly believe that a similar focus on security and a culture of defensive postures on gas pipelines is appropriate."

He added, "When we look through our assessments of pipelines, I would say that the vast majority of operators are already well beyond what would be a similar CIP standard. But, nonetheless, there is a good opportunity for further discussion on that matter."

"I don't have nearly as much visibility into the mechanics of how the pipeline systems actually operate," said Robb.

"I'm not in a position to say whether or not the TSA … approach is adequate or not."

Testifying later, independent consultant Alison Silverstein pointed out that no one from the gas industry was invited to appear on any of the four panels.

Silverstein also challenged the focus on fuel security, saying fuel shortages account for only a tiny portion of outage events. "We have a grid that some of the pieces on it are 70, 100 years old," Silverstein said. "Today we're built for 'Ozzie and Harriet' weather, and we're facing 'Mad Max' in terms of the magnitude of threats from extreme weather."

She also urged a focus on reliability measures with proven benefits, "like tree-trimming, the gift that keeps on giving, every season."

When to Press

LaFleur asked when FERC should press NERC and the industry on new standards, citing a "conservatism" built into NERC's industry voting mechanism. "Part of our job is to be annoying and push when there's something" that needs to be addressed, she said citing FERC's directives on physical security and geomagnetic disturbances.

"That's a great question," Robb responded. "I wish I had a crisp answer to it, but I don't. … I think there's a little bit of 'you'll know it when you see it' embedded in here."

Tim Gallagher, CEO of RE ReliabilityFirst, said the answer depends on the pervasiveness and imminence of the threat. "Standards are not in my mind the ideal way to respond to emerging or potential threats. Sometimes the threat or the risk can be addressed quite well outside of the standards process," he said.

The first panel in the all-day conference featured (from left) Jim Robb, NERC; Commissioner Marcelino Madrigal Martinez, Mexican Energy Regulatory Commission (CRE); Tim Gallagher, ReliabilityFirst; Sylvain Clermont, Hydro-Quebec TransEnergie; William Fehrman, Berkshire Hathaway Energy; Eric Schmitt, CAISO; Steven Naumann, Exelon; and Jack Cashin, American Public Power Association. | *© RTO Insider*

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The second panel at FERC's reliability conference featured (from left) Mark Lauby, NERC; Wes Yeomans, NYISO; Peter Brandien, ISO-NE; Bob Bradish, AEP; Carol Chinn, Florida Municipal Power Agency; Tom Galloway, North American Transmission Forum; and consultant Alison Silverstein. | © RTO Insider

Gallagher cited NERC's response to the widespread generation failures during the 2014 polar vortex. Afterward, NERC made site visits to willing generators and suggested corrective measures.

"If we had gone down the standards path in that case," he said, "we would not have been prepared for the next winter. Taking this more aggressive, non-standards approach, we were able to elevate performance — along with working with our RTOs and improvements they made — and the voluntary cooperation of the industry to have much better performance."

Steven Naumann, Exelon's vice president of transmission and NERC policy, said the time-consuming standards process is especially ill-suited for responding to cyber threats. "The threat is going to change. We're dealing with intelligent adversaries … so if we close one door they're going to look for another."

RC Function in West

LaFleur asked what FERC should be concerned about regarding Peak Reliability's plan to cede its role as the Western Interconnection's reliability coordinator to CAISO and perhaps others.

"The thing to remember about the Western Interconnection is it really works as one integrated machine," said Robb, noting that radially connected Alberta is an exception. "Having a unified reliability coordinator overseeing that system was very beneficial. One of the issues we deal with in the West is that a problem in the Northwest can manifest itself in New Mexico very, very quickly. So, I think the most important thing, as we shift to a multi-reliability coordinator system in the West, is that the seams agreements and operating protocols between them really recreate that wide area view for the entire interconnection. The most important thing that can happen right now is for the TOPs [transmission operators] and BAs [balancing authorities] in the West to declare where they are going to go so that we know where the seams are."

Glick asked how CAISO was going to address concerns he's heard from some entities in the West that CAISO's role in operating the markets and being the RC could lead to conflicts of interest — an issue that dogged SPP in the past.

"RC services are driven by compliance standards. They're operational and engineering in nature," responded Eric Schmitt, CAISO's vice president of operations. He said CAISO asked potential customers to help it create the framework for the new function.

"We think it honors independence and separation between our … BA reliability function and markets and RC services. Organizationally and process-wise, we're creating the kind of separation that the customers would like to see. Yes, there's more discussion to be had around that as we go forward, but we think that was a good start."

Standardizing Inverter Configurations

Schmitt also called for standardization of the configuration of inverters on renewable generation, citing the ISO's problem with utility-scale solar tripping offline. (See *Solar Inverter Problem Leads CAISO to Boost Reserves*.)

"Nobody ever told the inverter owners how to program them," said Robb. "The good news is industry has been very responsive. I think we've solved the problems that we know of. We may find others."

Robb said NERC expects to begin work in August on two Standard Authorization Requests (SARs) on inverters.

Don't Attempt to Control the Future

Panelists in the conference's third session looked to the future and urged the commission not to attempt to control what it looks like.

"I think the way we've been thinking about essential reliability services is right on point," said John Moura, NERC's director of reliability assessment and system analysis. He cited several examples of recent grid-level issues, such as frequency response, that have been addressed with interaction between NERC and FERC.

Quanta Technology President Damir Novosel, who appeared on behalf of the IEEE Power & Energy Society, said the key is "knowing what we want to accomplish through [performance] standards, then [having] the market that will value what [we] want to accomplish."

Speaking for the Large Public Power Council, ElectriCities of North Carolina CEO Roy Jones urged the commission to

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ensure that any resource that can provide the necessary services has access to the market to do so. He called for driving the standardization of storage resources further upstream to manufacturers, where "it's more efficient to work on it there once so that everything coming down the assembly line has that standard."

Wabash Valley Power Association CEO Jay Bartlett, who appeared on behalf of the National Rural Electric Cooperative Association, said regulators should first determine the right information to know about new equipment on the system so "that we can effectively model it and ensure that we don't spend good money after bad, trying to cover parameters that we can't model with reserves."

Nicholas Miller, a principal at HickoryLedge, called for standards and market signals that are "outcome-based, not enabling-based," because "there's a lot more knobs that can be turned with inverted-based resources than with synchronous machines."

Peter Gregg, CEO of Ontario's Independent Electricity System Operator, said managing data is essential for the future.

"If we think about how our systems are becoming more complex, they are only going to become more complex," he said. "I think our challenge is, how do we better leverage the data that we're creating … how to actually access, interpret, analyze and use that data."

Information Sharing

On the final panel, which focused on cybersecurity, NERC Senior Director Bill Lawrence discussed NERC's plan to expand its Cybersecurity Risk Information Sharing Program (CRISP) to improve information sharing.

"Right now, CRISP covers well over 75% of the meters in the United States. … We have a very good sample set of what's going in and out of IT networks," Lawrence said.

