RTO Insider

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CAISO Says Constrained Tx Contributed to Blackouts

Convergence Bidding, Under-scheduling also Major Causes, Report Says

By Hudson Sangree and Robert Mullin

A report on the causes of California's August blackouts details for the first time the role that convergence bidding played in masking tight supply and contends that constrained transmission prevented much needed imports from reaching the state.

The 107-page report to Gov. Gavin Newsom by CAISO, the California Public Utilities Commission and the state Energy Commission blames previously discussed causes, including extreme heat induced by climate change and inadequate resource planning. And it expands on the allegation, mentioned in passing at recent CAISO meetings, that load-serving entities failed to anticipate their needs when scheduling in the day-ahead market.

"We have identified several factors that, in combination, led to the need for the CAISO to direct utilities in the CAISO footprint to trigger rotating outages," the organizations wrote.

Constrained transmission into California exacerbated energy shortfalls during the rolling blackouts of Aug. 14-15, CAISO said.

"There was no single root cause of the outages, but rather, a series of factors that all contribut-

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PSPS Relief Funds Not Spent as Intended, CPUC Says (p7)

PG&E Under Scrutiny in Deadly Zogg Fire

Cal Fire Seizes Equipment in Investigation

By Hudson Sangree

California fire investigators are looking at a Pacific Gas and Electric distribution line as the possible cause of the Zogg Fire, which killed four residents and destroyed more than 200 structures southwest of Redding, Calif.

The 56,000-acre fire started on Sept. 27 near the rural Shasta County community of Igo. Among the victims were a 45-year-old mother and her 8-year-old daughter, who died trying to escape the flames.

A PG&E distribution line, the Girvan 1101 12-kV circuit, serves customers in the area of Zogg Mine Road and Jenny Bird Lane, where the fire began, PG&E said in an *incident report* to the California Public Utilities Commission on Friday.

Wildfire camera and satellite data on Sept. 27 showed "smoke, heat or signs of fire in that area between approximately 2:43 p.m. and 2:46 p.m.," it said.

"A PG&E SmartMeter and a line recloser serving that area reported alarms and other activity between approximately 2:40 p.m. and 3:06 p.m. [on Sept. 27], when the line recloser de-energized that portion of the circuit," PG&E said. "The data currently available to PG&E do not establish the causes of the activity on the Girvan 1101 circuit or the locations of these causes."

On Oct. 9, investigators with the California Department of Forestry and Fire Protection (CAL FIRE) told PG&E they had taken its equipment as part of their investigation of the

Continued on page 8

MISO Lays Out Seasonal Capacity Options

By Amanda Durish Cook

MISO resource adequacy staff are considering multiple options in the RTO's effort to implement a sub-annual capacity mechanism and define new reliability criteria.

MISO has said it could define unique seasonal system reliability requirements as a bulwark against its increasing emergency events outside summer months. The RTO's analyses indicate an emerging wintertime loss-of-load risk. MISO said it could be in the position of facing a winter peaking situation when electrification picks up in 2035 and beyond.

The shift could prompt MISO to issue a sub-annual reserves requirement based on a seasonal resource adequacy construct.

Stakeholders attending a virtual Resource Adequacy Subcommittee meeting Oct. 7 asked if MISO would run a Planning Resource Auction (PRA) four times per year.

MISO Director of Research and Development Jessica Harrison said several options are under consideration, including an annual construct that reflects sub-annual needs, one annual auction with seasonal or monthly seg-

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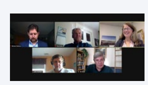

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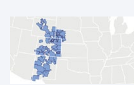

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In this week's issue

CAISO/West News

CAISO Adds Scarcity Pricing to Policy 'Roadmap'

By Hudson Sangree

CAISO said Wednesday it plans to begin a stakeholder initiative on scarcity pricing with an issue paper and formal start in January.

The planned measure is a response to the energy emergencies of August and September, which required CAISO to order rolling blackouts Aug. 14-15. The state avoided additional blackouts only through extraordinary conservation measures, including removing Navy ships from shore power.

Scarcity pricing had been part of the ISO's efforts to enhance its day-ahead market and extend the Western Energy Imbalance Market from a real-time to a day-ahead market. But the shortages caused a reassessment, Brad Cooper, the ISO's senior manager of market design policy, said during a web conference on the annual update to CAISO's three-year policy initiatives *roadmap*.

"Prompted by the conditions that occurred this summer, we're now planning a separate initiative that we're going to prioritize for next year that's going to explore enhancements to our scarcity pricing provisions," Cooper said.

"Recently FERC approved our … Order 831 compliance filing, which in some cases raises the bid cap to $2,000, but it does that in relationship to fuel costs," Cooper said. "Last summer, a lot of times, prices outside the ISO went above $1,000, and that was not driven by fuel costs but by scarcity conditions. Those events really drove home the need to improve our market pricing in those scarcity conditions."

In September, CAISO's Market Surveillance Committee recommended the ISO pursue a scarcity pricing initiative to deal with the types of severe shortfalls seen in mid-August and over Labor Day weekend. (See *CAISO MSC Urges Scarcity Pricing for Emergencies*.)

"The experiences of mid-August again signal the urgency of such an initiative," the committee said in its unanimous opinion, which it forwarded to the CAISO Board of Governors. "These conditions will likely grow more frequent, and the region is in need of a more coordinated approach to managing scarcity conditions."

Prices during the Western "heat storm" in August rose to $1,000/MWh or more and showed the need for higher-priced import offers during times of regional scarcity, the committee said. CAISO and market participants have noted that ICE prices for imported energy from neighboring states rose from $1,500 to $1,750 at the Palo Verde trading hub, which feeds into Southern California.

Scarcity pricing is triggered in markets when systems become so strained that reserve margins meant to protect the grid from collapse are threatened, as happened during the August blackouts.

A root cause analysis of the August blackouts by CAISO and other California agencies showed transmission constraints prevented ample, available imports from reaching the CAISO market and did not cite scarcity conditions. (See *CAISO Says Constrained Tx Contributed to Blackouts*.)

Cooper said he hopes to see an issue paper released soon after Jan. 1.

"We haven't worked out the detailed schedule yet, but that's our goal," he said.

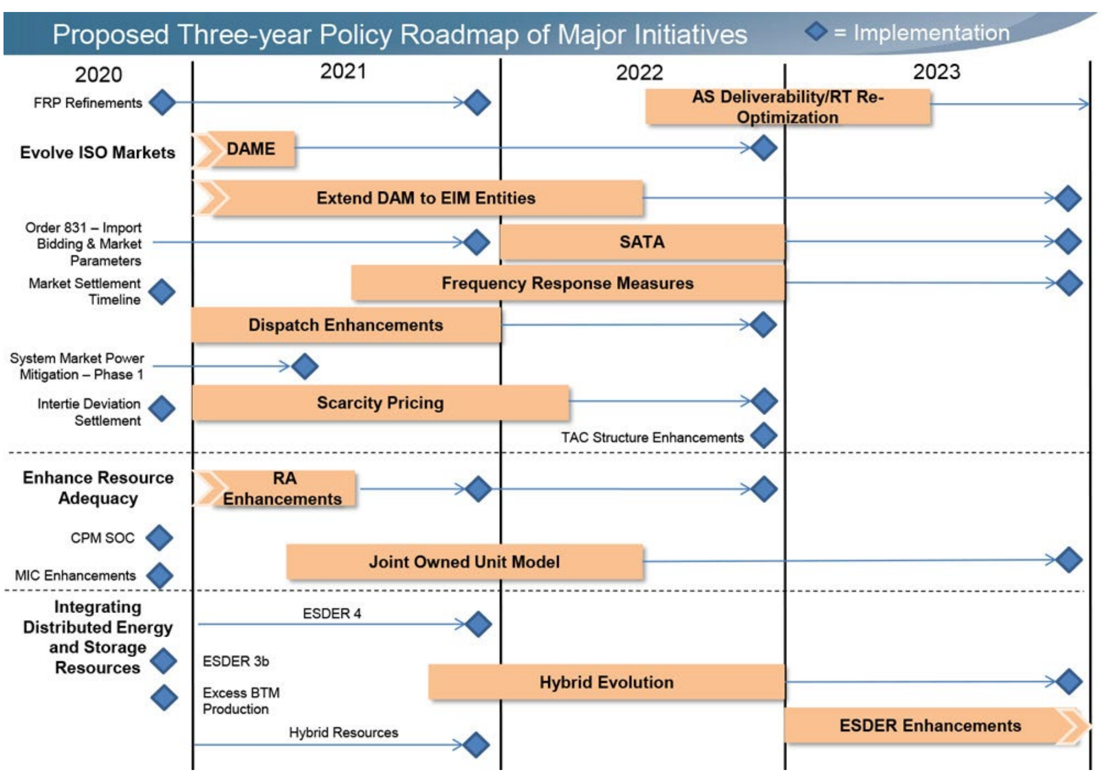
Other major initiatives in the roadmap include resource adequacy enhancements, day-ahead market enhancements and an effort to the extend the Western Energy Imbalance Market from a real-time to a day-ahead market.

All three could help CAISO meet its reliability issues as it switches from a market largely dependent on natural gas generation to one that plans to meet its capacity requirements through renewable energy and storage, ISO staff members said during the web conference.

A high priority is addressing the state's summer evening net demand peak, after solar power goes offline but demand remains high during heat waves. The energy emergencies of August and September occurred under such conditions.

"A robust RA program is critical to ensuring reliable resources are procured with the right operational attributes and are available to the CAISO in order to serve load in all hours," said Lauren Carr, an infrastructure and regulatory policy specialist with the ISO who presented the RA initiative.

The 2021 roadmap of policy initiatives is expected to go before the Western EIM Governing Body and the CAISO Board of Governors in December. ■



Scarcity pricing will be part of CAISO's policy roadmap come January. | *CAISO*

CAISO/West News

CAISO Says Constrained Tx Contributed to Blackouts

Convergence Bidding, Under-scheduling also Major Causes, Report Says

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ed to the emergency."

The rolling blackouts were the first to sweep the state since the energy crisis of 2000-2001. Over two days, about 812,600 households — representing about 2.4 million people — lost power.

Outmoded RA Planning

In an expected finding, CAISO said the state was unprepared to meet the extreme Western heat wave of Aug. 14-19 and that resource planning now must assume there will be similar events caused by climate change.

During the mid-August "heat storm," California experienced four out of the five hottest August days since the ISO and the CEC began tracking such data in 1985, the report said. The organizations use an average daily temperature composite to predict electricity consumption across the CAISO region.

"Current resource adequacy planning standards are based on a one-in-two peak weather demand plus a 15% [planning reserve margin] to account for changing conditions," the report said.

But the August heat wave was a one-in-35-year event "not anticipated in the planning and resource procurement time frame, which is necessarily an iterative, multiyear process." The state needs more supply resources, including battery storage for wind and solar, and must use new planning criteria for long-term projections, it said.

The rolling blackouts were made worse by transmission constraints and other causes, but "it is unlikely that current RA planning levels would have avoided rotating outages" under the same conditions, even without those contributing factors, it said.

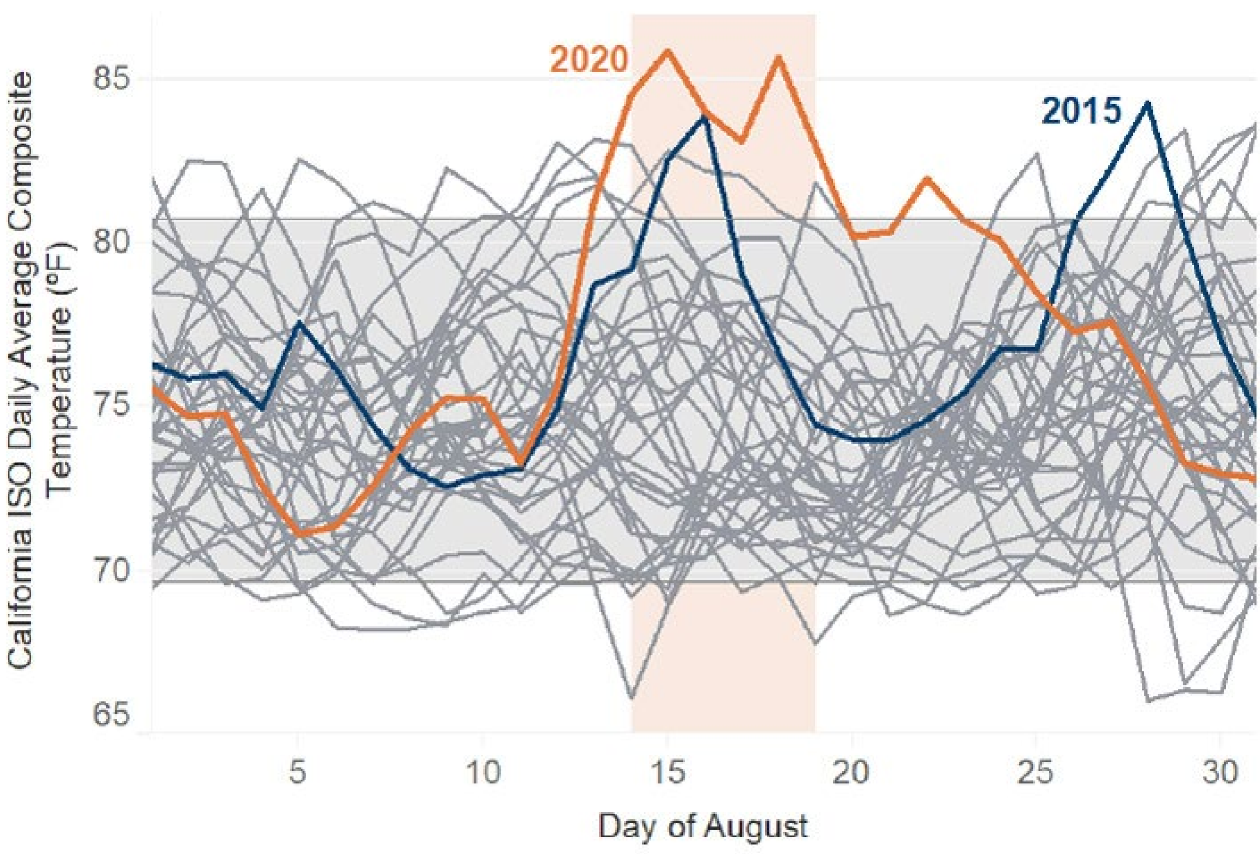
Constrained Supply

Import bids in the day-ahead market were 40 to 50% (2,600 to 3,400 MW) higher during the August energy emergency than typical RA requirements from imports in August, but the output couldn't get where it need to go, the organizations said.

"Despite this robust level of import bids, transmission constraints ultimately limited the amount of physical transfer capability into the CAISO footprint," the report said.

A major transmission line in the Pacific Northwest upstream from CAISO was on forced outage because of weather conditions, and the California Oregon Intertie (COI) was derated, the report said.

"The derate reduced the CAISO's transfer capability by approximately 650 MW and caused congestion on usual import transmission paths across both COI and Nevada-Oregon Border," it said. "In other words, more imports were available than could be physically delivered, and the total import level was less than the



The 2020 heat storm was a one-in-35-year event, the California Energy Commission said. | *CEC*

CAISO/West News

amount the CAISO typically receives."

Under-scheduling

CAISO said LSE scheduling coordinators "collectively under-scheduled their demand for energy by 3,386 MW and 3,434 MW below the actual peak demand for Aug. 14 and 15, respectively."

During the net peak — the hours after solar goes offline but demand remains high on hot days — LSEs under-scheduled demand by 1,792 MW for Aug. 14 and 3,219 MW for Aug. 15, the ISO reported. The blackouts on those days occurred in the net-peak hours.

"The under-scheduling of load by scheduling coordinators had the detrimental effect of not setting up the energy market appropriately to reflect the actual need on the system and subsequently signaling that more exports were ultimately supportable from internal resources," the report said.

CAISO said its own peak forecasts were 825 MW below actual demand for Aug. 14 and 559 MW above actual demand for Aug. 15. Its forecasts for the net demand peak times were 511 MW and 632 MW above actual demand.

But during the mid-August events, "it was difficult to pinpoint these contributing causes because processes that normally help set up the market masked the under-scheduling," the report said.

One of the processes was convergence bidding, a financial hedge that some observers believed could have been used to game the market.

"As the name suggests, convergence bidding is intended to allow bidders to converge or moderate prices between the day-ahead and real-time markets," the report said. "Under normal conditions, when there is sufficient supply, convergence bidding plays an important role in aligning loads and resources for the next day. However, during Aug. 14 and 15, under-scheduling of load and convergence bidding clearing net supply signaled that more exports were supportable."

"Once this interplay was identified on Aug. 16 after observing the results for trade day Aug. 17, convergence bidding was temporarily suspended for Aug. 18 trade date through the Aug. 21 trade date," it said.

During those days, when conditions remained much the same as Aug. 14-15, further blackouts were averted.

RUC Flaw

The report also delved into complications stemming from a flaw in CAISO's residual unit commitment (RUC) process. The ISO runs the RUC after the day-ahead Integrated Forward Market (IFM) process to avoid real-time supply shortages in rare cases when LSEs under-schedule demand.

The report notes that inputs into the RUC process differ from the outputs of the IFM in three ways:

- Load cleared in the IFM is replaced by CAISO's own day-ahead forecast, which does not include exports.
- Wind and solar schedules cleared in the IFM are replaced by CASO's wind and solar forecasts.
- Virtual supply and demand that cleared in the IFM's convergence bidding market are removed.

The RUC itself consists of two passes: a scheduling run intended to address any unresolved market constraints based on "an intricate but prescribed set of relative priorities" for relaxing the constraint or curtailing schedules; and a pricing run to produce prices that align with both the $1,000/MWh bid cap and the scheduling run.

To ensure that schedules produced by the IFM are physically feasible, the RUC process enforces a power balance constraint to ensure that forecast load can be met in real time.

In 2014, CAISO implemented the Pricing Inconsistency Market Enhancement (PIME) to address inconsistencies between schedules and prices. PIME redirected both the IFM and the RUC to use pricing run results as the source of both prices and schedules.

"Through these RUC constraints, the CAISO determines what portion of the day-ahead schedules are physically feasible and which portion that market participants should tag when the E-Tag is submitted in the day-ahead," the report said.

After the Aug. 14 and 15 blackout events, CAISO determined that rather than reducing the volume of infeasible exports scheduled in the IFM, the RUC pricing run instead relaxed the power balance constraint, compromising the ISO's ability to meet actual load. But the ISO found that the RUC's scheduling run (no longer used to set final schedules) would have relaxed the IFM's scheduled exports before relaxing the power balance constraint.

As a result, CAISO said it stopped using the PIME functionality in its RUC process beginning Sept. 5, allowing it to use scheduling run results for RUC schedules rather than pricing run results. ■

CAISO/West News

9th Circuit Vacates FERC Orders in PG&E PPA Dispute

Ruling Fails to Address Issues Leading to Jurisdictional Row

By Robert Mullin

The 9th U.S. Circuit Court of Appeals on Wednesday vacated two FERC orders that last year threatened to force a jurisdictional standoff with the federal judge overseeing Pacific Gas and Electric's bankruptcy. The court also vacated an order by the bankruptcy court but declined to resolve the issues at the heart of the dispute.

The conflict goes back to the onset of PG&E's Chapter 11 proceeding, in January 2019, when FERC issued two declaratory orders saying it shared authority with the U.S. Bankruptcy Court over any of the $42 billion in power purchase agreements that PG&E might seek to modify in bankruptcy (EL19-35, EL19-36). (See *FERC Claims Authority over PG&E Contracts in Bankruptcy*.)

As part of its bankruptcy filing, PG&E had asked bankruptcy Judge Dennis Montali to issue an injunction confirming his court's exclusive jurisdiction over the utility's rights to alter or reject PPAs and other FERC-related agreements.

The issue arose after NextEra and Exelon petitioned FERC for declaratory orders against PG&E because of concern that PG&E would try to get out of high-cost contracts it had signed with owners of solar, wind and other renewable electricity sources.

FERC acknowledged that the law over conflicts between the Federal Power Act and the Bankruptcy Code was unclear. The commission staked out a compromise position asserting that the commission and courts held "concurrent jurisdiction" over PPAs in cases such as PG&E's.

Montali initially took a cautious approach to the jurisdiction issue, asking FERC's and PG&E's attorneys to reconcile their differences over the matter. But once that effort failed, the judge issued a declaratory judgement stating that FERC had no authority over the contracts and that PG&E did not need commission approval to reject any of them. (See *'FERC Must be Stopped,' PG&E Bankruptcy Judge Says*.)

