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New Rules Threaten Mexico's Foreign Energy Investment

Government's Action Favors CFE Monopoly over Renewable Resources

By Tom Kleckner

Mexico's government has been chipping away at the country's electricity market reforms ever since Andrés Manuel López Obrador assumed the presidency in December 2018.

Mexican President Andrés Manuel López Obrador | *Office of the Presidency*

A planned 2019 auction of renewable energy contracts, dominated by foreign private investment, was canceled. Natural gas contracts with private developers were renegotiated. Attempts were made to grant clean energy certificates, awarded to clean energy generators that began operations after August 2014, for legacy state-run hydro plants.

In April, the government suspended synchronization trials for 28 wind and solar projects and placed indefinite limits on the amount of electricity renewable resources can provide to the grid, measures that affected 4.5 GW of capacity.

The final blow may have come on May 15, when the government announced new regulations that give priority to electricity generated by Mexico's state-run electricity monopoly, Federal Electricity Commission (CFE). Relying on gas and heavy fuel oil, CFE's energy costs are as high as $141/MWh. In comparison, renewable energy, without marginal costs, goes for about $20/MWh and has generally been dispatched first.

Mannti Cummins, Energía Veleta | *© RTO Insider*

No wonder, then, that as renewable developer Mannti Cummins put it, a WhatsApp war

Continued on page 3

CPUC Approves PG&E Bankruptcy Plan

Commissioners Warn PG&E that Failure Could Mean Replacement

By Hudson Sangree

The California Public Utilities Commission unanimously approved Pacific Gas and Electric's Chapter 11 reorganization plan Thursday but warned it will now have regulatory mechanisms to end the utility's century-old electric monopoly should it fail to ensure public safety.

Part of the *proposed decision* approved by the CPUC provides for a detailed six-step process of enforcement and oversight by the commission that could eventually lead to it placing conditions on — or revoking — PG&E's certificate of public convenience and necessity (CPCN), which grants the utility monopoly status over 70,000 square miles of Northern and Central California, with its 5.4 million customer accounts.

"This is the time for a PG&E to emerge from bankruptcy that must be reborn with safety as its top priority," Commissioner Clifford

Continued on page 4

PJM End-of-life Proposals Fail at MRC

By Michael Yoder

A proposal to open end-of-life (EOL) transmission projects in PJM to regional planning and competitive bidding was narrowly defeated in a vote at the Markets and Reliability Committee meeting Thursday.

The proposal *won support* from 100% of the End-Use Customers, 97% of the Electric Distributors and 71% of Generation Owners. But it was opposed by 59% of Other Suppliers and all but two of 14 Transmission Owners.

The "joint stakeholders" *proposal* from American Municipal Power (AMP), Old Dominion Electric Cooperative (ODEC) and others failed with a sector-weighted vote of 3.23 (65%). The proposal needed a sector-weighted vote of 3.33 (66.7%) for passage.

Transmission owners would have been required to notify PJM and stakeholders of any facility nearing the end of its life at least six years before its retirement date so that the project could be included in five-year planning models and potentially opened to competitive bidding. It would also modify the supplemental project definition to exclude EOL projects, which would become a new category of regionally planned projects.

A proposal by PJM also failed with a sector-weighted vote of 1.77 (36%) at the MRC.

Despite failing at the MRC, supporters of the joint stakeholders proposal unsuccessfully attempted to bring it to a vote at the Members Committee meeting in the afternoon after Chair Steve Lieberman, of AMP, recused himself from the meeting.

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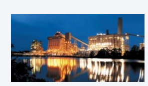

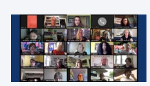

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erupted that afternoon and into the evening. (Because Mexican phone companies charge for texts, many phone users resort to the WhatsApp Messenger tool.)

"I read through [the rules], and it hurt. 'I can't believe they're doing this. I can't believe they're doing this,'" Energía Veleta's Cummins told *RTO Insider*. "It's just the weirdest thing I've ever seen.

"I've been in kind of a daze since then," he said. "This flips the whole market on its head. It kills renewables. They've taken some body blows and punches, but it's a knockout for renewables."

The new policy also limits new power generation permits and places additional restrictions on new renewable resources. That places at risk 44 renewable projects, worth about $6.4 billion, scheduled to begin commercial operation this year and next.

Mexico's Ministry of Energy (SENER) said the rules were necessary because of a drop in demand caused by coronavirus lockdowns and to preserve the grid's reliability, safety and continuity. Market participants and observers aren't buying that and note the rules will allow CFE to burn fuel oil the country's state-run petroleum company, Pemex, can't sell in a world awash with oil.

A May 18 *report* produced by global law firm Norton Rose Fulbright said, "SENER has eliminated any doubt that power sector policy in Mexico is being driven by the state-owned utility and dominant market player [CFE], rather than by sound and competitive policy principles enshrined in Mexican law."

That would make a seer of José María Lujambio, former legal counsel at Mexico's Energy Regulatory Commission (CRE) and the Austin, Texas-based energy practice leader for Mexican law firm Cacheaux Cavazos & Newton. A couple of years ago, he predicted CFE would enjoy a "privileged position" under AMLO, as López Obrador is more commonly known. (See *Changes Add Uncertainty to Mexico's Power Market*.)

"It's another chapter, perhaps the most shocking, among several specific measures that have put obstacles in place for private participation," Lujambio said last month.

Duncan Wood, director of the Wilson Center's Mexico Institute and an internationally respected specialist on North American politics, said no one should have been surprised by the recent announcements. AMLO came into power promising greater state control of the country's natural resources and cracking down on what he said was private corruption.

"Still, it came as a bit of a shock because it's such an obvious, blatant aggression against the energy reform of 2013," Wood said in a WhatsApp message. "What we're seeing here is an attempt to centralize control of the electric system, to promote CFE as the dominant actor within the electric sector.

"Ultimately, this is all about increasing political power and centralizing control over the economy," he said. "This is one way of attempting to eliminate competition for CFE, not just in terms of competition for generating electrons but about competition for the supply of electricity to the market. If CFE becomes the only actor that can supply electricity, that gives it an enormous amount of political power."

AMLO's "actions prove he wants to stick it to private companies," Cummins said.

'Huge' Potential

Ambassadors from the EU and Canada were quick to respond to the latest measures, sending letters to SENER Minister Norma Rocío Nahle on May 15 that were almost immediately leaked to the Mexican media. European companies ENGIE, Enel, Iberdrola and Vestas and several Canadian firms dominate Mexico's renewable market.

"This agreement establishes various actions and strategies [for] operational control, which put at risk the operation and continuity of renewable energy projects of Canadian companies in Mexico," wrote Graeme Clark, Canada's ambassador to Mexico.

"Potential investors will be completely freaked out by this move," Wood said.

Some market participants expect legal injunctions to stop the rules before they are in place. That's what happened following April's suspension of market tests for renewable resources. The country's grid manager backpedaled and began preoperational testing again.

Wood pointed out that during AMLO's May 18 mañanera — as his daily morning two-hour press conferences are called — the president said he respects the decision of the courts.

"I don't think this is the end of the story, however," Wood said.

SENER's proposal was published in Mexico's version of the *Federal Register* on May 15, but not before pushback from the National Commission on Regulatory Improvement (CONAMER), which determines whether new laws have an economic impact. CONAMER called for regulatory impact studies and a 20-day public comment period, saying the new measures would pose compliance costs on companies.

Those requests were to no avail. The commission's chief *resigned* the afternoon of May 15. An hour later, Cummins said, the decree was published.

"It's clearly illegal," he said. "Not only did they not follow the procedures in making changes to regulations, they pushed it through on this fast track."

"The planning and reliability of the National Electric System requires rational economic regulation for the accelerated and progressive incorporation of all energies," SENER said in a statement May 16. "In the case of intermittent energies, they must be incorporated through the intervention and necessary support of plants that have full availability and provide planning and operational reserves."

As if to rub salt in the wounds, CFE Director Manuel Bartlett *said* last month that private renewable companies should pay for part of the market's baseload power. "Do you think it's fair for the CFE to subsidize these companies that don't produce power all day?" he asked Reuters.

So where does Mexico's electricity market go now? Wood said that barring an electoral loss in 2022's "mid-terms" and an ensuing AMLO resignation, private developers will have to wait until the next administration takes over in 2024 for a change in fortunes.

"Mexico has incredible natural endowments for renewable energy," he said. "It has shown that if you create the right legal framework and regulatory framework, then companies from around the world are willing to invest in renewable energy and produce electricity at an incredible low cost.

"There are huge opportunities for renewable energy long-term," Wood said. "But short-term, not a lot." ■

CAISO/West News

CPUC Approves PG&E Bankruptcy Plan

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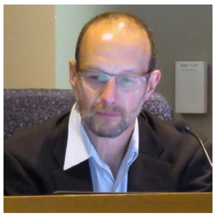
Rechtschaffen said. "Your future depends on it. There's nothing more or less than that at stake."



Commissioner Clifford Rechtschaffen | © *RTO Insider*

The CPUC decision also required PG&E to replace most of its board members and upper management, and to link executive compensation to safety performance. The utility agreed to break up its operations into eight regional entities and to allow a commission-appointed observer to report on its progress from inside corporate headquarters.

CPUC President Marybel Batjer | *California State Assembly*

CPUC President Marybel Batjer said she believed the regulations will drive change at PG&E, but if they don't, the commission is prepared to take further action.

"This transformed company must move from one that is held tightly in the grip of continual correction, of failures, to one that is a model company that is respected for how it serves its customers and community," Batjer said.

The CPUC's acceptance of PG&E's Chapter 11 plan was necessary for it to exit bankruptcy, along with the U.S. Bankruptcy Court's approval, which could come as soon as this week. (See related story, *Trial Begins to End PG&E Bankruptcy*.) The separate but parallel proceedings converged last week because the CPUC's decision, originally scheduled for May 21, was delayed by an inappropriate *ex parte* communication. (See *Improper Email Delays CPUC Vote on PG&E Plan*.)

Last year's Assembly Bill 1054 tasked the CPUC with ensuring that PG&E's reorganization plan serves the public interest, including "the electrical corporation's resulting governance structure … in light of [its] safety history, criminal probation, recent financial condition and other factors deemed relevant."

Government investigations found faulty PG&E equipment started the November 2018 Camp Fire, the deadliest in state history, as well as devastating wildfires in 2017 and 2015 and the San Bruno gas pipeline explosion in 2010.

CPUC headquarters in San Francisco | © *RTO Insider*

'We Need a Public Utility'

The series of catastrophes prompted critics to call for a state takeover of PG&E, especially after the utility filed for bankruptcy protection in January 2019 as it faced massive wildfire liabilities.

Gov. Gavin Newsom was among those who threatened state intervention should the company fail to meet his demands for a new board and management, though he ultimately agreed to PG&E's Chapter 11 plan with the CPUC's added conditions.

Dozens of public speakers in Thursday's hearing repeated calls for a public takeover, telling commissioners that PG&E's Chapter 11 proposal would not do enough to prevent future wildfires or reform its safety culture. Public comments filled the first two-and-a-half hours of the four-hour voting meeting.

Many speakers said PG&E's primary mission will remain earning profits and rewarding shareholders, the same behavior that they said led to the fires of 2017 and 2018. In April 2019, federal Judge William Alsup, who is overseeing PG&E's criminal probation stemming from the San Bruno gas explosion, said the utility paid out $4.5 billion in dividends in recent years while neglecting tree trimming and other line maintenance, resulting in the wildfires.

Charlotte Quinn, with the Democratic Socialists of America, told the commissioners that PG&E needs to be accountable to voters, not shareholders.

"We need a public utility," Quinn said. "The existing and proposed for-profit model is the cause of fires and explosions, death and destruction and old, unsafe infrastructure. Until the profit motive is removed, the energy grid will remain unsafe for communities, just as it has been proven over and over again."

CPUC Commissioner Martha Guzman Aceves | © *RTO Insider*

Commissioner Martha Guzman Aceves said she shared such concerns but was reassured by a bill in the State Legislature that could provide a means for turning PG&E into a public-benefit corporation called Golden State Energy. The measure, Senate Bill 350, by Sen. Jerry Hill, was scheduled for a hearing Thursday in the Assembly Utilities and Energy Committee.

Statutory authority for replacing PG&E as a for-profit monopoly has been lacking, Guzman Aceves noted.

"Fortunately today, through the governor's leadership and the legislative leadership, we have Sen. Hill's bill, SB 350, that will soon provide us as a state with the tools to replace PG&E with a customer-elected public option should they fail," Guzman Aceves said. "This bill will give ratepayers a genuine alternative. If PG&E fails to provide safe, reliable and affordable energy service, then the commission could petition the court to appoint a receiver or revoke PG&E's CPCN." ■

CAISO/West News

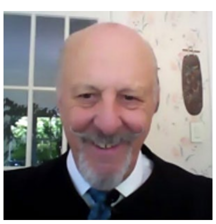
Trial Begins to End PG&E Bankruptcy

Skeptics Get Last Chance to Sound off on Company's Plan

Judge Dennis Montali confers with lawyers for PG&E and fire victims by Zoom video on May 27.

By Robert Mullin and Hudson Sangree

A three-day trial that could conclude the bankruptcy of Pacific Gas and Electric began Wednesday via videoconference, with the judge presiding from his breakfast room.



Judge Dennis Montali presided over the trial from his Bay Area home.

PG&E's Chapter 11 case is the sixth-largest bankruptcy in U.S. history and by far the largest of any energy utility. The COVID-19 crisis has forced it to be decided by U.S. Bankruptcy Court Judge Dennis Montali from his home, with lawyers arguing from remote locations.

The "confirmation" proceedings to approve or deny PG&E's proposed reorganization plan lasted just an hour on the first day, with only one witness called: Christina Pullo, a vice president with claims administrator Prime Clerk. On Thursday, the utility's chief financial officer took to the virtual stand in bankruptcy court to face questions about the "feasibility" and "fairness" of the utility's reorganization plan for the thousands of victims of wildfires sparked by its equipment.

Pullo confirmed the results of the vote, previously filed in court papers, that showed at least 85% of fire victims and an overwhelming majority of other creditors approved of PG&E's reorganization plan. That plan, valued at close to $60 billion, includes $13.5 billion for fire victims, $11 billion for the insurance companies and hedge funds that hold third-party subrogation claims, and $1 billion in compensation to local governments for fire-related expenses. (See *PG&E Bankruptcy Moves Toward Conclusion*.)

The company plans to issue nearly $26 billion in new stock to help pay for the plan.

Pullo faced cross-examination by William Abrams, a wildfire victim who has represented himself throughout the proceedings. Abrams has repeatedly said he opposes the plan because it doesn't do enough to ensure victims get paid or to force PG&E to become a safer utility.

On Wednesday, he asked Pullo about alleged voting irregularities and about Prime Clerk's connection to PG&E via its parent company Duff & Phelps, which Abrams said holds a sizable stake in PG&E. As a non-lawyer, his questioning was frequently interrupted by instructions from the judge and objections from some of the dozen or so attorneys who participated in the hearing.

The next day, Tom Tosdal, an attorney representing about 1,000 victims of the 2018 Camp Fire, pressed CFO Jason Wells on the bankruptcy soundness — and justness — of the trust.

Of the nearly 40 classes of claimants in the bankruptcy proceeding, Tosdal noted, only the fire victims were being compensated with stock whose value is tied to PG&E's future performance — a risk in the face of ongoing wildfire threats that could bring more claims against the utility in the future.

Tosdal said the fire victims were being treated worse than subrogation claimants poised to receive full cash settlements. He said the subrogation class itself consisted of two "types": insurers that have paid out claims to their customers and PG&E shareholders that purchased subrogation claims against the company before it entered bankruptcy.

Tosdal cited the hedge fund Baupost, a PG&E investor that starting in November 2018 *bought* $6 billion in claims against the utility for 30 to 35 cents on the dollar — prompting an objection from PG&E attorney Theodore Tsekerides.

"I don't think that's relevant to any of the discussions of the classification issue — who holds those claims. They are what they are," Tsekerides said.

"It goes to fairness, your honor," Tosdal said. Montali allowed Tosdal to proceed.

Tosdal asked Wells if Baupost owned many shares of PG&E common stock.

CAISO/West News

"They do," Wells replied.

"And do you understand that Baupost bought those subrogation claims at a discount, meaning less than 100% on the dollar?" Tosdal asked.

"I do," Wells said.

But Wells demurred when Tosdal then asked if he knew that PG&E investors paid a "substantial discount" in their purchase of company subrogation claims.

"So, when this bankruptcy ends, and the subro class is paid $11 billion cash, those PG&E investors, who purchased subro claims against their own company at a substantial discount, stand to make a big profit, correct?" Tosdal continued.

Tsekerides again objected, saying the issue of the discount is "completely irrelevant" to the issue of confirming the bankruptcy plan. Such claims are traded "all the time" in Chapter 11 cases, he said.

Montali turned to Tosdal: "Why is it helpful for to me to make a determination? It is a fact of life that claims are traded at discounts in lots of companies. Why is it relevant to my determination?"

"Because, your honor, when we started this case, I remember that you told everybody on the record, [in the] first hearing, that the most important group in this case to be taken care of are the fire victims," Tosdal said. "And instead, what is happening here is that the fire victims are getting stock instead of cash, and the effect of that is to provide investors in this company, who have purchased subrogation claims at a discount, with billions of dollars of profit. That is the reality, whether it's customary for there to be a second market."