But information sharing methods are still limited, he said.

"Whenever we start talking about … automated information sharing, I like to throw 'HV' in front of that: human verified. Right now, we don't have the trust on any information shared to be able to apply directly to production systems without awareness of the consequences it might have. So, we don't have machine-to-machine yet," said Lawrence, adding that the National Laboratories and federal research and development programs are working on trust models "to separate the wheat from the chaff."

The Department of Energy's Carol Hawk said the labs are also looking into "containerizing" power system applications so that each is isolated with a decreased chance of being compromised.

Hawk said cybersecurity staff could use the operational nature of the industry itself to protect against attacks. "Here's an example: Each component in [a] system is designed to perform a very specific, limited function. We have developed technology that will allow the system to deny by default any unexpected cyber activity. … If it's not expected, don't allow it," she explained. Hawk said with the system effectively locked down by only allowing its intended function, it "shrinks the cyberattack surface." She added that protective relays could use modeling to analyze within four milliseconds whether a command sent by an adversary would destabilize the grid.

"So I see a bright future … because we can use characteristics of that operational

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FERC & FEDERAL NEWS

Annual FERC Reliability Conference Takes on Resilience

Continued from page 27

environment to protect itself, to automate a response that makes sense," Hawk said.

Trinity Cyber President Marie O'Neill "Neill" Sciarrone said addressing cybersecurity issues has changed little from her time at the Department of Commerce's Critical Infrastructure Assurance Office in the early 2000s.

"We were coming out of Y2K and addressing the Code Red [virus], and you realize we're talking about the same thing today we were talking about in 2000, and that's sad. And that's basically where we are," Sciarrone said. She urged the sharing of more "actionable information."

"You can share … IP addresses for someone to block, but you're not giving the context of why or how the threat is evolving or how the threats to their IT systems are making their way to their [operation technology] systems," she said, adding that it's "absurd" to prepare for an unnamed adversary.

"When it comes down to it, we all need to admit adversaries have more motivation, more funding, more resources than any of us, and we need to bind together and be very transparent and open about what we're seeing, how we're acting, how we're solving problems, and be as willing as they are to adopt modern technology and to be flexible and to move if we're going to combat that. Otherwise, we're fighting with both arms behind our back," Microsoft's Matt Rathbun said.

NERC CIP Standards

LaFleur asked whether the NERC CIP standards are sufficient or excessive.

"We hear the standards were just a baseline — any self-respecting company has gone well beyond that. In other parts, we hear that we are way too restrictive and should be cut back. … [Edison Electric Institute] said we should have a moratorium on standards; there are too many," she said.

Lincoln Electric System's Paul Crist said utilities must balance compliance with emerging security threats. He said situations can arise where software vendors become compromised, but removing their software would lead to noncompliance. Crist admitted CIP standards "are probably a struggle for all" and said his company tries to balance the risk of violating compliance with having sufficient incident response capabilities. He noted that some vendors deliberately refuse to offer CIP compliance.

Rathbun said CIP guidance is not clear enough to issue any guarantees an entity will pass an audit.

"I have 78 certifications. CIP is not one of them," he said.

Dragos' Ben Miller said the industry's understanding of threats is limited: "We have anecdotes. We don't have large data sets. So I think it's hard from a standards process … to chase the threat."

After Hawk suggested asset owners may not be able to afford to cover the costs of sophisticated cybersecurity programs, LaFleur said she's never spoken to a transmission owner who doesn't have the opportunity to recover cybersecurity costs in rates.

Hawk said the issue of cost may emerge with research and development programs for new technologies.

"If a company is wanting to do something on their system, buy a new package to make it more secure, and they are not able to fund that, we would like to know about that," LaFleur said. "There are so many things we can't control, that are not within FERC's authority. Utility rates are one of the things we actually do."

Michael Kuser, Rory D. Sweeney, Amanda Durish Cook and Rich Heidorn Jr. contributed to this report.

Q2 Company Earnings

PSEG Earnings, Combined Cycle Fleet Grow in Q2

By Rich Heidorn Jr.

Public Service Enterprise Group announced second-quarter earnings of $269 million ($0.53/share), more than doubling the $109 million ($0.22/share) in profits a year earlier, which were weighed down by costs related to the early retirement of the company's Hudson and Mercer generating stations.

Operating earnings for the quarter were $325 million ($0.64/share), up modestly from 2017's $316 million ($0.62/share).

Public Service Electric and Gas earnings rose 12% year over year thanks to continued investment in transmission and distribution. PSE&G has invested more than $3 billion in electric and gas infrastructure in the past year.

The company recently finished construction of the third and final phase of its $1.2 billion, 345-kV Bergen-Linden Corridor (BLC) project. It was "one of the larger and more complex projects we have built and was finished safely on time and on budget," CEO Ralph Izzo said on an earnings call Thursday.

Izzo told analysts that the company is not jeopardized by the long-running dispute over cost allocation for the BLC. (See *FERC Rethinking DFAX for Stability Tx Projects*.)

"The issue is who pays, not whether we get paid," he said. "So PSE&G will get fully compensated for its transmission investments."

PSEG projects $14 billion to $18 billion in capital spending through 2022, 90% of which will be on "regulated growth initiatives" at PSE&G, said CFO Daniel Cregg. The spending should support a compound annual growth rate of 8 to 10% over the period, officials said.

The company sees investment opportunities in the legislation signed by New Jersey Gov. Phil Murphy in May that raises its renewable generation targets, boosts storage and offshore wind, and revamps its solar program. PSE&G plans to seek approval of $2.9 billion in investments in energy efficiency, electric vehicle infrastructure and battery storage over six years. It also expects its three New Jersey nuclear plants to receive about $200 million annually under the state's zero-emission certificates beginning in April 2019. (See *Gov. Signs NJ Nuke Subsidy, Renewables Bills*.)

New Generation

PSEG Power began commercial operation of its two newest generators in the second quarter, the Keys Energy Center, a 755-MW plant east of Brandywine, Md., and Sewaren 7, a 540-MW generator in Woodbridge, N.J.

Sewaren 7 is replacing Units 1, 2, 3 and 4 of its existing Sewaren coal-fired plant, which are being retired after about 70 years of operation.

With the addition of Sewaren and Keys, PSEG will have more than 4,000 MW of combined cycle gas turbines, one-third of its total fleet.

Bridgeport Harbor 5, a 485-MW dual-fuel, combined cycle plant in Connecticut, is expected to go online in mid-2019.

The investments in the three plants "reflect our recognition of the value of opportunistic growth in the power business," the company said in its quarterly securities filing. "These additions to our fleet both expand our geographic diversity and adjust our fuel mix and are expected to enhance the environmental profile and overall efficiency of Power's generation fleet."

Analyst call transcript courtesy of Seeking Alpha.