The dispute became a moot point in the Chapter 11 proceeding when PG&E chose to honor all PPAs with its suppliers.

Clearing the Path

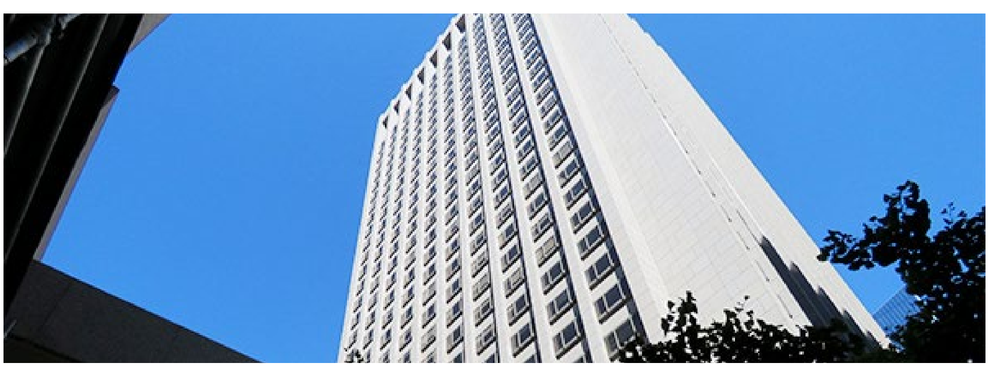
The 9th Circuit's *ruling* addressed two petitions: one from PG&E to review FERC's declaratory orders and another from FERC to review Montali's declaratory judgement.

"The orders all involved the same question: whether a Chapter 11 debtor can cease performing under its wholesale power contracts with the approval of the bankruptcy court, or whether FERC's consent is also needed," the three-judge panel wrote.

"We need not — and cannot — reach the merits of this dispute, because the cases became moot when the bankruptcy court confirmed a reorganization plan requiring PG&E to assume, rather than reject, the contracts at issue," the court found.

The one remaining question: How to treat the "unreviewed" orders?

The judges moved to vacate all three, applying the rule set forth in *Munsingwear v. United States*, which holds that "[w]hen a case becomes moot on appeal, the 'established practice' is to reverse or vacate the decision below with a direction to dismiss." That decision "clears the path" for any future relitigating of the issues, preserving the rights of all parties involved while prejudicing none of them "by a decision which ... was only preliminary."



PG&E headquarters in San Francisco | © *RTO Insider*

The judges noted that all parties involved in PG&E v. FERC agreed the court should vacate the bankruptcy court's declaratory judgement. However, FERC and the power suppliers protested giving similar treatment to the commission's orders, asking that they remain in place.

"FERC and the intervenors point out that PG&E proposed assuming the power contracts in the reorganization plan ultimately confirmed by the bankruptcy court. They argue that PG&E's involvement in this process renders vacatur inappropriate," the judges noted.

But the court disagreed, saying the circumstances justified vacatur even though PG&E had a hand in mooting its own petition in the matter.

"Importantly, the company did not intend to circumvent our review of FERC's orders. … Rather, PG&E twice moved for expedited consideration of these cases so that we could resolve them prior to resolution of the bankruptcy proceedings," the 9th Circuit found. "The company also urged us to hear the cases over FERC's related ripeness arguments."

The court went on to point out that PG&E's actions to moot Montali's order were in part attributable to "coercion" by the state of California, which required the utility to reach a bankruptcy plan by June 20 in order to become eligible to draw on the state's $21 billion wildfire liability fund.

The court also found that vacating FERC's unreviewed orders would prevent the orders from having an adverse impact on PG&E or any other utility in the future.

"At the heart of these cases lies a dispute concerning FERC's powers over contract performance, including a question of what constitutes a rate change under the filed-rate doctrine and Federal Power Act," the court wrote. "These issues could well arise outside of bankruptcy. While the orders are declaratory, and we cannot say with certainty how they might affect PG&E or others, we think the better course is to eliminate that concern."

The court held that its decision did not express any opinion on the merits of the dispute and should not harm FERC, "as it can easily reassert its position in future proceedings." ■

PSPS Relief Funds Not Spent as Intended, CPUC Says

Millions Meant for At-risk Customers May Have Gone to Wealthier Homeowners

By Hudson Sangree

Portable solar and batteries are meant to help medically vulnerable customers during power shutoffs under the state's SGIP program. | *Edison International*

A big part of $612 million intended to provide battery backup to homes in high fire-threat areas has been gobbled up by customers who use electricity to pump well water instead of helping the low-income and medically vulnerable residents it was meant for, the California Public Utilities Commission said Thursday.

The CPUC approved $830 million for its *Self-Generation Incentive Program* (SGIP) in January, with $612 million dedicated to "equity" and "equity resiliency" subsidies to aid residents who face repeated public safety power shutoffs (PSPS) by utilities to prevent wildfires. Thousands of the program's targeted customers rely on electrically powered medical equipment to keep them alive. (See *California PUC Devoting $1.2B to Self-generation*.)

In its decision, the CPUC authorized investor-owned utilities to collect $166 million annually from ratepayers from 2020 to 2024. However, the commission did not include income criteria for the well-pump grants, which are part of the program, nor did it prevent customers from applying for funds for their vacation homes.

"We were seeing some second-home residents" receive the hefty grants, which pay the full cost of battery storage and solar cells to charge the units, said Commissioner Clifford Rechtschaffen.

The program's "very clear focus was on helping the most vulnerable customers and communities in high fire-threat areas and ones that had been affected by multiple PSPS events," Rechtschaffen said. "In particular, we targeted medical baseline customers, low-income customers and critical care facilities in disadvantaged communities."

"The program provides very, very generous subsidies," he said.

More than eight months after the decision took effect, with one of California's worst fire seasons in full force, the state's three large investor-owned utilities haven't started reaching out to medically vulnerable customers, Rechtschaffen said.

Instead, developers of storage systems have targeted households with wells, regardless of income, and scooped up much of the funding that was supposed to last through 2024.

Commissioner Martha Guzman Aceves said an informal analysis by her staff showed that only a small percentage of the storage contractors were licensed by the state.

Pacific Gas and Electric has already committed its $270 million share of the multi-year program and has hundreds of customers on a waiting list, Rechtschaffen said. Southern California Edison and San Diego Gas & Electric have doled out 50% and 60% of their shares, respectively, he said.

Half the applications have been for well-pump programs, while 30% have been for medically vulnerable customers, he said.

In his *proposed decision*, Rechtschaffen wrote that "if current trends continue, incentive awards to electric-pump … customers threaten to severely limit the … funds available to the many other types of eligible residential and non-residential customers."

He proposed adopting income eligibility criteria for grants that haven't already been funded, requiring households to show they fall below 80% of an area's median income and that a well provides water for their primary residence.

"Requiring electric-pump well customers to meet the same income eligibility restrictions required of most other …. residential customers levels the playing field and helps ensure that other types of customers with critical resiliency needs have the opportunity to use equity resiliency budget funds," he wrote.

The decision would apply the new criteria to grants that were submitted but not fully funded as of Aug. 17, when Rechtschaffen issued a letter advising utilities of the commission's concerns.

Several commissioners expressed unease about applying new rules retroactively to those who have already filed for funding.

"We evidently made a serious omission" in not restricting the funds based on income, said Commissioner Genevieve Shiroma. But "to now go back and say, 'Oops,'" and change the rules for pending applications, "I'm very uncomfortable with that," she said.

CPUC President Marybel Batjer said she shared her colleagues' worries about retroactivity but believes the program must be fixed.

"I'm very concerned about the equity program and it being oversubscribed so quickly when this was [planned] to be a three-year rollout," Batjer said. "On balance, I think we have to address it. And I agree, Commissioner Rechtschaffen, with your assessment, but I do feel we need more consideration on this item."

The commissioners voted unanimously to put off a decision until their next meeting on Oct. 22 so they could gather more information and weigh their options. ■

CAISO/West News

PG&E Under Scrutiny in Deadly Zogg Fire

Cal Fire Seizes Equipment in Investigation

Continued from page 1

Zogg Fire, PG&E said.

"PG&E is cooperating with CAL FIRE in its investigation," the utility said. "This information is preliminary."

CAL FIRE has not yet determined how the fire started, PG&E noted.

Involvement in another major fire would mark the fourth year in a row that PG&E equipment has been blamed for highly destructive conflagrations. Its equipment started the worst fires of the October 2017 "fire storm" in Napa and Sonoma counties and the November 2018 Camp Fire, which killed 85 people and destroyed the town of Paradise.

The company emerged from bankruptcy in June after agreeing to pay fire victims, local governments and insurers $25.5 billion in the 2017-18 fires and pleading guilty to 85 felonies stemming from the Camp Fire. (See *PG&E Sentenced; Bankruptcy Plan Approved*.)

CAL FIRE also determined that a PG&E transmission line started the Kincade Fire, which tore through Sonoma County wine country in October 2019.

The company has avoided blame so far for any of the major wildfires of 2020, one of the worst fire seasons on record. A series of massive fires sparked by lightning on Aug. 17-18 includes the August Complex, the first California wildfire to exceed 1 million acres. It was 67% contained as of Sunday, state and federal fire officials said.

In total, more than 8,000 wildfires have burned nearly 4 million acres in California this year.

Until Friday's report — which PG&E also sent to the U.S. Securities and Exchange Commission — only one other investor-owned utility in California had fallen under suspicion for starting a major fire in 2020. (*Calif. IOUs Escape Blame for Fires so Far*.)

In a Sept. 15 *report* to the CPUC, Southern California Edison said the U.S. Forest Service had asked the utility to remove a section of its overhead conductor as part the agency's investigation of the Bobcat Fire, still burning in the mountains and foothills northeast of Los Angeles.

SCE said it had experienced a "relay operation" on the 12-kV circuit at approximately the same time and in the same place as the fire started, but it contended that a fire camera had recorded smoke from the blaze prior to the incident.

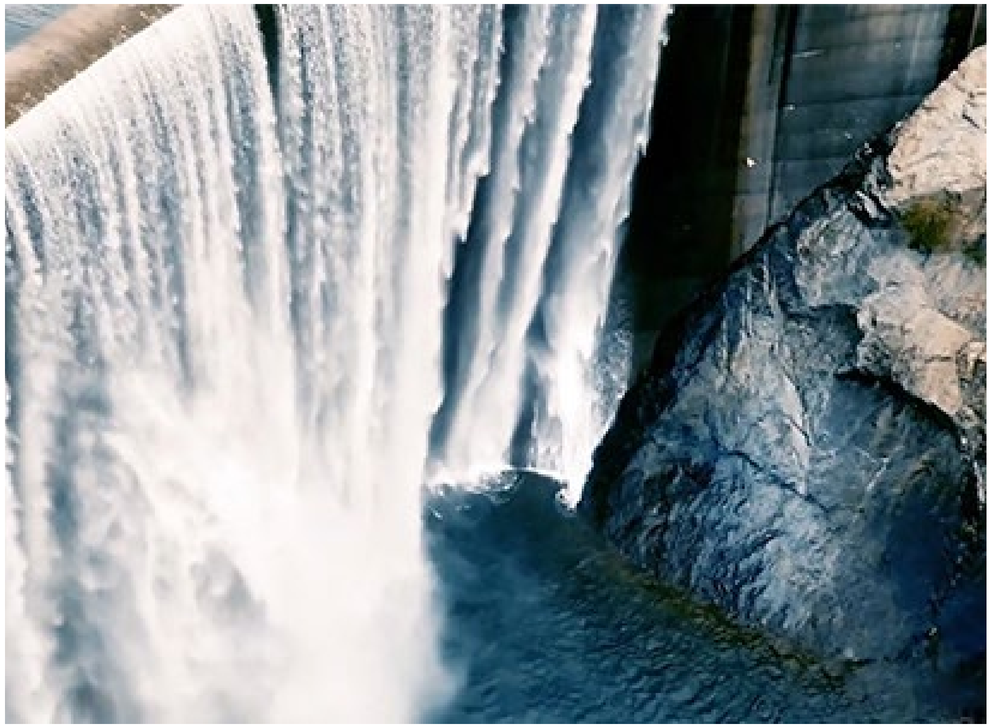
"While USFS has not alleged that SCE facilities were involved in the ignition of the Bobcat Fire, SCE submits this report in an abundance of caution given USFS' interest in retaining SCE facilities in connection with its investigation," the utility told the CPUC. ■

Searchers indentified at least four sets of human remains in the Zogg Fire. | *Shasta County Sheriff's Office*

ISO-NE News

NEPOOL Markets Committee Briefs

Amendments on DDBT for FCA 16 Fall Short



Hydro-Québec Dam | *Hydro-Québec*

The New England Power Pool Markets Committee last week rejected ISO-NE's *proposal* for recalculating the dynamic delist bid threshold (DDBT) for Forward Capacity Auction 16, along with several proposed amendments to the RTO's plan, none of which attracted the necessary 60% for endorsement.

The DDBT issue consumed half of the first day of the committee's three-day meeting.

The DDBT for FCA 15 for 2024/25 is $4.30/kW-month. The Tariff requires the threshold, which was last updated in 2017/18, be recalculated for FCA 16 (2025/26).

The RTO proposed recalculating the DDBT annually using publicly available data, saying it would address transparency concerns and keep the threshold aligned with current and expected market conditions.

It would make the DDBT the average of the preceding FCA price and the price the capacity that cleared in the preceding FCA intersects with the estimated system-wide demand curve for the upcoming FCA. The threshold would not exceed the net cost of new entry (CONE) or fall below 75% of the preceding FCA price; the net CONE limit would apply if the two overlapped.

Jeffrey Bentz, director of analysis for the New England States Committee on Electricity (NESCOE), expressed concern in his *presentation* that setting the DDBT too high or at net CONE could improperly allow some bids to escape the scrutiny of a market power review. NESCOE proposed lowering the upper bound to 85% of net CONE or 125% of the prior auction clearing price, saying it would strike a better balance between the design objectives of providing adequate review to prevent market power and limiting unnecessary administrative interference.

NESCOE also proposed limiting the maximum rate of change in the DDBT from auction to auction to 30% of net CONE.

In a *memo* to the committee, ISO-NE's Matthew Brewster wrote that NESCOE's proposals would "constrain the DDBT value relative to the [RTOs'] proposal under various conditions, which could undermine this key enhancement achieved with the new DDBT calculation method. … By preventing the DDBT from adjusting to reflect projected market conditions for the next FCA, the amendments would cause the DDBT to remain a lagging, or 'stale' estimate of the appropriate delist bid review threshold."

The memo also said that "while NESCOE suggests a one-directional remedy within the DDBT for (potential) errors" in net CONE, it does "not appear to provide a reasoned basis for the numerical value of the proposed cap at 85% of net CONE." Additionally, NESCOE's other proposed DDBT cap of 125% of the last FCA clearing price "has only a superficial symmetry with the floor present in the ISO's design.

"The underlying assumption of this 125% cap is that the supply curve becomes flat at prices 25% higher than the last FCA clearing price," the memo continued. "However, that outcome is not supported by theory … nor is it plausible in practice. The supply curve generally is increasingly steep as quantity increases (up to the point where prices reach true net CONE)."

The NESCOE amendments failed with only 34% support.

The committee also rejected proposals by Calpine and Vistra Energy's Dynegy unit to address what Bill Fowler, president of Sigma Consultants, said is the disadvantage faced by resource owners having to lock in static delist bids four months before the FCA.

At the September Markets Committee meeting, Fowler said the DDBT should be set at a "reasonable margin" — 50 cents to $1/kW-month — above the expected clearing price. (See "Change to Delist Bid Threshold," *ISO-NE Challenged on Wind, Solar, Storage Revenues*.) Fowler revised the *proposal* last week, calling for "a small cushion" varying with the level of the expected clearing price, declining to zero if the expected clear is at net CONE. It won only 49% support.

Also rejected was a Calpine/Dynegy proposal to eliminate the obligation to commit to a bid price in October and make the October static delist finalization requirement a cap on auction prices.

ISO-NE's proposed DDBT changes, the last vote, received only 44.5%. The RTO will file the proposal with FERC despite the lack of stakeholder endorsement.

Support for Forward Reserve Market Sunset

On a voice vote, the committee approved ISO-NE's *proposal* to sunset the forward reserve market (FRM) to avoid conflicts with its proposed Energy Security Improvements (ESI) initiative, which is awaiting FERC action.

ISO-NE News

(See *ISO-NE Sending 2 Energy Security Plans to FERC*.)

The FRM awards obligations for 10-minute non-spinning reserves and 30-minute operating reserves, but the RTO said it is becoming unnecessary because of ESI and transmission investments and market changes that address locational constraints and reward resource flexibility.

The RTO's proposal included two alternatives. If FERC issues an order approving ESI as filed before Dec. 31, the RTO will file a "non-contingent" Tariff change by the end of 2020 to sunset the FRM on June 1, 2025, coinciding with the start of the 2025/26 capacity commitment period.

If FERC does not rule on ESI before the end of the year, the RTO would file a "contingent" FRM sunset that would take effect if FERC approves ESI as filed.

If FERC rejects ESI, the RTO will not file either Tariff change. The RTO said future discussions with stakeholders on reserves might be necessary if this is the eventual outcome.

The RTO plans a vote by the Participants Committee in November.

RTO Seeks Modifications for EERs, RAs

Ryan McCarthy of ISO-NE *presented* proposed modifications to the qualification process for energy efficiency resources (EERs) to better account for expiring measures. The RTO also wants to change the monthly reconfiguration auction (RA) and bilateral qualification rules to better account for new financial assurance and performance accounting rules.

The proposal would set the seasonal qualified capacity to the lower of the amount of capacity that has cleared as "new" in prior FCAs or the amount of measures marked commercial plus FCA cleared non-commercial MWs on critical path schedule (CPS) monitoring. The proposed methodology would apply to both the FCA and all annual RA qualifications.

An EER will have two years from the start of the commitment period in which it first received a capacity supply obligation to install its measures. Previously cleared EERs will have until May 31, 2027, to install all measures.

As additional EE clears in the FCA, the capacity will be factored directly into the load reconstitution process. The RTO said the proposal will better align qualified capacity with its performance capabilities.

The RTO would assign monthly qualification to resources that become commercial during the capacity commitment period. The monthly qualification will track delayed commercial resources and allow non-commercial capacity to participate in monthly RAs and bilateral qualifications.

The Markets Committee will vote on the proposals next month. EER qualification changes would become effective in February 2021 for FCA 16. The monthly qualification changes would become effective in January 2022 and implemented for the March 2022 monthly reconfiguration auction and bilateral qualification period.

CCP	SOI MW	Com. MW (A)	Non-Com. MW (B)	QC 'Cap' (C)	Seasonal QC Min(A+B, C)
CCP 13	30 MW			30 MW	30 MW
CCP 14		5 MW	25 MW	30 MW	Min(5+25,30) **30 MW**
CCP 15		35 MW	0 MW	30 MW	Min(35+0,30) **30 MW**
CCP 16		28 MW	0 MW	30 MW	Min(28+0,30) **28 MW**
CCP 17		21 MW	0 MW	30 MW	Min(21+0,30) **21 MW**

The proposed methodology by ISO-NE is expected to increase energy efficiency qualification values. | *ISO-NE*

GIS Working Group to Consider Mass. Clean Generation' Changes

The MC agreed to direct the Generation Information System (GIS) Operating Rules Working Group to consider changes to the GIS and the GIS Operating Rules to reflect the addition of "Clean Existing Generation" (CES-E) to the *Massachusetts Clean Energy Standard*. The changes were requested by the Massachusetts Department of Environmental Protection.

NEPOOL counsel Paul Belval of Day Pitney said in a *memo* that DEP revised its regulations to include a requirement that retail load-serving entities subject to the standard have a certain percentage of energy from "Clean Existing Generation Units."

Clean existing generation units are nuclear or hydroelectric units with a nameplate capacity of at least 30 MW that began commercial operation before Jan. 1, 2011, and satisfy specific geographic requirements. In addition to adding a new category in the GIS, the DEP regulations pose two additional rule changes. Multiple co-located GIS generators could have their generation aggregated, and certain annual caps on qualifying output would have to be allocated among those GIS generators. Also, certain generators in Newfoundland and Labrador could be eligible. That would require a slight expansion of the area where qualified generators can receive unit-specific certificates in the GIS.

The committee is not being asked to vote on any changes to GIS rules, the memo said, but should refer issues to the working group to discuss and determine potential rule revisions.