Montali shut down Tosdal's argument, sustaining Tsekerides' second objection.

"The fact that an investor, whether it be Baupost or Joe Blow, bought a claim at a discount has nothing to do with how that person will end up being treated," the judge said. "Your argument tells me that you or your clients don't like the plan. But the plan isn't going to turn on the discount rate that an investor paid or didn't pay. The fact of the matter is a subrogation creditor who didn't sell his claim at a discount is going to be treated the same as a speculator who bought another subrogation claim at a discount. It doesn't matter."

The question of the "feasibility" of the wildfire victims' trust was at the heart of questions from Abrams, who focused on the concern that claims from future wildfires could compromise the value of a trust heavily dependent on the company's share price.

"Would you agree that more wildfires are a risk to the feasibility of the plan?" Abrams asked Wells.

"The risk of catastrophic fires is something that we're actively managing," Wells responded. "The combination of all of the work we're doing to prevent those fires, as well as the passage of Assembly Bill 1054, create the conditions that would make our plan financially feasible." Passed by the California legislature last year, AB 1054 establishes a wildfire insurance fund for the state's utilities. PG&E must exit bankruptcy by June 30 to qualify for coverage under the bill.

Abrams questioned PG&E's ability to mitigate future wildfire risk, citing its past record and what he called its current lack of preparedness. Wildfires are up 60% in California for the first four months of this year compared with last, *according* to Gov. Gavin Newsom.

Abrams pointed to recent finding by U.S. Judge William Alsup, who is overseeing PG&E's criminal probation for causing the 2010 San Bruno pipeline explosion, that the company must quickly improve its safety performance to avoid sparking new wildfires. (See *Judge Orders PG&E to Improve Line Inspections*.)

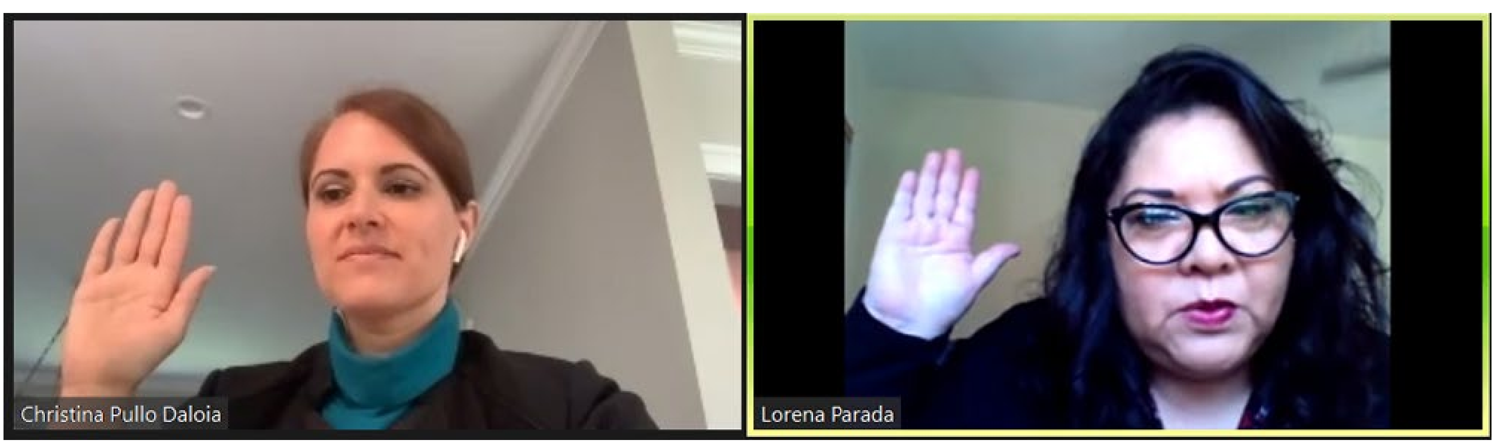
Overcoming an objection from Tsekerides, Abrams pressed Wells about the number of C-hooks the company has replaced in its aging transmission network (Wells didn't know) and how much of its annual vegetation management program it has completed this year (one-third as of the end of the first quarter, Wells said).

While Montali provided Abrams with ample time to argue his points and air his views, the judge also evinced skepticism that he will be swayed by his challenge to the utility's plan.

"You, for one, don't have a lot of confidence in PG&E going forward, but that's not the point," Montali told Abrams. "I have to see if the Bankruptcy Code has been satisfied, and it gets [to be] more than that, because the governor has to be satisfied; the Public Utilities Commission has to be satisfied. And you may be unsatisfied, but if all of those things come together, I then have to be persuaded that PG&E is not likely to need further reorganization under the bankruptcy laws."

The California PUC on Thursday voted unanimously to approve PG&E's bankruptcy plan, a key step in moving the plan forward. (See related story, *CPUC Approves PG&E Bankruptcy Plan*.)

Confirmation hearings will continue into this week, when the bankruptcy court will listen to legal arguments related to the plan. ■



Court clerk Lorena Parada swears in witness Christina Pullo of Prime Clerk at the start of the trial.

ERCOT News

ERCOT Technical Advisory Committee Briefs

Stakeholders Endorse Voting Changes for Virtual Meetings

Given the continued uncertainty of future in-person meetings, ERCOT stakeholders last week endorsed several bylaw amendments and rule changes to improve electronic meetings and votes.

As if to hammer the point home, the changes were among 15 voting items in an email vote that did not become official for two days. ERCOT rules currently require two full business days to allow stakeholders to return their votes.

Vickie Leady, ERCOT's assistant general counsel, told the Technical Advisory Committee on Wednesday that the grid operator's bylaws "never contemplated a situation with the scale and duration" in which stakeholders "could not safely convene together in one place."

"It's creating a risk to ERCOT," Leady said.

ERCOT closed its facilities to most outside visitors and canceled in-person meetings in early March. Meetings have been conducted virtually ever since.

Legal staff proposed widening the definition of "urgent matters" to include when it would be "difficult or impossible" for a quorum of directors or subcommittee members to physically convene in one location. The changes would allow teleconference meetings and actions that, if otherwise delayed, "may result in operational (including, but not limited to those activities and functions affecting the ERCOT market or system), regulatory, legal, organizational or governance risk."

Staff made other changes to the bylaws to

Cheniere Energy's Corpus Christi LNG plant is fueling the need for additional transmission infrastructure. | *Bechtel*

closely align with the Texas Open Meetings Act and Texas Business Organizations Code's teleconference technology methods.

The changes will now go before the Board of Directors during its June 9 teleconference. If approved, the board would issue a call on June 10 for a special meeting to vote on the bylaw changes by July 2. The changes would then be filed with the Texas Public Utility Commission by July 31 for its approval.

The TAC also approved several changes to its rules allowing for roll call votes. Chair Bob Helton, with ENGIE, said the committee would be using consent agendas to compensate for the extra time taken by email votes.

Corpus Christi Tx Project Gets OK

The TAC unanimously approved a $219 million transmission project, previously approved by the Regional Planning Group, that addresses more than 1 GW of future industrial load growth on the north shore of Corpus Christi Bay expected by 2024.

As recommended by staff following an independent review of AEP Texas' proposal, the Corpus Christi North Shore RPG Project will comprise 36 miles of 345-kV lines, 8 miles of new and upgraded 138-kV lines, two new 345-kV substations and three 345/138-kV transformers.

LNG plants account for more than half of the additional load. Cheniere Energy has developed an LNG export terminal in Corpus Christi's harbor. Two trains are currently in operation, with a third planned to come online in the first half of 2021.

ERCOT's review concluded that its recommended option does not cause new or additional congestion. Staff determined the 138-kV upgrade met economic planning criteria and added it to the project.

AEP's Richard Ross said the company "supports and is comfortable at this point in time" with ERCOT's recommendation.

Cheniere's Corpus Christi LNG plant under construction | *Cheniere Energy*

ERS Payments up 1.6% to $48.2M

Staff shared ERCOT's *annual report* on its emergency response service but received no questions from members. The report is required annually by the PUC (*27706*).

According to the report, demand response and behind-the-meter generation received $48.2 million in capacity payments during the pro-

ERCOT News

gram year for curtailing load or sending power to the grid, a 1.6% increase from the $47.5 million for the previous time period.

ERCOT deployed ERS twice last year during August's two energy emergency alerts. The two deployments lasted a total of 95 minutes.

Members Disagree over Change to ERS' Return

The TAC on Friday took up a second email vote to consider the only Nodal Protocol revision request (*NPRR1006*) that did not clear the email vote.

In a vote that closes at 5 p.m. today, committee members will weigh NPRR1006's approval as amended by comments from Direct Energy.

The NPRR had received only four votes (Lower Colorado River Authority, South Texas Electric Cooperative, Exelon and Reliant Energy Retail Services), with 20 members opposing and two abstaining.

The change would return ERS resources in a linear curve over a four-and-a-half-hour period following recall, instead of 10 hours. It also changes the process for annually updating the parameter by removing a real-time deployment price adder from the real-time ancillary service imbalance payment or charge.

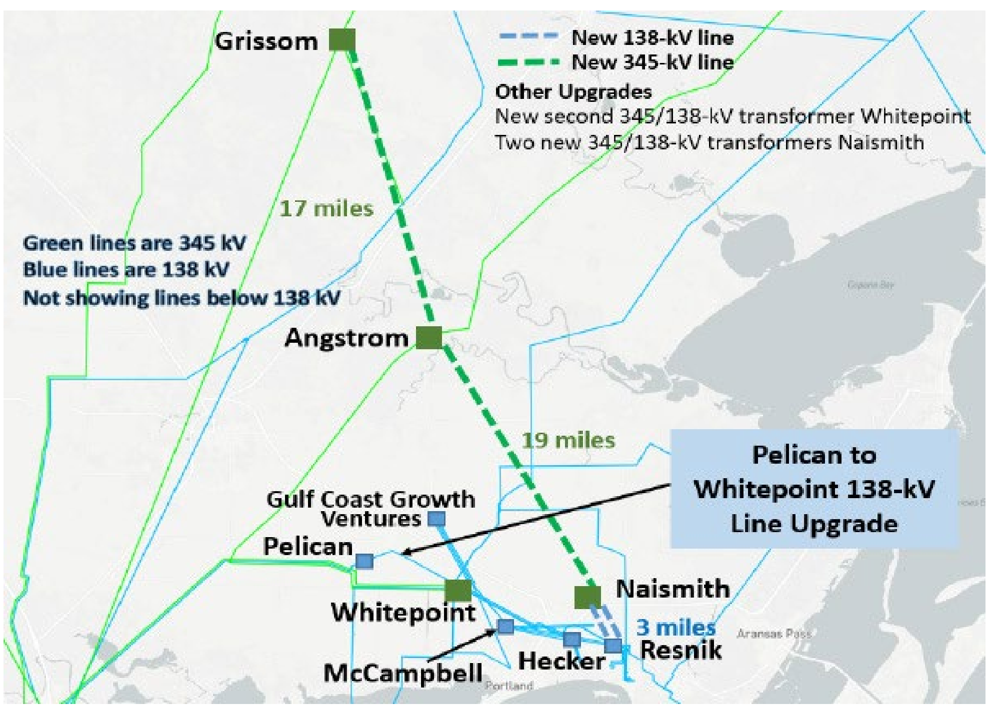
Direct Energy expressed concern over the unintended consequences of the price adder's elimination from the equation. The company urged interested parties to file their proposed changes in a separate NPRR "to facilitate the quick movement of the original intent of this NPRR through the approval process."

Direct Energy's Sandy Morris said stakeholders have not had the time or analysis to understand the full implications of the proposed change. Should the matter be separated, she wrote, "it could possibly continue through the proper channels of analysis and debate and still be implemented at the same time as … NPRR1006."

The committee's email vote unanimously approved eight other NPRRs, a change to the Nodal Operating Guide, an Other Binding Document revision request (OBDRR) and two system change requests (SCRs):

- *NPRR933*: adds specific timing requirements for retail electric providers and non-opt-in entities to notify ERCOT of the DR and price-response programs they offer to customers, the level of participation in those programs and the deployment events associated with those programs.
- *NPRR975*: clarifies that load forecast models will be used to select the seven-day load forecast based on expected weather and requires ERCOT operations to explain its selection, improving transparency for market participants.
- *NPRR987*: includes the contribution of energy storage resources (ESRs) to physical responsive capability and real-time online reserve capacity in the ancillary service imbalance calculation.
- *NPRR989*: establishes ESRs' technical requirements for voltage support service (including reactive power capability) and primary frequency response.
- *NPRR1018*: clarifies several provisions regarding the termination and suspension of a qualified scheduling entity (QSE) and the ability of a load-serving entity or resource entity to act as a "virtual" or "emergency" QSE.
- *NPRR1019*: addresses switchable generation resources (SWGRs) moving from a non-ERCOT control area to the ERCOT control area by creating a proxy energy offer curve with a price floor of $4,500/MWh for each RUC-committed SWGR and including a lost revenue cost component to the switchable generation cost guarantee.
- *NPRR1021*: shortens the default uplift invoice's issuance timeline from 180 days to 90 days and allows ERCOT to use the best available settlement data when calculating each counterparty's share of the default uplift.
- *NPRR1022*: modifies how QSEs and congestion revenue right account holders (CRRAHs) submit banking information changes to ERCOT by removing the ability to submit the information with a Notice of Change of Information via email or fax. The NPRR creates a new form, Notice of Change of Banking Information, that a QSE/CRRAH must execute and submit through the market information system's certified area.
- *NOGRR204*: together with NPRR989, codifies concepts described in the Battery Energy Storage Task Force key topics and concepts No. 4 (*KTC-4*) and establishes ESR technical requirements.
- *OBDRR017*: aligns language within the operating reserve demand curve's methodology for calculating the real-time reserve price adder with protocol revisions under NPRR987 and changes the real-time operating reserve calculation to consider an ESR's state of charge when calculating the resource's contribution to the online operating reserves.
- *SCR807*: increases the CRRAHs' total CRR transaction limit by 33% to 400,000 market transactions during CRR auctions.
- *SCR809*: updates the validation rules imposed on ERCOT's external telemetry and used in the resource limit calculator. ■

— Tom Kleckner



The Corpus Christi North Shore Project addresses LNG and other industrial growth. | *ERCOT*

ISO-NE News

NEPOOL Markets/Reliability Committee Briefs

Planning Continues for Future Grid

Participants at a joint meeting of the New England Power Pool Markets and Reliability committees were encouraged to look west, think big, consider NYISO's example in planning for a grid in transition and keep the bigger picture in mind to avoid getting bogged down in irrelevant details.

Advanced Energy Economy (AEE) submitted a *paper* recommending that ISO-NE and NEPOOL consider borrowing from NYISO's effort, which identified as its central proposition: "how the wholesale markets in New York can continue to provide the pricing and investment signals necessary to reflect system needs and to incent resources capable of resolving those needs."

New England's study "should similarly address the transition to the future grid, not just the end state," AEE said.

NYISO in December 2019 issued its Grid in Transition *report* to map the planning for a grid increasingly dominated by a slew of clean energy resources, a transition driven primarily by state policy. The ISO this year is devoting at least one day a month for stakeholders to discuss reliability and market issues related to the challenge of integrating renewable resources. (See *NYISO Focus Turns to Grid 'Transition'*.)

"Importantly, discussion of these potential market reforms is not being held up while The Brattle Group completes a longer-term quantitative analysis as part of a related but separate process that kicked off earlier this year," AEE said.

Brattle representatives in May presented NYISO stakeholders with an interim report on New York's evolution to a zero-emission power system, modeling operations and investment in scenarios of increasing electrification for the years 2024, 2030 and 2040. They are considering feedback before presenting the final study results in June. (See *NYISO Examines 'Evolution' to Zero Emissions*.)