FirstEnergy Almost Free of FES Bankruptcy

By Rory D. Sweeney

FirstEnergy has reached what CEO Charles Jones called a "big milestone" in its process of unwinding from FirstEnergy Solutions, the bankrupt merchant generator that was until recently a subsidiary.

The FES bankruptcy settlement is now "definitive, comprehensive" and includes FES, its subsidiaries, FirstEnergy Nuclear Operating Co. and a committee for unsecured creditors, Jones said Wednesday. It builds on agreements FirstEnergy announced in April while reporting its performance for the first quarter. (See *FirstEnergy Announces Mixed Earnings, Plan for FES Bankruptcy*.)

"This definitive, comprehensive settlement defines and quantifies all of FirstEnergy's obligations with respect to FES and FENOC," Jones said.

The Aug. 1 announcement came as part of FirstEnergy's review of its second-quarter performance, which exceeded both revenue and earnings expectations. The company reported quarterly adjusted earnings of 62 cents/share, which beat expectations by 9 cents, and revenue of $2.7 billion, which was $130 million over projections. Revenue increased $100 million compared to the same quarter last year, while earnings were up 18 cents/share year over year.

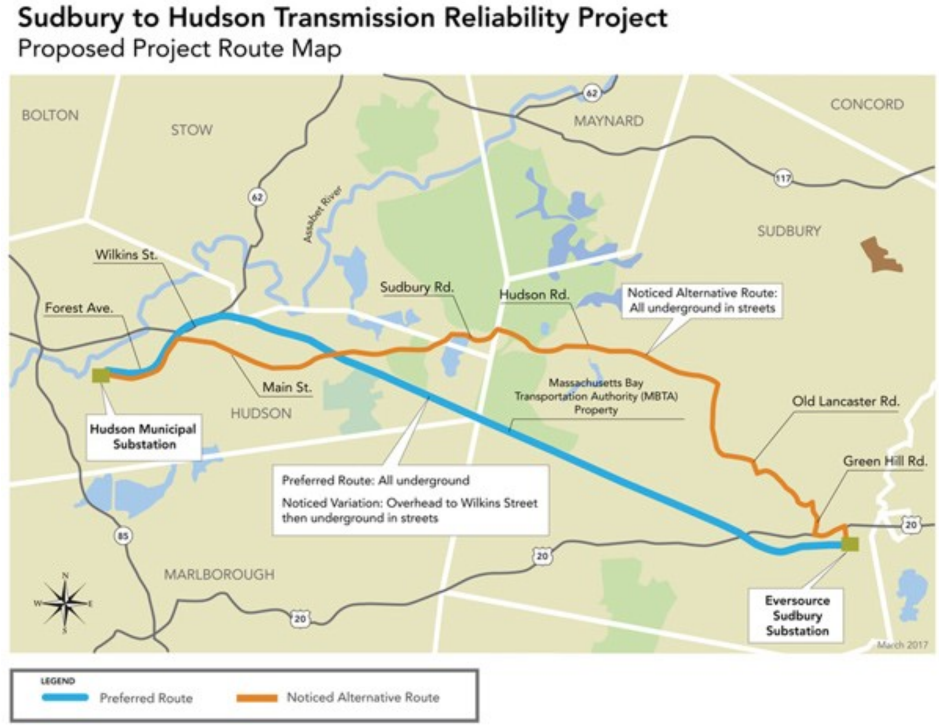
The settlement credits FES for nine months of its shared services costs with FirstEnergy and entitles the former subsidiary to continue purchasing the services through June 2020. FirstEnergy also agreed to increase its cash payment and cover costs for some FES employee benefits, which represent $218.5 million in additional costs incurred by FirstEnergy. FES is expected to file the agreement by the end of August as part of its bankruptcy case and to receive approval in September.

While FirstEnergy no longer has any merchant generation assets, Jones maintained his strong advocacy for financial supports for nuclear and coal units, saying that "the market policies in our country have severe flaws" and that he will "continue to be a loud advocate" for changes. Shuttering large-scale plants "is not going to be a good thing for the 6 million customers that I look out for," he said. Jones said he remains "hopeful" that the U.S. Department of Energy "will eventually step forward to do something to stabilize" those plants.

Q2 Company Earnings

Eversource Boosting CapEx by $600 Million

By Michael Kuser



| Eversource

Eversource Energy said Wednesday that it is increasing its capital spending over the next three years by $600 million, bringing the total to $7.1 billion through 2021.

"This incremental capital will be split between $300 million for electric transmission, $200 million for electric distribution and $100 million for natural gas distribution infrastructure investments," Eversource CFO Phil Lembo said in an analyst call. "To be more specific, on the electric transmission system, we now plan to accelerate the upgrades of aging wooden transmission structures and expect to replace thousands of them with new steel poles over the next several years.

"The primary driver of this increased level of expenditure will be investments in resiliency and reliability," Lembo said. He added that the figures do "not include any potential initiatives that may emerge from the grid [modernization] reviews in Connecticut or Massachusetts."

Eversource, New England's largest utility, offers retail electricity, natural gas service and water service to approximately 3.6 million customers in Connecticut, Massachusetts and New Hampshire.

Q2 Earnings Increase 5%

The company reported second-quarter earnings of $242.8 million ($0.76/share), up slightly more than 5% compared with $230.7 million ($0.72/share) in the same period a year ago.

Eversource's transmission unit earned $112.7 million in the quarter, up nearly 17% from a year earlier, primarily because of higher investment in its electric transmission system.

The company's electric distribution business earned $101.3 million in the second quarter, down more than 20% from last year primarily because of the sale of New Hampshire generation assets, higher property tax expenses and revenue decoupling for eastern Massachusetts customers. Distribution rate increases partially offset the decline.

Eversource earned $5 million from natural gas in the quarter, up 11% from the same period a year ago. Colder weather in 2018 increased natural gas sales in Connecticut, where sales are not currently decoupled. The company's Aquarion Water unit, acquired in December 2017, earned $7.2 million in the second quarter.

Regulators' Support

Harsh storms this spring underscored the need to accelerate resilience investments, spending supported by state regulators, the company said.

The Massachusetts Department of Public Utilities this spring approved $133 million of additional grid modernization investments for NSTAR Electric over the next three years, in addition to $100 million authorized in 2017 for two battery storage initiatives and initial electric vehicle infrastructure.

The DPU also instructed NSTAR to file a three-year rate plan for continued grid modernization efforts beginning in 2021, which the company expects to submit sometime in 2020.

Growing demand in the Boston and Cambridge area prompted the company to upgrade several key substations.

On May 1, subsidiary Connecticut Light & Power's new three-year rate plan took effect with an initial distribution rate increase of about $64 million. Two smaller increases will follow in 2019 and 2020.

Connecticut regulators also approved a base amount of $270 million per year in investments "aimed at making the grid more resilient, such as smart switches, enhanced tree trimming, upgrades to our poles and their integrity, and substation security," Lembo said.

Eversource expects to file a separate grid modernization plan in Connecticut before the end of this year, he said.