Order 841 Compliance Update

Jennifer Wolfson of ISO-NE *updated* the committee on the RTO's plan for responding to an Aug. 4 FERC order on the RTO's second Order 841 compliance filing. (See *FERC OKs Most of ISO-NE 2nd Storage Compliance*.)

The RTO proposes Tariff changes to comply with two FERC directives. The first change would address FERC's concern that the Tariff language preventing double payment for charging energy at the retail and wholesale levels would allow host utilities to decide whether an electric storage resource (ESR) may participate in its markets. It would be effective in the first quarter of 2021.

The second responds to FERC's directive that the Tariff include the bidding parameters the RTO will use to account for the state of charge and duration characteristics in the day-ahead energy market. It would be effective Jan. 1, 2026.

The RTO will seek votes on the proposed revisions at the committee's next gathering on Nov. 9-10 and at the Participants Committee's Dec. 3 meeting. ■

— Jason York

ISO-NE News

NEPOOL Debates Parameters for 2025/26

Stakeholders, ISO-NE Differ on Figures, Approaches

By Jason York

The NEPOOL Markets Committee last week debated 13 amendments to proposed updates to parameters for Forward Capacity Auction 16 (2025/26).

Many of the amendments, which were discussed during the last half of the committee's Oct. 6-8 virtual meeting, challenged revenue figures proposed by *Concentric Energy Advisors* (CEA) and *Mott MacDonald*, two consulting firms hired by ISO-NE to update the FCM parameters.

Deborah Cooke, the RTO's principal analyst for market development, *presented* responses to stakeholder questions about updates to the net cost of new entry (CONE) and offer review trigger prices (ORTPs).

The discussions continued a debate from the committee's September meeting and previewed votes scheduled for November. (See *ISO-NE Challenged on Wind, Solar, Storage Revenues*.)

Face-off on Offshore Wind

Abby Krich and Alex Worsley of Boreas Renewables presented four amendments on behalf of RENEW Northeast, *including* capital costs and the investment tax credit for the ORTP calculation for offshore wind. A capacity offer below the ORTP triggers a unit-specific review by the Internal Market Monitor to verify the resource's cost.

RENEW said the RTO's proposal to use \$5,876/kW (2019\$) for the overnight capital cost of OSW and assumption of a 12% tax credit results in an ORTP of \$39.17-39.38/kW-month, which RENEW believes is double the actual cost. RENEW has proposed using a lower overnight capital cost of \$3,000/kW (2019\$) and a higher tax credit of 18%.

Krich said \$3,000/kW is a reasonable, middle-of-the-range estimate of expected costs for OSW projects in New England. A capital cost of up to \$3,200/kW would still result in an ORTP of \$0.

CEA *said* the RENEW analysis is "inappropriate," and its estimated ranges should be revised upward. CEA challenged RENEW's use of data from European and Chinese projects.

Krich told *RTO Insider* after the meeting that ISO-NE's cost was accurate "8-10 years ago,"

The Block Island Wind Farm, off Rhode Island | *Block Island Ferry*

ISO-NE News

but they are no longer appropriate.

'More Reasonable' EAS Revenues

Ben Griffiths, an energy analyst for the Massachusetts Attorney General's Office, offered a *summary memo* and *presentation* that outlined "a straightforward optimization model to more reasonably estimate" energy and ancillary services (EAS) revenue available to a storage device. Griffiths said the AG's model produces "an operational schedule for storage that maximizes revenues" from participation in three of the RTO's markets — energy, 10-minute spinning reserves and regulation — while respecting the storage device's technical limitations.

Griffiths added that the AG disagrees about the "reasonableness of the CEA EAS revenue estimates for battery storage resources."

A reasonable operator using a battery for energy, reserves and regulation should be able to earn $54.87/kW-year, assuming the Forward Reserve Market (FRM) sunsets, and $59.11/kW-year, assuming the FRM is maintained, Griffiths wrote. CEA's contrasting estimates average EAS revenue from these three markets at $45.71/kW-year with an FRM sunset and $55.26/kW-year assuming it is maintained." (See "Support for Forward Reserve Market Sunset," *NEPOOL Markets Committee Briefs: Oct. 6-8, 2020*.)

Griffiths said these revenue estimates are "conservative" and the AG's office "fully expects that more advanced dispatch schemes could yield higher revenues."

NEPGA Proposes Amendments on Amortization Period, Owner's Cost

The New England Power Generators Association (NEPGA) *proposed* changing the amortization period for the net CONE reference unit (a GE 7HA.02 gas-fired combustion turbine) to 15 years from 20 years. NEPGA's Bruce Anderson said the 20-year amortization period fails to reflect the risks faced by developers, which creates "a finite period concluding in economic obsolescence." There is "no evidence that the reference unit would be able to sustain its annual cash flows in real dollar terms for 20 years," he added.

Anderson said NYISO recently reduced its reference unit's economic life to 17 years to recognize the potential impact of New York state law and policy. In New England, most states have renewable portfolio standards requirements that involve the procurement of energy from non-carbon-emitting resources.

Additionally, NEPGA put forth an *amendment* that would take a "bottom's up approach" to the owner's cost. NEPGA proposes $12.45 million in owner's cost — almost five times Mott McDonald's $2.5 million estimate, which Anderson said is "woefully inadequate" to cover the known owner's costs, let alone any contingencies.

NEPGA said its figure takes into account initial screening studies and work sufficient to qualify for the FCA and obtain a capacity supply obligation (CSO), plus activities necessary to install the equipment, interconnect it and ensure successful commercial operation. NEPGA said it ignored costs associated with electrical interconnection, network upgrades, gas interconnection, gas pipeline upgrades, initial fuel inventory and financing costs, while Mott McDonald said its estimate captured these activities and contingencies.

At NEPGA's request, CEA and Mott McDonald *updated* their dispatch to include seasonal intraday fuel price premiums ranging from 4% in summer to 20% in winter.

NEPGA had asked for time on the agenda to amend the net CONE proposal to include an intraday premium in the event CEA and Mott McDonald chose not to account for it in their updated modeling. NEPGA said it will evaluate the consultants' proposed intraday premium accounting and could bring forward an amendment at the November committee meeting.

NESCOE Amendments Look at Reference Unit, PfP

While NEPGA sought to shorten the reference unit's assumed life, NESCOE said it should be increased. NESCOE's *two amendments* would boost the useful economic life of the reference unit to 25 years and escalate pay-for-performance (PfP) revenues to account for inflation.

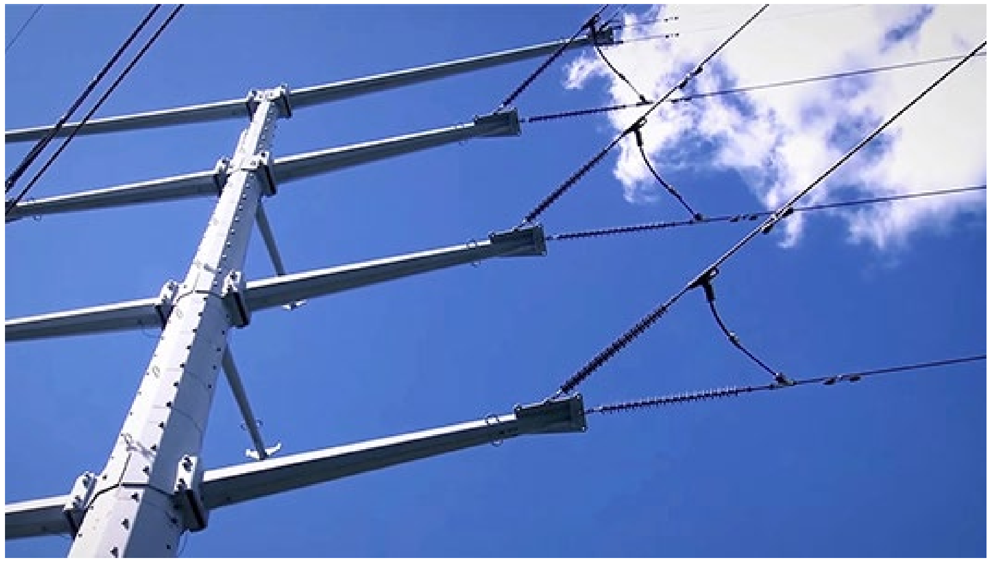
NESCOE proposed that the net CONE resource should be increased to reflect the expected economic life of the reference unit and that PfP should be increased for inflation, reflecting the recalculation of the performance payment rate (PPR) every three years. There are no corresponding Tariff language revisions since these amendments are changes to input assumptions in the analysis.

Calculating net CONE using a 25-year life for the resource reflects a better balance between the physical life of these facilities and a reasonable expectation of their economic life, NESCOE said. The estimated reduction in net CONE is $0.63/kW-mo. Adjusting PPR revenues for inflation is more consistent with the treatment of other revenues with an estimated reduction in net CONE of $0.12/kW-mo., it added. ■

MISO News

ATC Shifts to MISO Allocation Model for Tx Upgrades

By Amanda Durish Cook



| American Transmission Co.

After years of using its own generator interconnection cost allocation method, American Transmission Co. will transition to MISO's after FERC last week gave the company its approval.

ATC's revision will apply to the 2020 cycle of generators interconnecting to its system, or any interconnection request submitted on or after April 29, 2019 (*ER20-2619*).

MISO currently allocates 90% of necessary transmission upgrades above 345 kV to the generator and 10% to load on a systemwide basis. Costs for upgrades rated below 345 kV are 100% assigned to the generator.

In 2006, MISO adopted a reimbursement approach where 50% of a generator's network upgrade costs would be repaid to the interconnection customer through credits against transmission service charges, if the customer could prove its generator had been designated as a network resource or held at least a one-year contract to supply capacity or energy. That process was only in effect for three years.

ATC opted not to use the MISO approach. The transmission utility instead used a 100% reimbursement policy for interconnecting generators that could prove they were fulfilling network needs. ATC also never adopted MISO's 10% postage-stamp allocation for network upgrades 345 kV and above, which replaced the 50% reimbursement procedure in MISO's Tariff in 2009.

With the commission's approval, ATC will use the 10% postage-stamp allocation provision and phase out its 100% reimbursement policy. The utility said most MISO transmission owners already use the RTO's cost allocation approach and that the transition would bring more homogeneity with the RTO's interconnection procedures. ATC also said its revaluation of cost allocation was prompted by FERC's recent decision reinstating TOs' option to self-fund network upgrades. (See *FERC Upholds MISO Self-fund Order, Glick Dissents*.)

Clean Grid Alliance, the American Wind Energy Association and the Solar Council argued against ATC's proposal, contending the April 2019 effective date violates rules against retroactive ratemaking. They argued that interconnection customers have already entered the MISO queue's 2020 cycle "with the reasonable expectation that the current cost allocation rules would apply." The parties pointed out that 45 projects planning to interconnect to ATC entered the 2020 queue cycle and reminded FERC that it previously supported "stability and predictability" in grid operators' queues.

But FERC said an interconnection customer's generator interconnection agreement, signed upon completion of MISO interconnection queue studies, should be considered the Rubicon for projects in the queue. ATC's proposal does not affect existing executed or unexecuted GIAs, the commission said, "because prospective generators in MISO's 2020 queue cycle are not scheduled to execute GIAs until July 2022, nearly two years in the future." ■

MISO News

MISO Lays Out Seasonal Capacity Options

Continued from page 1

ments, multiple seasonal auctions or monthly auctions across the planning year.

MISO is also exploring the use of additional risk assessments beyond loss of load, including the expected unserved energy calculation, where MISO calculates the expected amount of energy when load is set to exceed generation.

Senior Manager of Resource Adequacy Coordination Lynn Hecker said there could be additional "administrative burden" on MISO and its members if it develops separate planning reserve requirements and resource accreditations for each season.

"That's really on the MISO to-do list, to get a better idea of what — if any — administrative burden … the proposed construct options might create," she said.

If MISO moves to a sub-annual version of the capacity auction, Hecker said it would reduce its focus on summer peak modeling and forecasting in favor of pinpointing multiple loss of load risk hours throughout the year, called resource adequacy hours. RA hours would likely occur in summer and winter.

Harrison said MISO must decide if it should rely more on forward-looking projections or historical data to establish accreditation and reserve requirements using resource adequacy hours.

"In a time of slower-paced change, that's reasonable; in a time of fast-paced change, that's less reasonable," she said of historical data being a predictor of system conditions.

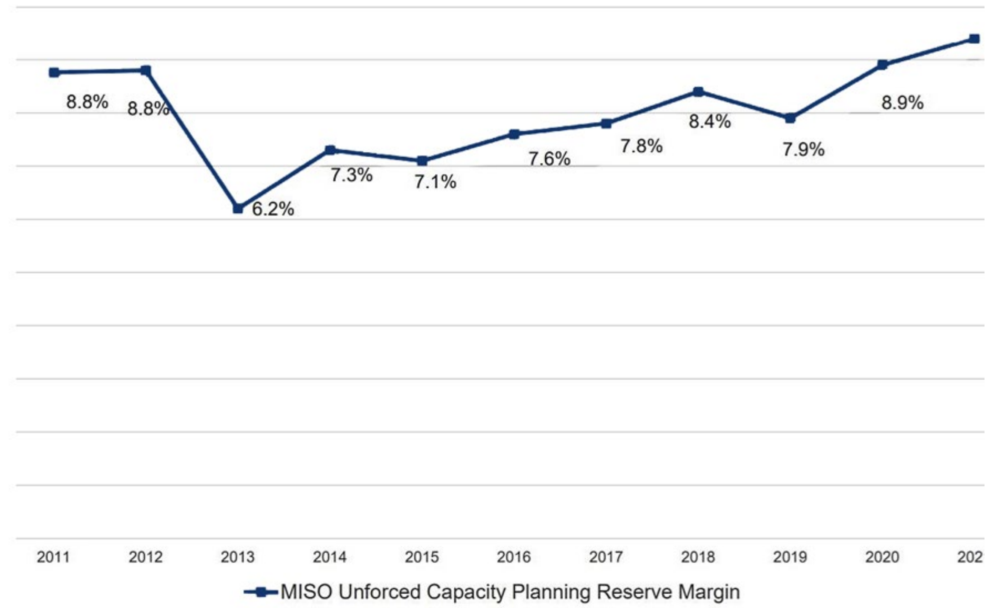
Seasonal capacity auctions might give way to more seasonal economic outages, MISO and members said.

Harrison said MISO will be mindful of a seasonal auction's possible effect of corralling too many generation outages into shoulder seasons. The RTO might consider must-offer obligations on capacity resources for each sub-annual period.

"The more granular we go, the more complex it will be to implement," Hecker said.

The State Authority Quandary

The possibility of new reliability requirements has MISO and members probing the complicated relationship between MISO and state authority.



MISO's UCAP planning reserve margin 2011-2021 | *MISO*

Some stakeholders have said that a move toward additional reliability criteria could infringe on state jurisdiction over resource adequacy and that MISO's existing annual local clearing requirements and planning reserve margin are sufficient for reliability needs. (See *MISO Closer to Seasonal Capacity, Reliability Reqs*.)

To date, no states have ever requested that MISO increase or decrease a planning reserve margin, said MISO Managing Assistant General Counsel Michael Kessler.

The MISO Tariff stipulates that states have the authority to *supersede* the RTO and set their own planning reserve margins, but they cannot change MISO's local reliability requirements or local clearing requirements. MISO would have to incorporate a state-set planning reserve margin into its planning resource margin requirements if it received a special state margin figure for a set of jurisdictional utilities. The Tariff also prohibits MISO from developing a resource adequacy requirement that conflicts with "state reliability or safety standards."

Kessler said there's "no other entity … than a state authority" that can alter MISO's planning reserve margin requirement.

Some stakeholders questioned why states wouldn't also have at least some authority over local reliability requirements or local clearing requirements if resource adequacy is ultimately the states' prerogative.

Six of MISO's ten local resource zones include territory from two or more states.

"Our interpretation of the Tariff — our literal reading of it — is that states do not have the authority to create a different local reliability requirement other than the one established by MISO," Kessler said.

If a state chooses to set a lower planning reserve margin, the local clearing requirement of a local resource zone would still apply, Kessler said, with MISO still responsible for procuring capacity up to the requirement. Costs of the extra capacity procurement would be uplifted to the entire MISO footprint.

WEC Energy Group's Chris Plante asked whether states could use a different loss of load risk than MISO's one-day-in-10-years standard. A state's decision to rely on a two-days-in-10-years risk would seem to affect zonal clearing and reliability requirements, he said.

"We haven't had to work through a scenario where some of these mechanics would apply," Kessler said, adding that MISO could pursue a deeper legal analysis of interaction between the Tariff and state law.

Plante has noted that states already largely rely on MISO's recommended margins to set their resource adequacy plans.

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MISO News

MISO Market Subcommittee Briefs

Combined Cycle Modeling Delayed a 3rd Time

MISO has at once rebranded and postponed its attempt to develop more sophisticated modeling software that can accommodate different combinations of combined cycle units and their dependencies.

The delay marks the third time MISO has *pushed back* an effort at combined cycle generation modeling. It also renamed the more involved process "multiple configuration resource" modeling.

MISO Director of Business and Digital Transformation Dhiman Chatterjee announced the further delay during an Oct. 8 Market Subcommittee call. MISO projects it will be able to model combined cycle interdependencies sometime late in 2025 at the earliest.

MISO first planned to put improved combined cycle modeling in place by 2020, then delayed until 2022, and again into mid-2023. The RTO said its current market platform couldn't technically handle the software. (See "At Least 1 Market Project Delay," *New MISO Platform Headed to the Cloud*.)

MISO now says General Electric is delaying delivery of a new market clearing engine beyond original expectations, making combined cycle modeling an even more distant prospect.

Chatterjee also said MISO experts, already working on other priorities, will be further taxed by implementation of FERC *Order 2222*, which requires RTOs to enable aggregators of distributed resources the opportunity to compete in organized markets.

MISO has previously said it could save anywhere from $14 to $34 million annually if it implemented enhanced combined cycle modeling.

"This is beyond frustrating," Xcel Energy's Kari Hassler said. "I'm flabbergasted MISO continues to push this project out even though there are substantial savings to be had … This is a product that the entire footprint needs."

Stakeholders asked if MISO could do something in the meantime to incrementally model combined cycle generators. Chatterjee said MISO is trying to be as transparent as possible about the challenges of implementing the modeling on its existing market platform.

"I just find it odd that [General Electric] said this is so complex of an ask when they've done something similar in SPP, and SPP has had it for about three years now. The complexity level is not extremely high," Hassler said.

MISO's Dhiman Chatterjee | © *RTO Insider*

Chatterjee said SPP in fact encountered some technical difficulties when it introduced similar modeling. He also said SPP's market clearing engine and interfaces are different from MISO's.

"The tools are all customized, individualized for each RTO, and that's why it's so complex," Chatterjee said.

"We'll try to be ready, and if an opportunity presents itself, we'll jump on that," he added.

MISO Braces for 2nd Hurricane

At the time of the Oct. 8 meeting, Executive Director of Market Operations and Resource Adequacy Shawn McFarlane said MISO was preparing for the then-Category 3 Hurricane Delta, the 25th named storm of the 2020 Atlantic hurricane season.

"Unless you've been living under a rock, you know we have another hurricane forming in the Gulf and headed to Louisiana," McFarlane said.

While Hurricane Delta's projected landfall is only about 10 miles east of where Hurricane Laura made landfall, McFarlane said the relatively good news was that the new storm is weaker and faster-moving. He also said a weekend landfall means less load to be possibly interrupted.

"So on a relative basis, that is a better situation," McFarlane said.

MISO *declared* conservative operations and a transmission advisory for its South region beginning Friday.

McFarlane warned that Entergy's Louisiana territory is still experiencing transmission line outages from the last storm. Hurricane Laura's landfall on Aug. 27 brought MISO's first load-shed orders and widespread transmission damage. (See *MISO Keeps Advisories in Effect a Week After Laura*.)

"Certainly, we're not as resilient as we could be because of Hurricane Laura," he said.

IMM Reassures Stakeholders on Coal Self-commitments

MISO's Independent Market Monitor reiterated that most coal self-commitment decisions in the footprint are made prudently.

Last month, Monitor David Patton provided MISO's Board of Directors analysis showing that most of the footprint's coal self-commitments are profitable. (See *MISO IMM Rebuts Uneconomic Coal Commitment Studies*.) This time, he brought the results to stakeholders.

"We don't see the level of concern that prior studies have indicated," Patton told stakeholders.

The Union of Concerned Scientists has released its own study concluding that Xcel Energy, DTE Energy, Cleco Power and Consumers Energy repeatedly make uneconomic coal generation commitments, costing ratepayers. (See *UCS Analysis Knocks Coal Self-commitments*.)

