RTO Insider

Your Eyes and Ears on the Organized Electric Markets

CAISO ■ ERCOT ■ ISO-NE ■ MISO ■ NYISO ■ PJM ■ SPP

ISSN 2377-8016 : Volume 2017/Issue 33 August 22, 2017

Grid Operators Manage Solar Eclipse

By Jason Fordney, Tom Kleckner, Amanda Durish Cook, Rory D. Sweeney and Michael Kuser

FOLSOM, Calif. — CAISO and other electric grid operators across the country managed large and rapid swings in solar generation output Monday during the first continent-wide total eclipse in nearly a century.

ISOs and RTOs were well prepared for the event, especially in solar-heavy California where the obscuration of the sun took thousands of megawatts of utility and rooftop solar off the grid. CAISO had to ramp up hydro and natural gas generation as solar dropped off, then do the reverse more quickly than usual as the sun came back

"We wanted to make sure we could make it if it was an extremely hot day, or if it was a mild day," CAISO Executive Director of Operations Nancy Traweek said. She added that the ISO had reached out to solar and hydro operators and asked them to be prepared for the event.

The last total solar eclipse to occur in the continental U.S. was before the growth in solar power in 1979 and was viewable only from the Pacific Northwest, according to NASA. Monday's was the first total eclipse since 1918 to span the width of the U.S.

As eyes equipped with protective glasses turned upward around the country, CAISO employees excitedly gathered outside the building, some with family members, to view the event.

Continued on page 34

MISO employees view the eclipse from the RTO's Little Rock, Ark., office. | *MISO*

Sempra Outmuscles Berkshire Hathaway for Oncor

By Tom Kleckner

Stepping in where others have failed, San Diego's Sempra Energy on Monday announced a $9.45 billion cash deal to acquire bankrupt Energy Future Holdings and its 80% interest in Texas utility Oncor.

© RTO Insider

Sempra's move short-circuited a looming battle between Berkshire Hathaway Energy and hedge fund Elliott Management, the largest holder of EFH bonds, which had opposed as too low BHE's $9 billion all-cash offer in July. Elliott said it was working on a competing bid totaling $9.3 billion. (See *PUCT Staff Welcomes Buffett's Oncor Bid; Debtor Miffed*.)

Elliott spokesperson Michael O'Looney said the investment fund is "supportive" of Sempra's

Continued on page 23

Calpine Going Private in $5.6B Deal

By Rich Heidorn Jr.

Calpine announced Friday it has agreed to be acquired by Energy Capital Partners and other investors for $5.6 billion in cash, or $15.25/share, a 51% premium to Calpine's share price when news of a potential deal became public in May, and a 13% bump from Thursday's close.

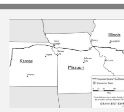
Energy Capital Partners, a private investment firm, is being joined by a group of investors led by the Canada Pension Plan Investment Board, which said it will invest $750 million, and Access Industries, a privately held company with investments in a wide variety of industries and companies, including Warner Music Group, Houston-based oil and natural gas producer EP Energy, and Russia-based aluminum manufacturer UC RUSAL.

The investors will be purchasing Calpine's 26-GW fleet of 80 power plants in operation or under construction, the largest fleet of natural gas generators in the U.S. Its assets are concentrated in California (5,500 MW of natural gas and 725 MW of geothermal); Texas (13 combined cycle plants totaling 9,000 MW) and the East (31 plants totaling 9,400 MW in 14 states and Canada, most of them in

Continued on page 23

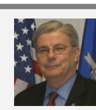
SPP Disappointed as MISO Axes Last Interregional Project

(p.17)



Clean Line Ponders Options After Grain Belt Rejection

(p.22)



New NARUC Head Calls for NEPOOL Transparency

(p.27)