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Q2 COMPANY EARNINGS

NRG Earnings Rebound on Cost-cutting, Asset Sales

By Michael Kuser

NRG Energy reported net income of $24 million ($0.23/share) in the second quarter, compared with a $16 million loss (-$1.98/share) a year earlier. Earnings from continuing operations were $121 million in the quarter, up 22% from the same period last year.

The company credited cost-cutting measures, the sale of assets and the consummation of a settlement with its spun-off GenOn Energy business. "Our portfolio is demonstrating once again the value of integration between retail and generation during the volatile summer months, particularly in Texas," CEO Mauricio Gutierrez said during an earnings call Thursday.

The company has realized $225 million in cost savings through the second quarter of 2018 and is on track to close up to $3 billion in asset sales this year.

Record Peak in Texas

Gutierrez noted that the supply/demand balance in ERCOT is the tightest it has been in many years because of steady load growth and the retirement of nearly 5 GW of generation in the past 12 months.

"This market tightening led to an increased probability of scarcity conditions this summer, which was reflected in higher forward prices," he said. "So far, demand has not disappointed, setting a new record peak of over 73 GW in July. However, this record load was met with equally impressive reliability across the grid, which tempers real-time pricing." (See *ERCOT Sets New All-time Demand Record; Prices Spike*.)

"In other words, it took nearly perfect systemwide reliability to meet the summer peak demand," he said.

"These conditions create an opportunity for both sides of our business and highlight the longer-term value of our integrated approach."

Big East

Results from the PJM capacity auction this past May reflected fewer new builds and significant amounts of uncleared capacity, signaling more disciplined development and bidding behavior, Gutierrez said. On a "same-store" basis, NRG cleared more megawatts at higher prices than the previous auction, he added.

Going forward, the company will seek assets in "premium locations," Gutierrez said, noting that NRG now has 85% of its PJM fleet in the ComEd zone, which separated to clear at $196/MW-day.

"Throughout the East, we are encouraged by the multiple regulatory avenues for market reform that could benefit both our generation and retail businesses," Gutierrez said.

NRG increased its bet on retail sales in June, when it completed its acquisition of XOOM Energy, an electricity and natural gas provider with more than 300,000 customers primarily in the East, for $208 million. The company expects XOOM to add $11 million of net income and $45 million of adjusted EBITDA annually.

Faster Asset Sales

The company also highlighted its progress in unwinding its relationship with GenOn, the product of the merger of RRI Energy and Mirant, which NRG purchased in 2012 for $1.7 billion. GenOn filed for Chapter 11 bankruptcy in 2017. NRG executed a settlement in July that included releases from GenOn and will terminate shared services on Aug. 15. Other than certain pension and post-retirement obligations and certain claims for REMA, an indirect GenOn subsidiary, the settlement provides NRG full releases from GenOn and its

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Eversource Boosting CapEx by $600 Million

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Maintaining Margins

Eversource and its partner Orsted formed Bay State Wind for offshore wind solicitations but lost out this spring as Vineyard Wind won the 800-MW award for Massachusetts and Deepwater Wind picked up orders in Rhode Island and Connecticut. (See *Mass., R.I. Pick 1,200 MW in Offshore Wind Bids*.)

Lee Olivier, Eversource executive vice president for business development, said the company did not want to dilute its earnings for the sake of winning.

"We put in a compelling bid with returns that were consistent with the current returns we have in transmission, and that was risk-adjusted," Olivier said. "Now clearly others took a different view of that, perhaps took more risk and lower returns, but we're not in this thing to win for the sake of winning."

Eversource sees potential for up to 7,000 MW of additional offshore wind in the Northeast by the middle of the coming decade.

"We see the long-term offshore wind becoming a major component of the bulk power system in New England," Olivier said. "In Massachusetts, you have an additional 800 MW of authorization; that will likely come in our opinion early next year. We will participate in that. You've got a bill in the Massachusetts legislature that would authorize another 1,600 MW of offshore wind."

Connecticut on July 31 issued a request for proposals seeking 12 TW of clean energy, he said.

"It could be Class 1 energy [wind and solar] but also could be existing nuclear and hydro, so we see that as a potential opportunity for offshore," Olivier said. "They have authorized essentially 2,400 MW of offshore wind that's kind of a specific RFP to offshore wind and probably the first 800 MW will come up in late this year or early 2019."

Q2 COMPANY EARNINGS

NRG Earnings Rebound on Cost-Cutting, Asset Sales

Continued from page 31

debtor and non-debtor subsidiaries.

GenOn is planning to exit bankruptcy on Oct. 1.

NRG closed on the sale of Boston Energy Trading and Marketing, as well as on its Spanish Town asset, a solar facility in the Virgin Islands, while reaching an agreement to sell its interest in two additional assets, the Keystone and Conemaugh coal-fired power plants in Pennsylvania.

"We actually had anticipated selling these assets in 2019, but we were able to accelerate this timeline and execute on the opportunity to monetize these assets ahead of schedule," Gutierrez said.

The sale of NRG Yield has received all necessary regulatory approvals and should close in the third quarter, he said. The company's sale of its South Central portfolio — 3,555 MW of gas- and coal-fired generation on the Gulf Coast — is also expected to close in the second half of this year.

Analyst call transcript courtesy of Seeking Alpha.

Con Ed Q2 Earnings Rise 7%

By Michael Kuser

Consolidated Edison earned $188 million ($0.60/share) in the second quarter, a 7% increase from $175 million ($0.57/share) in the same period last year.

The company reported about $2.7 billion in revenue for the quarter, a 2% increase over last year.

Adjusted earnings, which exclude the effects of a gain on the sale of a solar electric production project in 2017 and the net mark-to-market effects of Con Edison Clean Energy Businesses, were $189 million ($0.61/share) compared with $178 million ($0.58/share) in 2017.

Following a proceeding investigating a New York City subway power outage (Case 17-E-0428), the state Public Service Commission last year required Con Ed's primary utility subsidiary, Consolidated Edison Company of New York (CECONY), to upgrade electrical equipment that serves the system. Costs related to that matter totaled $180 million, including $30 million in capital and operating and maintenance costs reflected in the company's electric rate plan and $150 million deferred as a regulatory asset.

Through June 30, CECONY's costs related to March 2018 storms amounted to $126 million, while fellow subsidiaries Orange and Rockland Utilities (O&R) and Rockland Electric Co. had storm-related costs of $48 million and $18 million, respectively. Recovery of those costs is subject to review by the PSC and the New Jersey Board of Public Utilities. Con Ed and CECONY are unable to estimate the amount or range of their possible loss in connection with the storms, they said.

In May 2018, PSC staff recommended a $10.6 million increase in O&R's electric rates and a $6.7 million decrease in O&R's gas rates, both reflecting an 8.6% return on equity. In June 2018, O&R filed an update to its requested rate increases, changing its request to a $30.4 million increase for electric and a $0.5 million decrease for gas, seeking a 9.75% ROE.