Patton said self-committed coal dispatch returned fewer revenues in 2019 only because all energy prices were lower across MISO.

MISO Communication System Still a Source of Frustration

MISO has conceded again that its communication system for emergency resources needs to be more user-friendly.

The acknowledgment came during a review of load-modifying resource performance for an early 2019 generation emergency.

Market participants use the nonpublic MISO Communication System (MCS) to update availability of their load-modifying resources for use in emergency conditions.

"I know the MCS is not the most beloved system, but it does provide important information to MISO," MISO Corporate Counsel Jacob Krouse told stakeholders during an Oct. 7 Resource Adequacy Subcommittee conference call. MISO stakeholders have long criticized MCS as being clunky and difficult to navigate. (See *Stakeholders: MISO System Fix Too Late for Summer*.)

MISO *issued* a maximum generation event Jan. 30-31, 2019, in its North and Central regions during a record cold snap. While it called on more than 180 LMRs, only 21% met their expected load reduction. MISO levied almost $3 million in penalties to underperforming LMRs, and nine market participants sought alternative dispute resolution that lasted until early 2020.

Krouse said during the course of the dispute resolution, market participants indicated they were confused about what data they needed to input into the MCS. Some market participants weren't following MISO's requirement to furnish the MCS with their most up-to-date LMR availability data either, Krouse said.

He also noted that the MCS contained "default values inconsistent with LMR registration information," which was fixed with monthly updates.

Krouse said there was confusion among MISO market participants on whether scheduling instructions would come from the MCS or another MISO mode of communication.

Krouse said MISO is working on MCS improvements following discussion from the *Demand Response and MCS Alignment Task Team*, formed last year. Further MCS improvements might be rolled out in mid-2021. ■

— Amanda Durish Cook

MISO Lays Out Seasonal Capacity Options

Continued from page 14

"I think states increasingly look to MISO to establish their reserve margins," he said during a special Aug. 21 MISO teleconference to discuss resource availability.

Zone 7 Reliability Requirements Questioned

Stakeholders are expressing consternation over draft 2021/22 PRA reserve requirements. This year, MISO began factoring unavailable generation due to planned outages into its loss of load expectation (LOLE) modeling, *resulting* in higher local reliability requirements for almost all local resource zones.

MISO is estimating it needs a 9.4% unforced capacity (UCAP) planning reserve margin, up from last year's 8.9% figure. Translated into an installed capacity basis, MISO needs an 18.3% reserve margin requirement in 2021, compared with 18% last year. (See *MISO Planning Reserve Margin to Climb in 2020*.)

The need for more padding is the most dramatic in Lower Michigan's Zone 7. Some stakeholders said it was unfair that a few individuals in MISO's modeling group could have such an outsized impact on capacity requirements.

Customized Energy Solutions' Ted Kuhn asked for "guardrails" in the LOLE modeling inputs process so members could expect more stability in the results.

MISO said its LOLE analysis showed that Lower Michigan runs the risk of more peak demand days in September than other local resource zones.

MISO plans to publish final LOLE results by Nov. 1.

For the 2020/21 planning year, Zone 7 cleared at a cost of new entry price of $257.53/MW-day, due in part to a new MISO rule banning capacity resources from taking extended outages. (See *MISO: New Outage Rules Boosted Mich. Capacity Prices*.)

MISO Independent Market Monitor David Patton *said* two resources in Zone 7 raked in a combined $154 million in the 2020/21 Planning Resource Auction despite being on outages over the entire summer.

"Those resources are effectively unavailable even though we pay them the same," Patton said during an Oct. 8 Market Subcommittee conference call.

Patton said he has long calculated leaner capacity margins than MISO projects because of the RTO's failure to incorporate outages into its capacity picture.

Meanwhile, Planning Adviser Davey Lopez said MISO's short-term resource availability and need fixes were successful in freeing up an additional 5-10 GW in capacity over the past year, as planned.

MISO launched new Tariff rules early last year to introduce demand response capability testing, seasonal documentation of the availability of load-modifying resources and a 120-day notice period for planned generation outages. (See "Near-term Filings," *MISO to Continue Resource Adequacy Talks in 2019*.) The rules were meant as a stopgap measure to buy the RTO more time to flesh out bigger ideas.

"We are striving to come up with longer term solutions. The first phase was intended to buy time," Lopez said, adding that MISO must continue working on the longer-term PRA changes. "Capacity margins continue to erode." ■

NYISO News

NY Solar Plus Storage to Grow 'Dramatically'

Clockwise from top left: Michael DeSocio, NYISO; Pete Fuller, Autumn Lane Energy Consulting; Anne Reynolds, ACE NY; Bill Acker, NY-BEST; and John Brodbeck, EDP Renewables. | *ACE NY*

By Michael Kuser

The Alliance for Clean Energy New York (*ACE NY*) last week drew 162 people to a virtual meeting to hear solar developers, industry experts and a NYISO official discuss projects that pair solar energy with energy storage.

Bill Acker, NY-BEST | *ACE NY*

Timing is crucial, and pairing energy storage with renewables allows the energy to move out of congested pockets, said Bill Acker, executive director of the New York Battery and Energy Storage Technology Consortium (*NY-BEST*).

"Instead of moving the energy at rush hour, you move the energy off of rush hour and you have what some people call virtual transmission," Acker said. "Even beyond congestion, you have the situation when you get to very high renewables on the grid, where you literally have over-generation; even if you had the transmission, you wouldn't be able to use the energy. Again, shifting the time allows you to use the energy."

Because renewable energy projects paired with storage are proving popular with developers, NYISO in July decided to speed up its hybrid modeling capability, aiming to complete the enhancement in 2021. (See "Exciting Times," *Overheard at NY-BEST's 10th Annual Meeting*.)

Following is some of what we heard at the meeting.

Solar and Wind Benefit

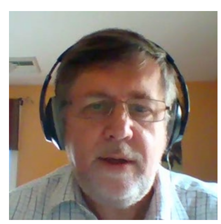
"Storage is increasingly an area of focus for us; it is going to be paired with solar in all forms," said David Gahl, senior director of state affairs in the Northeast for Solar Energy Industries Association.

In 2019, storage was paired with 5% of solar, "but we're expecting that number to increase dramatically by 2025. In the distributed space, 25% of all behind-the-meter solar will be paired with storage," Gahl said.

The growth is being driven in part by the eligibility of hybrids for the investment tax credit and by state goals, Gahl said. "In the utility-scale space … solar is increasingly paired with storage resources, with over 8 GW of commissioned projects that include storage right now. That represents nearly one in five of the contracted projects out there," he said.

New York's solar-plus-storage market is being driven by the Climate Leadership and Community Protection Act, which set targets of getting 70% of the state's electricity from renewables, and deploying 3 GW of energy storage and 6 GW of distributed solar, by 2030. The Public Service Commission laid out the state's storage deployment policy in a December 2018 order, since updated (*18-E-0130*).

The New York State Energy Research and Development Authority is working to meet the goals via three *pathways*: state-subsidized incentives, contracts with the state's investor-owned utilities and pairing a renewable energy certificate bid with storage, Gahl said. (See *NY Utilities, Developers Tweak Storage Procurement Terms*.)



John Brodbeck, EDP Renewables | *ACE NY*

In addition to providing the opportunity for more ancillary services, storage makes use of the spilled or "clipped" energy, adds duration and allows discharge at times better suited for the grid or the economics of the unit, said John Brodbeck, senior manager of transmission at EDP Renewables North America. With approximately 700 MW operating in New York, it is the largest owner of wind generation in the state.

"As a wind generator, we've been able to reg down for a while. To be able to reg up would be a good thing," said Brodbeck, referring to ancillary services that help maintain the grid's frequency. "There's plenty of problems though … interconnection issues, modeling issues, how does it operate within the market and metering issues."

NYISO was "pretty swift" to act on paired storage, and the stakeholder discussions quickly came to the concept of co-located storage

NYISO News

resources (CSR), which is the simplest form of a hybrid unit: essentially two separate units at the same site, he said.

FERC in August gave final confirmation on most of NYISO's new storage rules. (See *NYISO's 2nd Storage Compliance Almost Hits Mark*.)

"You can get some ancillary services from the storage side, and the intermittent [resource] can charge the storage resource, and those are good things," Brodbeck said. "The whole AC-coupled, DC-coupled issue seems to have been resolved nicely in NYISO," with the ISO *allowing* both AC and DC coupling configurations between intermittent and storage resources. "The current state of the *rules* for CSR is it does allow a single interconnection request, so we don't need to have multiple interconnection requests in the queue or in the class year, and the injection can be sized to less than the total electrical capability of the unit, which allows some additional flexibility." (See *Hybrid Resource Developers Ask for Uniform Rules*.)

Michael DeSocio, NYISO | *ACE NY*

"With 700 MW of wind, our plan is that at some point in the future, we'd be adding storage to most of those sites," Brodbeck said. "Many renewable sites, especially solar sites, are going to be wanting storage either as part of the original design or added on later. ... I think you'll see storage being added to a large number of units. Our concerns are about having to go back and getting it resized for interconnection, making sure that interconnection plan can be done expeditiously to get online quickly."

A More Complicated Grid

The evolving grid is going to be much more complicated than the old one-way power flows of the past, said Pete Fuller, principal of Autumn Lane Energy Consulting.

"You've got rooftop solar, vehicle-to-grid applications, microgrids, solar, wind, storage, hybrids — you've got a lot more things going on out on the grid that are separate and distinct from those big central power plants," Fuller said. "As I think about hybrids, the real goal here is to create something through co-located or otherwise aggregated resources that somehow is greater than the sum of the parts. It creates additional value, certainly for the developer owner, because that's what generates the investment and the interest, but also creates additional value for the grid."

Michael DeSocio, director of market design at NYISO, said that "the energy storage rules that went commercial at the end of August are technology-agnostic."

The ISO's new rules focused on storage technologies that are dispatchable, which varies depending on the capabilities of the technology. For example, "if compressed air

Pete Fuller, Autumn Lane Energy | *ACE NY*

can inject and withdraw without needing to change state — in other words go offline for a little bit to change the state of its compressors to do that — it could be an ESR [energy storage resource]," DeSocio said.

The model does not exist in the market today for compressed air that needs to go offline between injection and withdrawals, he said.

"It's something that we've thought about building as part of the ESR model but ultimately put aside given that we don't have any projects in the queue for any of those technologies," DeSocio said. "We do have a model for limited energy storage resources that's been around since 2009, which allows flywheels and smaller batteries to provide regulation service. ... When we talk about hybrid resources and the co-located model, we're focused on energy storage that is dispatchable and can provide energy as well as resources that are dispatchable." ■

NYISO News

FERC: NY DR Program Not Exempt from Offer Floor Rule

Glick Dissents over 'Arbitrary Distinctions'

By Rich Heidorn Jr.

FERC ruled Wednesday that New York's Commercial System Distribution Load Relief Programs (CSRP) are not entitled to an exemption from NYISO's buyer side mitigation (BSM) because they were designed in part to offset transmission investment (*EL16-92-001, et al.*).

The ruling by FERC Chair Neil Chatterjee and Commissioner James Danly, both Republicans, sparked a dissent from Democratic Commissioner Richard Glick, who said it was the latest example of the commission's campaign against state clean energy efforts.

The dispute resulted from a paper hearing initiated by the commission in February, when it narrowed the resources exempt from NYISO's BSM rules in southeastern New York. Granting a rehearing request by the Independent Power Producers of New York, that ruling partly reversed the commission's 2017 decision granting a blanket exemption from the rules for special-case resources (SCRs), a type of demand response. (See *FERC Narrows NYISO Mitigation Exemptions*.)

The commission said the blanket exemption ignored the fact that certain payments made to SCRs outside NYISO's capacity market could provide the resources with the ability to suppress capacity market prices below competitive levels.

The commission said that SCRs' offer floors should include only the incremental costs of providing wholesale-level capacity services and that "payments from retail-level demand response programs designed to address distribution-level reliability needs" should be excluded from the calculation of SCRs' offer floors.

The February order initiated a proceeding to evaluate retail-level DR programs individually to determine whether their payments should be excluded.

Wednesday's ruling concluded that CSRP should be subject to BSM but that payments received under the Distribution Load Relief Programs (DLRP) qualify for exclusion from the calculation of offer floors.

Under Con Edison's DLRP, customers receive notification two hours before a DLRP event, which is called to address an isolated need. In contrast, the utility's customers receive notification at least 21 hours before a CSRP event, which is called in response to system-wide peak demand.

"The record in this proceeding demonstrates that the purpose of the DLRPs under consideration is to maintain distribution-level reliability by reducing distribution system demands in response to contingencies and other emergencies," the commission said.

"We find, however, that the CSRPs under consideration are not designed to address and do not address solely distribution-level reliability needs, and therefore payments received under those programs must be included in the calculation of SCR offer floors in NYISO. … Both Con Edison and Orange and Rockland state that the CSRPs under consideration provide network load relief to the system during peak hours to address system-wide needs under peak load operating conditions."

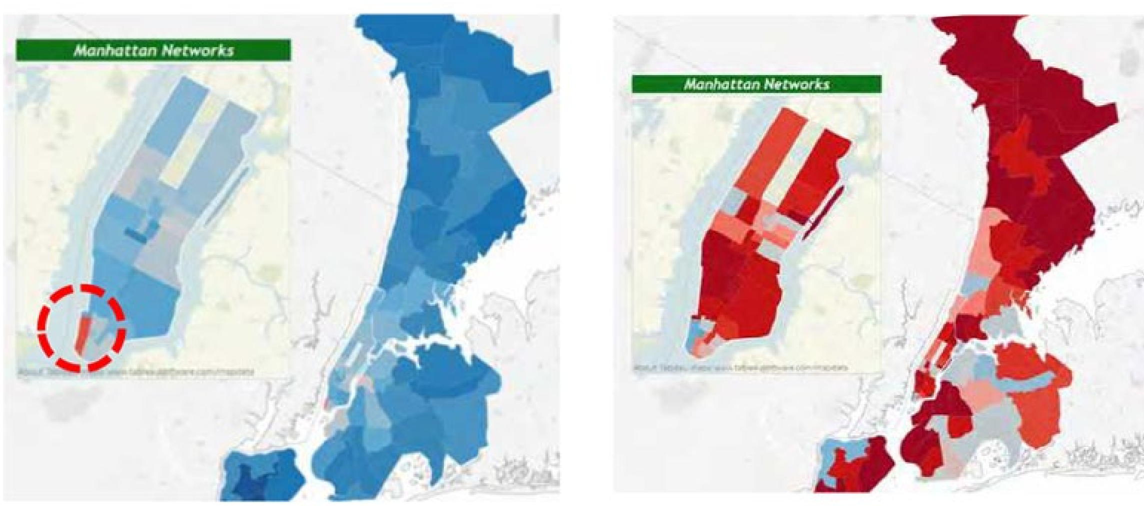
The commission said its case-by-case review of DR programs ensures a balance between the need to protect NYISO's capacity markets while avoiding inappropriate barriers to DR's participation in the market.

Glick disagreed, saying the order "once again perverts buyer-side market power mitigation into a series of unnecessary and unreasoned obstacles to New York's efforts to shape the resource mix."

"Buyer-side market power rules — often referred to as minimum offer price rules or MOPRs — that were once intended only as a means of preventing the exercise of market power have evolved into a scheme for propping up prices, freezing in place the current resource mix, and blocking states' exercise of their authority over resource decision making," Glick wrote.

Glick said the majority made "arbitrary distinctions" between different types of retail-level demand response programs.

"The record before us suggests that both DLRPs and CSRPs are retail-level programs directed at distribution system issues. They do so by having retail customers curtail their consumption in order to reduce the stress on particular elements of the distribution system," he said. "That solves a very different issue than NYISO's SCR program, which addresses peak demand on and the reliability of the bulk power system by, among other things, calling on demand response to maintain adequate operating reserves. To see that, one need look no further than the fact that the dispatch of DLRPs and CSRPs rarely overlaps NYISO's SCR dispatch." ■



FERC said New York's Distribution Load Relief Programs (left) are exempt from buyer-side mitigation rules but that Commercial System Distribution Load Relief Programs (right) are not. | *Con Edison*

NYISO News

NY Officials Create Waste Emissions Panel

Power Generation Panel to Complete Work Plan this Month

By Michael Kuser

The New York State Climate Action Council on Thursday approved creation of an advisory panel on waste emissions to be established by Department of Environmental Conservation (DEC) staff.

The panel joins six *others* set up in August, along with a Just Transition Working Group to ensure social equity in the council's proceedings.

Martin Brand, NYDEC | *NYDPS*

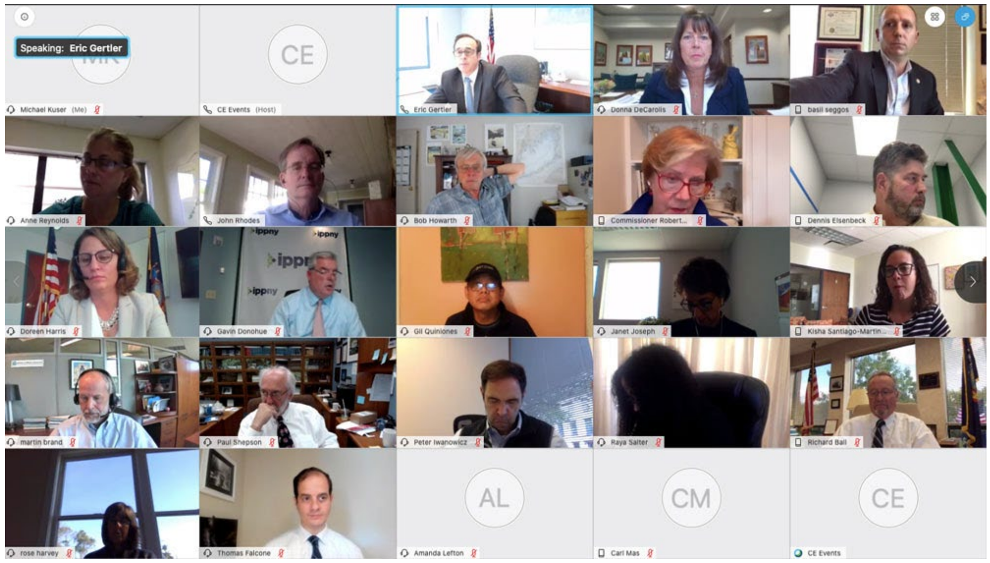
"We're going to evaluate emissions and mitigation strategies for a wide range of these waste generating sectors, including the traditional municipal and commercial solid waste generation infrastructure; facilities like transfer stations, landfills and waste-to-energy; and municipal combustors and co-gen facilities," DEC Deputy Commissioner Martin Brand said. (See *NY Seeks Comment on Proposed Emissions Limits*.)

The DEC also plans to look at all the handling, transportation and disposal aspects for that infrastructure, including some of the large-scale construction and demolition debris and materials processing activities around the state, Brand said.

New York's Climate Leadership and Community Protection Act (CLCPA) directs the DEC to measure greenhouse gas emissions on a common scale using the carbon dioxide equivalence metric (CO2e) and the 20-year global warming potential (GWP20) of each gas, as derived from the U.N.'s Intergovernmental Panel on Climate Change (*IPCC*).

In addition, the CLCPA mandates that 70% of electricity consumed in the state should come from renewable resources by 2030 and that electricity generation should be 100% carbon-free by 2040.

"The waste stream overall for the greenhouse gas emissions for the state is smaller than fossil fuel use, but it's not trivial — about 20% of statewide emissions are coming from this industry and these sources," said CAC member Robert Howarth, Cornell University professor of ecology and environmental biology.



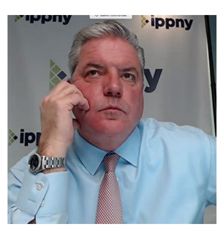
The NY State Climate Action Council met via webinar October 8, 2020. | *NYDPS*

If looked at in detail, 95% of the total emissions

Robert Howarth, Cornell University | *NYDPS*

from waste in New York is methane, not carbon dioxide, said Howarth, who recently published a *study* that shows methane emissions have grown as carbon dioxide emissions have declined, leaving New York's total GHG emissions in 2015 virtually unchanged from 1990. (See *NY Study Highlights Rising Methane Emissions*.)

"When we think about the panel, I suggest that the membership be focused not on who the economic players are in the waste industry, but rather on where the GHG emissions are actually coming from," Howarth said. "Our goal, of course, is to reduce those, so I would suggest a big focus on landfills, certainly on water treatment plants."