Focus on Task

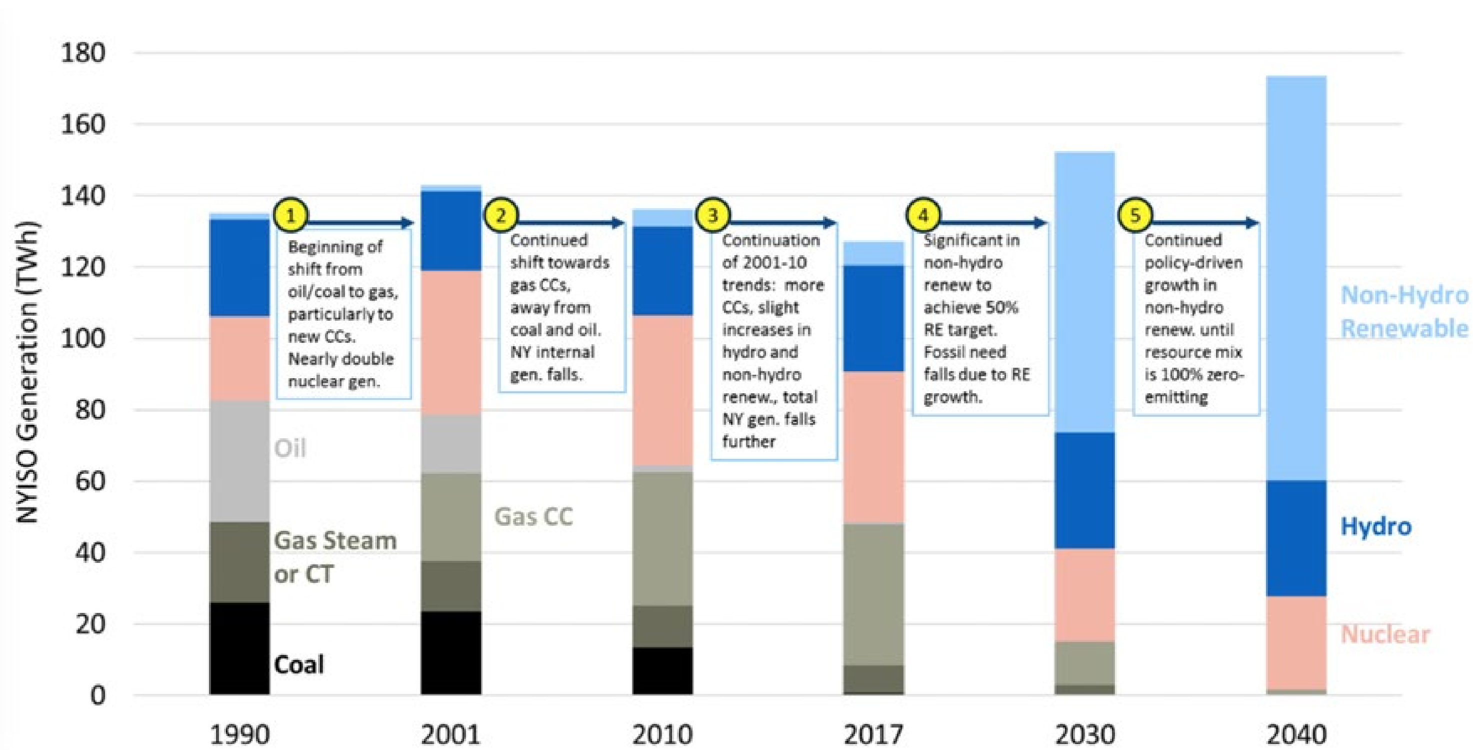
New England States Committee on Electricity Senior Counsel Ben D'Antonio *presented* NESCOE staff's preliminary thinking on the transition study that NEPOOL expressed interest in conducting. The presentation was to focus stakeholders on prior and ongoing studies to help define what study areas remain.

In response to a stakeholder question about possible gaps in current market rules, NESCOE Director of Analysis Jeff Bentz clarified the states' collective aim.

"We didn't want to be in a place where we are with ESI [Energy Security Improvements], where we have this market construct problem and we're all forced to do it in a hurry," Bentz said. "The idea here was, can we look at where we think we're going to be 10 years from now and then try to determine whether the market construct we have today will work in that future state, and if not, what market construct will we need?" (See *ISO-NE Sending 2 Energy Security Plans to FERC*.)

[Note: Although NEPOOL rules prohibit quoting speakers at meetings, those quoted in this article approved their remarks afterward to clarify their presentations.]

Bentz added that "by knowing where we need to be in the future, it could inform the best transition path."



Change in New York supply, 1990-2040 | *NYISO*

ISO-NE News

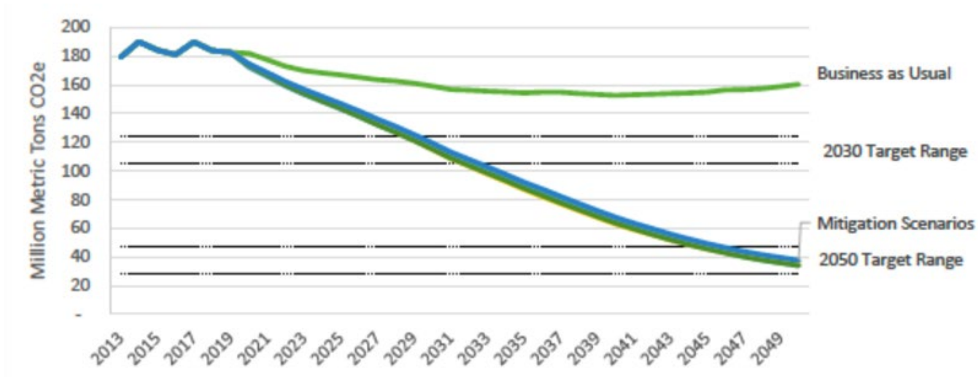
Pete Fuller of Autumn Lane Energy agreed that NEPOOL and the RTO need to focus on a "broad-brush" effort.

The goal isn't to hit a precise target, such as "intercepting an asteroid in a particular time and place," but to establish a market framework to move the system in the right direction, said Fuller, who presented *recommendations* with the endorsement of NEPOOL members NRG Energy and Sunrun.

"I'm concerned that we could get ourselves caught in some highly detailed analysis ... and missing the big picture here," Fuller said.

"I think we can make a number of assumptions about what is the transmission topology and that it will resolve itself over time as offshore wind gets developed and integrated, as new resources enter, as electrification happens and flows change, as energy storage comes and so forth," Fuller said. "That all can largely be left to be worked out by parallel, different processes, not this one."

Giving policymakers comprehensive economic comparisons of various levels of decarbonization? Determining whether the region needs a higher-voltage bulk network, potentially including offshore cables, to integrate the future resource mix? Evaluating the technical potential and viability of hydrogen electrolysis and storage, CCS, modular nuclear and any number of other new technologies?



NESCOE points out the gap in current studies between business-as-usual versus mitigation scenarios through 2050 for New England. | *NESCAUM*

"That's not our task here," Fuller said.

The task, according to Fuller, is to focus on two key questions: "Will our current market designs support a reliable low-carbon resource mix? And if not, what should we do about it?"

Future is Now

Other stakeholders said that New England has already effectively started the future grid planning process, as Brattle last September issued a *study* on what the region must do to achieve at least an 80% reduction in greenhouse gas emissions by 2050.

Xiaochuan Luo, ISO-NE technical manager for business architecture and technology, presented a *slidedeck* covering the RTO's current capabilities for modeling and tools addressing various time horizons.

"If the Future Grid study would benefit from these capabilities, the ISO offers them to assist in that effort," Luo said. "If there is a gap between our modeling processes and tools and those deemed necessary for the Future Grid studies, the ISO will work with stakeholders on the best way to address such gaps."

The RTO is accepting stakeholder proposals for what kinds of analysis should be performed in the future grid study and associated analysis assumptions this year, with agenda topics and timing to be submitted to the MC *secretary* by June 12 for the next meeting. ■

— Michael Kuser

ISO-NE News

NEPOOL Transmission Committee Briefs

Further Compliance with Order 845

The New England Power Pool Transmission Committee on May 26 voted to recommend the Participants Committee support ISO-NE's filing to address rejected portions its FERC Order 845 compliance filing (ER19-1951).

The PC will vote on the issue at its meeting Thursday.

FERC issued Order 845 in 2018 to set *pro forma* minimum standards for large generator interconnection procedures and agreements. In its March ruling on ISO-NE's original compliance filing, the commission rejected the RTO's proposed rules related to the availability of surplus interconnection service (SIS), which allows an affiliate or third party to obtain unused interconnection service from an original customer. That was followed by a May 19 *rejection* of the RTO's request for clarification on the issue.

"While ISO-NE's pleading nominally styles itself as a 'Motion for Clarification,' in substance, it is a request for rehearing because, for example, ISO-NE is asking the commission to reconsider the requirement to identify the specific upgrades necessary for surplus interconnection service," FERC said.

ISO-NE Director of Transmission Strategy and Services Al McBride presented the RTO's *plans* regarding the application of SIS in relation to network resource interconnection service, developed in response to stakeholder feedback from the April TC meeting. (See *NEPOOL Transmission Committee Briefs: April 28, 2020*.)

"Committee members described how arrangements could be made, for example, to identify when the surplus customer would not operate when the original customer needed to operate," McBride's presentation noted.

McBride said the ISO-NE has continued to "evolve" its understanding of how co-located resources using SIS can operate in the energy and capacity markets, including when a limiting device is used to limit the overall output of a co-located facility. The RTO is proposing that the original interconnection customer would identify and eventually memorialize in the interconnection agreement the terms of use of the SIS, McBride said.

The RTO is also now proposing to adopt FERC's Order 845/845-A pro forma language regarding the scope of study for SIS requests, he said.

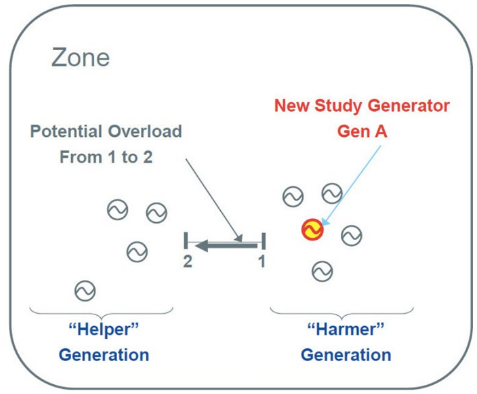
"They did speak to the scope of study in their response, and I think that essentially constituted feedback to us," McBride said.

[Note: Although NEPOOL rules prohibit quoting speakers at meetings, those quoted in this article approved their remarks afterward to clarify their presentations.]

Further changes will become effective March 19 if accepted by the commission, with the compliance filing required by July 17.

Settlement with NETOs on PTO Rates

The TC voted to recommend that the PC support ISO-NE Tariff revisions to carry out the settlement agreed to among New England Transmission Owners (NETOs), FERC staff and municipal utilities on pool transmission formula rates (EL16-19).



The Network Capability Interconnection Standard Test helps ISO-NE ensure that a new generating resource under study does not cause overloads that cannot be fixed in time for the capacity commitment period. | *ISO-NE*

A FERC administrative law judge on April 22 *ordered* the hearing in abeyance until early June because of delays related to the COVID-19 pandemic.

On behalf of the NETOs, Eversource Energy's director of transmission rates and revenue requirements, Lisa Cooper, updated the TC, as she did in April, on the regional network service settlement proceeding initiated by the commission in 2015. The TC discussed the matter in executive session. ■

— Michael Kuser

MISO News

Price Tag Rising for MTEP 20

By Amanda Durish Cook

The 2020 MISO Transmission Expansion Plan (MTEP 20) is shaping up to become one of the RTO's most expensive ever.

Being developed virtually with stakeholders because of COVID-19 measures, the plan so far contains 510 proposed projects at a combined $4.06 billion, the priciest since MISO's 2011 multi-value project portfolio. If approved by the RTO's Board of Directors in December, MTEP 20 will best last year's plan, which rang in with 480 projects at $4 billion. (See *MISO Board OKs $4 Billion MTEP 19*.)

Broken down, the transmission investment contains:

- 149 reliability-related projects at nearly $1.1 billion;
- 133 age- and condition-related upgrades at $1.05 billion;
- 77 baseline reliability projects at $783 million;
- 88 generator interconnection projects at $512 million;
- 55 projects necessary to accommodate load growth at $606 million; and
- eight projects to be built for other local needs at $26 million.

Of those, MISO South accounts for 47 project proposals valued at $750 million.

Stakeholders at subregional planning meetings last week wondered whether some load-growth projects may be scaled back or withdrawn as the catastrophic economic impact of the COVID-19 pandemic continues to play out.

MISO Senior Manager of Expansion Planning Edin Habibovic said transmission owners might revise some projects based on COVID-19 effects, adding that the RTO will have more information on individual load-growth projects during a final round of subregional planning meetings in August. He said discussions over why some load-growth projects drop out likely won't be disclosed publicly.

Ameren Illinois and Entergy Texas have so far submitted some of the costliest MTEP 20 projects, with the former planning four projects between $74 million and $91 million for reliability and age and condition needs, while the latter is tendering three projects between $65 million and $77 million in response to load growth in its territory.

MISO said it will test one of Ameren's reliability project submissions — the 345-kV New Holland NW-Neoga South line rebuild in central Illinois — for economic benefits that might allow it to be cost-shared as a market efficiency project.

Altogether, Ameren proposed 152 new projects at an estimated $1.4 billion in its Illinois and Missouri service areas.

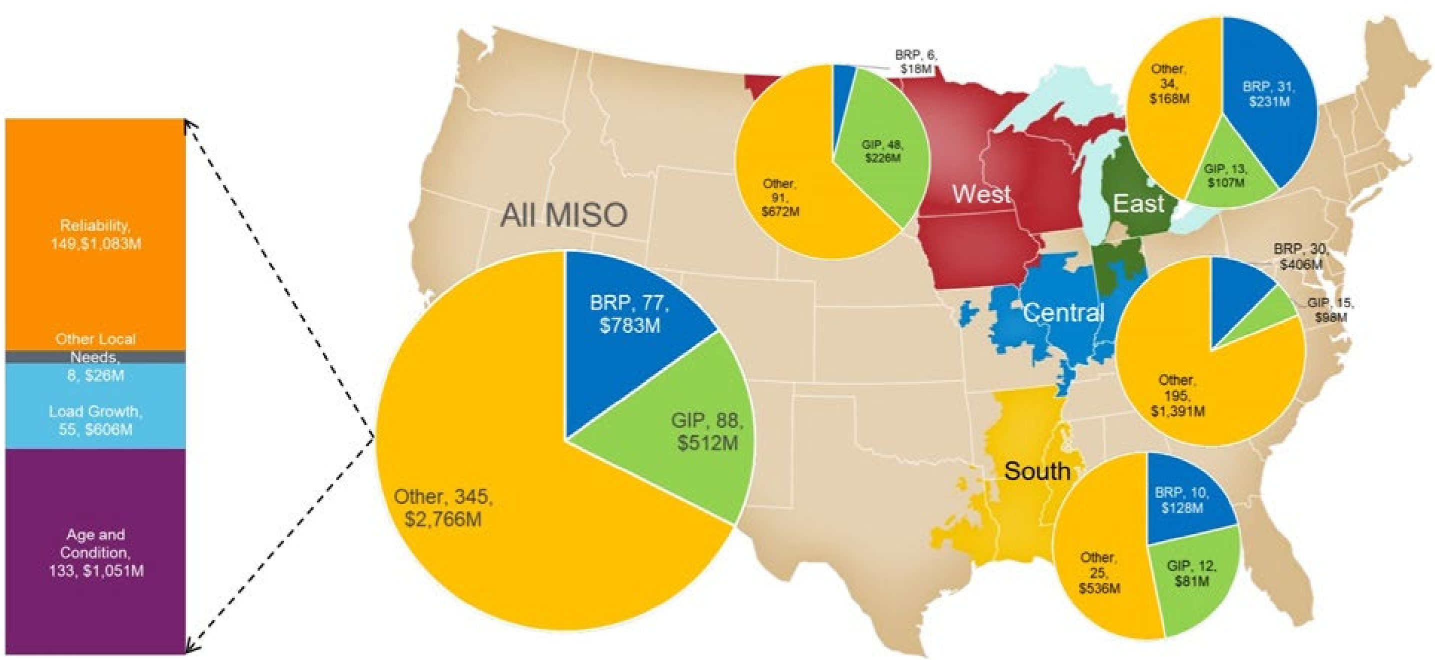
Some stakeholders asked why Ameren was suddenly making such big investments in transmission.

MISO expansion planning team member Scott Goodwin said Ameren is this year using a three- to five-year outlook on transmission projects instead of an annual planning horizon. Senior Manager of Expansion Planning Thompson Adu also said MISO has been coordinating with Ameren on issues that require transmission upgrades.

"We make sure we agree with the projects and justifications that they have given to us," Adu said.

Stakeholders also asked if MISO performs any

Continued on page 14



MTEP 20 project investment by region | *MISO*

MISO News

UCS Analysis Knocks Coal Self-commitments

By Amanda Durish Cook

Dolet Hills power plant | *Cleco Power*

Coal plant self-commitments saddled Midwest electricity customers with $350 million in unnecessary costs in 2018, according to a new analysis from the Union of Concerned Scientists, which is calling on regulators to rein in the practice through investigations.

"*Used, But How Useful?*" concludes that individual ratepayers could have saved an average of $60 if the most efficient existing resources in MISO were deployed instead of coal self-scheduling in 2018.

"We found that not every coal plant in the Midwest operated uneconomically, but the utilities that did it the most drove down market prices, effectively squeezing out cleaner, cheaper sources such as wind and solar power," Sandra Sattler, senior energy modeler at UCS, said in a press release.

UCS said savings from eliminating the self-dispatches could have more than doubled the amount MISO claimed it saved its members that year through efficient centralized dispatch. The RTO's 2018 *value proposition* estimated its efficient energy dispatch saved members anywhere from $282 million to $312 million during the year.

"We decided that having a published report on which utilities were not acting in the public interest would be useful to regulators. We hope this will be a helpful tool for commissioners trying to tackle this problem," UCS Climate and Energy Senior Energy Analyst Joe Daniel told *RTO Insider*.

This isn't the first time UCS has publicly questioned the practice of vertically integrated utilities being allowed to operate units out of merit at times when their production costs exceed the wholesale market price. UCS pressed the issue last year at the National Association of Regulatory Utility Commissioners' annual meeting. (See *Enviros, States Question Coal Self-commitments*.)

Daniel said the solution isn't as simple as just abolishing must-run designations in MISO.