RTO Insider

CAISO ERCOT ISO-NE MISO NYISO PJM SPP

Editorial

Editor-in-Chief / Co-Publisher
Rich Heidorn Jr. 202-577-9221

Deputy Editor / Senior Correspondent
Robert Mullin 503-715-6901

Production Editor
Michael Brooks 301-922-7687

Contributing Editors
Julie Gromer 215-869-6969
Peter Key

CAISO/West Correspondent
Jason Fordney 571-224-8960

ISO-NE/NYISO Correspondent
Michael Kuser 802-681-5581

MISO Correspondent
Amanda Durish Cook 810-288-1847

PJM Correspondent
Rory D. Sweeney 717-679-1638

SPP/ERCOT Correspondent
Tom Kleckner 501-590-4077

Subscriptions and Advertising

Chief Operating Officer / Co-Publisher
Merry Eisner 240-401-7399

Account Executive
Marge Gold 240-750-9423

Marketing Assistant
Ben Gardner

RTO Insider LLC
10837 Deborah Drive
Potomac, MD 20854
(301) 299-0375

Subscription Rates:

Payment Frequency	PDF-Only	PDF & Web
Annually:	$1,350.00	$1,650.00
Quarterly:	380.00	475.00
Monthly:	150.00	175.00

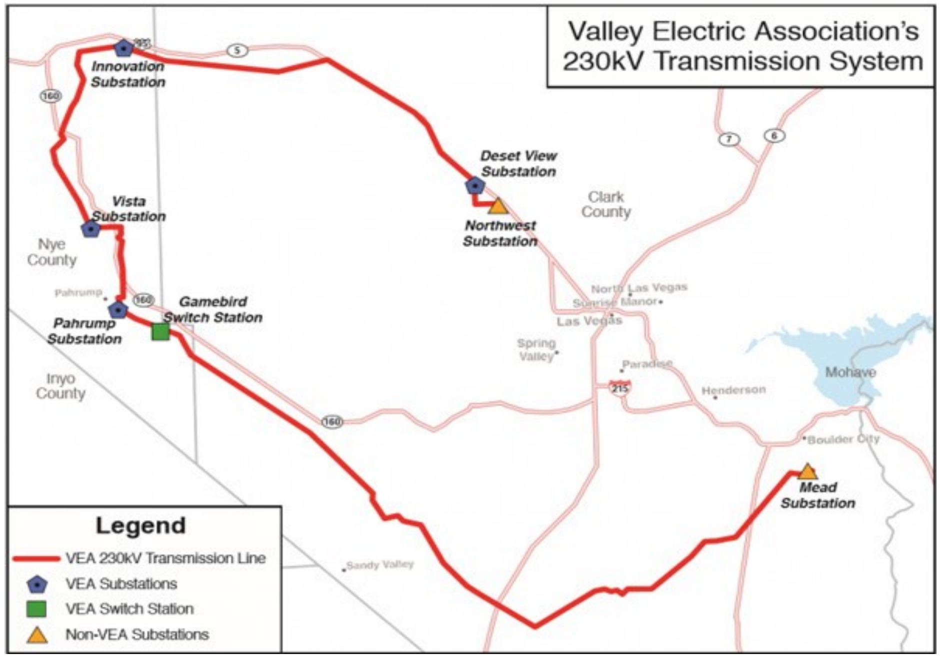
See details and Subscriber Agreement at rtoinsider.com.

IN THIS WEEK'S ISSUE

CAISO NEWS

GridLiance Gets OK to Acquire Valley Electric Tx Assets

By Robert Mullin



Valley Electric Association

FERC last week approved GridLiance West's acquisition of Valley Electric Association's 230-kV transmission network in a deal valued at about $200 million (EC17-49).

The deal will provide GridLiance with a strategic foothold in an area that bridges the CAISO market with the interior West. (See *Valley Electric Board Approves Sale of 230-kV Network to GridLiance*.)

The commission also granted GridLiance's request for incentive rate treatment for operating the network. And while FERC accepted the company's formula rate template for filing, those rates will be subject to a further evidentiary hearing before a settlement judge to determine the reasonableness of proposed rate inputs, return on equity and income tax allowance (ER17-706).