Gavin Donohue, IPPNY | *NYDPS*

Gavin Donohue, CEO of the Independent Power Producers of New York (IPPNY), said it is "really appropriate" how DEC has decided to reach out to local government authorities and waste management experts to help inform the panel's deliberations.

Flexible Generation

John Rhodes, PSC | *NYDPS*

Of all the topics being covered by the panel on power generation, resource mix is especially important, said Public Service Commission Chair John Rhodes, who leads the advisory panel.

"Which resources need to come up, which resources need to come down, and how do we get resources into the mix that can provide flexibility, which is going to be a big theme of our panel," Rhodes said.

There also are a series of topics surrounding equity in terms of access to clean energy solutions, access to new jobs in the burgeoning industry and affordability for the many low-income New Yorkers who face a heavy energy burden, he said.

The panel intends to finalize its work plan in October before briefing the CAC on priority policies and strategies in December, ahead of making final recommendations in March, Rhodes said, noting it would evaluate the costs and benefits of recommended strategies, informed by the value of carbon established in accordance with the CLCPA.

"In New York we've seen a number of studies that look at decarbonization, that try to inform the discussion and create greater aware-

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ness of the issues, such as how to manage electrification, how to create flexibility and, importantly, how to avoid overbuilt scenarios of extreme new peaks, which are the bane of every system," Rhodes said.

"I was glad to see carbon pricing on the agenda, but you didn't list interaction with other panels," Howarth said. "I'd like to see carbon pricing done in a context of all fossil fuel use, including transportation and housing and all, and not simply in the electricity sector."

"That was a deliberate punt," Rhodes said. "You're right, carbon pricing certainly should be discussed economywide. It's a little above my pay grade to think about who should take that on, which I could see being a Climate Action Council-level issue."

Anne Reynolds, ACE-NY | *NYDPS*

Anne Reynolds, executive director of the Alliance for Clean Energy New York (ACE NY), brought up biofuels and renewable natural gas and asked Rhodes if the panel considered defining the term "emission-free."

"There's a requirement for 70% renewables by 2030 and 100% emissions-free by 2040, and the statute's pretty clear on what counts as renewable but a little more vague on what counts as emission-free after that," Reynolds said.

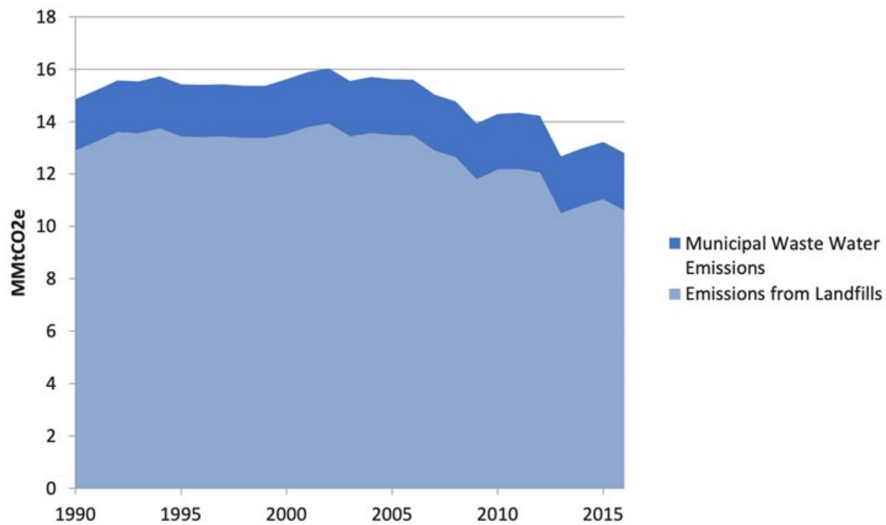
The topic did not come up on the panel but should be dealt with, Rhodes said.

Paul Shepson, Stony Brook University | *NYDPS*

CAC member Paul Shepson, dean of Stony Brook University School of Marine and Atmospheric Sciences (SoMAS), asked what panel or panels would consider methane emissions, particularly if in big cities they prove to be coming from natural gas infrastructure.

"Many of the panels are going to be dealing with the issue of methane emissions," said CAC Co-chair and DEC Commissioner Basil Seggos. "We may want to charge every panel with considering that, and then find a way to bring all the panels together in a joint session to cross-fertilize recommendations, rather than creating a new panel."

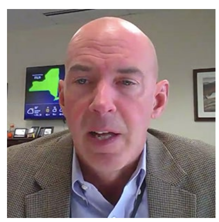
Administrative Law Judge Molly T. McBride will conduct two public comment hearing *webinars* for the proposed emissions rule on Oct. 20, and the *DEC* will accept public comments until Oct. 27.



A NYSERDA report last year shows GHG emissions from waste management (MMtCO2e), 1990–2016. | *NYSERDA*

Grid in Transition

NYISO CEO Rich Dewey *presented* on the grid operator's Grid in Transition initiative, which is taking place in conjunction with a state-mandated grid study underway by the New York State Energy Research and Development Authority and Department of Public Service to identify distribution upgrades, local transmission upgrades and bulk transmission investments needed to meet the state's clean energy goals (Case No. *20-E-0197*).



Rich Dewey, NYISO | *NYDPS*

"Upstate New York is pretty carbon-free already, in terms of the supply, and downstate there's a high intensity of carbon producing power plants," Dewey said. The challenge will be to move that power into New York City to displace the generation that's coming from those resources, and that will be instrumental to how we achieve those goals."

Tammy Mitchell, chief of bulk electric systems for the DPS, presented an *overview* of the grid in New York and how her office and the PSC regulate utilities, renewable energy programs and electric rates.

"Notably, the commission-approved energy affordability program provides $237 million in bill assistance to about 937,000 low-income utility customers to offset electric utility costs," Mitchell said.

Tammy Mitchell, NY-DPS | *NYDPS*

Donohue said that "renewables and what we have today, wind, solar and storage, are not going to get us to where we need to go all alone. We need new technologies ... what do we need to do marketwise to attract those new technologies?"

The goal that electricity be 100% carbon-free by 2040 is the real challenge, especially getting rid of that last small percentage of nonrenewable resources, Dewey said.

"We feel pretty comfortable that 70% by 2030 can be achieved by wind, solar and storage — you just have to make the right kind of investment, and they have to be located in the right spot," Dewey said. "But we do not believe we can get to 100% carbon-free electricity without some sort of development of these newer technologies that can be dispatchable, that can be available and still be carbon free."

The ISO is a big proponent of markets as the way to achieve the state's environmental goals, he said.

"You take that risk off the ratepayers and you put it on the investors," Dewey said. "Our approach is carbon pricing, but it's not just carbon pricing. ... The types of resources we need are a little bit different when you start thinking about backstopping the intermittency of the renewables, so you're going to need units that can respond quickly, ramp quickly." ■

NYISO News

OSW Growth to Test New York's Transmission Grid

Technical Conference Informs Officials on Investment, Planning Needs

By Michael Kuser

Transmission congestion around New York City could increase after the first 6,000 MW of offshore wind is interconnected without coordinated planning, *NYISO* told state officials Friday.

The state hopes to develop 9,000 MW of offshore wind (OSW) by 2035.

"Having offshore wind energy interconnect to load centers in the city and on Long Island "certainly helps offset some of the transmission constraints that you might experience; but nevertheless, to meet a total 9,000-MW goal of offshore wind, there absolutely will be transmission constraints," said NYISO Vice President for System and Resource Planning Zach Smith at a technical conference hosted by the state's Department of Public Service and the New York State Energy Research and Development Authority (NYSERDA).

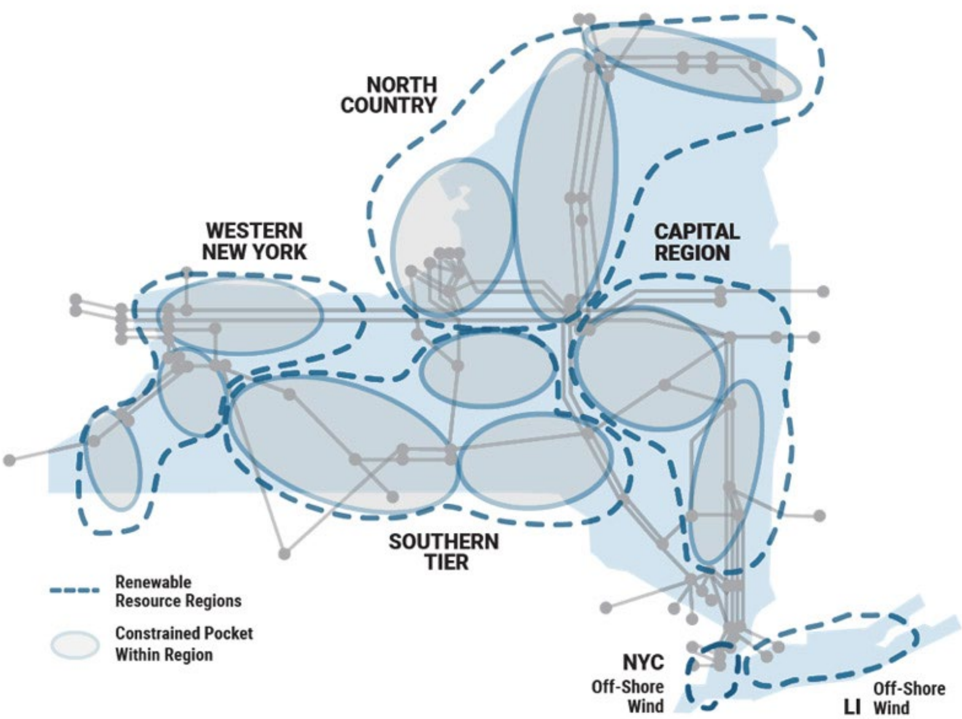
The conference is intended to inform a study to be completed by year-end on an investment plan to be established by the Public Service Commission for distribution and local transmission upgrades and a second plan for bulk system transmission investments (Case No. *20-E-0197*). (See *NYPSC Launches Grid Study, Extends Solar Funding*.)

Offshore wind is central to compliance with the Climate Leadership and Community Protection Act (CLCPA, *A8429*), which mandates that 70% of electric power in New York come from renewable resources by 2030 and that electricity generation be 100% carbon-free by 2040.

Smith noted that in the 2019 Congestion Assessment and Resource Integration Study (*CARIS*), published in July, the ISO only modeled 6,000 MW of OSW for the 70%-by-2030 scenario. As generation increases up to 9,000 MW, transmission constraints around the city and Long Island will worsen, he said. (See *Bulk Tx, 115-kV Upgrades Needed for NY 70×30 Goal*.)

"There could even be a tipping point, where as you increase beyond that 6,000 MW, it could get much worse than what we've identified," Smith said. "We assumed projects be interconnected according to what's been proposed in the NYISO interconnection queue. [It's possible] projects might interconnect much differently than what we assumed in our study, and if they do, then the results will change.

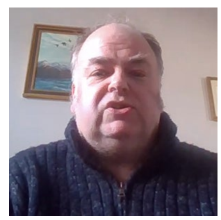
"We believe in general that our results are valid in terms of being indicative of constraints, but when you really dive into the details ... those individual transmission constraints really are driven by some of the assumptions on points of interconnection, and that is particularly true with regard to offshore wind," he said.



NYISO Generation Pockets: This NYISO map shows renewable generation that would be curtailed due to insufficient bulk and local transmission capability to deliver the power. | *NYISO*

HVDC Gains Favor

Technology providers and independent transmission developers also presented the conference with their ideas on how New York's grid could evolve, including the prospect of more high-voltage direct current (HVDC).



Ben Marshall, HVDC Centre | *NYDPS*

Ben Marshall of the National HVDC *Centre* in Scotland said the capacity of HVDC in Great Britain will grow from 8 GW today to an estimated 45 GW by 2028 and is expanding in other parts of Europe as well, especially in conjunction with offshore wind interconnections.

Electronic devices that measure the system and take actions increasingly dictate the performance of the grid, Marshall said. Decisions around constraints operate across seconds, decisions around frequency operate across second- to half-second periods and decisions around voltage control are made across hundreds of milliseconds, Marshall said.

"Control systems are making decisions within tens of microseconds; they're operating very quickly, very flexibly, and it's important that they operate correctly," he said.

Marshall also pointed to the emerging risks of having system controls be digital rather than analog: "If I look under the hood of an older car, I know what I'm seeing with the carburetor, but in a new one, all I see is plastic ... which is similar to what's going on with the proprietary control systems, so you need either to counter that effect or to contain it."

Elizabeth Griffin of Con Edison Transmission

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Elizabeth Griffin, Con Edison | *NYDPS*

said DC technology will be a critical tool to maximize the state's transmission investments.

"Based on currently proposed projects, it appears that DC will be the future for projects to bring renewables downstate via a potential Tier IV REC [renewable energy credit] procurement, as well for the upcoming offshore wind procurements, just given the distance of the current leaseholds from potential interconnection points," Griffin said.

DC also has several advantages over AC that make it particularly well-suited for New York's emerging transmission needs. "DC allows for the maximum utilization of transmission capacity – in the same right of way you can flow more power over DC – as well as for a level of control that is not available on AC lines," she said." DC also allows for long distance underground and underwater transmission options that we think will help improve community acceptance by avoiding the need to install additional transmission towers."

Regulators need to determine how to manage transmission, and particularly how NYISO will operate intrastate DC lines that are integrated with the existing New York Control Area network to maximize its advantages, Griffin said.

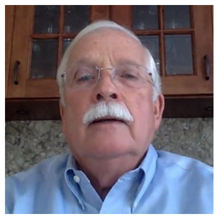
Shared infrastructure can maximize the benefits and minimize the environmental impacts of transmission, "which can be particularly beneficial for offshore wind and for aggregating renewables to bring them into New York City," Griffin said. "Unfortunately, the substations themselves, particularly in Zone J, are often very constrained due to limited real estate, limited physical space within the substation and limited electric capacity. When an open bay at a substation is used to connect less than the maximum capacity potential for that substation, the ability to connect additional volumes without physically expanding the substation may be lost."

Creating access to the existing transmission grid will require significant additional underground transmission infrastructure that would be best developed with expansion in mind and shared among transmission projects, she said.

"Well-planned and coordinated transmission can make sure that these limited interconnection points are used to provide the maximum benefit and capacity to the system," Griffin said. "A separate offshore grid will be better for customers in terms of grid reliability, flexibility and total cost effectiveness when compared to the individual generator lead-line approach that has been pursued to date and was appropriate for the initial projects."

Pancaking and Cost Savings

Transmission developer Anbaric Development Partners determined that 1,500 MW of load was typical of 3 a.m. on any Sunday on Long Island and that therefore there will always be more wind than load. So early on, it started to think about where to put this energy.

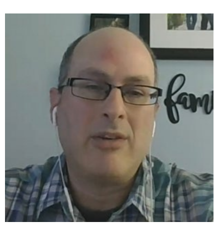


Howard Kosel, Anbaric | *NYDPS*

The company found 23 points of interconnection (POI) in the city and on Long Island, which screening reduced to about a dozen. Some of the POIs were in good locations but needed to be upgraded to increase their injection capability, said Anbaric Partner and Project Manager Howard Kosel.

"We set a criterion of $1 million per megawatt, and we capped it at $50 million, because we had to set the bar somewhere," Kosel said. "As we started to grow to get to the 9,000 MW, we were [learning about] the impact the particular POI had on the next POI ... it became obvious that upgrading POIs required careful sequencing so as to prevent pancaking, whereby the next POI loses transfer capacity ... [and] we saw that we could save upgrade costs of $500 million to $1.2 billion."

Offshore wind's intermittency will be complemented by solar and wind energy from northern, central and western New York state, where three public policy transmission projects are now underway under FERC Order 1000.



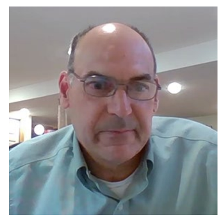
Lawrence Willick, LS Power | *NYDPS*

Innovation is a key benefit for those projects, said Lawrence Willick, senior vice president for project development at LS Power Development, which is partnering with the New York Power Authority on a 345-kV transmission project to relieve congestion at the Central East interface.

"In each case, the selected proposal was selected because of the unique technical features," Willick said. (See *NYISO Board Selects 2 AC Public Policy Tx Projects*.)

Fernando Gallinas Victoriano, business development manager for Avangrid Networks, said that integrating 9 GW of offshore wind requires "a planned, coordinated approach" for New York City and Long Island.

"The HVDC technology could be used over existing cables and rights of way, or even through new greenfields, in order to facilitate larger transfer capacity in the system, and with lower implementation periods," Victoriano said. "Incremental transfer capacity with neighboring systems will bring significant reliability benefits to New York."



Paul Haering, NY Transco | *NYDPS*

Paul Haering, vice president of capital investments at NY Transco, said that technology and innovation will be critical to achieving the state's clean energy goals, and that the long time it takes to build transmission "is why we need to act quickly."

NY Transco was created to develop and own high-voltage electric transmission facilities in New York, and comprises the transmission subsidiaries of Avangrid, Con Edison, National Grid and Central Hudson Electric and Gas. ■

PJM Operating Committee Briefs

| © RTO Insider

Manual Changes Endorsed

PJM stakeholders unanimously endorsed two manual changes at the Oct. 8 Operating Committee meeting.

Darrell Frogg, senior engineer of generation for PJM, *reviewed* updates to *Manual 14D: Generator Operational Requirements*.

Frogg said section 7.5.1 was changed to reflect that cold weather operational exercises will no longer be administered by PJM and instead be handled by generation owners. The RTO is recommending that generation owners self-schedule testing of resources that have not operated in eight weeks leading up to Dec. 1.

One change was made from the first read in September, Frogg said. Section 7.3, critical information and reporting requirements, calls for providing notification to PJM dispatchers at least 20 minutes prior to a change in state of each generating unit and will include any changes of more than 50 MW to the output of a self-scheduled resource that is not following the security-constrained economic dispatch (SCED) basepoint. Frogg said the change resulted from stakeholder questions.

Vince Stefanowicz, senior lead engineer of generation, *reviewed* updates to *Manual 10: Pre-Scheduling Operations* in a periodic review. The changes include several clarifying changes but nothing substantive, he said.

Stefanowicz said minor changes were made from the first read, including replacing the term "eDART Installed Capacity (eDART ICAP)" with the term "eDART Reportable MW" in Section 2.1, generation outage reporting overview. Stefanowicz said several stakeholders expressed concern over possible confusion with the capacity market term of ICAP.

Both manual updates will go to the Oct. 29 Markets and Reliability Committee meeting for first reads and final endorsements in November.

Day-ahead Schedule Reserve Update

David Kimmel, senior engineer of performance compliance, *reviewed* the preliminary proposed changes to the 2021 day-ahead scheduling reserve (DASR) requirement. He said the numbers may slightly change when the measure is brought for final endorsement in November.

The DASR is the sum of the requirements for all zones within PJM and any additional reserves scheduled in response to a weather alert or other conservative operations. It is the sum of the three-year average of under-forecasted load forecast error (LFE) and the three-year average of eDART forced outages.

Kimmel said the preliminary 2021 DASR requirement is 4.78%, slightly lower than the 2020 requirement of 5.07%. He said the number comes from the LFE component of 2.18% and the forced outage component of 2.6%.

Stakeholders will be asked to endorse the changes at the next OC meeting. The final 2021 DASR value will be incorporated into Manual 13 changes and be implemented in January.

	Load Forecast Error Component 80th Percentile Absolute Error				Forced Outage Rate Component All Forced Outage Tickets				Day Ahead Scheduling
Season	2018	2019	2020	Rollup	2018	2019	2020	Rollup	Req.
Winter	2.25%	2.06%	2.05%	2.12%	3.66%	2.81%	2.19%	2.89%	5.01%
Spring	2.04%	1.84%	2.73%	2.20%	3.16%	2.24%	1.71%	2.37%	4.57%
Summer	2.48%	2.48%	1.95%	2.30%	2.81%	2.43%	2.34%	2.53%	4.83%
Fall	2.33%	1.13%		1.73%	2.59%	2.07%		2.33%	4.06%
Annual				2.18%				2.60%	4.78%

DASR Requirement Components | *PJM*

Manual First Reads

Stakeholders heard several first reads of minor manual changes.

Maria Baptiste of PJM *reviewed* updates to *Manual 3A: Energy Management System Model Updates and Quality Assurance*. Baptiste said the changes include correcting grammatical mistakes and updating references to the behind-the-meter generation (BTMG) rules that took effect in September 2019. (See "Non-retail BTM Generation Rules Endorsed," *PJM MRC/MC Briefs: Sept. 26, 2019*.)