"There are plenty of power plants that use the must-run designation economically," he said. "The uneconomic commitments will continue in another loophole unless state regulators come in and stop it."

Daniel said a good first step for regulators is to open investigatory dockets into utilities that exhibit high costs.

"That way there's a frank discussion between regulators, utilities and intervenors," Daniel said. "The regulators have an obligation to disallow imprudent costs. … Running power plants that are expensive when there's lower-cost energy available on the open market is imprudent. … If a commission would scrutinize and disallow tens of millions in imprudent costs, I am confident that the utility's reaction would be to figure out how to solve the problem themselves. Smart utilities won't let it get to that point. Smart utilities will see that commissions are taking things seriously and be proactive."

When the Minnesota Public Utilities Commission opened a docket last year to investigate Xcel Energy's self-scheduling of coal plants, Daniel said, the utility quickly proposed converting its coal plants to seasonal and economic use. Missouri and Indiana have also opened investigatory dockets into utility self-commitments. (See *Ind. Regulators Scrutinize Duke Self-commitments*.)

Biggest Offenders

According to the UCS report, Xcel subsidiary Northern States Power uneconomically ran its Allen S. King and Sherburne Country coal plants at a $56.9 million loss in 2018. If the utility had opted for more efficient generation in the MISO market, the average residential ratepayer could have saved $54 that year, UCS said.

UCS named Cleco Power the worst offender, saying it uneconomically generated electricity from its Dolet Hills and Brame Energy Center coal plants at a $123.3 million loss in 2018, costing Louisiana ratepayers an average of $184 over the year compared with more economic electricity available in the market.

Dolet Hills co-owners Cleco and Southwestern Electric Power Co. have indicated they may retire the plant as early as 2021. Earlier this year, the utilities agreed to retire the plant by 2026 as part of a deal reached with the Sierra Club. The conservation group has claimed that closing the plant would save ratepayers more than $60 million per year.

Cleco spokesperson Jennifer Cahill pointed out that the company and SWEPCO pledged beginning last year to only operate Dolet Hills in the demand-heavy summer months, or when requested by MISO.

"Furthermore, Cleco Power intends to seek regulatory approval to retire the Dolet Hills Power Station and the nearby mine that supplies the plant with coal. The closing dates for the power station and mine will be subject to discussions with stakeholders, including the Louisiana Public Service Commission and regional transmission organizations," Cahill said in an email to *RTO Insider*.

MISO News

DTE Energy's five coal plants uneconomically generated power at a $94.7 million loss in 2018, costing individual ratepayers an extra $61, UCS also reported.

UCS said MISO's greatest potential for savings "generally appear where the worst actors operated: Xcel Energy in Zone 1, Cleco in Zone 9, and DTE and Consumers Energy in Zone 7."

The report also said coal self-commitments in MISO suppressed market clearing prices by 2.4% — or 63 cents/MWh — in 2018. The group also noted the self-commitments suppress independent power producers' revenue in "all MISO transmission zones."

"By exploiting gaps in regulatory oversight and loopholes in wholesale market rules, rate-regulated utilities are cutting ahead in the merit-order line. Rate regulation, coupled with a lack of scrutiny when it comes to cost recovery, has enabled these utilities to lose money in the market without incurring actual losses on their balance sheets," UCS wrote, adding that in many parts of the U.S., the cost to buy and burn coal "exceeds the market price in most hours of the year."

Self-commitment 'Loopholes'

UCS said it makes economic sense for coal plants to respond to market price signals and begin operating more infrequently, allowing lower-cost natural gas and renewables to fill the gap. But the group characterized existing state regulatory frameworks and rate cases as "loopholes" that allow unchecked self-commitment decisions to persist.

"It is doubtful that changes to this practice will materialize if regulated utilities are continually allowed to recover fuel costs, without scrutiny or incentives to improve operations," UCS said. "Utilities will throw up strawman excuses for why their coal plants are so uneconomic, but it is not incumbent on the regulator to innovate on behalf of the utility. Rather, utility companies are obligated to come up with a solution, and regulators should either approve or disapprove of the companies' proposals."

Daniel said residential ratepayer costs are more important than ever, with many staying at home more often because of the ongoing coronavirus pandemic.

And he said new resource additions to achieve UCS' saving estimates are unnecessary.

"You could safely operate the grid with lower-cost existing resources that already exist. You should use what you have as efficiently as possible. And that's not what happening. Utilities are preferentially selecting coal-powered plants at the expense of customers," Daniel said.

To arrive at the millions in potential savings, UCS used modeling software that accounts for MISO system limitations, transmission constraints and power plants' ramping times and capabilities, Daniel said.

He acknowledged that MISO aggregates the number of uneconomic coal commitments in its footprint but doesn't call out specific generators or utilities like UCS' latest analysis.

"What really differentiates this research is we used a production cost model and the same software MISO does to come up with these numbers," Daniel said. ■

Price Tag Rising for MTEP 20

Continued from page 12

research to confirm the necessity of TOs' age and condition projects.

Adu said TOs must justify those projects to MISO, but not all of them provide photos or engineering analyses.

No Midwest-South Tx Solution this Year

MTEP 20 will not contain a long-awaited transmission upgrade to secure more transfer capability on the Midwest-South subregional transmission constraint, stakeholders also learned.

David Severson, a MISO economic studies engineer, said that while there were a "couple promising project candidates," the RTO will not recommend any Midwest-South transmission projects to the board this year.

Last year, MISO received and screened 35 project ideas to reduce dependence on its Midwest-South transfer constraint. Nine projects passed an initial screening, with three of those showing the required 1:1 or better cost-benefit ratio. (See *MISO Floats New Option for Midwest-South Constraint*.)

Missouri Public Service Commission economist Adam McKinnie asked why MISO planners don't submit one of the three project finalists for consideration in the 2020 cycle of the RTO's and coordinated system plan with SPP, developed to identify potential interregional economic transmission projects.

"I'm waiting for a good reason to hold off on a good solution for another year," McKinnie said. The transfer limit study has been ongoing since the MTEP 19 cycle.

"We can use the project candidates for a really good starting point in the future," Severson said. "Further study efforts under an expanded scope would be better served under MTEP 21 future assumptions and models." MISO is currently redoing its 20-year futures assumptions to factor increased renewable generation and zero-carbon goals in time for the 2021 cycle of transmission planning.

Some stakeholders have criticized the study, saying that MISO focused too narrowly on only increasing the existing contract path capacity and not on a potentially more beneficial increase in physical transfer capability located somewhere else between the Midwest and South regions.

North Study Extends into 2021

Meanwhile, results are pending on MISO's other special MTEP 20 study on the North Region economic transfer. The study evaluates transfer limitations caused by non-thermal constraints between the renewable-rich northwestern portions of the footprint and load centers in the Upper Midwest. MISO said it's studying wind generation transfers from the Dakotas, Minnesota and Iowa to Wisconsin and Illinois.

That study will also extend into MTEP 21. MISO economic planner Ryan Hay said that while the study is largely academic, possible transmission projects could be identified and submitted in MTEP 21.

MISO has said the study is the first of its kind and will serve to develop a template for identifying and incorporating non-thermal transmission limits into its production cost analyses. Currently, MISO's typical economic studies don't consider non-thermal operational limits. (See *MWEX Study Could Elicit New Tx Planning for MISO*.) ■

MISO News

MISO Seeks LBA Input on Load Forecasting

By Amanda Durish Cook

MISO is calling on expertise from its local balancing authorities to help improve load forecasting, RTO engineers said last week.

Operational Forecast Planner Adam Simkowski said during a special workshop May 19 that the call for LBA involvement stems from the Jan. 17, 2018, cold spell that caused MISO and SPP to call for voluntary load reductions from customers and nearly forced load shedding in MISO South.

FERC last year issued a *report* on the event that, among other things, called for improvements to MISO's three- and five-day-ahead load forecasting. The commission recommended that the RTO work with its LBAs to achieve better results. (See *FERC Calls for Cold Weather Reliability Standard*.)

MISO is interested in learning more about how LBAs conduct forecasting and is asking them to share their methodologies and accuracy assessments, Simkowski said. He asked LBAs to contact the RTO by June 9.

Simkowski said MISO is so far concentrating on becoming more accurate with events that can be anticipated three and five days out, including snowstorms, tropical depressions, and substantial temperature swings and deviations.

LBAs already submit day-ahead and seven-day forecasts to MISO daily. Simkowski said the RTO's load forecasts are generally more accurate than those submitted by the LBAs.

To build forecasts, MISO combines data into its software from LBAs, its own seasonal modeling, historic load data and live load and weather data. It shares the forecasts with customers, who can offer adjustments. MISO forecasters can manually adjust the forecast model if they don't agree with the software results. The RTO also checks forecast accuracy later.

MISO creates an hourly load forecast for control room planners that is updated every 15 minutes and extends seven days out. It also generates a five-minute forecast updated every five minutes that looks six hours ahead.

The RTO also estimates daily peaks over the next 31 days for the purposes of outage coordination.

Senior Operational Forecast Engineer Dorsana Desai said most of MISO's load forecasting errors can be attributed to weather that doesn't behave as predicted.

"One degree of temperature forecast error results in up to 2,000 MW of load forecast error," she said.

MISO missed its load forecasting mark most egregiously on Sept. 15, 2018, Desai said, when MISO planned for about 85-degree Fahrenheit temperatures on average. Actual temperatures clocked in closer to 89 F, resulting in a 7.6-GW under-forecasting error.

Desai also said the 2017 solar eclipse in mid-August eluded MISO forecast engineers. The event — and widespread cloud cover and thunderstorms following soon after — had the RTO overestimating load by about 6 GW. Desai said MISO expected demand to rebound after the eclipse. ■

Entergy crews in MISO South during extreme cold on Jan. 17, 2018 | *Entergy*

Online Protesters Reject NY Gas Supply Plans

By Michael Kuser

More than 130 New Yorkers gathered in an online forum Thursday for a "people's hearing" organized by nearly a dozen environmental groups to protest the possibility of National Grid increasing the state's supply of natural gas by adding vaporizing capacity, trucking in compressed natural gas and other measures.

Michaela Ciovacco, NYCP

"This people's hearing marks an unprecedented coming together of campaigns and minds to tackle getting off fracked gas and moving to renewables, first by focusing on the upcoming June 11 decision by the [New York] Public Service Commission on National Grid's plan to meet downstate energy demand," said Michaela Ciovacco of New Yorkers for Clean Power (NYCP).

The group helped organize the event as a member of Renewable Heat Now, along with Sane Energy Project, Alliance for a Green Economy, Mothers Out Front, Sierra Club, Food & Water Action, NY Renews, Stop the Williams Pipeline Coalition, Heatsmart Tompkins and No North Brooklyn Pipeline.

New Jersey and New York regulators two weeks earlier denied permits for the Williams pipeline, also known as the Northeast Supply Enhancement (NESE) project, which would have carried natural gas from Pennsylvania across New York Harbor into the Rockaways, Queens.

"Neither the utility nor the Public Service Commission have scheduled a public hearing, so that's why we came together," Ciovacco said.

The organizers claimed that any increase in fossil fuel usage would violate the spirit and the letter of the state's Climate Leadership and Community Protection Act, signed into law last July. It mandates that 70% of the state's electricity come from renewable resources by 2030 and that generation be 100% carbon-free by 2040. (See *Cuomo Sets New York's Green Goals for 2020*.)

Conflicting State Policies

National Grid spokesperson Karen Young told *RTO Insider* that a May 8 press *release* detailed how the company has been fulfilling its 2019 agreement with the PSC to propose long-term *solutions* for downstate gas supply and demand.

The company's "no-infrastructure" option includes reducing gas demand through incremental energy efficiency measures, demand response and electrification.

The company this past winter and spring held six public meetings attended by more than 800 people, and altogether more than 7,500 public comments have been filed with the PSC.

National Grid found itself at odds with Gov. Andrew Cuomo last November when he criticized a company moratorium on new gas hook-ups that the company attributed to supply concerns. Cuomo issued a *letter* demanding that its gas subsidiaries connect all customers for whom it had denied service under the moratorium or he would seek "to revoke National

More than 130 people gathered online May 28 for a "people's hearing" on National Grid's plans to supply natural gas to downstate New York.

NYISO News

Grid's certificate to operate its downstate gas franchise." (See *National Grid Vows to Expand NY Gas Service*.)

PSC Chair John B. Rhodes on Oct. 11 had signed an order forcing National Grid subsidiaries Brooklyn Union Gas (KEDNY) and KeySpan Gas East (KEDLI) to connect 1,100 of 3,300 customers that had been denied natural gas service connections (Case *19-G-0678*). KEDNY has approximately 1.2 million customers, and KEDLI has 590,000 customers on Long Island.

Jackie Weisberg, Brooklyn resident

Brooklyn resident Jackie Weisberg addressed her comments during the online protest to Cuomo: "I oppose the National Grid fracked gas proposal because these pipelines are like the COVID-19 virus. They are insidiously infecting our communities. Selling us the so-called benefits of fracked gas is not what we need now, or ever. They have no business continuing the work in North Brooklyn [on the Metropolitan Natural Gas Reliability Project], and they are opposed in Connecticut and elsewhere."

Young said "the Metropolitan Natural Gas Reliability *Project* is a system integrity project, it's not one of the long-term capacity solutions — it does not bring additional supply to New York."

Eyes of the PSC

In its Nov. 26, 2019, *agreement* with National Grid, the PSC mandated that an independent monitor submit quarterly reports to keep it apprised of the company's progress in finding ways to provide gas service to all its customers in downstate New York.

The monitor's third *report*, filed May 26, said that it attended all the public meetings and afterward began "monitoring the key executive meetings conducted internally at National Grid to address its compliance."

In assessing the company's development of long-term solutions, the report said it reviewed implementation of energy efficiency and demand response and "makes no formal findings or recommendations but provides observations regarding National Grid's progress and positions."

The monitor highlighted National Grid in April having hired Ernst & Young to review the company's "development of natural gas demand scenarios and the identification and selection of options to meet demand."

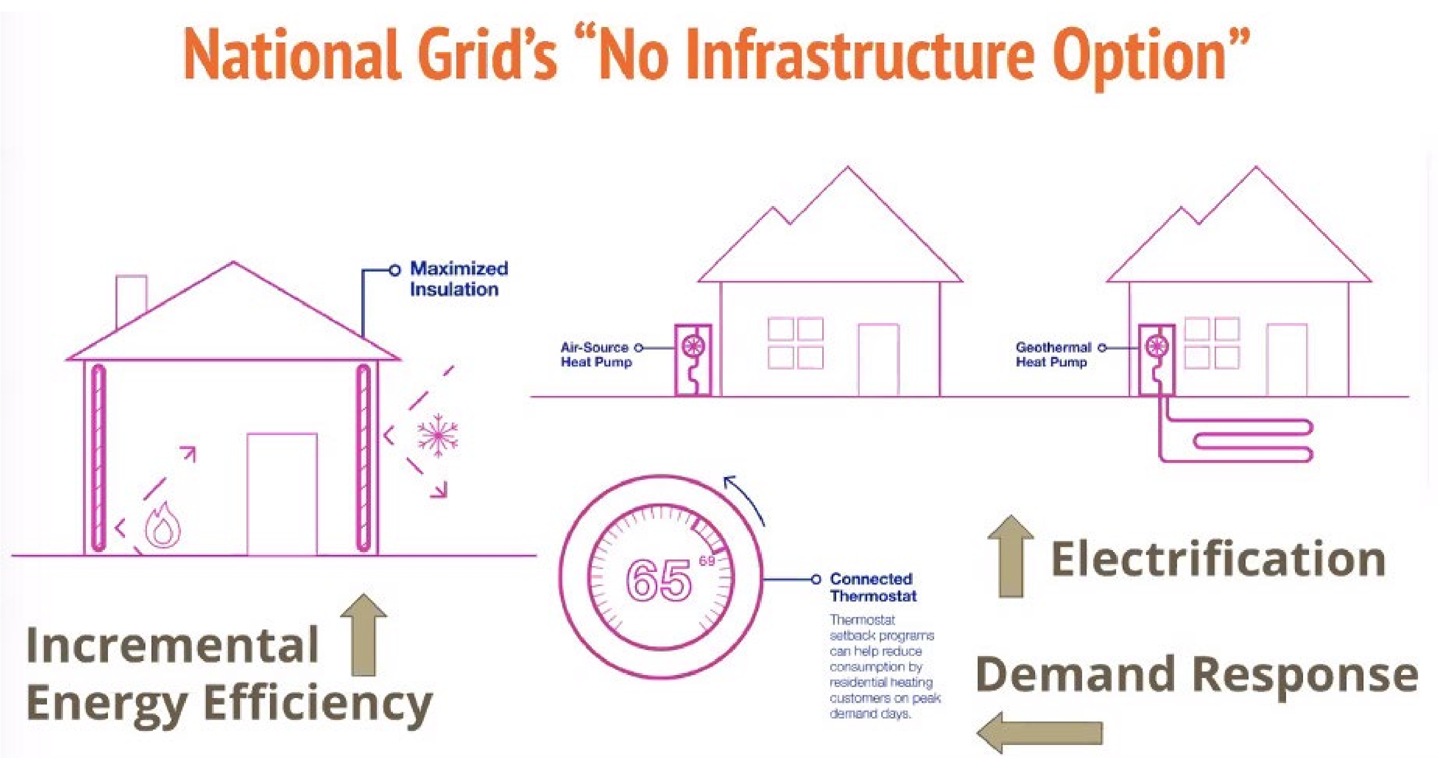
National Grid's analysis turns on a design day standard, currently a 24-hour period with an average temperature of 0 degrees Fahrenheit in Central Park. The last design day was in 1934, and many public comments questioned the suitability of that standard today, the monitor said.