The decision to approve the transaction came despite objections from some CAISO members who contended that the transaction would result in increased in costs to ISO stakeholders.

GridLiance will be taking over 164 miles of 230-kV lines linking Valley Electric's base in Pahrump, Nev., with both Las Vegas and the Mead substation — a major delivery point for power wheeled into California — as well as substations along the length of the system. The sale will earn Valley Electric 2.4 times its investment in the system, which significantly increased in value when the cooperative joined the ISO in 2013.

In a filing with FERC, GridLiance said that incorporating its revenue requirement into CAISO's High Voltage Access Charge will increase that charge by about 0.48%, or $10.8 million. The company attributed the rate bump to the differing business structures of Valley Electric, which is a nonprofit rural electric cooperative, and GridLiance, a for-profit startup that will incur greater costs for overhead, administrative costs and taxes.

GridLiance argued that the increased cost would be offset by the benefit of having the transmission network of a well-funded transmission company that would add competition to the CAISO market and be focused on expansion and enhancement of the ISO transmission system.

The Transmission Agency of Northern California (TANC) contended that, although GridLiance had promised not to recover through rates any acquisition premium paid for the Valley Electric network, the $10.8 million increase in the ISO's transmission revenue requirement (TRR) constituted such a premium. TANC noted that the increase represented a near doubling of the TRR for the network — without GridLiance having incurred any costs for improvements or modifications. The agency also argued that the transaction would not result in any "quantifiable or non-quantifiable" benefits that would offset the increased costs.

Southern California Edison (SCE) contended that the initial revenue requirement included in GridLiance's proposed formula rate may be "unjust and unreasonable" and possibly included "improper and unsubstantiated costs and expenses." SCE argued that the commission could not decide about the acquisition without fully vetting the impact of GridLiance's formula rate filing.

The "Six Cities" utilities of Anaheim, Azusa, Banning, Colton, Pasadena and Riverside raised many of the same concerns, asking why the revenue requirement for the transmission facilities will increase just because of a transfer of ownership.

FERC came down firmly on the side of GridLiance, saying the 0.48% increase in the access charge was "not unexpected" given the company's capital structure, tax obligations and "need to earn a return." The commission also determined that GridLiance had presented evidence that increased costs would result in offsetting benefits.

"GridLiance West represents that it intends to develop needed upgrades and important transmission projects that will improve system reliability and increase transmission capacity to meet growing demand for renewable resources, including, and in particular, exports out of the Valley Electric area," the commission said.

Valley Electric said that it would be unable to perform those necessary upgrades in a timely manner.

"Due to its singular focus on developing and owning transmission facilities, GridLiance West will not face the difficult decisions Valley Electric has faced in allocating its limited financial resources among the various infrastructure development needs within its service territory," the commission said.

CAISO NEWS

California Awarding $45 Million for Microgrids

By Jason Fordney

The California Energy Commission meets Aug. 17. | © RTO Insider

Sacramento, Calif. — California is offering $45 million in grants for the development of microgrids on a variety of siting categories to stimulate development of new distributed energy resources.

California Energy Commission staff on Thursday gave curious developers both broad guidance and more practical advice regarding the program, which has wider parameters than a similar solicitation two years ago. Energy officials see DER such as microgrids, energy efficiency, energy storage, electric vehicles and demand response as increasingly critical to help manage renewables.

Gravely

"The goal of it is to allow creativity" and demonstrate both the technology and a business case, not "science projects," CEC Deputy Division Chief Mike Gravely said. "Obviously we are looking for a project that has commercial viability and a potential for future success." The commission is hoping to develop a standard configuration that can be adopted on a wider scale, and to define methodologies to evaluate their benefits. It is also important to identify a market where they can function, he said.

The application deadline for the funding opportunity is Oct. 20, with awards anticipated to be announced next January and associated agreements beginning in June 2018. The commission is due to approve the awards in March.