Lagy Mathew of PJM *reviewed* updates to *Manual 3: Transmission Operations*. Mathew said the changes featured minor clarifications, including defining the term "extra-high voltage (EHV)" lines as those equal to or greater than 345 kV.

Kevin Hatch of PJM *reviewed* updates to *Manual 12: Balancing Operations* to address changes from the five-minute pricing and dispatch Market Implementation Committee special sessions. Hatch said PJM has been working with the Independent Market Monitor to identify sections of Manual 12 to be updated and to improve transparency on the dispatch process.

Hatch said the changes include updated terminology for "day-ahead market" instead of the outdated "two-pass system."

Stakeholders will be asked to endorse the changes at the November OC meeting. ■

— Michael Yoder

PJM News

FERC OKs LS Power Acquisitions

Rejects Monitor's Mitigation Request

By Rich Heidorn Jr.

Panda Hummel Station, a 1,096.5-MW combined cycle plant on the Susquehanna River near Sunbury, Pa. | *Bechtel Corp.*

FERC on Thursday approved LS Power's acquisition of two generating facilities in PJM, rejecting the Independent Market Monitor's request for behavioral mitigation measures to address market power.

The commission approved LS Power's purchase of the Panda Hummel Station, a 1,096.5-MW natural gas-fired facility in Pennsylvania owned by several individuals and Siemens Financial Services, a subsidiary of Siemens AG (*EC20-55*).

Separately, the commission approved LS Power's purchase of Jersey Central Power & Light Co.'s 50% interest in the Yards Creek Pumped Storage Station, a 420-MW facility in New Jersey (*EC20-65*). The commission had approved LS Power's purchase of the other 50% share of Yards Creek from PSEG Fossil LLC, a subsidiary of Public Service Enterprise Group, on Sept. 1 (*EC20-49*).

The Market Monitor argued that the three purchases should be considered together, saying they would increase concentration in some locational energy markets, have a significant impact on PJM's market for regulation and increase concentration in the capacity market. Concentration in the Eastern Mid-Atlantic Area Council and MAAC locational deliverability areas (LDAs) would drop.

The Monitor said generators with market power can avoid mitigation by using varying markups in their price-based offers and by offering different operating parameters or using different fuels in their price-based and cost-based offers.

Yards Creek Pump Storage Station in New Jersey | *RE Warner and Associates*

Because of that, it said LS Power's combined cycle and combustion turbine resources should be prohibited from submitting price-based incremental energy offer curves that include both positive and negative markup relative to the cost-based offer. It also said they should be barred from submitting price-based offers with higher economic minimum output megawatt limits than the cost-based offer and required to submit cost-based offers for all available fuel types for dual fuel units.

The Monitor also expressed concern over the concentration in the ownership of fast-start resources, which it said allows sellers with high market shares the ability to use physical operating parameters to exercise market power. It said LS Power should be required to submit operating parameters for its fast-start units that meet PJM's parameter limits.

The Monitor said pumped hydro units in PJM are not mitigated when their owners fail the three pivotal supplier test, allowing them to strategically withhold economic energy or to produce excess, uneconomic energy. It said the company should be required to follow the day-ahead schedule produced by the PJM hydro optimizer in real-time operations for Yards Creek and Seneca Generation, a 484-MW pumped storage facility in Pennsylvania.

LS Power's pump storage units should also be prohibited from submitting simultaneous dual offers for both RegA (slow regulation) and RegD (fast regulation) products in PJM because it can result in uneconomic solutions, the Monitor said.

Finally, the Monitor said, LS Power should be required to make capacity offers at no greater than the net avoidable cost rate (ACR) because structural market power in PJM's capacity market is endemic.

The commission rejected all of the Monitor's proposed restrictions. It said the Monitor failed to show that the transactions will increase market power and said its proposed restrictions on offers from LS Power's combined cycle and combustion turbine units "relies on existing perceived limitations of PJM's market power mitigation."

FERC also dismissed the Monitor's proposed mitigation on LS Power's pumped storage units, saying it was "based on general concerns about certain elements of PJM's market design that are not specific to the [Yards Creek] transaction. This Section 203 proceeding to evaluate the proposed transaction is not the appropriate venue for raising or addressing general concerns regarding market design."

The commission said the transactions' aggregate 1,517 MW is too small to have a material impact on the RTO's ancillary services markets. It also rejected the Monitor's call for limiting LS Power's capacity offers to net ACR, noting that the company's post-transaction market share in the MAAC LDA is 4.6%. ■

PJM PC/TEAC Briefs

Planning Committee

Installed Reserve Margin Study Results

PJM stakeholders last week unanimously endorsed an installed reserve margin (IRM) of 14.4%, down from 14.8% required in 2019, along with new winter weekly reserve targets.

During the Oct. 6 Planning Committee meeting, PJM's Patricio Rocha Garrido *reviewed* the *2020 Reserve Requirement Study* (RRS) results, which determined the IRM and forecast pool requirement (FPR) for 2021/22 through 2023/24 and establishes the initial IRM and FPR for 2024/25. The results are based on the 2020 capacity model, load model and capacity benefit of ties (CBOT).

The 2020 capacity model is putting downward pressure on the IRM, Garrido said, with the average effective equivalent demand forced outage rate (EEFORd) of 5.78%, compared to 6.03% in the 2019 RRS. Garrido said the lower average EEFORd was caused by the increased representation of combined cycle units and gas turbines.

The CBOT — the help PJM can expect from imports during peak loads — is estimated to increase pressure on the IRM. Garrido said imports from neighboring RTOs have decreased from 1.6% in 2019 to 1.5% in 2020.

"We're getting a little less help from our neighbors," Garrido said.

The FPR is essentially the same as 2019, Garrido said, coming in at 1.0865 (8.65%) instead of 1.086 the previous year.

Garrido said the study results will also be used in the 2022/23, 2023/24 and 2024/25 Base Residual Auctions (BRA). He said delays in the 2019 BRA for 2022/23 necessitated the use of data from the 2020 study.

The PJM and world load models used are based on the 2002-2014 period that were approved at the August PC meeting. (See "Load Model Selection," *PJM PC/TEAC Briefs: July 7, 2020*.) Analysis from the *2020 PJM Load Forecast Report* released in January was also used.

Erik Heinle of the D.C. Office of the People's Counsel asked if the IRM and FPR would be updated after the first BRA was conducted to make sure the modeling is kept accurate.

Garrido said the driver of FPR is load uncertainty, so the results of the BRA wouldn't matter for the FPR and does not necessitate a recalculation. Garrido said the recalculation is triggered by a new load forecast, which will be released in January.

Garrido also won a same-day endorsement after conducting a first read of the *2020/21 winter weekly reserve targets*, which are slightly changed from last winter.

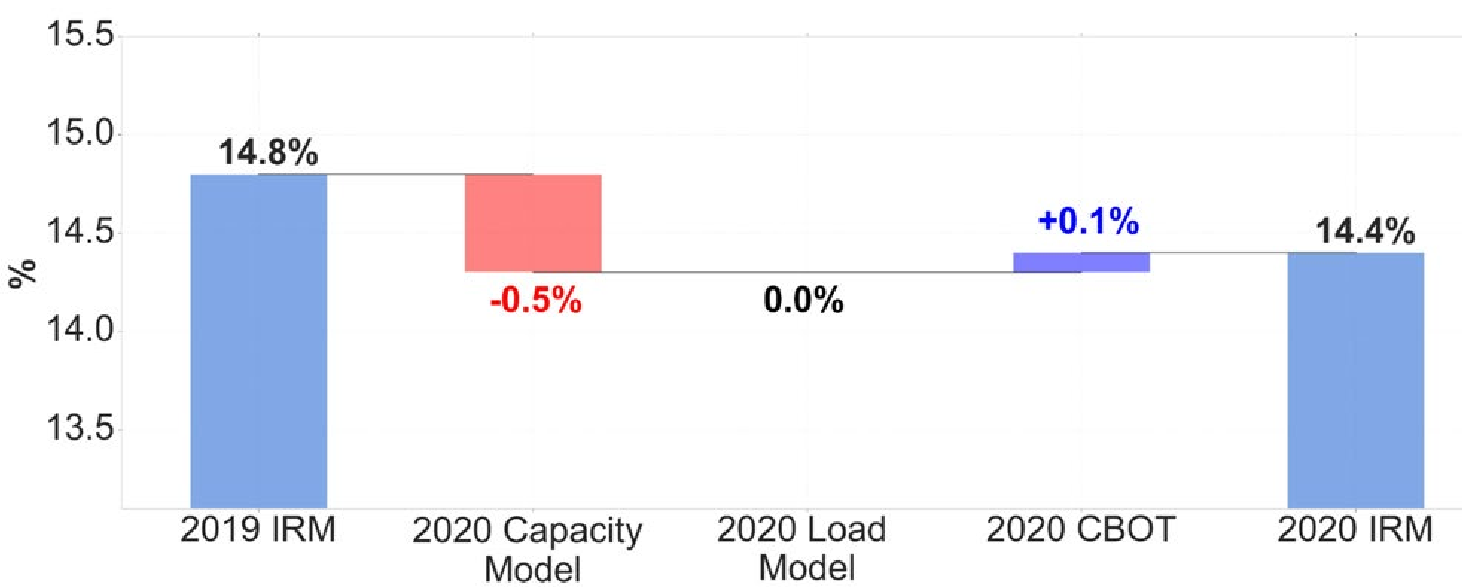
The targets for December, January and February are 23%, 27% and 23%, respectively, compared to 22%, 28% and 24% last year.

Ken Seiler, PJM | © *RTO Insider*

Part of the reserve requirement study, the targets help staff coordinate planned generator maintenance scheduling and cover against uncertainties by ensuring that the loss-of-load expectation (LOLE) for winter is "practically zero," according to the study. For the entire year, PJM sets the LOLE at one occurrence in 10 years.

Interconnection Queue Initiative

Ken Seiler, vice president of planning, *discussed* PJM's plan for a series of workshops to explore ways to improve the efficiency and effective-



| PJM

PJM News

ness of its interconnection queue process.

Seiler said more than 660,000 MW of generation requests has been studied since the inception of the interconnection process in 1999. More than 70,000 MW has been energized in that time.

"The process has served us well, but the process continues to change," Seiler said. "We believe it's time to take a look at some changes within the queue."

Seiler said the interconnection process has seen many improvements over the years, including automation of tools and additional staffing. PJM currently has 122,000 MW in the interconnection queue with 88% of the megawatts made up of renewable generation sources.

The most recent queue that closed at the end of September has more than 560 projects, Seiler said, with more than 40,000 MW of energy requesting to be interconnected. Of the 560 projects, he said, 500 are either solar or storage.

Based on feedback from stakeholders and the increasing volume and size of the interconnection requests, Seiler said PJM decided it was time to take a "fresh look" at the interconnection process. Four workshops are proposed, including a review of the interconnection process, stakeholder presentations, PJM's response to the stakeholder presentations and paths forward.

Seiler said the construct for the workshops would be based on federal policy and FERC Order 2003, which established procedures and agreements for interconnection of new and expanded large generators. (See *FERC Orders Indemnification Provision for PJM Tariff*.) The first two workshops would take place before the end of the year.

Adrien Ford of Old Dominion Electric Cooperative asked if PJM is looking for feedback on how stakeholders should proceed at looking at the interconnection process or on things that need to be changed in the process.

Seiler said PJM is looking for both things that need to be changed and a process forward to make the changes. He said the RTO has already identified things that need to be changed, but there are also hidden problems that can be identified by stakeholders.

"We want to hear what everyone has to say and what objectives are there and what the end goal is," Seiler said. "We want to hear everything before locking down a plan to move forward."

Sharon Segner, LS Power | © *RTO Insider*

Sharon Segner, vice president of LS Power, said she appreciated the idea of having the workshops but wondered why the RTO hadn't drafted a problem statement and issue charge to start an official stakeholder process. Segner said it costs time and resources for members to address issues, but with a formal stakeholder process there's an opportunity to change rules instead of simply having discussions.

Seiler said there hasn't been a defined problem that would necessitate a solution, so PJM wanted to identify problems through a workshop first before initiating the stakeholder process.

Dave Anders, PJM | © *RTO Insider*

Dave Anders of PJM said a similar workshop method was conducted when stakeholders began looking at the energy price formation issue in 2017. (See *PJM Stakeholders Explore Price Formation, Seek Transparency*.) Anders said the workshops are designed to expose areas of interest for members to address in the stakeholder process.

ELCC Data Submission

Andrew Levitt, PJM | © *RTO Insider*

Andrew Levitt of PJM's market design and economics department provided an overview of the effective load-carrying capability (ELCC) data submission requirements and the applicable deadlines for intermittent and limited duration resources.

ELCC, which is already used by MISO, NYISO and CAISO, evaluates reliability in each hour of a simulated year and compares a resource mix with limited resources against one with unlimited resources.

Members endorsed a joint stakeholder proposal at the September Markets and Reliability and Members committee meetings to use the ELCC method to calculate the capacity value of limited-duration, intermittent and combination (limited-duration plus intermittent) resources. The proposal was endorsed over the objections of the Independent Market Monitor and other stakeholders who said the proposal was flawed and could have profound and unforeseen effects on the capacity market. (See *ELCC Method Endorsed by PJM Stakeholders*.)

PJM is attempting to make a FERC filing by Oct. 30 to satisfy a paper hearing procedure started last year to investigate whether the RTO's 10-hour minimum run-time requirement for capacity storage resources is unjust and unreasonable. (See *FERC Partially OKs PJM, SPP Order 841 Filings*.)

Levitt said PJM needs data submittals from certain resource types by Nov. 1 to release ELCC results by December, the soonest FERC is likely to approve the October filing. Levitt said ELCC could be in place for the 2022/23 BRA.

Under the new rules:

- "Immature" and planned solar and onshore wind projects that intend to deliver capacity in 2022/23 must provide estimates of hourly historical production back to June 1, 2012, based on site conditions and historical weather. PJM defines an "immature" resource as solar and onshore wind projects that came into service after June 1, 2012.
- Immature and planned offshore wind, landfill gas and hydro without storage that intend to deliver capacity in 2022/23 must provide estimates of hourly historical production back to June 1, 2012.
- All energy storage resources, hybrids and hydropower with non-pumped storage must provide relevant physical parameters, including MWh of storage.

Manual 14C Update

Mark Sims, PJM's manager of infrastructure coordination, provided a first read of changes to Manual 14C: Generation and Transmission Interconnection Facility Construction.

Sims said minor changes are being proposed to Manual 14C as part of the biennial cover-to-cover review. Some of the changes include an update of the with the latest Tariff provisions clarifying the filing process for title transfers and associated title documentation in Section 5.

New sections on cost tracking for baseline projects and another for supplemental cost tracking are also being proposed, Sims said.

PJM will seek approval of the changes at the Nov. 4 PC meeting.

PJM News

Transmission Expansion Advisory Committee

IEC Project Status

Transource's proposed alternative plan for the eastern segment of its Independence Energy Connection project | *Transource Energy*

Questions over the status of the controversial Independence Energy Connection (IEC) transmission project were raised during a market efficiency presentation at the Oct. 6 TEAC meeting.

Nick Dumitriu, senior lead engineer for PJM, provided an *update* on the 2020/21 long-term market efficiency window. Dumitriu said the *2020 Market Efficiency Analysis Assumptions* whitepaper was shared with the PJM Board of Managers for consideration at their Sept. 15 meeting.

Dumitriu said a preliminary market efficiency base case was *posted* Sept. 4, and a retooled base case is expected to be posted by the end of October. The final base case and congestion drivers will be posted in December before the start of the 2020/21 long-term window.

LS Power's Sharon Segner asked if Transource Energy's Independence Energy Connection running between Maryland and Pennsylvania will be examined by PJM during the reevaluation analysis scheduled to be completed between October and December as part of the Regional Transmission Expansion Plan (RTEP).

PJM selected the $383 million IEC — its largest market efficiency project to date — during the 2013/14 long-term planning window to address congestion in the AP South interface. The RTO has since reviewed its benefits to the grid several times, determining in each round that the project remains the most effective way to reduce load costs. (See *Updated: Transource Files Reconfigured Tx Project*.)

Tim Horger of PJM said the RTO has continued to look at the status of the project and is "taking seriously" the project review.

The project received a certificate of public convenience and necessity (CPCN) from Maryland in July. (See *Md. PSC OKs Independence Energy Connection Deal*.)

Horger said PJM is deferring a review of the project pending a ruling from the Pennsylvania Public Utility Commission. Transource is seeking the PUC's approval of land acquisition, siting and construction for a 230-kV line in Franklin and York counties. The record closed with the filing of reply briefs in late September (Docket # *A-2017-2640200*).

Horger said an update on the project will be provided at the November TEAC meeting.

Segner said PJM has an Operating Agreement requirement to continue reevaluating projects until all required permits have been received.

Horger said the project is in a unique situation where a CPCN has been issued by one of the states involved in the permitting process. He said there are "a lot of moving parts" involved in the project, including reliability impacts.

"LS Power would maintain the position that you have an obligation to follow your Operating Agreement under all circumstances," Segner said. ■

— Michael Yoder

PJM MIC Briefs

Manual 18 Update

PJM stakeholders last week endorsed a "quick-fix" manual revision to correct a date reference in Manual 18 following a discussion in which some members objected to the process and suggested further talks on lingering pseudo-tie issues.

Jeff Bastian, PJM | © RTO Insider

Jeff Bastian of PJM reviewed the problem statement and issue charge to correct Manual 18's reference to the effective date for notifying pseudo-tied resource owners of their assigned locational deliverability area (LDA) prior to each delivery year. The Market Implementation Committee endorsed the measure with 78% support (149 votes) at its Oct. 7 meeting.

Bastian said under initial Capacity Performance provisions, a performance shortfall was calculated for external generation capacity resources only during performance assessment hours for when the emergency action was declared for the entire PJM region.

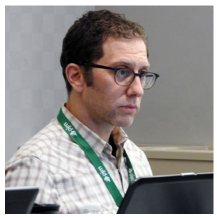
However, in November 2017, FERC accepted changes to be effective with the 2020/21 delivery year that would calculate a performance shortfall for external generation capacity resources for any performance assessment interval for which performance by such external resources would have helped resolve the emergency (ER17-1138). (See FERC OKs Change to MISO, PJM Pseudo-Tie Rules.)

PJM Manual 18 changes made to conform with the accepted provisions incorrectly specified the provisions as being effective with the 2021/22 delivery year, Bastian said.

Carl Johnson, PJM Public Power Coalition | © RTO Insider

Carl Johnson of the PJM Public Power Coalition said he recognizes what PJM was trying to accomplish with the change and why it would be done in the quick-fix process. Johnson said he represents some members who were involved in the FERC docket on the issue who still have concerns they feel are unresolved and would like to see PJM address them in a new problem statement and issue charge.

Johnson said the PPC would like to address some of the issues that FERC said were out of scope for the proceeding but should be raised in the stakeholder process. He cited questions about pseudo-tied resources' obligations, how they receive pricing and penalties that may be imposed on an external resource. (See FERC Sets Hearings in PJM Hydro Pseudo-Tie Spat.)



Steve Lieberman, AMP | © RTO Insider

Steve Lieberman, assistant vice president of transmission and PJM affairs for American Municipal Power (AMP), said he agreed with Johnson about opening a stakeholder process to examine unresolved issues. AMP was one of the entities that challenged PJM's requirements for pseudo-tied generators. (See FERC Sides With PJM on Pseudo-Tie Challenges.)

Lieberman said he was concerned by PJM's use of the quick-fix process to make the change because it affects a specified delivery year that has already started.

"It just strikes me as a little unsettling that we would be making a change after the start of a delivery year," Lieberman said. "I just don't like seeing us go down the path of making changes that specify a specific start time that's already passed."

Bastian said the Tariff correctly lists the 2020/21 delivery year as the effective date, superseding the manual language. Bastian said the idea was to make the two documents consistent and eliminate the discrepancy.

Sharon Midgley, Exelon | © RTO Insider

Sharon Midgley of Exelon said her company is supportive of PJM's quick-fix and didn't think it was appropriate to hold up a conforming change to a manual to discuss other issues. Midgley said Exelon would support stakeholders continuing a discussion and bringing forward a new problem statement and issue charge.

Behind-the-meter Generation

Members unanimously endorsed clarifications to the behind-the-meter generation (BTMG) business rules for units changing status from netting against load to participating in PJM markets.