Con Ed reported its Clean Energy Businesses having 1,383 MW of renewable energy production projects in service and 218 MW under construction.

CenterPoint Misses Expectations with $75M Loss

CenterPoint Energy on Friday reported a second-quarter loss of $75 million ($0.17/share), compared to a profit of $135 million ($0.31/share) a year earlier. The company's adjusted earnings of 30 cents/share fell short of Zacks Investment Research expectations of 32 cents.

The quarter's loss included a pre-tax write down of $242 million to reflect the Houston-based company's investment in Time Warner. AT&T acquired Time Warner in June, with CenterPoint receiving $53.75 and 1.437 shares of AT&T common stock for each share of Time Warner common stock it held.

CenterPoint endured a morning roller coaster ride Friday on Wall Street before its stock plunged in after-hours trading. After opening at $28.10/share, the stock closed at $27.96 before losing 12 more cents after the closing bell.

CEO Scott Prochazka said during a conference call with financial analysis that the company's electric, gas and Enable Midstream joint venture businesses performed well, accounting for a 25% increase in revenue to $2.8 billion from 2017's second quarter.

Prochazka said the company's $6 billion acquisition of Indiana electric and gas utility Vectren is progressing well. The company expects to close the deal in the first quarter of 2019. (See *CenterPoint Energy to Acquire Vectren in $6B Deal*.)

However, Prochazka also said the cost of CenterPoint's Freeport Master Plan project has more than doubled, from $250 million to $650 million, as a result of "more defined analysis" of infrastructure and environmental-related routing issues. ERCOT approved the project last year to solve reliability issues near the Freeport area south of Houston. (See *ERCOT Stakeholders OK $246.7M in Freeport Reliability Projects*.)

CenterPoint plans to file a certificate of convenience and necessity with the Texas Public Utility Commission in September.

— Tom Kleckner

Q2 COMPANY EARNINGS

SCANA Shareholders Approve Sale to Dominion

By Peter Key

SCANA stockholders last week overwhelmingly approved the company's sale to Dominion Energy, moving the deal one step closer to completion.

In a vote taken at a special meeting July 31, shareholders voted 72% in favor of the sale, more than the two-thirds required for approval.

The sale now has only three more major hurdles to clear: authorizations by South Carolina and North Carolina regulators, and the Nuclear Regulatory Commission. FERC and the Georgia Public Service Commission have already approved the deal, and the Federal Trade Commission has indicated it won't try to block it on antitrust grounds.

SCANA shareholders also voted against paying severance packages to executives if

V.C. Summer expansion project | *SCANA*

they are let go after the sale is completed, but that vote is nonbinding. SCANA has set aside $110 million in severance for its executives, attorneys for the South Carolina legislature said last week.

If approved, the deal would be a stock-for-stock transaction with Dominion paying two-thirds of a share of its stock for each SCANA share it acquires. At Dominion's July 31 closing price of $71.71, the company would be paying $6.83 billion for SCANA.

SCANA became an acquisition target after its failed attempt to expand the V.C. Summer Nuclear Station in Fairfield County, S.C. It and Santee Cooper, a utility owned by the state of South Carolina, gave up on the expansion last summer after spending $9 billion on it over a decade.

If the deal goes through, it would give Dominion 6.5 million regulated electric customer accounts, 31.4 GW of generation capacity and 93,600 miles of electric transmission and distribution lines.

The deal is controversial, in large part because customers of SCANA's South Carolina Electric & Gas subsidiary have already been charged more than $2 billion for the failed expansion and continue to pay about $27 a month for it.

South Carolina passed a bill that would roll back most of the payment, but SCANA is challenging its constitutionality.

Dominion Earnings up on Power Demand, Tax Cuts

By Rich Heidorn Jr.

Dominion Energy reported earnings of $449 million ($0.69/share) in the second quarter, up from $390 million ($0.62/share) for the same period in 2017, boosted by increased power sales and higher-than-expected benefits from tax cuts.

Excluding one-time rate credits and charges related to plant retirements and other matters, operating earnings for the quarter were $560 million ($0.86/share), above the company's guidance range of 70 to 80 cents and up 33% from $421 million ($0.67/share) a year earlier.

"Based on the very strong results for the second quarter, we expect to be in the upper half of our 2018 guidance range, and our 2017 to 2020 earnings growth rate remains 6 to 8%," CFO Mark F. McGettrick said during an earnings call Thursday.

The Power Generation Group had $639 million in cash flow, aided by lower operating and maintenance expenses and favorable weather.

CEO Thomas Farrell said Virginia Power's weather normalized sales for the first six months of the year were 2.25% above 2017, driven by increasing demand from data centers and residential customers. "Over the past year, we have added over 400 MW of demand capacity across 14 data centers and expect to see continued strong growth," Farrell said.

Millstone Update

On Wednesday, the Connecticut Department of Energy and Environmental Protection issued its final solicitation for zero-carbon resources after changing terms to allow Dominion to offer its Millstone nuclear plant.

The company submitted Millstone's financials to the state in May, seeking qualification of the nuclear plant as an "at-risk" resource. "We expect Millstone to be granted at-risk status, which means the bids will be judged on price and non-price attributes, such as carbon, economic impact and fuel security," Farrell said. Bids are due Sept. 14, with a selection of winners expected by the end of the year.

Farrell noted that the company's nuclear fleet has been operating for 660 days without an unplanned reactor shutdown, besting the previous record of 339 days set in 2012.

New Resources

The company's Cove Point LNG export facility entered commercial service early in the second quarter and has loaded more than 60 Bcf of LNG on 19 cargoes.

Dominion's $1.3 billion 1,588-MW Greensville County (Va.) combined-cycle power station is on budget and 95% complete, with commercial operations expected late this year.

The company will soon seek Virginia regulators' approval of its proposed Coastal Virginia Offshore Wind project, a 12-MW, two-turbine test project being developed with Orsted, of Denmark.

Analyst call transcript courtesy of Seeking Alpha.

Q2 COMPANY EARNINGS

Refinancing, Completed Tx Round out NiSource Q2

By Amanda Durish Cook

NiSource last week reported second-quarter earnings of $23.2 million ($0.07/share), compared to a net loss of $44.4 million ($0.14/share) for the same period a year ago because of a hefty refinancing fee. (See *NiSource Blames Debt Refinance Fee for Q2 Loss*.)

The Merrillville, Ind.-based parent of Northern Indiana Public Service Co. and Columbia Gas earned $299.3 million ($0.86/share) for the first half of 2018.

Speaking during an Aug. 1 earnings call, CEO Joe Hamrock said the company has taken steps to strengthen the company's finances in response to federal tax cuts, including offering about 25 million shares ($600 million) of common stock in a private placement and refinancing $760 million in long-term debt through the issuance of $400 million of preferred stock and $350 million of five-year notes.