Successful projects must be designed to be permanent and must advance technology while helping the state meet its clean energy goals. Projects fall within three program areas: applied research and development, technology demonstration and deployment, and market facilitation.

Projects to be funded are divided into three siting categories: $22 million is allocated for microgrids on military bases, ports and tribal lands; $12 million for projects in low-income areas; and $11 million for local communities, rural areas, industrial complexes and local schools.

The minimum award amount for a single project is $2 million and the maximum is up to $7 million. Developers must obtain matching funds equal to at least 20% of the award amount if it is $5 million or less, and 25% if the award is $5 million to $7 million. Match funding can include cash, equipment, materials, information technology services, travel, subcontractor costs, labor and other expenses.

CEC manages the money collected through the Electric Program Investment Charge (EPIC), a retail ratepayer surcharge. The purpose of the EPIC program is to benefit customers of the state's three investor-owned utilities — Pacific Gas and Electric, San Diego Gas & Electric and Southern California Edison — by investing in clean energy projects that promote reliability and lower costs. Projects that leverage other funds such as federal support will be given priority, and they must be in IOU territory.

Most of the projects funded following a 2015 solicitation are at the point where equipment is being installed and the systems are fully operational, "thus facilitating the collection of valuable data on performance, value streams and reliability," CEC said in the grant funding opportunity. In the first round of funding, the state received 40 proposals from which it picked seven winners. The commission said the facilities "are providing a wealth of information on microgrid configurations, interconnection of different DER through a single controller, and system interconnection challenges."

The earlier funding includes $5 million for a low-carbon community microgrid at Humboldt State University and a microgrid automation project at a community college. San Diego Gas & Electric received $5 million for a photovoltaic microgrid and another $5 million funded a microgrid at the Laguna Wastewater Treatment Plant. Overall, the state has awarded $470 million to 279 projects with $223 million in matching funds, which CEC highlights in its online Energy Innovation Showcase.

The discussion showed what CEC has learned. Sometimes projects don't work or cease operation the day state funding ends — undesirable outcomes that have even led to equipment appearing on the eBay website.

Humboldt State University

CAISO NEWS

EIM Members Wary of Need for CAISO Wheeling Charge

By Jason Fordney

CAISO's proposal to provide transmission revenue to balancing authority areas (BAAs) that wheel power between other BAAs received a wary response from Western Energy Imbalance Market (EIM) stakeholders last week.

Currently BAAs that wheel power are only paid if the system is congested.

The compensation change is part of a package of refinements that CAISO is developing, including fundamental changes to the way transmission is treated in the developing market. EIM entities filed comments on the proposals Thursday.

Wheeling is on the increase as the EIM grows and more regions are added. When Powerex is integrated in April 2018, for example, Puget Sound Energy will be positioned to wheel power from British Columbia to the south. Powerex markets a BC Hydro portfolio of about 17,000 MW of generating capacity, about 12,000 MW of which is hydro.

FERC staff tentatively approved the integration of Powerex in a delegated order Aug. 9. (See *Wary FERC Approval for Powerex EIM Agreement*.)

Powerex said it supports the compensation proposal and wants CAISO to adopt a net wheeling charge on all EIM transactions to pay for it. The Canadian government-owned company said that such transactions represent a significant portion of import and export volumes, "which suggests that such transactions may be critical to the EIM's ability to generate benefits."

But the company said that any wheeling charge should not impede economic dispatch and reduce EIM benefits. It is "critical that any such charge be designed in a manner that ensures that the incremental hurdle rate that is created is as small as possible. Such transactions may be critical to the EIM's ability to generate benefits," it said.

PacifiCorp, which has been operating in the EIM since the market went live in November 2014, said it has concerns about the proposal, arguing that "it is too early to understand if there is truly a market problem to be solved." The company said CAISO should wait until after Portland General Electric, Powerex and Idaho Power are integrated to get a better understanding of how resources will be scheduled in the expanding market. PacifiCorp owns about 10,600 MW, including about 2,500 MW of wind, and plans to retire 3,650 MW of coal-fired capacity by 2036.