Terri Esterly, PJM | © RTO Insider

Terri Esterly of PJM reviewed the problem statement and issue charge addressing the clarifications, saying a BTMG unit can be designated as a capacity resource or energy resource in the wholesale markets or be designated as BTMG netting against load on a unit-specific or partial-unit basis. Any BTMG unit seeking to be designated in whole or in part as a wholesale resource must submit an interconnection request.

BTMG rules were developed beginning in 2003 within the Behind-the-Meter Generation Working Group, Esterly said, and there has been limited review of the rules governing them since their development. Esterly said the OC in 2019 endorsed clarifying updates to BTMG business rules focused solely on the reporting, netting and operational requirements of non-retail BTMG.

Esterly said the Tariff and Manual 14D updates are needed because of the increased development of distributed energy resources and load-serving entity requests for adjustments to network service peak load and obligation peak load to reflect new BTMG.

The key work activities include providing education on existing BTMG business rules on status changes in the Tariff and Manual 14D. Work also will include reviewing and identifying business rules related to status changes that would benefit from clarification or additional detail or that may conflict with existing rules.

Stakeholders are expected to work on the issue for four months.

Midgley asked how the BTMG effort lines up with PJM's compliance activities associated with FERC Order 2222 and what steps the RTO will take to make sure there are no conflicts between what stakeholders develop in the BTMG effort versus what is developed for Order 2222. (See FERC Opens RTO Markets to DER Aggregation.)

Esterly said the BTMG effort is to clarify existing rules but additional changes may be needed because of Order 2222.

PJM News

Real-time Values Market Rules

Laura Walter, senior lead economist, provided an *update* on the work completed during the MIC special sessions on real-time values market rules and reviewed the proposed packages from the solutions *matrix*.

The special sessions have been taking place since January, after stakeholders endorsed an issue charge at the December Markets and Reliability Committee meeting. (See "Real-time Values," *PJM MRC Briefs: Dec. 19, 2019*.) The *problem statement* said observations indicated real-time values were being used to consistently override unit-specific parameter limits or approved parameter limited exceptions.

The original intent of RTVs was to provide a way for generation operators to communicate current operating capability to PJM if their resources couldn't meet their unit-specific parameter limits or approved exceptions, Walter said. Generators opting to use RTVs forfeit operating reserve credits and make-whole payments.

In a nonbinding poll conducted in August, 55% of stakeholders said they supported the PJM package, and 10% gave support for the IMM package, while 71% said they were happy with the status quo.

Walter said market participants that repeatedly fail to reflect actual operating conditions in their submitted operating parameters could be referred to FERC for enforcement. The package also calls for adding real-time values to the Tariff. Currently, real-time values are mentioned only in the manual, Walter said.

The IMM proposal includes removing minimum run time from the list of eligible parameters with RTV submissions. It also said units that choose to run longer can self-schedule beyond the minimum run time, with PJM operator notification.

The proposal also prevents withholding by using longer minimum run time, Walter said. Any penalties collected are to be allocated to daily real-time load.

The MIC will vote on the PJM and IMM packages at the November meeting with a first read scheduled for the December MRC meeting.

Manual 15 Review

Stakeholders unanimously endorsed revisions to Manual 15 as part of the biennial review. Gabrielle Genuario of PJM reviewed *updates* to *Manual 15*, including reformatting and rewording in sections 2.6.1 and 2.6.8 to provide more clarity.

The revisions will be voted on at the Oct. 29 MRC meeting and the Nov. 19 MC meeting.

Manual 11 Revisions

Vijay Shah of PJM *reviewed* proposed updates to *Manual 11: Energy & Ancillary Services Market Operations*. Shah said the changes involve increasing transparency and conforming to current PJM process as part of *the five-minute dispatch and pricing problem statement*.

The changes include an added reference to the day-ahead and real-time sections in Section 2.2: Definition of Locational Marginal Price and updated "LMP verification" to "price verification" throughout Section 2.10: Verification Procedure as verification includes review of real-time and ancillary service prices.

Stakeholders will vote on the proposed updates at the November MIC meeting. ■

— Michael Yoder

SPP News

FERC Approves SPP-AECI Competitive Project

FERC on Wednesday approved a cost-and-usage agreement between SPP and Associated Electric Cooperative Inc. (AECI) that could result in the RTO's first competitive project under Order 1000 (*ER20-2707, ER20-2708*).

The letter order accepted the terms and conditions governing the construction, ownership, operation and cost for the installation of 345-kV terminal equipment at AECI's existing Blackberry substation, the endpoint for SPP's 109-mile, 345-kV Wolf Creek-Blackberry transmission project. It also accepts Tariff revisions to include the substation's construction costs in each SPP transmission owner's respective annual transmission revenue requirement.

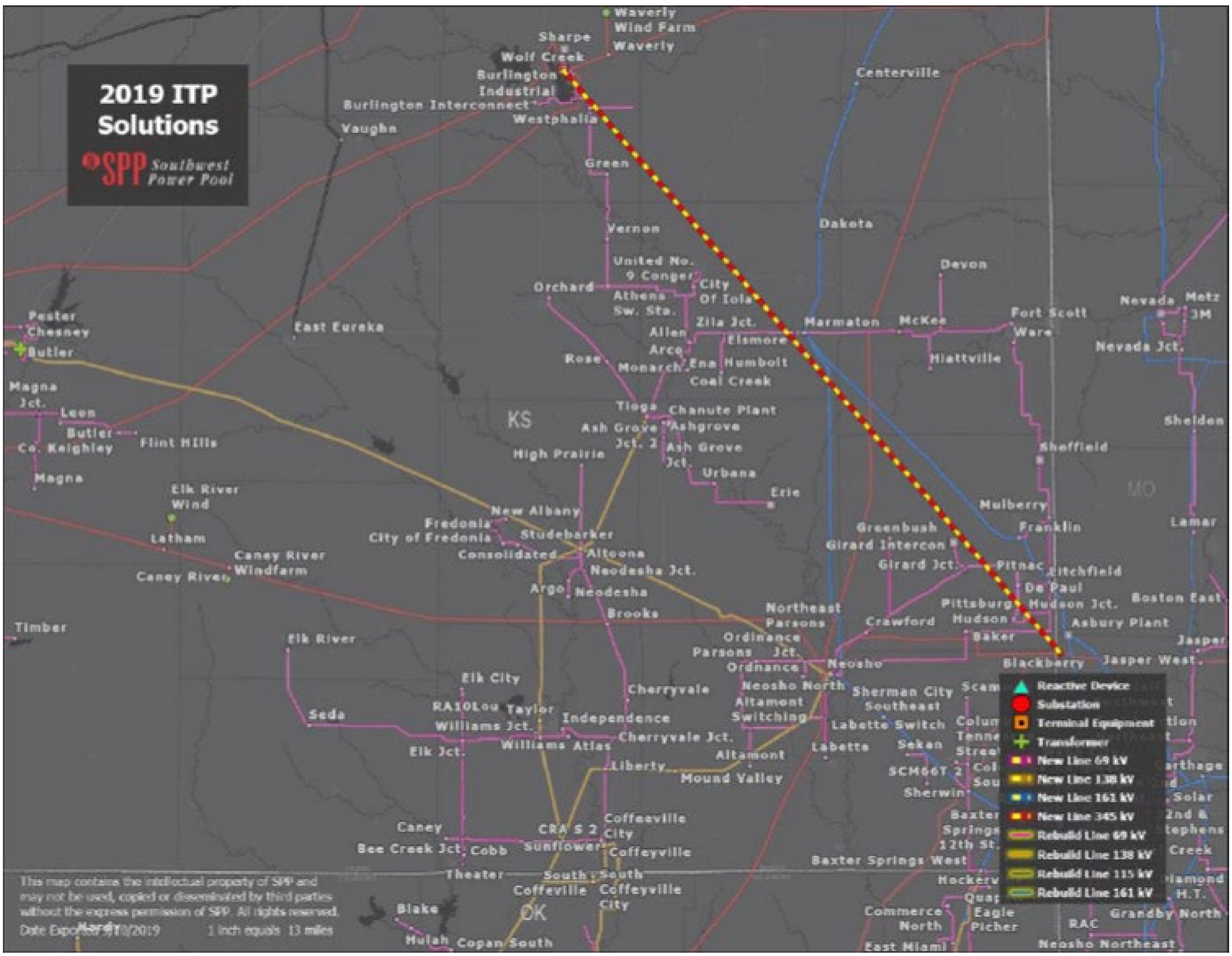
"We were glad to see that outcome," Neil Robertson, SPP's interregional relations senior engineer, said in breaking the news Wednesday morning to the Seams Steering Committee.

The Wolf Creek-Blackberry project is expected to cost $152 million. SPP members will fund the line according to load-ratio share. The RTO's Board of Directors last month lifted a suspension on the project and authorized the Oversight Committee to create an industry expert panel (IEP) to evaluate responses to a request for proposals, which staff have since issued. (See "Board Lifts Suspension on Competitive Upgrade," *SPP Board of Directors/MC Briefs: Sept. 22, 2020*.)

SPP awarded its first competitive project in 2016 to Mid-Kansas Electric, but the project was later canceled because load projections dropped over time. (See *SPP Cancels First Competitive Tx Project, Citing Falling Demand Projections*.)

A third competitive project has already been evaluated by an IEP and will be brought before the board for its consideration in October. ■

— Tom Kleckner



SPP's Wolf Creek-Blackberry project (dotted line), connecting to the AECI system | *SPP*

SPP News

FERC Denies Complaint vs. Tri-State G&T

FERC on Friday rejected Gladstone New Energy's complaint that Tri-State Generation and Transmission's generator interconnection procedures caused the renewable developer to lose its queue position and be assigned network upgrade costs by an "inappropriate" restudy (*EL19-97*).

The proceeding stemmed from Gladstone's 2017 interconnection request for a 78-MW wind facility in New Mexico. Tri-State's final system impact study in 2018 pinned the costs for interconnection facilities and network upgrades at $31.7 million, requiring Gladstone to provide a $7.9 million security deposit.

In April 2018, Gladstone asked Tri-State that its interconnection request be placed into deferral over concerns with the study's report. The project remained in deferral until September 2019, when Tri-State approved Gladstone's request to proceed out of deferral. In November, under Gladstone's protest, Tri-State conducted a system impact restudy. Tri-State filed a facilities study agreement in March, and FERC accepted it, with Gladstone again protesting.

FERC rejected Gladstone's argument that Tri-State "improperly" restudied the project, saying the restudy and the inclusion of a higher-queued project in its allocated costs were just and reasonable.

Gladstone argued that Tri-State's interconnection procedures were outdated and did not conform with FERC's large generator interconnection procedures (LGIP). But the commission said events prior to Sept. 3, 2019, were outside of its jurisdiction. Tri-State only became FERC jurisdictional on that date. (See "Ruling Permits Tri-State to Become FERC Jurisdictional," *SPP FERC Briefs: Week of March 16, 2020*.)

The commission also noted that it accepted Tri-State's proposed LGIP in March, finding them consistent with the pre-jurisdictional procedures that provide projects exiting deferral to be subject to restudy, unless Tri-State deems such analysis unnecessary. FERC said that Gladstone was aware that, as it entered deferral, a restudy was possible once it exited. ■

— Tom Kleckner

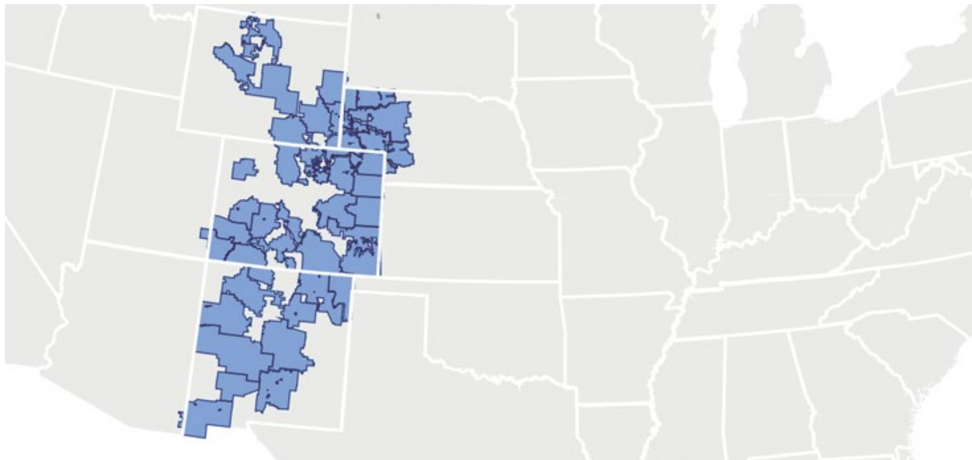
Colfax County, N.M., is home to Gladstone New Energy's proposed wind facility. | *Lands of America*

SPP News

Tri-State Increases Members' Self-supply Options

Cooperative to Cut Rates by 8% in Seven Years

By Tom Kleckner



Tri-State's members cover much of the Rocky Mountains. | *Tri-State Generation and Transmission*

Colorado cooperative Tri-State Generation and Transmission Association said Wednesday it will cut its rates by 8% by the end of 2023 and give members additional flexibility to provide their own power, addressing two of its members' most frequent complaints.

CEO Duane Highley acknowledged during a press conference that members had asked for more leeway in self-supply options to increase their use of renewable energy, calling the actions a "green energy dividend."

"It's been lots of work, but the cooperatives have come together cooperatively to find ways to make this work for everyone," Highley said, apparently unaware of his play on words. "We've all agreed this is a fair way to share costs."

Highley was backed by two member representatives, Poudre Valley Rural Electric Association CEO Jeff Wadsworth and Southeast Colorado Power Association CEO Jack Johnston, and former Colorado Gov. Bill Ritter, director of the Center for the New Energy Economy.

Ritter lauded Tri-State for its Responsible Energy Plan, which the co-op unveiled in January with similar fanfare. The plan's components include 50% renewable consumption by 2024, reduced emissions by closing coal plants in Colorado and New Mexico, and additional self-supply and local renewable energy flexibility for members. (See Tri-State to Retire 2 Coal Plants, Mine.)

"This was not an easy result to get to. None of this is easy," Ritter said. "They're living up to the commitments they made in the Responsible Energy Plan. We're going to make a commitment to lower rates for the next few years. That is something I think we should all applaud."

The announcement followed a meeting at which Tri-State's Board of Directors approved the rate cut and the Contract Committee's process to implement partial requirements contracts with its utility members.

"You typically don't hear about electric utilities lowering rates, so we're grateful to Tri State and board for this big lift," Wadsworth said.

Beginning with an "open season" nominating period in early 2021, utility members can transition to the new contracts by expressing their interest in shares of the 300-MW of system-wide self-supply capacity allocation. The open season capacity accounts for 10% of Tri-State's system peak demand.

Members can self-supply up to 50% of their load requirements, subject to availability in the open season. This expands on the current 5% self-supply provision and a new *community solar provision*.

The 5% cap has frustrated Tri-State's 42 utility members, some of whom are involved in regulatory litigation to leave the co-op. (See *Tri-State, Delta Officially Part Ways*.)

Tri-State has recently added three non-utility members, making it *FERC*-jurisdictional. The commission in March found Tri-State to be under its jurisdiction, a ruling it affirmed in August. (See *FERC Affirms its Jurisdiction over Tri-State G&T*.)

FERC Rejects Interconnection, GIA Procedures

As the press conference proceeded online, FERC issued an order rejecting Tri-State's proposed Tariff revisions modifying its generator interconnection procedures and generator interconnection agreements (GIAs) without prejudice to a submitted revised proposal (*ER20-2593*).

Tri-State said it intends to refile a revised proposal.

FERC in March accepted Tri-State's Tariff revisions establishing the jurisdictional rates and terms and conditions for transmission service over its Western Interconnection facilities, but set the matter for hearing and settlement judge procedures to determine their justness and reasonableness. (See "Ruling Permits Tri-State to Become FERC Jurisdictional," *SPP FERC Briefs: Week of March 16, 2020*.)

Tri-State proposed to reform its interconnection queue by transitioning from the *pro forma* sequential first-come, first-served study approach to a first-ready, first-served cluster study. The cooperative said the change was consistent with or superior to its *pro forma* large and small generator interconnection procedures (LGIP/SGIP) and the large and small GIAs.

The revisions would have established an informational interconnection study process — to assist customers make business decisions about their generation facilities before entering the queue — and a definitive interconnection study process. Tri-State said interconnection customers must demonstrate site control and meet increasingly stringent readiness milestones as they advance through the interconnection phases.

FERC found that Tri-State did not demonstrate several revisions to be consistent with or superior to the *pro forma* LGIP: 1) its proposal to allocate network upgrade costs based on a distribution factor analysis; 2) the requirement for interconnection customers to select energy or network resource interconnection service (ERIS/NRIS) before beginning one of the study process' phases; and 3) the requirement for interconnection customers entering a transitional process to demonstrate readiness within 10 days of the revised LGIP's effective date. ■

SPP News

Seams Steering Committee Briefs: Oct. 7, 2020

Staff Share Details on 2020 ITP, Joint Studies

SPP staff last week said they considered several seams-related projects with MISO in their 2020 Integrated Transmission Planning (ITP) assessment but eventually declined to pursue them over differing methodologies in calculating benefits and costs.

"Rest assured we're going to continue to look at these areas in the future," SPP's Kirk Hall told the Seams Steering Committee during its Oct. 7 meeting, referring to three 345-kV projects along the Nebraska-Iowa border.

"MISO and SPP staff continue to work on understanding the cost differences," Hall said. "Hopefully, we'll come back with something that is agreeable to all parties."

Hall shared a near-final version of the ITP assessment with the SSC. Staff identified 54 projects in the final portfolio, which includes 92 miles of 345-kV transmission lines and 141 miles of rebuilt high-voltage infrastructure. It estimated $532 million of engineering and construction costs but projected a 4.0-5.2-to-1 benefit-to-cost ratio.

The 2020 ITP takes a 10-year look at system reliability and economic needs. Staff spent more than two years evaluating more than 2,200 solutions, and said the projects will solve 163 system needs, help levelized market prices, improve congestion hedging and facilitate access to low-cost energy.

The ITP assessment will be taken to SPP stakeholders and the Board of Directors later this month for their approval.

Neil Robertson, SPP's interregional relations senior engineer, said the grid operator remains "committed to coordinating" with MISO. The RTOs once again failed to agree on an interregional project during their fourth coordinated system plan (CSP) study but have since agreed to combine forces on a year-long transmission study to identify "comprehensive, cost-effective and efficient upgrades." (See *MISO, SPP to Conduct Targeted Transmission Study*.)

"SPP will … work with MISO and determine how we would rectify costs differences if we decided to factor in whether a project can be recommended or not," Robertson said.

He said SPP and MISO analyzed 10 needs in their CSP, but no solutions met "fundamental requirements."

Robertson also discussed the *final report* of SPP's joint CSP with Associated Electric Cooperative Inc. The entities will combine forces on what would be the RTO's first competitive project under FERC Order 1000. (See *FERC Approves SPP-AECI Competitive Project*.)