"To illustrate the point, National Grid has determined that the 24-hour period with the coldest average temperature in Central Park over the last 30 years was approximately 4 degrees F and took place in 1994," the report said.

The monitor faulted National Grid for being too conservative on the one hand and too extreme on the other for assuming the increased reliance on compressed natural gas trucking through 2035, despite the practice raising "risk, cost and reliability questions."

"Based on forecast figures provided by National Grid to the monitor, several more middle-ground approaches ... indicate possible opportunities to move forward that are less stark than simply choosing between NESE or the no-infrastructure options," the monitor said.

It also said that the company is not fully accounting for the reduced demand impact from the current pandemic, despite its own reporting that the reduced demand added a year to the predicted time when demand will exceed supply, to the winter of 2022/23. ■



National Grid non-gas proposal | *National Grid*

NYISO Management Committee Briefs

ISO Ends Sequestration of Control Room Staff

NYISO has suspended the sequestration of its control room operators but is in no hurry to bring its other staff back to ISO offices as New York begins its recovery from the coronavirus pandemic, CEO Rich Dewey told the Management Committee on Wednesday.

The ISO ended sequestration for its Krey Boulevard control center operators on May 4 and that for Carman Road two weeks later, Dewey said. "We think we're in a reasonable posture to suspend the sequestration of those staff members," he said, adding that the ISO is prepared to resume sequestration if there is a resurgence of infections in the region.

For now, Carman Road staff are handling the day shift, with Krey Boulevard working nights.

Other NYISO staff are "almost exclusively" continuing to work from home while the ISO tracks the state's reopening plans.

Although the ISO does have return-to-office plans, Dewey said it will be "conservative" in implementing them. "There's no particular schedule for when we will start phasing people back into the office," he said. With telework "working pretty well … we're not going to be in a rush to change that posture."

Dewey said the joint Board of Directors/Management Committee meeting scheduled for June 15-16 at the Sagamore Resort on Lake George has been converted to a virtual session. Like past in-person gatherings, the meetings will include both general sessions involving all attendees, and breakouts with individual board members and about 10 stakeholders.

"It's very important for our board members to get feedback from market participants," Dewey said. "I think we've demonstrated that the technology is quite capable. ... We won't have the normal social interaction, but we'll do the best we can under the circumstances."

The topics will include the "Grid in Transition" and "Navigating Uncharted Territory," which will explore post-pandemic economic changes that may impact the sector.

Summer Capacity Assessment

NYISO's baseline analysis shows a 1,721-MW capacity margin surplus for the summer peak in 2020, a drop of 506 MW from 2019, said Wes Yeomans, vice president of operations.

The 90th percentile forecast shows a 193-MW shortfall, a decrease of 616 MW from last year. Such extreme conditions might require the ISO to either tap its 2,620 MW of operating reserves or call on emergency operating procedures, including voltage reductions, emergency purchases and voluntary load reductions, for up to 3,080 MW.

The *summer assessment* shows 2,273 MW in generation deactivations, including the state's last two coal-fired plants (the 155-MW Cayuga Unit 1 and the 655-MW Somerset plant) and the retirement of Unit 2 of the Indian Point nuclear plant (1,299 MW), which *shut down* at the end of April.

The ISO has one new generating asset, the 1,177-MW *Cricket Valley* combined cycle plant in Dover, N.Y.

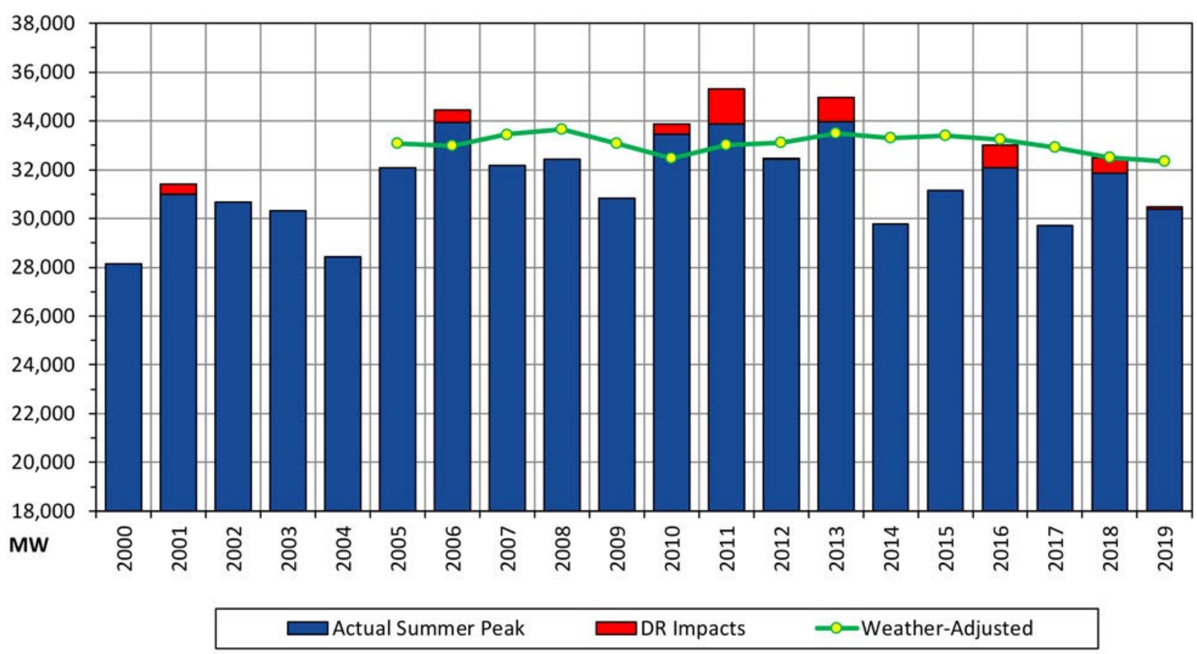
60-minute Rule for Energy Storage

The Management Committee approved *changes* to section 4.4.3.1.1 of the Services Tariff to only award energy storage resources (ESRs) energy schedules that are sustainable for at least 60 minutes during a reserve pick-up (RPU) event.

The change was prompted by concern that during an RPU, real-time dispatch may award a larger energy schedule than an ESR can sustain for 60 minutes, as required by the Northeast Power Coordinating Council.

This can occur because the real-time dispatch/corrective action mode used to perform an RPU must issue updated schedules very quickly and thus only looks out 10 minutes. ■

— Rich Heidorn Jr.



New York Control Area summer peaks: 2000-2019 | *NYISO*

NYISO News

Five New Recommendations from NYISO Monitor

By Rich Heidorn Jr.

Potomac Economics' 2019 *State of the Market Report* for NYISO adds five new recommendations while concluding the ISO's markets "performed competitively" last year.

Potomac's Pallas LeeVanSchaick *told* the NYISO Management Committee on Wednesday that 2019 energy prices were the lowest in the past decade, dropping 22 to 34% from 2018. He cited a 22 to 41% drop in natural gas prices from expanded production, and muted demand from a mild winter and summer.

Mild weather, energy efficiency and behind-the-meter solar generation contributed to the lowest average load in more than a decade, the ISO's Market Monitoring Unit said.

Capacity prices also fell to 8 to 26% of the net cost of new entry (CONE) outside of New York City, thanks to reduced local capacity requirements and new capacity additions. Although New York City prices rose, they still represented only 58% of net CONE. "That's an indication of significant capacity surpluses," LeeVanSchaick said.

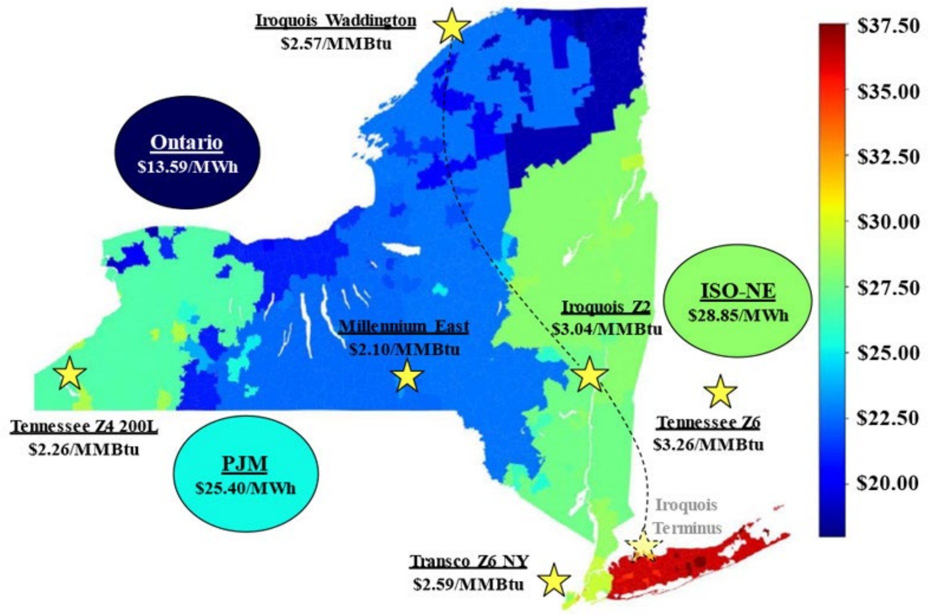
The five new recommendations are in addition to 17 from prior reports.

Only one of the new recommendations — modifying the "Part A" test to allow public policy resources to obtain exemptions when it would not result in price suppression below competitive levels — was identified as a high priority. The MMU said the change is needed to ensure buyer-side mitigation (BSM) rules are balanced between protecting the market from price suppression and facilitating the state's desire to control its resource mix.

"The BSM measures were originally designed to prevent entities from suppressing capacity prices below competitive levels by subsidizing uneconomic new entry of a conventional generator," the Monitor said. "The BSM measures are not intended to deter states from promoting clean energy and other legitimate public policy objectives."

It said it supports a plan NYISO developed with stakeholders that allows public policy resources to avoid mitigation if enough existing capacity exits the market, or if demand increases enough to boost capacity requirements. The proposal was filed with FERC on April 30 (*ER20-1718*).

The MMU also recommended that:



Real-time energy prices, natural gas prices and congestion in 2019 | *NYISO*

- Day-ahead and real-time reserve clearing prices should incorporate reserve constraints for Long Island. Currently reserve providers on Long Island are paid clearing prices for the larger Southeast New York region. Changing the compensation would improve incentives and "provide better signals to new investors in … the long term," the Monitor said.
- Increase the offer/bid floor from -$1,000/MWh to -$150/MWh. Negative prices are used when ISO operators reduce external interface limits or curtail external transactions to maintain transmission security on an external interface. In this rare situation, external transaction schedulers can buy power at "arbitrarily" low prices, resulting in uplift for NYISO customers. "We recommend raising the bid and offer floor to a level that is closer to the range of potential avoided costs of supply for generation resources," the Monitor said. "Negative $150/MWh should be more than adequate to provide such flexibility."
- Translate the annual revenue requirement for the demand curve unit into monthly demand curves reflecting their reliability value. NYISO's capacity market currently is divided into six-month summer and winter capability periods with a single capacity requirement and demand curve for each, although the reliability value of resources is much greater in high-demand July than the shoulder month of October. The bifurcation "may lead to inefficient incentives for resources that are not consistently available during all 12 months," the Monitor said. It recommended switching to monthly capacity demand curves with a minimum reference point high enough to ensure resources have incentives to coordinate planned outages with the ISO. The remainder of the demand curve unit's annual revenue requirement would be allocated in proportion to the marginal reliability value of capacity across the 12 months. "These changes would concentrate the incentives for resources to sell capacity into New York during the peak demand months of the summer (i.e., June to August)," it said.
- Translate the demand curve reference point from installed capacity (ICAP) to unforced capacity (UCAP) terms based on the demand curve unit technology. The capacity demand curves currently are based on net CONE, estimated in ICAP terms and then converted into UCAP based on the regional average derating factor, which reflects the forced outage rates of the existing fleet and UCAP-ICAP ratios of intermittent resources. This technique results in the monthly capacity demand curves being set higher than if the derating factor of the demand curve technology were used. "This inconsistency will become more pronounced as additional intermittent resources are added to the system," the Monitor said. ■

Stakeholders Urge PJM Action on Carbon Pricing

By Michael Yoder and Rich Heidorn Jr.

Stakeholders are encouraging PJM to take a more active role in facilitating carbon pricing as more states look to join the Regional Greenhouse Gas Initiative (RGGI).

Marji Philips, LS Power | *© RTO Insider*

Marji Philips, LS Power vice president of wholesale market policy, suggested that PJM should support a FERC technical conference that would bring together state regulators, stakeholders with RGGI experience, other RTOs and supply-side groups. LS Power is part of a coalition of independent power producers and renewable energy and trade groups that petitioned FERC in April to convene a technical conference on integrating carbon pricing into organized wholesale markets (*AD20-14*). (See *IPPs, Renewable Groups Seek FERC Carbon Pricing Conference*.)

Philips said PJM can support a technical conference without endorsing carbon pricing and help states achieve their environmental goals without having a uniform carbon price.

"PJM's always been a leader in advocating that markets drive reliability," Philips said during the *Carbon Pricing Senior Task Force*'s May 19 meeting, its seventh since its formation last summer. "Now is not the time to abdicate that leadership by not participating in something like this."

Market Monitor

John Hyatt of Monitoring Analytics *recommended* PJM "provide a full analysis" of the impact of carbon pricing on generating units and the revenues that would result to allow "states to consider a potential agreement on the development of a multistate framework for carbon pricing and the distribution of carbon revenues."

The Independent Market Monitor said a $10/metric ton carbon price would increase short-run marginal costs by $3.34/MWh (24%) for a new combined cycle plant and $8.63/MWh (31%) for a new coal plant. For 2019, that would have increased LMPs from $27.32/MWh to $30.71/MWh, a 12% rise, based on the impact on the marginal units' offer prices (not including a counterfactual redispatch of the system).

A $50/ton price would boost combined cycle plants' costs by $16.72/MWh (122%) and coal plants by $43.15/MWh (156%).

The Monitor said a $10/ton carbon price would generate $3.6 billion annually in carbon allowance revenues in PJM states.

The current patchwork of state policies has resulted in wildly varying renewable energy credit (REC) prices within PJM, with an implied carbon price ranging from $5.63 to $19.21/ton in 2019. Solar REC prices last year ranged from an implied price of $50.23 to $806.35/ton, the Monitor said.

The varying REC prices are "inconsistent with an efficient market and inconsistent with the least-cost approach to meeting state environmental goals," it said.

"Using an RGGI model would leave carbon pricing within the control of the states and not of FERC or PJM," Monitoring Analytics President Joe Bowring said. "States could define the desired carbon price. The carbon price would simply be part of the short-run marginal cost of operating units in PJM and treated like fuel or other emissions costs."

Vistra Energy

Becky Robinson of Vistra Energy *said* her company needs a supportive market policy to achieve its emissions goals. Vistra has announced a goal to reduce CO_2-equivalent emissions by more than 50% by 2030 and by 80 to 100% by 2050 from 2010 levels.

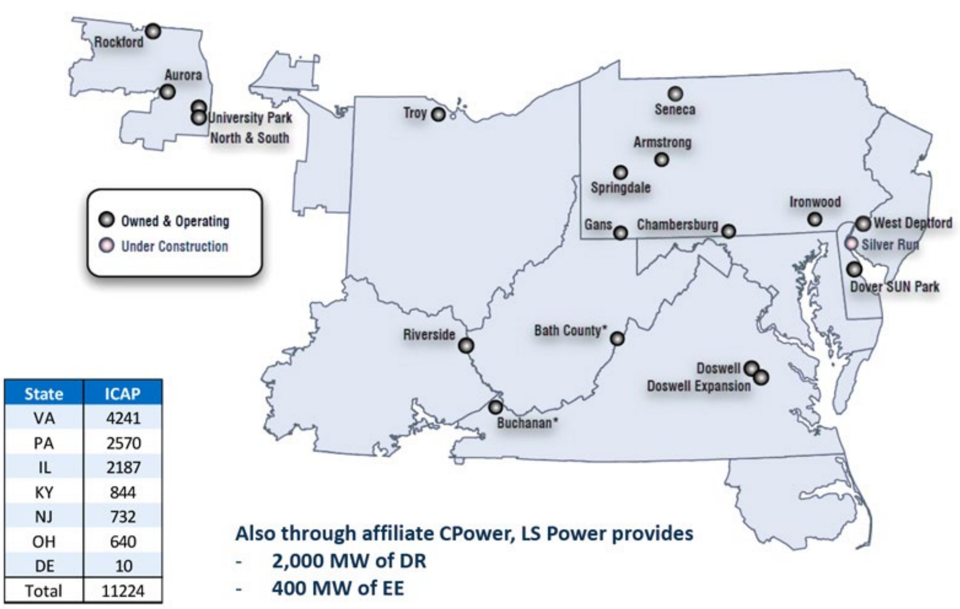
She said a national, economy-wide price on carbon with dividend payments to help alleviate the rise in energy costs would be the best solution. But she said discussions like the ones happening in the senior task force are a step toward developing a fix.