"Due to financial statement impacts and the timing of federal tax reform implementation, our year-over-year consolidated results can be difficult to compare," CFO Donald Brown said. "However … we are making continued progress on managing our annual operating and maintenance expenses, and we now expect our annual O&M expenses to be down approximately 4% in 2018 versus 2017."

NiSource also remains on track to invest up to $1.8 billion in regulated utility infrastructure in this year, Hamrock said.

Hamrock said NiSource subsidiary Northern Indiana Public Service Co. placed two major Indiana transmission projects into service during the quarter, including the 100-mile, 345-kV Reynolds-Topeka transmission line and the 70-mile, 765-kV Greentown-Reynolds line. The projects, which cost a combined $600 million, were both part of MISO's 17-project multi-value portfolio approved in 2011. (See *MISO Triennial Review Shows Multi-Value Project Benefits*.) Hamrock said the lines will "enhance regionwide system reliability, provide environmental benefits by increasing access to wind and solar energy and improve access to lower-cost electricity for customers."

NIPSCO has also solicited 90 proposals for replacement capacity through its integrated resource plan, targeted for submission to the Indiana Utility Regulatory Commission by the end of the year.

Hamrock said the company received a "robust response to our request for proposals that should provide diverse options to meet our customers' electricity needs for years to come." He added the proposals total more than 20 GW with "several diverse fuel options."

In its last IRP, NIPSCO announced it planned to retire 50% of its coal-fired fleet by 2023. The company retired its 480-MW Bailly Generating Station Units 7 and 8 in northern Indiana on Lake Michigan in May, according to schedule. Both units were more than 50 years old.

Entergy Sees Quicker Exit from Pilgrim, Palisades Nukes

By Tom Kleckner

Entergy accelerated its march toward becoming a "pure play" utility Wednesday, announcing the sale of its Pilgrim and Palisades nuclear facilities for their accelerated decommissioning.

Financial analysts congratulated Entergy executives on the news during the second-quarter earnings call, where the company announced adjusted earnings of $1.79/share, beating Zack's consensus estimate of $1.26 by 42%.

CEO Leo Denault said the plants' sale "solidifies" Entergy's plans to fully divest itself of three of the four nuclear plants in its Entergy Wholesale Commodities (EWC) business.

Entergy's share price jumped Wednesday by almost $2 — from $81.03/share at the market's open to a high of $82.99 — before falling back to close at $81.82.

Earlier this year, Entergy reached an agreement with Vermont state officials to sell its Vermont Yankee plant to NorthStar Group Services, which will handle the decommissioning. The plant was shuttered in 2015. The company is waiting on regulatory approvals to sell the plant's holding company.

The transaction includes the transfer of the plants' operating licenses, spent fuel and nuclear decommissioning trusts, to Comprehensive Decommissioning International, a newly formed joint venture between Holtec International and SNC-Lavalin.

Entergy received a "nominal" cash consideration in the deal, which must clear the Nuclear Regulatory Commission and other regulators.

"You could afford it if you could demonstrate the ability to close a nuclear plant," CFO Drew Marsh told analysts. "The main objective was to move the risk to a party capable of [decommissioning] and doing it much quicker than we can."

Pilgrim, located in Plymouth, Mass., is scheduled to end operations by June 2019, and Palisades, in Covert, Mich., is to close in early 2022. The two plants date back to the early 1970s. They generate almost 1.5 GW of power between them and employ 1,200 people.

Entergy's Indian Point nuclear plant in New York will close by 2021, according to an agreement between the company and state officials. Denault said there was "nothing to read" into not including Indian Point in the deal.

The company reported earnings of $245 million ($1.34/share), excluding a one-time tax benefit of 31 cents/share for the settlement of a 2012-2013 IRS audit. That compared to $410 million and $2.27/share a year ago.

EWC reported a loss of $57 million in the quarter. Entergy affirmed its 2018 consolidated operational earnings guidance range of $6.25 to $6.85/share.

Company Briefs

EDP Wind Farm to Power Facebook Data Center

Headwaters I turbines | *EDP Renewables*

EDP Renewables North America announced Aug. 2 that it will build a 50-turbine wind facility in Randolph County, Ind., for $300 million.

Facebook has already signed a 15-year power purchase agreement for 139 of the Headwaters II Wind Farm's 200 MW to power its planned 970,000-square-foot data center in New Albany, Ohio.

Work on Headwaters II is expected to begin in fall 2019, according to EDP. The company also operates the 200-MW Headwaters I in the county, which is rural Eastern Indiana, close to the Ohio border.

More: *Richmond Palladium-Item*

Central Hudson Board Appoints New CEO

Freni

Central Hudson Gas & Electric's board of directors Aug. 3 appointed Charles A. Freni as president and CEO, effective Sept. 15.

Freni has been with the company for more than 30 years and currently serves as senior vice president of customer services, transmission and distribution. He has also served as vice president of engineering and environmental affairs.

He replaces Michael Mosher, who has been appointed CEO of fellow sister utility FortisAlberta.

More: *Central Hudson Gas & Electric*

Avangrid Launches 'Green' Balancing Authority in WECC

Avangrid Renewables said Aug. 1 it has launched its "Green" Balancing Authority in the Western Interconnection.

The Avangrid unit said the BA's 1,300 MW of renewable generation facilities makes it the largest renewable generation resource-only BA in Western Electricity Coordinating Council.

The BA will use a combination of owned and contracted resources, hour-ahead capacity purchases and intra-hour energy purchases, Avangrid said.

More: *Avangrid Renewables*

Westinghouse Electric Completes Sale, Emerges from Bankruptcy

Westinghouse Electric said Aug. 1 it has completed its sale to Brookfield Business Partners and re-emergence from Chapter 11 as a reorganized company.

The provider of nuclear technology, fuels and service had been a unit of Toshiba. It was forced to seek bankruptcy protection after its role in two attempts to expand U.S. nuclear power plants, one of which has been halted.

More: *Westinghouse Electric*

Alliant Energy Says No Coal, 80% Carbon Cut by 2050

Alliant Energy plans to remove coal from its generation mix and reduce its carbon emissions 80% by 2050, the company said in its corporate sustainability report, which it released Thursday.

The company also said it plans to increase renewables' share of its power generation to 33% by 2030 from 16% now. Coal currently provides 33% of Alliant's power. The company plans to cut that to 23% by 2024.

More: *Wisconsin State Journal*

Entergy Completes Moving Spent Vermont Yankee Fuel

Entergy said Aug. 2 it has completed placing the spent fuel from its closed Vermont Yankee nuclear power plant into sealed casks.

The completion of the $143 million project allows Entergy to drastically reduce the size of the protected area on the plant's grounds, which the Nuclear Regulatory Commission gave it permission to do on Aug. 2.

The completion of the project also clears the way for the potential sale of the plant site to NorthStar Group Services, which has proposed an accelerated cleanup for it.