It is possible that the increased wheeling over the past nine months was related to "anomalies" such as excess hydro or the outage at the Aliso Canyon natural gas storage facility, the Berkshire Hathaway-owned company said.

"PacifiCorp recommends that the initiative be postponed and continue to be monitored so that new entrants can make informed comments that truly reflect transfers across their systems," the company said.

The company also noted that CAISO had proposed market changes to accommodate the integration of Powerex, but that most of the additional functionality would not apply to PacifiCorp. The company believes Powerex will not be required to participate in security-constrained economic dispatch in its BAA like other EIM entities.

CAISO has two plans for the charges: an added "hurdle rate" into transmission costs that is distributed to participants in the transaction through a congestion offset; and an "ex-post" payment to entities facilitating the transmission that would be collected directly from the source and sink BAAs.

Monitor, Public Interest Groups Oppose

CAISO's Department of Market Monitoring said both approaches would cause inefficiencies. The charge appears to be a proxy for other EIM benefits, the department said, and is "overly simplistic" for cost allocation. "These inefficiencies may result from a per-megawatt-hour fixed cost recovery approach influencing bidding behavior, or more directly through the hurdle rate, which may lead to inefficient dispatch of EIM resources," the Monitor said.

A collection of public interest organizations also opposed the proposal, saying it could reduce overall EIM benefits and possibly reduce investment. The group includes Western Resource Advocates, the Natural Resources Defense Council and Western Grid Group.

"Not only will these schemes unnecessarily complicate the EIM's market design, thereby undermining its benefits, but they appear to be a solution in search of a problem, given that all EIM BAAs are importing and exporting more than they are facilitating wheeling,"

Continued on page 6

CAISO NEWS

CAISO Monitor Says Bid Rule Changes Flawed

By Jason Fordney

CAISO's Department of Market Monitoring criticized a recently proposed set of market rule changes as incomplete, urging a slower approach.

The department and other market participants recently submitted comments on CAISO's straw proposal for its Commitment Cost and Default Energy Bid Enhancements (CCDEBE) initiative. The proposal is designed to more accurately reflect unit commitment costs and overhaul the way the ISO calculates the default energy bid (DEB), which replaces bids of units found to have market power. (See *CAISO Developing New Bidding Rules*.)

The Monitor said it continues to recommend that CAISO split the proposal into parts and that more time is needed to develop dynamic mitigation. "The development and implementation of dynamic mitigation of commitments costs is relatively complex and the ISO has made very limited progress on developing technical details of an approach for actually implementing this," it said.

CAISO Senior Developer Cathleen Colbert presents CCDEBE on Aug. 3. | © *RTO Insider*

"Given the flaws and lack of detail in the ISO's commitment cost mitigation design," the Monitor does not support a proposal to raise the caps on market-based commitment cost bids above the current level of 125%.

One of CAISO's rationale for the new program is incentivizing flexible resources. The grid operator says that overly constrained supply offers discourage participation by some resources in the ISO and the Western Energy Imbalance Market (EIM), where the changes would also apply.

There are three power suppliers subject to the DEB: Arizona Public Service and Berkshire Hathaway's PacifiCorp and NV Energy. In comments filed Aug. 15, NVE said it supports increasing the flexibility of supply bids and reforming the DEB methodology "to ensure appropriate recovery of actual supply costs."

The Western Power Trading Forum said it supports the concept of the revised proposal but asked for additional information on the frequency of mitigation. The group supports CAISO's proposed hourly minimum load offers, market-based commitment costs subject to mitigation and improved estimates of commitment costs. It also offered suggestions on details of the market design.

Pacific Gas and Electric said it supports part of the proposal but wanted additional detail before it would endorse the changes. "PG&E continues to have concerns about committing to move forward with a dynamic mitigation design while many questions remain regarding design details, feasibility and cost," the company said. It said that more analysis is needed and that the dynamic mitigation should be split off from the rest of the CCDEBE proposal.