"We are definitely a believer in the power of economics to change markets and to drive change in the resource mix," Robinson said.

Disparate state policies regarding clean energy have left states wishing to act on carbon stymied by leakage with the dispatch of cheaper fossil fuel-generated power in nonparticipating states, she said. FERC rulings that expand the minimum offer price rule (MOPR) to cover state-subsidized generation have also undermined state efforts, causing some states to contemplate exiting PJM's capacity market. (See *NJ Regulators Weighing Input on Capacity Market Exit*.)

Vistra wants states to have an in-market clean energy policy option that would not be penalized by MOPR, Robinson said, and is open to sub-regional border adjustments or other market changes empowering state policies.

Robinson said the modeling presented by PJM so far has been "inconclusive" on the best border adjustment method, noting that emissions impacts differ depending on the configuration of participating states. RGGI currently



State	ICAP
VA	4241
PA	2570
IL	2187
KY	844
NJ	732
OH	640
DE	10
Total	11224

LS Power has more than 11,000 MW of generation in PJM. | *LS Power*

PJM News

includes New York, the six New England states and three PJM states: Delaware, Maryland and New Jersey. Virginia is also poised to join by the beginning of 2021, and Pennsylvania Gov. Tom Wolf issued an *executive order* in October directing state officials to develop a rulemaking by July 31 for joining the compact. (See *Critics: Pa. RGGI Hearing Stacked with Detractors*.)

During the May 19 task force meeting, PJM presented an updated *study* on carbon pricing and potential leakage mitigation mechanisms, expanding on another *report* issued March 27.

Robinson said the studies show that without border adjustments, carbon pricing works better as the pricing footprint gets bigger.

The reports found that with the Maryland, Delaware and New Jersey footprint in RGGI, carbon pricing alone increases net emissions in PJM, while border adjustments decrease net RTO emissions. With RGGI expanded to Virginia and Pennsylvania, carbon pricing alone decreases net RTO emissions, while border adjustments increase net RTO emissions. (See *PJM Panel Weighs Impact of Pa., Va. Joining RGGI*.)

"If what you care about is emissions, it's not clear that border adjustments are a good thing or a bad thing," Robinson said. "It's very case specific."

Jason Barker of Exelon asked Robinson what solution Vistra recommended the task force consider, noting that the group's *problem statement* and *issue charge* call for examining border adjustments and leakage mitigation.

Robinson said coming up with a "mutually agreeable solution" for all interested stakeholders should be the goal of the task force. For the states that are not interested in carbon pricing, there should be a mechanism for quantifying the incremental value of carbon pricing. The results should be presented to all the states in PJM to determine if the value outweighs the cost.

LS Power

Philips gave a *presentation* for LS Power, the second largest privately held generation company in the PJM market with more than 11,000 MW of capacity. She said LS Power remains "technology neutral" when it comes to generation — with resources including pumped storage, solar and natural gas combined cycle facilities — and continues to invest where price signals are transparent.

PJM's competitive market structures have allowed for ongoing investment opportunities that provide consumer benefits, Philips said, and the adoption of transparent carbon pricing within the RTO would continue to provide opportunities for investment and innovation.

"We want the markets to work so we can make investments in a renewable portfolio as well as everything else," she said.

Barker asked Philips what LS Power would like to see the task force accomplish.

Philips said she supports requests for more data from PJM on the cost and revenue impact to states and would also back Vistra in considerations about how border adjustments could and could not work.

The open-ended nature of the task force charter allows for broad discussions in search of solutions and could bring more changes if stakeholders actively encouraged input from state commissions and legislators, she said. PJM's markets have already driven change to policy and will continue to bring innovation.

"What PJM has done already in terms of driving down emissions is remarkable. And they've maintained regional reliability while doing it," Philips said. "Obviously, we wish everybody would embrace a carbon price because that would solve a lot of problems. But recognizing that's not going to happen at this point, we'd at least like to keep the ball moving and get as much of these externalities into the market and priced appropriately."

Exelon

Kathleen Robertson, director of strategic initiatives and environmental policy for Exelon, *said* PJM should immediately begin to develop border adjustments for RGGI, which is anticipated to cover the majority of the RTO's load by 2022.

Exelon's modeling assumed all RGGI generators have carbon costs included in their bids. Offers from non-RGGI generators would not include carbon costs, but power flowing from a non-carbon region to a carbon region would be subject to an additional wheeling cost.

Robertson said Exelon's analysis concluded that well designed border adjustments preserve efficiencies of regional energy markets and reduce emissions while preserving state policy choices. ■

PJM End-of-life Proposals Fail at MRC

Continued from page 1

After about 90 minutes of parliamentary jousting, the stakeholders called a vote to suspend the rules to allow consideration of their proposal, but the motion fell short of the two-thirds needed with a vote of 3.08 (62%).

ODEC's Mark Ringhausen, who *presented* the joint stakeholder package, said it would allow for Order 1000 competition in EOL projects that would ultimately lead to lower costs for ratepayers.

Ringhausen highlighted the TOs' May 7 *notification* that they were considering a Federal Power Act Section 205 filing to amend the Tariff as an alternative to the proposals under consideration. Ringhausen said the TO filing at FERC after June 8 would be similar to the PJM proposal, which had "almost zero transparency," giving the TOs control over most of the future transmission planning.

Dave Souder, PJM's senior director of system planning, presented the RTO's *package,* which would have required TOs to have a formal program for EOL determinations and to identify potential EOL projects five years in advance. Projects that "overlap" with RTEP violations would be included in a competitive window seeking regional solutions.

PJM cited language in the Consolidated Transmission Owners Agreement (CTOA) that allowed TOs to retain the authority to "build, finance, own, acquire, sell, dispose, retire, merge or otherwise transfer or convey all or any part of its assets, including any transmission facilities." The RTO also said its role was limited by two FERC rulings involving CAISO that concluded that equipment replacements that result in only incidental increases in system capacity are asset management decisions under TOs' exclusive control, not planning matters subject to FERC Order 890. (See *'Asset Management' not Subject to Order 890, FERC Rules*.)

"At the end of the day, we're going to have to agree to disagree," Ringhausen said of the stakeholders' insistence that their proposal complies with the CTOA and the PJM Tariff. "Hopefully, we can get this in front of FERC and make them look at it and say what the right outcome should be here for this process."

Mike Gahimer of the Indiana Office of Utility Consumer Counselor said PJM "misrepresented" the FERC orders. In the *order* involving Southern California Edison, Gahimer said, FERC stressed the limited scope of asset management as "looking at components, not entire substations or transmission lines for replacement."

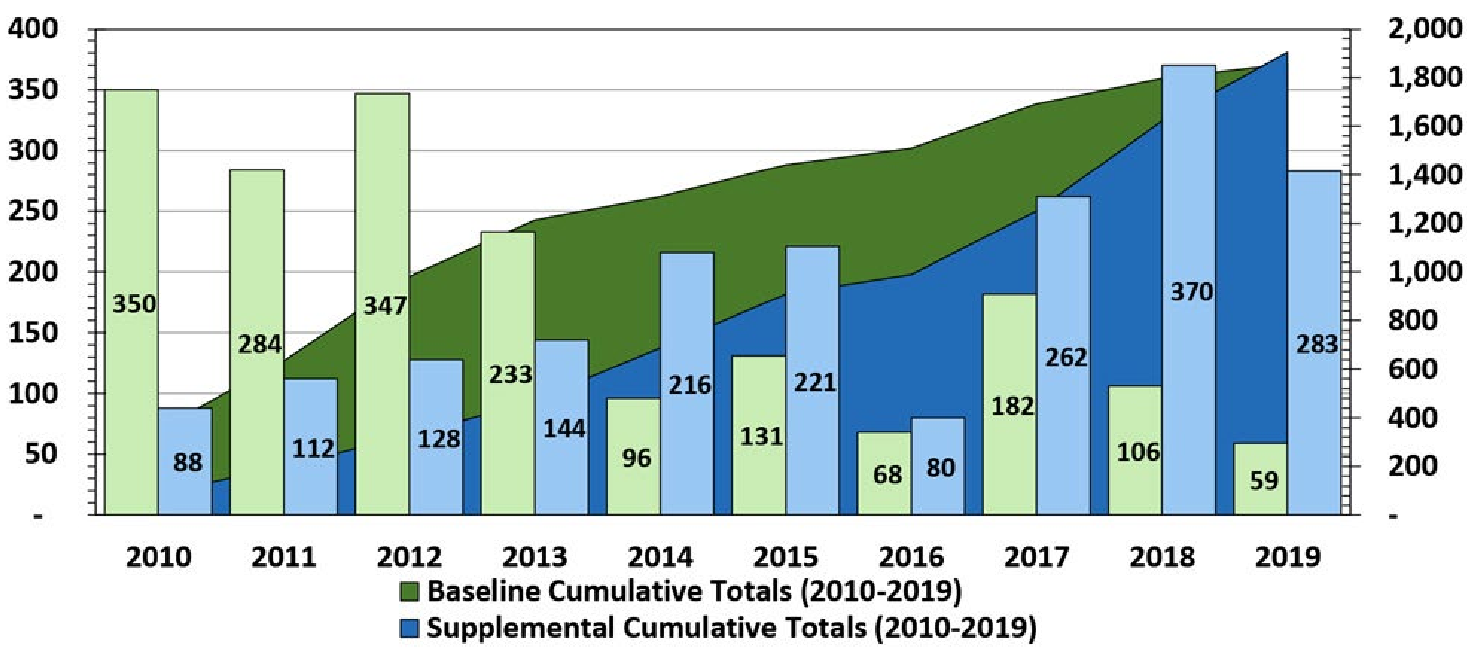
Gahimer said the joint stakeholder proposal didn't involve components, but rather lines and substations. "I don't think anyone, including the most biased among us, would claim that the projects at issue here are day-to-day projects," he said.

Ed Tatum, AMP | *© RTO Insider*

AMP's Ed Tatum said that with the amount of transmission infrastructure that's going to have to be replaced in the next decade, careful planning is going to be needed. He said PJM's expertise is essential to ensure that the planning for the grid of the future is simply not rebuilding the transmission system of the past. He fears the future of transmission planning will be moved out of the jurisdiction of PJM and back to the TOs without coming up with compromises.

"That's a great concern from the standpoint of those who believe transmission and an independent transmission planner is a cornerstone to competitive markets," Tatum said. "We think that PJM should be the independent planner. We think they bring value from a more holistic look."

Thursday's votes are unlikely to bring an end to the billion-dollar debate over control of EOL projects. The TOs could file the attachment after the 30-day comment period expires June 8. Supporters of the joint stakeholders proposal could file a complaint with FERC contending the current procedures are not just and reasonable. ■



Number of baseline vs. supplemental projects (2010-2019) | *PJM*

PJM News

Exelon, FE Ask PJM to Tighten Sector Selection Process

By Michael Yoder

Two incumbent transmission owners have called on PJM to take a more active role in policing stakeholder sector selections after the disclosure that LS Power had an affiliate improperly voting in the RTO's senior committees.


Sharon Midgley, Exelon | *© RTO Insider*

"Generally, we think that PJM's ruleset is a little lax, and some greater oversight of the process may be warranted," Sharon Midgley, Exelon's director of wholesale development, said during the Stakeholder Process Forum on May 26.

Exelon had previously raised questions about the propriety of two LS Power subsidiaries, West Deptford Energy and Riverside Generating, voting at the Jan. 23 Members Committee meeting in support of an LS Power resolution. The resolution, which was approved by the MC, objected to a Tariff attachment filed by the TOs to create a new confidential process to mitigate critical infrastructure on NERC's CIP-014-2 list. FERC approved the revision in March (*ER20-841*). (See *FERC OKs PJM TOs' Critical Tx Process*.)

During PJM's Annual Meeting on May 4, Dave Anders, director of stakeholder affairs, said the RTO had determined that the two companies are under common control and that West Deptford has been recategorized as an affiliate of Riverside, which is listed as the "parent" for 15 members in the Generation Owner, TO and Other Supplier sectors.

Midgley said LS Power "had been voting with two affiliates at the MRC and MC for many years."

An LS Power spokesman said Friday that "when notified of a challenge, LS Power cooperated with PJM to provide supporting information, but some of the additional information requested could not be provided prior to the PJM Annual Meeting, when PJM took action. LS Power has decided not to challenge PJM's decision." The company declined to comment further.

Under PJM rules, companies with multiple members are entitled to a vote for each of them at lower committees. But they only get one vote at the MC and Markets and Reliability Committee, where votes are sector weighted.

Those rules meant that Pepco Holdings Inc., which had been a strong voice for consumers within PJM as a member of the Electric Distributor sector, lost its independence and its MRC and MC votes when it was acquired by Exelon in 2016. Exelon Business Services, the parent for Exelon's 14 affiliates, votes in the TO sector. (See *Pepco to Lose its PJM Voice; Consumers Lose Frequent Ally*.)

A 2017 study by the University of Pennsylva-

Member	Previous Sector	2020 Sector Update
Allegheny Energy Supply Company, LLC	Transmission Owner	Generation Owner
Cleveland Electric Illuminating Company	Transmission Owner	Electric Distributor
CPV Three Rivers, LLC	Generation Owner	Other Supplier
Dynegy Power Marketing, LLC	Other Supplier	Generation Owner
Energy Harbor LLC	Transmission Owner	Generation Owner
Guernsey Power Station LLC	Generation Owner	Other Supplier
Hickory Run Energy LLC	Other Supplier	Generation Owner
Kincaid Generation, LLC	Other Supplier	Generation Owner
Metropolitan Edison Company	Transmission Owner	Electric Distributor
Northern Illinois Municipal Power Agency	Electric Distributor	Generation Owner
NTE Ohio, LLC	Other Supplier	Generation Owner
Ohio Edison Company	Transmission Owner	Electric Distributor
Pennsylvania Electric Company	Transmission Owner	Electric Distributor
Pennsylvania Power Company	Transmission Owner	Electric Distributor
RRI Energy Solutions East, LLC	Other Supplier	Generation Owner
Silver Run Electric, LLC	Other Supplier	Transmission Owner
South Field Energy LLC	Other Supplier	Generation Owner
Sunwave USA Holdings Inc.	Other Supplier	End-Use Customer
Tatanka Wind Power, LLC	Generation Owner	Other Supplier
Tri-County Rural Electric Cooperative, Inc.	Electric Distributor	Other Supplier

PJM announced at the Members Committee meeting May 4 that these members have updated their sector selection. | *PJM*

PJM News

nia's Kleinman Center for Energy Policy found that generation and transmission owners with multiple affiliates can dominate the voting at PJM's lower committees on proposed solutions. The power dynamic is reversed during votes at the MRC and MC, the report said, because sector-weighted voting often results in buyer-side stakeholders (the Electric Distributor sector and End-Use Customer sectors) exercising veto power over proposals resulting from the lower committees. (See *Can RTO Stakeholders Find Consensus on Big Issues?*)

Annual Sector Certification

At the May 26 forum, Midgley noted that PJM members are required to recertify or make changes to their sector assignments annually, with changes announced at the Annual Meeting. After sector changes are announced, stakeholders have 30 days to request PJM to investigate any questionable sector selections.

Midgley said that before this year's Annual Meeting, Exelon identified a member of American Municipal Power attempting to join the TO sector "when they weren't qualified to do so." Midgley declined to identify the company.

AMP votes at the senior committees as a member of the Electric Distributor sector, although it has affiliates in the TO and Other Supplier sectors. "That was certainly concerning to us," Midgley said.

Under section 8.1.2 of the Operating Agreement, companies considered a "related party" of a generation and transmission cooperative (i.e., one of its distribution cooperative members) or a joint municipal agency (joint agency members) are required to vote in the Electric Distributor sector.

Lisa McAlister, AMP's general counsel for regulatory affairs, said the company learned of the issue after being contacted by *RTO Insider* for comment Friday.

"From a conversation this morning with PJM … we learned that one of our members was unaware of the related parties sector limitation and mistakenly requested membership in the TO sector, since they are a transmission owner. PJM contacted our member and the error was rectified," McAlister said. "PJM administers its governing documents and quickly and correctly did so here. There was nothing nefarious about the member request, and we are uncertain as to Sharon's concern."

Rule Changes?

Midgley said PJM should consider whether members should be able to review proposed sector changes before they are implemented and if members challenged on their sector change should be required to vote in their old sector until the challenge is resolved by the RTO. She said existing rules allow members to vote in their new sector until a challenge is resolved, a process that can take up to three months to determine.

Exelon would also like a process to examine incorrect sector selections at any time of the year and to allow members to challenge sector selections rather than just during the annual review process, Midgley said. "We think this is a fertile ground for discussion."

FirstEnergy's Jim Benchek said his company also would like PJM to take a greater role in overseeing the process. Benchek said the "know your customer" procedures that came out of the special *report* on the GreenHat Energy default should be implemented by PJM regarding sector selections.

Anders said the RTO is implementing updates to the member onboarding process and know-your-customer efforts as a result of actions taken by the Financial Risk Mitigation Senior Task Force. Anders said some of the issues deal directly with sector selection, and PJM may formulate a report to present to stakeholders later this summer on some of the changes.