More: *VTDigger*

PG&E Lobbying Expenses Total $1.7M in Second Quarter

Pacific Gas and Electric spent $1.7 million on lobbying, including $1.1 million on advocacy related to proposed legislation dealing with its wildfire liabilities, in the second quarter, according to filings the utility made with the state.

That was more than the amount PG&E spent on lobbying all last year and was more than the $900,000 spent by Southern California Edison and the $502,000 by Sempra Energy in the quarter. It brought the total spent in the first half of the year by PG&E to $2.2 million.

More: *The Sacramento Bee*

FERC OKs Reduced Reactive Power Payments for Minn. Wind Farm

FERC on Wednesday approved an uncontested settlement reducing annual reactive power payments to the 200-MW Red Pine wind farm to $967,000, down from the company's proposed revenue requirement of $1.3 million. The facility, in Lincoln County, Minn., is interconnected Northern States Power's transmission system in MISO.

More: *ER18-563-001*

Average SC Customer Paying $6,200 for VC Summer

The average residential customer of Santee Cooper will have to pay about $6,200 through 2056 to pay off the South Carolina-owned utility's share of the failed attempt to expand the V.C. Summer nuclear power plant, according to its interim CEO Jim Brogdon.

Santee Cooper customers now pay only $5/month toward the cost of the failed project, but that will more than double over

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COMPANY BRIEFS

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the next five years, with the charge varying based on how much debt from the project is coming due.

Santee Cooper's partner on the failed project, South Carolina Electric & Gas, expects its typical residential customers would only have to pay $2,800 if its parent, SCANA, is bought by Dominion Energy.

More: The Post and Courier

PG&E Considering Breakup To Deal with Fire Liabilities

PG&E Corp. is considering breaking itself up so that only one division would have to file for bankruptcy protection as a result of losses due to fires, Reuters reported July 31, citing people familiar with the matter.

The company recorded a $2.5 billion charge against earnings in the second quarter to cover its Pacific Gas and Electric subsidiary's potential liabilities from fires.

The breakup option is one PG&E is discussing with law firm Weil, Gotshal & Manges, which the sources said it hired to explore restructuring its debt.

More: Reuters

Macquarie to Sell Bayonne Energy Center

Macquarie Infrastructure Corp. said July 29 it has agreed to sell the 644-MW gas-fired Bayonne Energy Center for $900 million in cash and assumed debt.

The company didn't identify the buyer for the Bayonne, N.J., power plant, which provides power to New York City via a cable that runs beneath New York Harbor to a substation in Brooklyn.

Macquarie expects the sale to close in the fourth quarter.

More: Macquarie Infrastructure Corp.

EverPower Wind Acquisition Gives innogy Renewables 2,000+ MW

Innogy Renewables US has closed on its acquisition of EverPower Wind Holdings' onshore wind business, making it the sole owner of more than 2,000 MW of onshore wind projects in various stages of development.

The innogy subsidiary now has a pipeline of wind projects in eight states, including three in late-stage development that it expects to be in operation by 2020.

More: Marathon Capital

Pattern Signs 2 Customers for New Mexico Wind Farm Power

Pattern Energy Group 2 said July 31 that two California power suppliers have signed 15-year power purchase agreements to buy electricity from the 200-MW Duran Mesa Wind Project it is developing near Corona, N.M.

Silicon Valley Clean Energy's PPA is for 110 MW and Monterey Bay Community Power's PPA is for 90 MW.

Pattern expects to begin construction on the wind farm late next year and have it up and running in late 2020.

More: Pattern Energy Group 2

FEDERAL BRIEFS

FERC Orders Mountain Valley Work Stoppage

FERC on Friday ordered an immediate halt to construction of the 303-mile Mountain Valley Pipeline in Virginia.

The commission cited the 4th Circuit Court of Appeals' recent ruling that remanded approvals by the Bureau of Land Management and Forest Service for a segment of the pipeline that runs through a national forest. While it said it did not have any reason to believe the agencies would not be able to comply with the court's orders, the commission said it could not predict when they would, or if they will alter the pipeline's route.

"Accordingly, allowing continued construction poses the risk of expending substantial resources and substantially disturbing the environment by constructing facilities that ultimately might have to be relocated or abandoned," FERC said.

More: The Roanoke Times

No Carbon Capture Plans For 8 of 10 Largest IOUs

Despite Congress recently tripling a subsidy for carbon capture and storage projects, eight of the country's 10 largest investor-owned electric utilities have no plans to buy and install equipment, a Reuters survey found.

American Electric Power, Dominion Energy, Duke Energy, Edison International, Exelon, Pacific Gas and Electric, Southern Co. and Xcel Energy cited the equipment's high costs and uncertain demand for the carbon dioxide it produces. Edison International and NextEra Energy Resources declined comment.

More: Reuters

Nuke Developer Sought Cohen's Help in TVA Purchase

Franklin Haney agreed in early April to pay President Trump's then-personal attorney Michael Cohen $10 million if Cohen helped him obtain funding for his company to buy the Bellefonte Nuclear Power Plant from the Tennessee Valley Authority and finish building it, according to people familiar with the matter.


Haney | GWU

A May 23 announcement by U.S. Rep. Mo Brooks (R-Ala.) said Haney was trying to attain $5 billion in loans from the Department of Energy for his company, Nuclear Development. Brooks, three other representatives from Alabama and one from Tennessee sent Trump a letter supporting Haney's effort to get the loans.

More: The Wall Street Journal

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FEDERAL BRIEFS

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Dragos: Hacking Group Breached US Utilities

A hacking group has breached the business networks of U.S. electric utilities and could develop the capability to access their operational networks in 18 to 24 months, according to cybersecurity firm Dragos.

The group, which Dragos calls "Raspite," has been penetrating targets in the U.S., Middle East, Europe and East Asia for at least a year. Symantec, which calls the group "Leafminer," has linked it to Iran.

More: *The Hill*

BLM Authorizes Pumped Storage Project's Tx, Water Lines

The Bureau of Land Management on Aug. 1 authorized the construction of a transmission line and water line on land it manages as part of Eagle Crest Energy's planned $2.5 billion pumped storage project in Riverside County, Calif.

The 500-kV, 12-mile transmission line would connect the project to Southern California Edison's Red Bluff substation, which also is located on BLM lands in Riverside County.

More: *Bureau of Land Management*

Report: 42 States Took Solar Power Actions Last Quarter

Forty-two states and D.C. took policy actions related to solar power during the second quarter, according to the North Carolina Clean Energy Technology Center's "50 States of Solar – Q2 2018 Quarterly Report."

The top five policy developments according to the report were Connecticut moving away from net metering; New Jersey adopting a community solar policy; Florida approving residential solar leasing; Idaho separating distributed generation customers into a unique group to study their rate structure requirement; and Colorado, Connecticut and New York reducing fixed charges.

More: *pv magazine*

STATE BRIEFS

ARIZONA

Judge Keeps Renewable Proposal on Ballot for Now

A July 31 ruling by Maricopa County Superior Court Judge Daniel Kiley means a proposal to increase the state's renewable portfolio standard to 50% by 2030 won't be removed from the November ballot yet, although it may be later.