Continued on page 7

EIM Members Wary of Need for CAISO Wheeling Charge

Continued from page 5

they said.

They also said that CAISO should not focus on minor inequities in the EIM because it distracts stakeholders from the benefits the market brings. If the ISO does pursue it, the groups support the ex-post payment approach, saying it is least disruptive to the market and would adapt well to a changing EIM.

Seattle City Light voiced strong opposition, saying that a more robust stakeholder review is needed before making such a change, noting that CAISO has not identified free riders or cost shifts. The municipal utility owns 2,000 MW of hydro and transacts in the EIM.

"City Light is particularly concerned with the proposal to address a benefits-related issue by implementing an additional cost to EIM entities. The addition of a new cost is an imprecise tool to address a concern over inequitable distribution of benefits," the publicly owned utility said.

Portland General Electric in its comments said it "is not convinced that this initiative has been appropriately scoped, or that the market design, policy and regulatory considerations have been fully considered, and therefore does not believe it is prudent at this time to move forward with either of the ISO's policy recommendations."

Southern California Edison (SCE) also opposed the changes, saying that participating in the EIM does not guarantee uniform benefits to all entities and CAISO.

"While SCE understands that examining the actual benefits and costs after the fact rather than relying on estimates prior to EIM is a good practice, SCE believes that in this case, the data support the current practice and policy and that no changes are warranted," the company said.

Arizona Public Service supported the proposal but said it should apply equally across the EIM and not offset the market's benefits.

Most stakeholders support CAISO's decision to eliminate from the package of market rule changes a plan to allow third-party transmission owners to participate in the EIM. There was lackluster interest from current EIM entities and it was thought the provisions would be little-used. (See *CAISO Drops EIM Third-Party Transmission Plan*.)

The ISO Board of Governors is due to review the package of changes at its Nov. 1 meeting.

CAISO NEWS

CAISO Seeks Changes to Boost Risk-of-Retirement Program

By Jason Fordney

CAISO last week unveiled its latest revisions to a program meant to compensate uneconomic generation units needed to maintain reliability.

After consulting with stakeholders since June, CAISO unveiled 20 changes to the Capacity Procurement Model Risk-of-Retirement Initiative (CPM ROR). The ISO is taking comments through Aug. 28 on the revised straw proposal, which is due to be reviewed by the Board of Governors on Nov. 1.

Stakeholders were skeptical of the program when it was proposed earlier this year, saying it does not address the fact that CAISO's energy market can no longer adequately compensate generation resources that are unprofitable but are still needed to manage the integration of large amounts of renewables (See *CAISO Stakeholders Question Risk-of-Retirement Initiative*.)

On a call last Tuesday, Pacific Gas and Electric representative Peter Griffiths asked how the CPM ROR process relates to a separate reliability-must-run process, as one of CAISO's stated objectives is to see if ROR could be used rather than RMR. "I just want to make sure that is a touchstone to some degree that we continue to look back at," Griffiths said.

CAISO Manager of Infrastructure Policy and Contracts Keith Johnson replied that "one of the objectives here is to see if CPM is a viable option." He said the changes are intended to increase the possibility of using the program, which has never been deployed since its creation.

"We want to see if there is a way that we can at least make the existing provisions work better so there is a higher probability that they will be used and useful," Johnson said. There are still circumstances in which RMR will be needed, he said.

Earlier this year, CAISO awarded RMR designations to Calpine's Yuba City and Feather River peaking plants after the company said it would be forced to retire the facilities if required to await a decision on CPM next year. (See *CAISO RMRs Win Board OK, Stakeholders Critical*.) Calpine said the RMR award was the only viable option, but CAISO wants the CPM ROR to be the primary backstop to generation shortages through retirement.

Most stakeholders support allowing any resource to apply for a ROR designation, including resources that are under a resource adequacy (RA) contract. Currently, generation resources that have an RA contract for the upcoming (January-December) RA year cannot apply for ROR designation. Capacity under a RA or RMR contract or another kind of CPM procurement may not receive ROR payments at same time.