Midgley said she was "happy to hear this is on [PJM's] radar screen."

Susan Bruce, representing the PJM Industrial Customer Coalition, said her members would be more comfortable having the RTO rather than stakeholders look at "individual business activities" of members, citing confidentiality issues.

20 Sector Changes

During this year's Annual Meeting, PJM *announced* that 20 stakeholders had changed sectors, more than double the number of sector selection changes in recent years. For comparison, five sector changes were announced at the Annual Meeting in 2019, six changes in 2018 and eight in 2017.

PJM spokesman Jeff Shields told *RTO Insider* that "there doesn't appear to be much out of the ordinary" in the sector changes.

"These new sector classifications reflect changes in corporate structures or the natural evolution of businesses within PJM," Shields said. "The decisions to make these changes are up to the individual members, in accordance with the Operating Agreement."

Several PJM stakeholders who changed sectors in May were contacted to determine what prompted their moves.

FirstEnergy's The Illuminating Co. moved from the TO sector to the Electric Distributor sector. Jennifer Young, manager of external communications for FirstEnergy, said the sector change reflected that the subsidiary does not own or operate transmission assets.

Young said FirstEnergy's transmission assets in Ohio are owned by another of the company's subsidiaries, American Transmission Systems Inc.

"The sector change was not prompted by any changes to asset ownership, but rather just to better reflect the type of operations performed by The Illuminating Co.," Young said.

The Northern Illinois Municipal Power Agency (NIMPA) moved from the Electric Distributor sector to the Generation Owner sector. Gary Holm, president of NIMPA, said the company has been filing as a Generation Owner since 2018 after filing as an Electric Distributor in 2016 and 2017.

Holm said he received an inquiry from PJM in early May about the sector selection, and he informed the RTO that the company had been filing as a Generation Owner since 2018 and wished to be filed in that sector.

"I cannot comment on any change in sector status because, according to our records, our status has remained constant since 2018," Holm said.

CPV Three Rivers, an affiliate of CPV Power Holdings, updated its sector from Generation Owner to Other Supplier. Tom Rumsey, CPV's senior vice president of external and regulatory affairs, said to qualify as a Generation Owner, an entity must have cleared a Base Residual Auction or have signed an interconnection service agreement, which Three Rivers has not done.

Rumsey said that when CPV Three Rivers' membership application was originally approved, the company was told they were being placed in the Other Supplier sector, but they were later notified by PJM that they had been placed in the Generation Owner sector.

"We both agreed that the project should really be in the Other Supplier sector until the project achieves either of those milestones," Rumsey said.

Energy Harbor, which emerged from the bankruptcy of FirstEnergy Solutions, switched from the TO to the Generation Owner sector, reflecting its separation from former parent FirstEnergy. ■

PJM MRC Briefs

Surety Bond Proposal Endorsed

Stakeholders at PJM's Markets and Reliability Committee meeting on Thursday endorsed a *proposal* to allow market participants to use surety bonds as collateral that had been awaiting a vote for more than a year.

The proposal, originally endorsed in October 2018 at the Market Implementation Committee with 61% support, allows the use of surety bonds as collateral for all market purposes except financial transmission rights, with a $10 million cap per issuer for each member and a $50 million aggregate cap per issuer. It was endorsed Thursday through acclamation vote with three members voting "no" and three abstaining.

If the *Tariff change* is approved at the Members Committee meeting on June 18, PJM said it will require the use of bond companies on the U.S. Treasury Department's certified list and a minimum credit rating of A with S&P Global Ratings, Fitch Ratings and AM Best, or A2 with Moody's Investors Service. PJM also will require one-day payment demand terms.

PJM's Kathleen McElwaine *reviewed* the proposal, which was deferred at the December 2018 MRC meeting until completion of the independent consultants' *report* on the GreenHat Energy default. It was deferred again in April 2019 pending PJM's appointment of a chief risk officer and a new chief financial officer. (See *PJM Stakeholders OK Risk Management Task Force*.)

PJM opposed a *proposal* by Exelon that would have allowed surety bonds as collateral for all market purposes including FTRs, citing limited experience in the use of surety bonds in FTR markets and the large size of past FTR defaults. The Exelon proposal also would have set a $20 million cap per issuer for each member and a $100 million aggregate cap per issuer.

Sharon Midgley of Exelon said her company supports the PJM package as an initial framework to introduce surety bonds into the market. Exelon maintains its proposal is better suited for the market and may consider proposing a change in the future, Midgley said.

She said the PJM package is "inferior" because its caps are more restrictive than those of ERCOT and NYISO. Greg Poulos, executive director of the Consumer Advocates of the PJM States, said the advocates had been struggling to find the best approach for the issue but found a "comfort level" with PJM's endorsement.

"It's been a good stakeholder process to allow PJM to get the expertise together and to help consumers make an informed decision on this," Poulos said.

PMA Credit Requirements

Members endorsed a "quick fix" Tariff *revision* to address a regulatory change in Ohio concerning the billing of network integration transmission service (NITS). The change was endorsed through acclamation, with one abstention.

In 2015, the Public Utilities Commission of Ohio moved NITS and other related charges to a non-bypassable rider that is the responsibility of the electric distribution company. The change means competitive retail electric suppliers serving load in Ohio are no longer allowed to collect NITS or any other transmission-related charges from end-use customers.

PJM requires load-serving entities to sign NITS agreements and post collateral based on their *peak market activity* (PMA) and gives itself the ability to make changes to a participant's PMA requirement when the RTO determines the PMA is not representative of expected activity. (See "'Quick Fix' on PMA Credit Requirements," *PJM MIC Briefs: April 15, 2020*.)

Capacity Capability Senior Task Force Issue Charge

Members unanimously endorsed revisions to the *issue charge* of the Capacity Capability

PJM News

Senior Task Force in response to FERC orders issued April 10 concerning PJM's methodologies for determining the capability of all resource types (*ER20-584 and EL19-100*).

PJM's Andrew Levitt said that when the *task force* was launched on April 7, the RTO hoped FERC would hold the proceedings in abeyance until Jan. 29, 2021, when it planned to file Tariff changes applying effective load-carrying capability measurements for all intermittent and limited-duration resources. FERC instead gave a deadline of Oct. 30, Levitt said, requiring changes to the timing and the scope of the issue charge. Under the revisions, all resources will be considered in the first phase of the initiative rather than just wind, solar and storage. (See *PJM MRC Moves Forward on Storage, Hybrids*.)

Fuel Requirement Issue Charge

Stakeholders unanimously endorsed changes to the Fuel Requirements for Black Start Resources *issue charge*, removing the minimum tank suction level (MTSL) from the key work activities. The activity was added to the newly approved Black Start Unit Involuntary Termination & Substitution Rules *issue charge*.

The Independent Market Monitor recommends that only a proportionate share of the MTSL for oil tanks shared with other resources be allocated for black start units. (See "Black Start Issue Charge Endorsed," *PJM Operating Committee Briefs: May 4, 2020*.)

Work on the black start issue is expected to take two to three months, and implementation of needed changes to governing documents is estimated to take about six months following the approval of Tariff changes.

Task Force Sunset

PJM's Dave Anders presented a *list* of task forces the RTO is proposing to sunset because they have been dormant.

Anders acknowledged that some stakeholders are concerned about whether some of the groups that were being targeted would need to be reactivated because of new developments, including pending FERC orders.

Several of the task forces on the list have not met for several years, including the Generator Offer Flexibility Senior Task Force (last meeting November 2015), the Energy Market Uplift Senior Task Force (March 2017) and the Primary Frequency Senior Task Force (December 2018).

Anders highlighted a few of the task forces proposed for sunset that saw recent activity, including the Modeling Generation Senior Task Force (MGSTF) that last met on May 15 and the Distributed Energy Resources Subcommittee (DERS) on May 18.

Glen Boyle of PJM provided a *report* on the potential sunset of the *MGSTF*, as well as work completed regarding soak time and corresponding voting results. Soak time refers to the minimum period a unit must run from the generator breaker closure until it is dispatchable. (See "Modeling Generation Senior Task Force Recommendations," *PJM MRC Briefs: Dec. 19, 2019*.)

The task force, created in 2017, developed the solutions to improve resource modeling for "complex resources" in PJM's market clearing engines, including combined cycle units, coal units with multiple mills and pumped hydro. Boyle also presented a final *report* on the task force.

PJM's Scott Baker discussed a *proposal* to consolidate the DERS and Intermittent Resources Subcommittee to create the DER and Inverter-based Resources Subcommittee (DIRS). The charter calls for providing a stakeholder forum to investigate issues and procedures related to distributed energy resources and inverter-based resources, including generation or electric energy storage resources connected to the distribution system and/or behind the meter.

Anders said stakeholders will be asked to endorse the task force sunsets at the next MRC meeting. ■

— Michael Yoder

Committee	Last Meeting Date	Issue Status/Notes
Generator Offer Flexibility Sr. Task Force (GOFSTF)	11/12/2015	Implemented
Energy Market Uplift Sr. Task Force (EMUSTF)	3/2/2017	Implemented
Incremental Auction Sr. Task Force (IASTF)	1/19/2018	Order on rehearing denied (3/26)
Summer Only Demand Response Sr. Task Force (SODRSTF)	9/20/2018	Recent order
Primary Frequency Sr. Task Force (PFRSTF)	12/5/2018	Work completed
Energy Price Formation Sr. Task Force (EPFSTF)	3/14/2019	Work completed, and order recently received with short time for compliance
Modelling Generation Sr. Task Froce (MGSTF)	5/15/2020	Separate report on agenda
Distributed Energy Resources Subcommittee (DERS)	5/18/2020	Separate report on agenda - potential combination with IRS
Intermittant Resources Subcommittee (IRS)	3/2/2020	Separate report on agenda - potential combination with DERS

Suggested group sunset | *PJM*

PJM ARR/FTR Review Could Pit LSEs vs. Financial Traders

By Michael Yoder

PJM's plan to hire a consultant to review the RTO's auction revenue rights (ARRs) and financial transmission rights markets appears likely to set up a conflict between load-serving entities and financial traders.

A draft of the proposed scope of work shared with stakeholders Wednesday poses nine issues for the consultant to address, one-third of which question the current market's balance between LSEs and other market players.

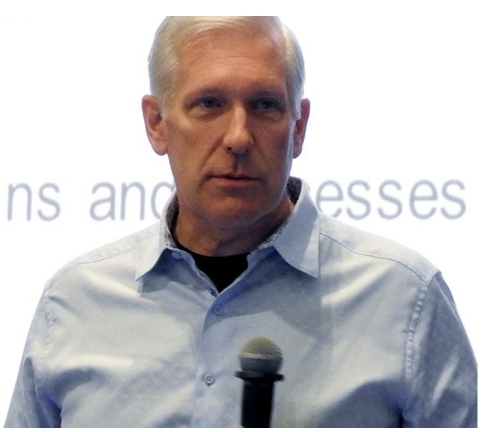
"Is load systematically disadvantaged under the current mechanism?" PJM asks. "Are there aspects of the current mechanism that result in profits to non-load-serving participants without commensurate or associated benefit to load?"

The draft also questions whether the current allocation of balancing congestion to load is appropriate, noting that "much of the negative balancing congestion in PJM can be attributed to financial products available in the day-ahead market, primarily up-to-congestion transactions (UTCs)."

It also asks whether the ARR allocation methodology should be changed "in order to increase the value of ARRs to load."

Dave Anders, PJM director of stakeholder affairs, who presented the draft to the ARR/FTR Market Task Force on Wednesday, said the RTO is seeking a consultant that has sufficient knowledge of the subject matter while also being independent enough to provide a "fresh look" at the issues.

The consultant is being hired in response to a recommendation in the "*Report of the Independent Consultants on the GreenHat Default*" that called for an outside expert to review PJM's FTR market and other PJM markets to evaluate the risks and the benefits of rule changes. (See "PJM Seeking Consultant on ARR/FTR Task Force," *PJM MIC Briefs: May 13, 2020*.)



Dave Anders, PJM | © *RTO Insider*

Anders said he recognizes stakeholders have a wide variety of views regarding what the consultant should accomplish.

"We want to make sure that stakeholders view the selection of the consultant, as well as the work that they perform, as credible," Anders said.

The draft includes an "overarching question" that asks whether the current ARR allocations and FTR auctions "constitute an appropriate mechanism in an LMP-based market by which to ensure that load receives the value of the transmission system for which it is paying through" network integration transmission service (NITS) and firm point-to-point transmission service charges.

Anders said PJM is requesting that the consultant first gain an understanding of the RTO's ARR/FTR mechanism and FERC orders that created the structure.

The scope of work also questions:

- the virtues of path-based vs. network allocations of CRRs;
- whether modeling differences between day-ahead and real-time markets are a cause for concern;
- whether new products should be offered, including a path-based FTR, and FTRs of different tenors (e.g., weekend-only, seven-day on-peak hours);
- whether some products should be removed from the FTR auctions; and
- whether FTR trading points that should be added or removed.

Susan Bruce of the PJM Industrial Customer Coalition said the independent review is something industrial customers are "welcoming with open arms."

Bruce said her group would like to see the scope of the consultant's review to include the role of the FTR market in generation development and understanding the role of liquidity in countering market power. "If [the FTR/ARR markets are] serving their intended purposes, then great," she said. "If not, then let's look under the hood a little bit more closely."

Susan Bruce, PJM Industrial Customer Coalition | © *RTO Insider*

Joe Wadsworth of Vitol said the questions concerning potential new products address practical commercial uses and were out of place in the consultant's scope of work. "To me, it's more of a practical commercial issue that would be driven by the experience of market participants that actually utilize the product," Wadsworth said.

Anders said the experience of market participants and commercial use of the product is something that should be considered in any determination to change the product mix. He also said the information that consultants could provide isn't necessarily a determination of whether a change is made.

Any changes resulting from the consultant's review would go through the normal stakeholder process, Anders said.

The review is expected to last a couple of months, Anders said, and will be dependent on feedback received from the consultant candidates.

Anders said PJM would not reveal the list of potential consultants now but said the RTO will make its selection and define the scope of the project "informed by input from all stakeholders."

During the task force meeting, the Independent Market Monitor outlined its proposal to directly allocate congestion revenues to LSEs.

Exelon, NextEra Resources and Public Service Enterprise Group countered with a presentation that alleged the Monitor's proposal would hurt customers, saying it "fails to understand how congestion and FTRs are currently employed by LSEs to manage risk." ■

PJM News

HVDC Initiative Endorsed by PJM Stakeholders

Wind Tx Line Seeks Capacity Status

By Michael Yoder

PJM stakeholders agreed Thursday to consider integrating HVDC converters as a new type of capacity resource in the RTO.

An *issue charge* by Direct Connect Development was endorsed by the Markets and Reliability Committee with a sector-weighted vote of 4.4 (88%), well above the 50% threshold.

Steve Frenkel, vice president of Direct Connect, *presented* the issue charge and *problem statement*, which seek to establish HVDC converter stations' eligibility to participate in the capacity market.

Winning such a change would allow Direct Connect's SOO Green HVDC Link — a 350-mile, 2,100-MW, 525-kV underground transmission line that would deliver renewable energy from upper MISO to Illinois and the PJM grid — to compete in the market.

"SOO Green is a merchant, non-cost-allocated project that is using innovative technology and commercial structures to match buyers and sellers," Frenkel said.

The Project

Direct Connect is planning to install the SOO Green line underground primarily along existing rail rights of way from Mason City, Iowa, to Plano, Ill., which Frenkel said would be the first major transmission project crossing the MISO-PJM seam. Construction is expected to begin in early 2022 and be completed by 2024.

Frenkel said the converter station will be directly connected to the PJM system and able to follow dispatch instructions and deliver energy on demand from a portfolio of "firm" generation supply, mostly wind turbines.

The PJM Tariff currently does not allow HVDC converters to participate in the Reliability Pricing Model market, which presents a market barrier to merchant resources seeking to sell bundled energy and capacity, he said.

While the converter station will be an internal resource within PJM able to offer comparable performance and services to other resources, Frenkel said, the RTO's current rules do not recognize HVDC converter stations as a capacity resource.

Opposition

Calpine's David "Scarp" Scarpignato said he was in favor of seeing the line built, but he said his company had concerns about taking on another issue charge with the amount of work already being done in the stakeholder process.

Scarp said he understood there are issues that need to be addressed, but in the HVDC issue, he said Calpine came to the "firm conclusion" that there was no problem that needed to be addressed. He said SOO Green can participate in the market through current processes, and the generators behind the line could also participate by following existing processes through pseudo-tie rules.

"We're breaking apart the current paradigm if you do this," Scarp said.

Frenkel said the existing Tariff does not address the market innovation his company is proposing.

"We'd appreciate the members be willing to have a conversation about how this technology can participate in the market," Frenkel said.

Paul Sotkiewicz of E-Cubed Policy Associates, representing Elwood Energy, said the HVDC issue didn't seem like a high-priority item to discuss. He agreed with Calpine's assertion that there were no obstacles to SOO Green's participation that weren't already addressed in the Tariff.

Sotkiewicz said all stakeholders should be able to bring issues they see as problematic up for discussion. But he said the problem statement and issue charge for SOO Green was a "single company" issue.