Kiley ruled that only the secretary of state can decide if the group behind the proposal, Clean Energy for a Healthy Arizona, violated the state election law requiring ballot measures to have a sponsor by not sufficiently promoting the fact that it was funded by a political action committee funded by California billionaire Tom Steyer. But even if it did, he said, the most the secretary of state can do is fine it.

Kiley also ruled, however, that Pinnacle West Capital and its Arizona Public Service subsidiary, which are trying to keep the proposal off the ballot, can try to show that Clean Energy for a Healthy Arizona didn't gather enough valid signatures to get it on the ballot in a trial scheduled for later this month.

More: *Arizona Daily Sun*

CALIFORNIA

San Onofre Settlement Parties Agree To PUC Request, Ending Proceeding

The parties involved in the San Onofre Nuclear Generating Station proceeding told the Public Utilities Commission on Aug. 2 that they have accepted its request that they remove a provision that would have funded greenhouse gas research from their settlement agreement.

The acceptance concludes the proceeding, as the commission had accepted the rest of the settlement on July 26. In the settlement, Southern California Edison, which owns the majority of San Onofre, and San Diego Gas & Electric agreed they wouldn't continue to make their customers pay for the $775 million in costs related to the plant that they had not recovered.

More: *Southern California Edison*

LOUISIANA

Entergy New Orleans Plan Lowers Overall Rates, Increase Some Bills

Entergy New Orleans on July 31 filed a rate plan with New Orleans City Council that would lower its overall rates by $20 million but increase the monthly bill of a residential customer in the city's Algiers section who uses 1,000 kW/month by $22.

The company said the increase would bring the rates of its Algiers customers, who had been served by Entergy Louisiana until 2015, in line with the rates of the rest of its customers.

In a separate filing, Entergy New Orleans asked the council to approve three utility-scale solar projects with 90 MW of capacity.

More: *Entergy*

Entergy Rates Lowered to Reflect Hurricane Cost Payoff

The Public Service Commission on Aug. 1 unanimously approved a rate reduction for Entergy that reflects the fact that the utility has recovered the costs of restoring service after hurricanes Katrina and Rita.

The reduction will take about $4.35 off the monthly bills of residential customers of Entergy Louisiana, who paid $99.98 for 1,000 kWh of electricity in July. It will trim about $2.57 off the monthly bills of residential customers in the area formerly served by Entergy Gulf States, who paid $90.26 for 1,000 kWh of power last month.

More: *The Advocate*

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STATE BRIEFS

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MAINE

Despite Subsidy, Biomass Plants Remain Offline

A quarterly performance report filed with the Public Utilities Commission by biomass generator Stored Solar shows that two of its plants have not produced power in four months.

The PUC in April voted to provide the wood-fired plants in West Enfield and Jonesboro with $1.2 million in state subsidies. A company official told the *Portland Press Herald* that low wholesale prices and values for renewable energy credits make operating the plants uneconomical.

More: *Portland Press Herald*

MASSACHUSETTS

Vineyard Wind Filing Shows Higher Rates

Vineyard Wind will deliver power from its offshore wind farm at an average price of 8.9 cents/kWh for 20 years, according to a contract it filed with the Department of Public Utilities on Aug. 1. The levelized price of power from the wind farm will be 6.5 cents/kWh.

The prices are higher than the average wholesale price of electricity in New England, which was 3.4 cents/kWh in 2017. Still, the administration of Gov. Charlie Baker said power from Vineyard Wind's project is very competitive with power from other types of generation and will result in slightly lower bills for the state's electric customers over the 20-year life of the company's contract.

More: *CommonWealth*

NEW MEXICO

Clean Energy Group Seeks Regulators' Recusal in PNM Case

A clean energy group on Aug. 2 asked the state Supreme Court to bar two utility regulators from ruling on Public Service Company of New Mexico's energy resource plan because the company's corporate parent donated $440,000 to a political action committee that campaigned for their re-election.

New Energy Economy had filed a motion in the case involving PNM's energy resource plan asking Public Regulation Commissioners Sandy Jones and Lynda Lovejoy to recuse themselves, but the commissioners rejected the motion.

More: *Santa Fe New Mexican*

NEW YORK

Regulators Reject Permit For Controversial CPV Plant

New York regulators on Friday refused to renew an air permit for Competitive Power Ventures' 680-MW Valley Energy Center, just weeks before the plant was expected to begin commercial operation. The Department of Environmental Conservation said in an Aug. 1 letter that it could not renew the plant's Air State Facility permit because it lacks a Title V Clean Air Act permit from EPA.

The company said the natural gas-fired plant was expected to finish testing within weeks. Its original state permit expired last Tuesday. "We remain committed to operating within all applicable operating permit requirements and look forward to working with the DEC to address any concerns they have," Tom Rumsey, senior vice president of external affairs at CPV, told reporters.

The plant has become an issue in the state's Democratic gubernatorial primary, with actress Cynthia Nixon, who is challenging Gov. Andrew Cuomo, joining fossil fuel opponents in a rally against the plant in April. It also figured in the felony corruption conviction of former Cuomo aide Joseph Percoco, who was convicted in March of accepting more than $250,000 from CPV through a $90,000-a-year "low show" job for his wife. Peter Galbraith Kelly, the CPV executive who arranged the job, pleaded guilty to a single count of conspiracy to commit wire fraud in May after jurors deadlocked on his case in March.

More: *Bloomberg*; *Times Union*

OHIO

Lake Erie Wind Farm Passes State Environmental Muster

The state Environmental Protection Agency has issued a water quality certificate of approval to Lake Erie Energy Development Corp. for its proposed Icebreaker Wind project, which would be the first freshwater offshore wind farm in North America.

The $126 million, 20.7-MW facility would initially have six turbines and be located 8 to 10 miles northwest of downtown Cleveland on Lake Erie.

More: *The Plain Dealer*

VERMONT

Utilities Call for Reduced Electricity Use During Heatwave

As the Northeast endures another heatwave, several of the state's utilities are asking customers to cut back their electricity use.

Vermont Electric Cooperative and Burlington Electric Department both sent notices to customers urging them to conserve energy during specific time periods: 4 to 9 p.m. Monday and Tuesday, and Monday afternoon and evening, respectively.

Forecasters expect temperatures to reach the 90s, and heat indexes the 100s, but no thunderstorms are expected.

More: *The Associated Press*; *WBTS*

VIRGINIA

Court Upholds Mountain Valley Pipeline's Water Certification

A three-judge panel of the 4th U.S. Circuit Court of Appeals on Aug. 1 upheld the state's water quality certification for the Mountain Valley Pipeline.

In its decision, the court rejected arguments by Sierra Club and other environmental groups that the State Water Control Board erred when it found a "reasonable assurance" that the natural gas pipeline would not harm streams and wetlands.

More: *The Roanoke Times*