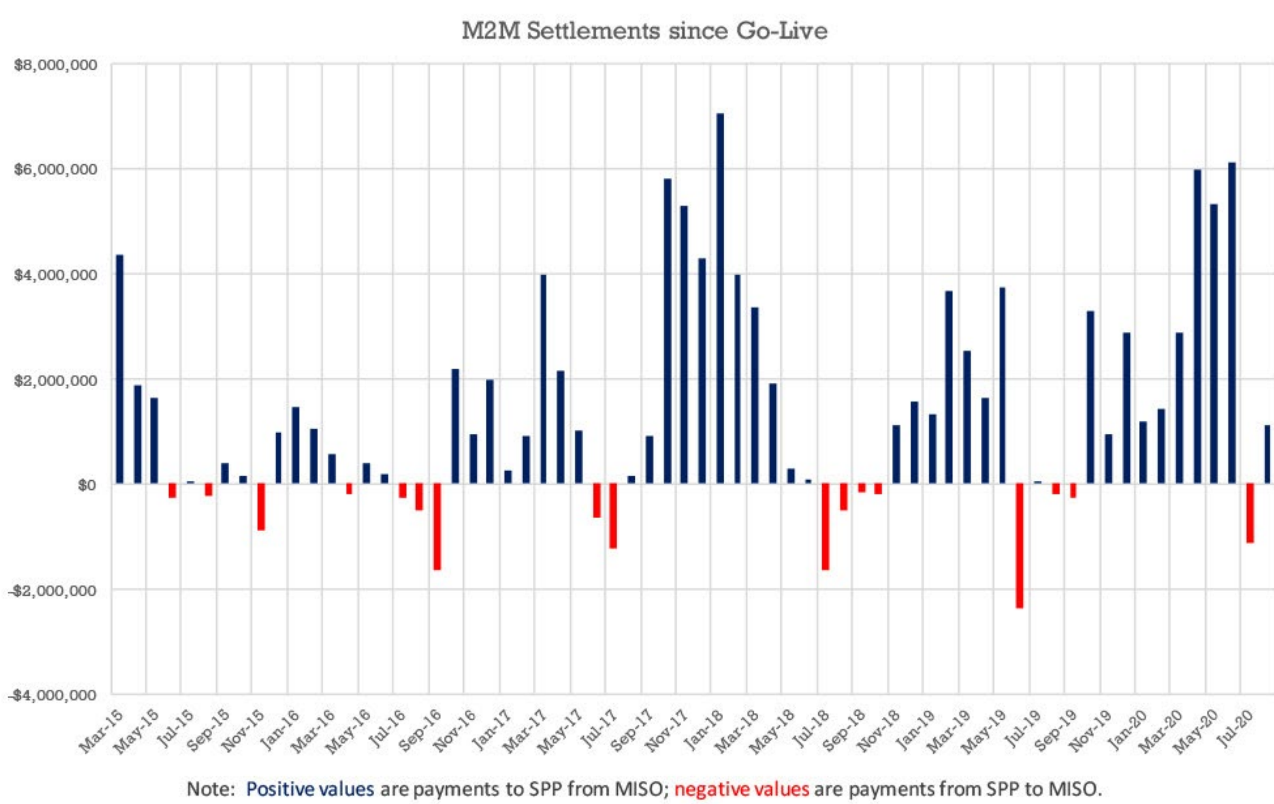
M2M Settlements Again Favor SPP

Market-to-market (M2M) settlements once again flowed in SPP's favor during August, staff told the committee, resulting in a $1.1 million accrual for the grid operator. Temporary and permanent flowgates were binding for 725 hours during the month.

SPP has now accrued $93.82 million in M2M settlements since it began the process with MISO in March 2015.

August marked the 10th time in 11 months, and the 49th time in 66 months, that settlements have ended up in SPP's favor. ■

— Tom Kleckner



SPP's market-to-market settlements with MISO are approaching $95 million. | *SPP*

Company Briefs

CenterPoint Challenged on Hedge Fund Investment

Advocacy groups Public Citizen and the Citizens Action Coalition of Indiana filed a complaint with FERC last week against CenterPoint Energy for allegedly failing to disclose its financial ties to a New York hedge fund (*EL21-2*).

The groups said the Houston-based utility had a responsibility to notify federal regulators that Elliott Management invested $1.35 billion this spring in exchange for significant management concessions, including Elliott's choice for board members and a new CEO. CenterPoint agreed to install two new board members preferred by Elliott, including former Halliburton CEO David J. Lesar and energy lawyer Barry T. Smitherman, according to the complaint. A month later Lesar was named CenterPoint CEO.

The groups said CenterPoint failed to comply with federal rules requiring utilities to disclose any significant change related to company control to FERC within 30 days.

More: *Houston Chronicle*

Amazon Unveils Rivian Electric Delivery Van Prototype

Amazon last week unveiled a prototype of one of its three electric vehicles being built in partnership with startup EV manufacturer Rivian. The company expects to have 10,000 electric delivery vans on the road worldwide by 2022.

The driver for the deal, struck in September 2019, was a pledge by CEO Jeff Bezos to create a delivery fleet that helps the company achieve net-zero carbon emissions by 2040. Amazon initially invested $440 million in Rivian in February 2019 and has participated in "multiple investment rounds since then," according to a spokeswoman for Rivian, which has raised about $6 billion from investors.

More: *Chicago Tribune*

Anbaric's Krapels Passes Away

Ed Krapels, Anbaric's founder and CEO, died Sept. 25 from a genetic lung disease called Alpha-1 Antitrypson Deficiency. Krapels, 71, had a lung transplant earlier this summer but was never able to recover, the company said.

Born in The Netherlands, in 1949, Krapels emigrated with his family to Puerto Rico in 1956 before moving to the U.S. mainland in 1959.

Krapels is credited with building Anbaric from one employee to a company with projects across North America, spearheading the development of the New York-New Jersey Neptune and Hudson 660-MW transmission lines and helping create the independent transmission industry in the U.S.

More: *Anbaric*

DTE Weighs Sale, Spinoff of Non-utility Units

DTE Energy is said to be considering unloading its natural gas pipelines and other non-utility operations, according to people familiar with the matter.

The people, who wished to remain anonymous, said the company is working with advisers to evaluate selling or spinning off the operations. They said no final decisions have been made and DTE could instead keep its current structure.

DTE's non-utility operations include gas pipelines, energy trading and energy development businesses. The divestiture would leave the company with an electric utility serving 2.2 million customers and a natural gas distribution business serving 1.3 million customers in Michigan.

More: *Bloomberg*

Duke Energy Plans to Double Renewables, Slash Emissions

Duke Energy last week said it aims to double its renewable energy generation by 2025 and reduce methane emissions in its natural gas business to net-zero by 2030.

Duke's capital plan calls for it to increase its renewable portfolio from 8 GW to 16 GW by 2025, triple the renewable capacity for its regulated utilities by 2030 and bring its total renewable capacity to 40 GW by 2050. The company also wants to add at least 11 GW of storage across by 2050.

The company, which has shuttered 50 coal-fired generating units since 2010, also said it wants to accelerate the retirement of its remaining coal fleet, including the shutdown of all of its coal units in the Carolinas by 2030. The company expects its current five-year capital plan will increase by about $2 billion to $58 billion. Beyond that, Duke's 2025-2029 capital plan will range from $65 billion to $75 billion.

More: *Duke Energy*

Meijer Rolling Out EV-Charging Stations

Midwestern retailer Meijer announced last week that it is teaming up with Electrify America to install 36 ultra-fast public electric vehicle charging stations at nine of its stores in Illinois and Michigan.

The future locations include Oswego, Aurora and Evergreen Park in Illinois; and Roseville, Allen Park, Bay City, Cadillac and Gaylord in Michigan.

Electrify America's 350-kW chargers can add about 20 miles of range per minute of charging.

More: *Progressive Grocer*

PG&E: 300 Weather Stations, 137 Cameras Installed

Pacific Gas & Electric has added 300 weather stations and 137 fire watch cameras this year as it approaches its goal of installing 400 stations and 200 cameras by the end of December. The growing network provides company meteorologists and analysts with detailed, real-time information during the wildfire season.

The stations provide temperature, wind speed and humidity data that is monitored and evaluated by an in-house meteorology team. The data is one of the many factors used to help decide if a public safety power shutoff is necessary.

The utility plans to install 1,300 stations by the end of 2021 — creating roughly one station for every 20 miles of transmission lines in high fire-threat areas — and install 600 cameras by the end of 2022. When complete, PG&E will have the ability to see more than 90% of its high fire-risk areas.

More: *Pacific Gas & Electric*

Federal Briefs

Court Strikes Down Rule Targeting Methane Leaks from Drilling

A federal court last week struck down an Obama-era regulation targeting methane leaks from drilling sites on public lands, arguing it went beyond the scope of the Bureau of Land Management's (BLM) jurisdiction. The ruling was the result of a lawsuit filed by oil and gas groups Independent Petroleum Association of America and Western Energy Alliance.

The 2016 rule required oil and gas companies to cut flaring in half, inspect their sites for leaks and replace old equipment that released too much methane. However, the court argued that while the rule was meant to reduce waste, it was instead used to regulate air quality, which is not the job of the BLM.

More: *The Hill*

EPA Union has 'No Confidence' in Agency's Reopening Plan

The executive board of the union that represents EPA employees voted unanimously last week to say they have no confidence in the agency's ability to protect employees as they return to their offices during the COVID-19 pandemic.

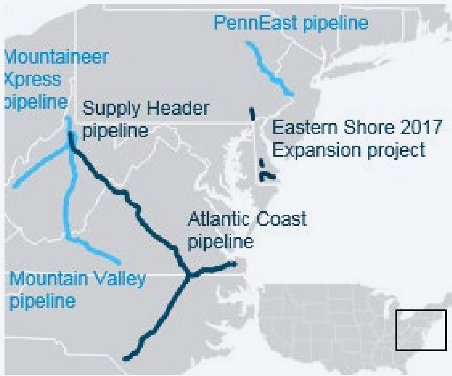
The American Federation of Government Employees criticized "EPA's determination to force workers back into EPA facilities for no mission-driven reason, despite agency employees successfully tele-working for months during the pandemic. Unnecessarily forcing EPA workers into offices will inevitably result in the spread of the virus, illness and possibly death."

EPA has reopened many offices across the country, with employees allowed to return on a voluntary basis.

More: *The Hill*

FERC Says Mountain Valley Work Can Resume

FERC last week lifted a stop-work order for all but 25 miles of the Mountain Valley Pipeline and will give the company another two years to complete the natural gas line that has already been six years in the making (CP16-10, CP19-477). It would run 303 miles between northwestern West Virginia and southern Virginia.



Although it acknowledged problems with erosion and sedimentation, FERC — in a 2-to-1 decision — found that allowing the pipeline to be completed is in the best interest of both the environment and the public. Commissioner Richard Glick dissented, saying lifting the order is "plowing ahead with construction in the face of uncertainty."

While two permits set aside by legal challenges have since been reissued, Mountain Valley still lacks approval to pass through the Jefferson National Forest.

More: *The Roanoke Times*

Mont. Gov. Questions Pendley's Actions

Montana Gov. **Steve Bullock** last week asked a judge to block three sweeping land use plans that would open most U.S.-owned lands in the state to energy development. Bullock claims the documents should be invalidated because the Trump administration's acting director of the Bureau of Land Management, Williams Perry Pendley, was removed from the post after a judge said he had been acting in the role unlawfully.

Bullock contends all actions undertaken during Pendley's 424 days atop the agency are now subject to legal challenge. Bullock said he was only challenging actions directly affecting Montana, leaving it to other states and conservation groups to challenge additional actions made during Pendley's tenure. Interior officials say none of the bureau's actions should be overturned since Interior Secretary David Bernhardt had the legal authority to delegate decision-making. It plans to appeal.

Meanwhile, Pendley said the court ruling has changed little as he continues to stay at BLM as one of its two deputy directors. "I have the support of the president. I have the support of the secretary of the Interior and my job is to get out and get things done to accomplish what the president wants to do — which means [increasing] recreational opportunities on federal land and [increasing] opportunities for jobs, so we can recover back to where we were pre-pandemic," Pendley said.

More: *The Associated Press*, *The Denver Post*, *The Hill*

Wyoming Lawsuit over Blocked Coal Export Terminal Still Alive

A lawsuit that alleges the state of Washington unconstitutionally stopped the development of a proposed coal export terminal that could have helped transport Wyoming coal to global markets may still be alive after the U.S. Supreme Court invited the acting solicitor general to file a brief to express the position of the federal government on the case.

Wyoming Gov. Mark Gordon, who said the latest proceeding signaled that the case still had a chance to be heard, asked the Supreme Court in January for a hearing on the dispute. The export terminal proposed for the West Coast would have allowed Montana and Wyoming to export more coal to other countries and, if completed, would have been the largest coal export terminal in North America. The landlocked states claim Washington violated the Dormant Commerce and Foreign Commerce clauses of the U.S. Constitution by inhibiting the export of a commodity.

The Supreme Court must then decide if it will accept the case. If it does, the case will likely go through pretrial proceedings.

More: *Casper Star-Tribune*

State Briefs

ARKANSAS

Entergy Customers to Receive Increased Bill Credit

Entergy Arkansas last week announced that customers can expect to save an estimated $94 million next year from the utility's membership in MISO. The credit is $19.6 million more than customers saved this year.

If approved by the Public Service Commission, the average residential customer using 1,000 kWh per month will see a 25% increase in the MISO credit. It will lower the bill an additional $1.11, bringing the total MISO credit to $5.55 a month.

More: *The Sentinel-Record*

CALIFORNIA

SCE Blamed for Fire on Hollister Ranch

Santa Barbara County fire investigators last week said a Southern California Edison power line sparked a vegetation fire on the Hollister Ranch in May.

A 156-acre fire ignited before 2:15 a.m. on May 7 after a SCE utility pole failed, fell to the ground and started the fire. More than 100 fire personnel were assigned to the fire at its peak.

More: *Noozhawk News*

CONNECTICUT

Lamont Signs Bill to Enhance Utility Accountability

Gov. **Ned Lamont** last week signed into law a bill that enhances protections for utility customers in the event of prolonged power outages and increases accountability among utilities. The bill emerged from criticism over Eversource Energy's response to Tropical Storm Isaias, which left thousands without power for up to nine days.

The bill's key provisions include a credit for outages and compensation for lost food and medicine; performance-based regulation of electric distribution companies; and greater accountability for storm preparation and response. It also allows the Public Utilities Regulatory Authority to implement lower rates during the recession.

More: *Hartford Courant*

MASSACHUSETTS

MBTA Embracing Renewable Energy

The Massachusetts Bay Transportation Authority announced last week that it plans to sign a three-year contract for 70% of its forecasted electricity needs — all of which will be renewable.

MBTA officials expect the electricity to cost less than $12 million a year, plus a premium of $859,000 for renewable energy credits. The authority's current contract is $15.5 million a year with no renewable energy.

More: *CommonWealth Magazine*

MINNESOTA

Supreme Court Wonders if New Wisc. Gas Plant Needs Further Review

The Minnesota Supreme Court will decide if the Public Utilities Commission must pursue a lengthy environmental review for Minnesota Power's proposed $700 million Nemadji Trail Energy Center in Superior, Wisc., following court arguments last week.

Minnesota Power intends to build the 525-to-625-MW natural gas plant with Wisconsin's Dairyland Power Cooperative, which will split the cost and power generated. Wisconsin and Minnesota regulators have approved the agreement, but the Minnesota Court of Appeals ruled in December that a further environmental review was needed.

Jason Marisam, an assistant attorney general representing the PUC, said the state's environmental protection laws do not apply to the commission's decision to approve "affiliate-interest" agreements that allow Minnesota Power to draw power from the plant. He said the PUC is not authorizing the construction nor operation of the plant.

A Supreme Court decision is expected by the middle of 2021.

More: *Star Tribune*

NEVADA

NV Energy Customers to see Larger Than Expected Bill Credit

NV Energy last week said it will provide a $120 million payout to its customers as a one-time credit on their October bills, which is double the company's previously announced payout of $59.7 million.

Average single-family homes can expect a $107.25 credit, which will replace the $53 credit first approved in September. Multi-family residential customers can expect a $60 credit, while small-business accounts will see a credit of roughly $53. Larger commercial customers will see individually tailored credits.

The Public Utilities Commission approved the payout, which comes as part of a settlement involving the company's general rate case.

More: *Las Vegas Review-Journal*

NORTH CAROLINA

Hertford County Solar Farm Slowed by Moratorium

Hertford County Commissioners last week unanimously approved a temporary moratorium on the development of solar farms. An official document will be drawn up so the board can formally adopt the moratorium as early as Oct. 19.

"A moratorium is not stopping or saying there can't be any more solar farms," Chairman Ronald Gatling said. "[A moratorium] allows us to look at the process in which solar farms are erected in Hertford County and the criteria that goes along with that. This does stop it until the moratorium has ended while we get information concerning the parameters of building solar farms. The moratorium sits in place, giving the county manager and other officials the opportunity to look at this."

The commissioners acted after receiving a petition bearing 62 names that sought to block the installation of a solar project on farmland in Murfreesboro. Hertford County currently has 13 solar farms, including one of the largest in the state: a 400,000-panel, 80-MW facility.

More: *Roanoke-Chowan News-Herald*

OKLAHOMA

EPA Gives State Authority over Tribal Environmental Issues

EPA last week granted Oklahoma authority to oversee enforcement of the federal Clean Air Act, Clean Water Act and Safe Drinking Water Act on the lands of the state's 38 federally recognized tribes.

In July, Gov. **Kevin Stitt** requested the authority using an Oklahoma-only provision in a 2005 transportation bill that allows the state to oversee environmental issues "in the areas of the state that are in Indian country, without any further demonstration of authority by the state."

EPA's own summary report notes that many tribes in Indian country opposed the decision.

More: *The Hill*

SOUTH DAKOTA

Willow Creek Wind Project Now Operational

Ørsted last week announced that their Willow Creek Wind Energy in Butte County is now operational.

The 103-MW project consists of 34 wind turbines on 20,000 acres of private land. It is the fifth-largest wind facility in the state.

More: *Rapid City Journal*

TENNESSEE

Vote Puts Memphis Departure from TVA in Limbo

The Memphis City Council last week voted 8-5 against approving a $520,000 contract between Memphis Light, Gas and Water and GDS Associates, a Georgia-based company that would have run the bidding process for Shelby County's future electricity supply — an essential step if Memphis is going to leave the Tennessee Valley Authority.

J.T. Young, CEO of the utility, said the company takes the vote as a signal that the city council did not want it to continue evaluating whether it should leave TVA. Still, he did not say the process was over and it is unlikely to end with the council's vote.

Several of those who voted against the contract have expressed support for leaving TVA but criticized the process being used. Some council members said the contract should go to Indiana-based ACES Power Marketing,

More: *Memphis Commercial Appeal*

VIRGINIA

Albemarle County Adopts Climate Action Plan

The Albemarle County Board of Supervisors last week adopted the county's first Climate Action Plan. The plan is the county's first step in a multi-phase, multi-year effort to reduce its contributions to climate change.

More than 31 strategies and 135 actions are included in the document, which are grouped into five sectors: transportation and land use; buildings; renewable energy sourcing; sustainable materials management and landscape; and resources and agriculture.

The county's next step will focus on implementing the plan.

More: *The Daily Progress*

Manufacturers Seek to Block State from Joining Carbon Market

The Virginia Manufacturers Association is suing the Department of Environmental Quality and state Air Pollution Control Board over revised regulations that will allow it to join the Regional Greenhouse Gas Initiative (RGGI). The lawsuit claims the DEQ followed an incorrect process in revising an existing carbon trading rule; it also says the new rule is "unlawful" and will adversely affect association members.

Virginia sought to join RGGI in 2018 when the DEQ proposed its initial rule governing its participation. But because the General Assembly must approve any exchange of state monies and the rule was drafted before the approval, the department developed a system in which the state would distribute carbon allowances to emitters, who would then sell them into the market and buy back only what they needed.

The Clean Energy and Community Flood Preparedness Act — the law authorizing the state's participation in RGGI — ordered the DEQ to incorporate the law's provisions into the existing rule "without further action by the [Pollution Control] board." However, the Virginia Manufacturers Association argues the revisions to the rule went beyond what the law allowed and "wrongfully broadened the statutory exemption."

More: *Virginia Mercury*

WASHINGTON

UTC Staff Opposes Puget Sound's Bid to Sell Colstrip Shares

The Utilities and Transportation Commission's staff last week said Puget Sound Energy's plan to sell part of its stake in the Colstrip coal plant in Montana is not in ratepayers' best interest and should not be approved by the commission.

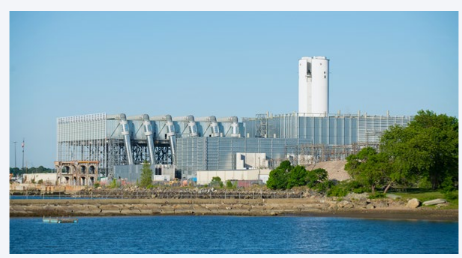
Staff found that PSE "failed to demonstrate that the proposed transfers of property are consistent with the public interest," and the sale terms hold "significant potential to cause harm to ratepayers," according to a summary by Chris McGuire, the assistant director of energy regulation. PSE insists the sale would benefit customers and allow it to reach its clean energy goals before 2025.

The staff recommendation was filed in advance of a public hearing about the proposed sale. The deal would turn over a 50% ownership stake in Unit 4 of the four-unit plant to Talen Energy and NorthWestern Energy. The deal requires approval by the utilities commission as well as the Montana Public Service Commission.

More: *The Seattle Times*, *KTVQ*

WEST VIRGINIA

Natural Gas Plant Tabled for Now



Energy Solutions Consortium of Buffalo, N.Y., announced Friday its natural gas project in Brooke County has been put on hold "due to changing conditions in the energy and financial markets."

The Economic Development Authority approved a $5.5 million loan guarantee for the project in September. It would have been the first natural gas plant in the state.

The company said it is "evaluating alternative options to move forward."

More: *The Associated Press*