"What I worry about is now this sets a precedent that allows all of us the ability to bring a very specific, focused issue charge to the membership," Sotkiewicz said. "If we all did, I worry that we'd completely flood the stakeholder process and simply paralyze it and really get so far down in the weeds we can't even see."

Frenkel said it is a "resource class" issue.

"While SOO Green may be the first project to cross the transom and rise to the level of attention of stakeholders, we don't see this as a single proposal," Frenkel said. "It's really about opening up an opportunity for a class of innovative resources." ■

| SOO Green

SPP News

AEP a Go with $2B North Central Wind Project

By Tom Kleckner

North Central Wind Project's three wind farms are slated to be online by 2021. | *AEP*

American Electric Power on Wednesday said it has received enough regulatory approvals to fully move forward with its 1,485-MW North Central Wind Project in Oklahoma.

AEP will invest about $2 billion in the project, which consists of three wind farms and will serve the company's Southwestern Electric Power Co. (SWEPCO) and Public Service Company of Oklahoma (PSO) affiliates.

The Louisiana Public Service Commission on Wednesday *approved* a settlement agreement that authorizes SWEPCO — which serves parts of Louisiana, Texas and Arkansas — to purchase 810 MW of nameplate wind capacity from the project. The PSC's approval included a "flex-up" option that could increase Louisiana's allocation of that capacity from 268 MW to an estimated 464 MW if Texas regulators do not approve the project.

The Arkansas Public Service Commission also accepted an option to increase the state's allocation — from 155 MW to about 268 MW if Texas rejects it — when it approved the project last month. The Texas Public Utility Commission's agenda for its open meeting Friday did not list the project for consideration.

"This investment is expected to save our customers approximately $3 billion over the next 30 years while supporting economic development in our communities," AEP CEO Nick Akins said. "We will continue to seek approval to provide a share of this renewable energy to our SWEPCO customers in Texas, as we believe the projects offer significant benefits to customers across our SWEPCO footprint."

AEP says the North Central Wind Project will save SWEPCO customers $30 billion over three years. | *AEP*

PSO received final Oklahoma Corporation Commission approval Feb. 20 for 675 MW. FERC has also approved the project.

The three facilities are being developed by Invenergy in north-central Oklahoma. One facility is expected to be completed by the end of 2020, the other two by the end of 2021.

The project replaces the $4.5 billion Wind Catcher Energy Connection. The plan involved a 2-GW wind farm and a 360-mile transmission connection, but it was canceled in 2018 by AEP when the Texas PUC rejected SWEPCO's attempt to acquire a 70% interest in the project. (See *AEP Cancels Wind Catcher Following Texas Rejection*.)

AEP's regulated integrated resource plans call for the addition of more than 8 GW wind and solar energy between 2020 and 2030. ■

Company Briefs

Alliant Announces Plans to Close Coal Plant, Purchase Solar Farms

Alliant Energy last week said it plans to close its 400-MW Edgewater coal plant in Sheboygan, Wisc., by the end of 2022. The company said the move aligns with its plans to deliver "cleaner, more cost-effective energy" and is the next phase in its transition to renewable energy. Jeff Ripp, the utility's director of regulatory strategy and solutions, said Alliant will seek to recover about $500 million of investment in the plant at the end of 2022. State regulators will review the plant's closure and cost recovery.

At the same time, the company said it plans to purchase about $900 million worth of new solar power plants in Wisconsin. The six projects totaling 675 MW are the first phase in the utility's plans to add up to 1 GW of solar by 2024.

Alliant planned to file applications with the Public Service Commission last week seeking permission to purchase the projects. The PSC is expected to issue a decision early next year. If approved, the plants would come online by the end of 2023.

More: *Wisconsin Public Radio*; *Wisconsin State Journal*

GE Sells Lighting Business

General Electric last week agreed to sell its GE Lighting business to Cape Cod-based Savant Systems for an undisclosed amount. The deal is expected to close by early July.

GE Lighting employs about 725 people, most of which are in the Cleveland area. Savant Chief Executive Robert Madonna said the business will continue to operate out of its headquarters and that he plans to keep the management team in place.

Savant said it will continue to use the GE Lighting name through a licensing agreement.

More: *The Boston Globe*

NRG Adds Accounts from Competitor

NRG Energy last week announced it acquired a "subset of residential customers" from Windrose Energy, a retail electric provider based in The Woodlands, Texas. The customers will be served by NRG-owned Discount Power beginning the last week of June.

NRG has been buying a lot lately, including last year's $300 million purchase of the retail power and natural gas business of Stream Energy. Two years ago, NRG bought Discount Power from Volterra Energy Holdings.

More: *Houston Chronicle*

Southern Co. Commits to Net-zero Carbon

Southern Co. last week announced it has pledged to set a net-zero carbon target for 2050.

The company said it aims to balance fossil fuel emissions and its natural gas business with reductions from expanding its portfolio of renewable energy and energy efficiency. It now expects to hit a 50% reduction in carbon emissions compared to 2007 levels "well ahead" of its previous 2030 target.

Despite the commitment, Southern has yet to release specifics on near-term changes that could help accelerate its decarbonization plans.

More: *GreenTech Media*

Tesla Cuts Prices in North America to Boost Demand

Tesla last week announced it has cut EV prices by as much as 6% in North America following a decline in demand.

The company's website showed the starting price for its Model S sedan is now $74,990, down from $79,990. Its Model X SUVs are now priced at $79,990 (from $84,990), and the lowest-priced Model 3 sedan is $2,000 cheaper at $37,990.

According to J.D. Power, auto retail sales in the U.S. likely halved in April from 2019. However, the firm believes sales in May are likely to improve because of pent-up demand and offered incentives.

More: *Reuters*

Williams to Add Solar to Natural Gas Facilities

Oklahoma pipeline operator Williams last week announced that it will install 1- to 40-MW solar farms at 48 company natural gas processing sites in nine states.

Williams CEO Alan Armstrong said the company views natural gas and solar as complimentary technologies with financial and environmental benefits.

The solar farms are expected to be placed into service in late 2021.

More: *Houston Chronicle*

Xcel Exploring Renewable Natural Gas Options

Xcel Energy last week said it is exploring renewable natural gas (RNG) options via extracting energy from livestock manure, landfills and water treatment refuse. The company aims to get its plans to regulators either late this year or in 2021.

Xcel will gauge customer demand in the coming months, with customer participation being voluntary and not subsidized by other ratepayers.

CenterPoint Energy has already proposed an RNG pilot program, but it was unanimously rejected last year by the Minnesota Public Utilities Commission. The high cost of RNG was a concern, along with questions about the transparency of RNG procurement and out-of-state gas sourcing. Still, the PUC asked CenterPoint to refine its proposal, which the company has continued to do.

More: *Star Tribune*

Federal Briefs

Trump Administration Aims to Buy Uranium for Reserve

The Department of Energy last week said the government may start buying mined uranium for a proposed uranium reserve "as soon as possible" as the Trump administration looks to increase the production of nuclear energy.

Benjamin Reinke, the department's head of the Office of Policy, said the reserve would be "ready to go" in case of a market failure so that reactors would not have to be shut down. The department last month issued a report detailing a plan to boost the industry, including a $150 million uranium reserve proposal, which would include purchasing the mineral from a small group of domestic producers.

The average price of uranium in 2019 was about $36/pound.

More: *The Hill*

Probe Finds Official Misused Office to Get Son-in-law Job at EPA

The Interior Department Inspector General Mark Lee Greenblatt last week announced his office found that Assistant Interior Secretary Douglas Domenech in 2017 reached out to a senior EPA official in person and later by email to advocate for his son-in-law when he was seeking a job at the agency. It's the second finding of ethical violations in six months against Domenech.

According to Greenblatt's office, no criminal violations were found. Breaking the law at issue becomes a criminal matter if it benefits the violator directly or the person's wife, child or business, but not if it involves an in-law, according to the federal code.

The son-in-law was not named or identified in the report, but one of two people familiar with the matter identified the him as Eric Frandy. Frandy married Domenech's daughter, Emily, in 2012, according to the couple's online wedding registry.

More: *The Associated Press*

Trump Admin. Gives Renewables More Time for Tax Credits

The Treasury Department and IRS last week issued a notice that will give some renewable companies that started construction in 2016 or 2017 an extra year before they must put their projects in service. The notice also allows additional time for those companies to receive materials for construction to meet a requirement to start construction. The rules are intended to help taxpayers qualify for the production and investment tax credits.

The IRS said it recognizes the COVID-19 pandemic has caused industry-wide delays in the supply chain to complete renewable energy projects otherwise eligible for important tax credits, and that the notice aims to "provide tax relief to affected taxpayers."

More: *The Hill*

US Renewables Produce More Electricity than Coal in Q1

Renewable energy sources produced significantly more electricity (17.5%) than coal during the first quarter of 2020 and topped nuclear power in February and March, according to data from the Energy Information Administration.

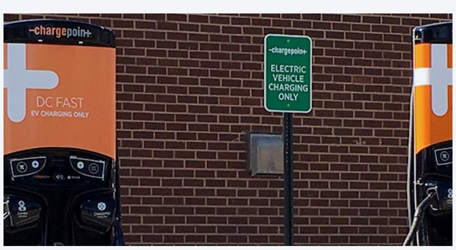
Solar-generated electricity expanded by 22.5% (compared to Q1 2019) and provided almost 2.6% of the nation's total. Wind grew by 17.4% and accounted for 9% total generation. Combined with hydropower, biomass and geothermal, renewables provided 20.8% of the country's total electrical output.

More: *Renewables Now*

State Briefs

CALIFORNIA

Pasadena Installs Largest Public EV Fast-charging Plaza



The city of Pasadena last week awarded a contract to Tritium to install 20 DC fast chargers. In addition to the 24 Tesla superchargers, Tritium's chargers make the Marengo Charging Plaza the largest public-access DC fast-charging location in the country.

The plaza has averaged more than 7,000 charging sessions per month through its first few months of operation.

More: *Renewable Energy Magazine*

CONNECTICUT

MIRA Asks for State Backing for Rehab Trash-to-energy Plant

Directors of the Materials Innovation and Recycling Authority (MIRA), the board responsible for Hartford's regional trash-to-energy plant, last week unanimously voted to end a multiyear, $330 million effort to rehabilitate the facility unless the state agrees by Aug. 31 to provide financial backing.

The board also cautioned that the state might be forced to ship 2.5 million tons of garbage a year to out-of-state landfills if it fails to offer major support. MIRA President Thomas Kirk said that without the backing, municipalities would pay as much as $145/ton for garbage disposal for the next 30 years, and that local officials have already rejected that option.

Gov. Ned Lamont's administration has hesitated to commit enough funding and declined to respond directly to the board's vote. Max Reiss, Lamont's press secretary, said the administration's response would be handled by "the Department of Energy and Environmental Protection, which deals directly with MIRA."

More: *The Connecticut Mirror*

Offshore Wind Farm PPA Submitted to PURA

Vineyard Wind, Eversource Energy and United Illuminating last week submitted a power purchase agreement for the 804-MW Park City offshore wind farm to the Public Utilities Regulatory Authority for review. The filing comes after several extensions to the deadline because of the impact of the COVID-19 pandemic.

The utilities would purchase energy and environmental attributes associated with the project for a 20-year term, per terms of the agreement. If approved, the project would provide the equivalent of 14% of the state's electricity supply and represents the largest purchase of renewable energy in state history. Plans call for the project to come online in 2025.

More: *Renews*

COLORADO

Xcel Energy Reaches Settlement on Microgrid Project

Xcel Energy last week reached a settlement agreement with Western Resource Advocates (WRA), which if approved by the Public Utilities Commission, will allow the utility to move ahead with a $23.4 million microgrid project.

The project, which calls for seven microgrids to incorporate storage, will provide 6 MW of microgrid capacity. The settlement would allow Public Service Company of Colorado to seek cost recovery via customer rates but requires Xcel to "provide robust testimony regarding expenditures" when it seeks its recovery.

WRA's main concern was that Xcel would use fossil fuel backup generators to charge the batteries. The sites all incorporate solar energy, but at least three of the seven also have fossil fuel backup generators. However, Xcel said it is unlikely that any of the systems will be charged with diesel generation.

Xcel plans to begin building the microgrids in January 2021 and have them completed within 18 months.

More: *Microgrid Knowledge*

IOWA

Utilities Board Approves Cardinal-Hickory Creek Tx Project

The Utilities Board last week approved a petition, submitted by ITC Midwest and the Dairyland Power Cooperative, for the construction, maintenance and operation of 14.25 miles of 345-kV line and 2.44 miles of 161-kV line of the Cardinal-Hickory Creek transmission project.

The board found that the proposal was in the public interest and granted the companies the right of eminent domain. However, the grant will be subject to easement modifications by the board.

More: *KCRG*

MICHIGAN

DTE, Consumers Shareholders Say 'No' to Political Spending Disclosure

Shareholders of DTE Energy and Consumers Energy have rejected calls for more transparency on the companies' contributions to tax-exempt nonprofit advocacy groups amid criticism on their political spending.

The Public Service Commission last year barred Consumers from contributing to 501c(4) nonprofits after the company was linked to a spike in political spending during the 2018 election. DTE also faced criticism last year from watchdog groups over its ties to multiple 501c(4) groups that promote policies also supported by the utility.

Although companies, including utilities and their political action committees, are required to disclose political contributions under state and federal election law, the same rules do not apply for tax-exempt groups.

More: *MiBiz*

Secord, Other Boyce Hydro Dams Damaged

FERC regional engineer John Zygaj last week wrote a letter stating initial observations found "erosion of the downstream slopes" at the Secord Dam, which is upstream from two dams that were breached two weeks ago.

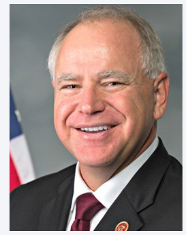
The Detroit News reported the Smallwood Dam was damaged even though Boyce Hydro officials indicated it had no "consequential" harm. On May 20, FERC ordered Boyce co-manager Lee Mueller to do an inspection of the Sanford, Smallwood and Secord dams three days after the water receded. The status of that inspection is unclear.

Boyce owns the four dams: Edenville, Sanford, Smallwood and Secord. FERC regulates all but Edenville, which is overseen by state officials. The Edenville and Sanford dams on the Tittabawassee River breached May 19 after heavy rains and winds. More than 10,000 people were evacuated before the floodwaters crested on May 20.

More: *The Detroit News*

MINNESOTA

Legislature Approves Net-zero Project for Prairie Island



The state legislature passed a bill last week that would give the Prairie Island Indian Community $46 million over three years toward the state's first "net-zero" clean-energy project. Gov. **Tim Walz** is expected to sign the bill.

The community would use conservation measures to reduce energy consumption while deploying solar power for electricity via the net-zero program.

The legislation would also allocate $10 million this year and $5 million in 2021 to Solar Rewards, which subsidizes small solar projects for Xcel Energy customers. The money would come from the state's renewable development account, which is funded by annual payments from Xcel.

More: *Star Tribune*

NEW MEXICO

PNM Files 'Decoupling' Case

Public Service Company of New Mexico (PNM) last week filed a request with the Public Regulation Commission to recover fixed service costs independently of how much electricity customers consume.

If approved, next year PNM would tally how much residential and commercial customers paid for electricity throughout 2021 and compare it with the total annual revenue the PRC authorized the utility to collect during the year to cover fixed costs. If the amount collected is less than the total allowed by the commission, PNM would apply a rate rider on customers' bills starting in 2022 to make up the difference. If customers over-pay, PNM would credit the difference.

That proposed rate mechanism, known as "decoupling," would ensure PNM always recovers fixed costs for providing service, effectively separating customer payments from consumption levels.

More: *Albuquerque Journal*

NORTH CAROLINA

Cooper Extends Utility Shutoff, Eviction Prohibitions

Gov. Roy Cooper last week said he signed an executive order to extend the prohibition of utility shutoffs for another 60 days and implement a moratorium on evictions for the next three weeks. The Council of State concurred on the order with no objections.

"North Carolinians need relief to help make ends meet during the pandemic," Cooper said. "Extending housing and utility protections will mean more people can stay in their homes and stay safe as we all work to slow the spread of this virus."

More: *WNCT*

TEXAS

Houston to Go 100% Green

Houston last week announced it is set to begin a new five-year contact with NRG Energy in July to power all its city-owned properties with renewable energy. The deal means the city will reach its goal of 100% renewable power five years earlier than anticipated.

Houston already buys more renewable power than any other city, according to EPA, and currently powers 92% of all city properties with a combination of wind and solar energy.

The contract includes options to extend the deal by up to two years.

More: *Bloomberg*

VIRGINIA

Regulators Warn Disconnection Moratorium is Unsustainable

The State Corporation Commission last week said the current ban on utility disconnections for nonpayment in response to the COVID-19 crisis "is not sustainable on an unlimited basis," and that an ongoing moratorium could lead to customers being burdened with higher bills or put smaller utilities at risk of running out of money. The SCC said the costs of the unpaid bills do not disappear and are shifted to other customers because of the companies' right to recoup certain costs.

The commission sought comment on three topics: how long the disconnection ban should last; how the costs of unpaid bills should be defrayed in the event of an extension; and whether voluntary measures could replace the current mandatory restrictions. The SCC will accept comments until Friday.

More: *Virginia Mercury*