Resource owners say that one current problem is that CAISO cannot initiate its study to determine the need for an individual unit until November of each year, just after all load-serving entities publish their RA requirements for the following calendar year. Generation owners have expressed concern that they don't know if their resources will have RA contracts until Oct. 31. One of CAISO's objectives is to provide for its ROR analysis to take place prior to the end of the RA contracting period.

Under the new proposal, windows would open in April and November each year for three types of ROR designations:

- Type 1 refers to non-RA resources for designation within the current RA compliance year (April window).
- Type 2 is for RA resources or non-RA resources for designation during the calendar year following the current RA compliance year (April window).
- Type 3 is for non-RA resources for designation during the upcoming RA compliance year (November window).

The straw proposal also clarified the criteria for an ROR designation: that the "grid cannot be reliability operated without that specific resource in service." CAISO plans to post reports within 30 days of such findings to allow stakeholders to comment.

CAISO's draft final proposal is due to be posted on Sept. 11, and another stakeholder call is set for Sept. 18.

Window	Type of Designation	Type of Request
April	Type 1	By non-RA resource for designation for current RA compliance year
	Type 2	By RA resource or non-RA resource for designation for calendar year following current RA compliance year
November	Type 3	By non-RA resource for designation for upcoming RA compliance year

Timing of requests for designation - windows | *CAISO*

CAISO Monitor Says Bid Rule Changes Flawed

Continued from page 6

CAISO has acknowledged that its time schedule has been rapid since the original straw proposal was issued on June 30, but it says it is aiming for approval at the Nov. 1 Board of Governors meeting. The ISO said that some parties are anxious to have the new rules approved.

After originally setting an Aug. 10 deadline for comments — only eight days after the revised straw proposal was posted — CAISO extended the comment period to Aug. 15.

The ISO has made several changes to the package based on stakeholder input. The initiative has other market adjustments, including alterations to the use of gas indices and rules to allow cost-based energy offers above $1,000/MWh, in compliance with FERC's November 2016 Order 831.

Some stakeholders thought the EIM Governing Body should sign off on the changes, but CAISO declined, saying it would offer only an advisory vote to the body since the initiative applies across all CAISO markets.

CAISO NEWS

CAISO Demand Response Problems Erode Participation

By Jason Fordney

Frequent rule changes and an uncertain market structure are causing dissatisfaction among CAISO demand response providers and eroding participation in the programs, those providers say.

Problems with data verification and settlement required the ISO to recalculate its 2016 DR results, and providers say there are other issues with the program, which aggregates utility customers to facilitate their participation in the ISO's wholesale markets.

"We have not received any energy payment of any dispatch of our resources going back to June 2016," EnerNOC Director of Regulatory Affairs Mona Tierney-Lloyd told *RTO Insider*. While Tierney-Lloyd doesn't think there are large payments still outstanding, "it is obviously sub-optimal," she said.

EnerNOC and other companies aggregate retail electric customers and bid the load reductions into the CAISO market to offset the need for generation. Wholesale DR aggregates and compensates electricity users that reduce their consumption to below a pre-established baseline. Separately, utilities also maintain DR programs in which they provide customers a financial incentive to decrease load.

Tierney-Lloyd believes there are several factors causing the decline in DR program participation, including rule changes and modifications to the way DR resources are dispatched. There are also inconsistencies between CAISO and California Public Utilities Commission rules, she said. Agency misalignment is the primary cause of what she said is significant decline in DR program participation.

"It takes work on our side to get those customers familiar with those rule changes," which also adds costs, she said.

During hot weather, it is more difficult for customers to reduce their usage below baseline, resulting in some taking efforts to reduce demand without getting paid. Others keep a close eye on CAISO operations and don't understand why they are getting dispatches when no shortages are seen on the system.

CAISO uses DR as a way to make the grid more efficient and reduce greenhouse gases associated with climate change. While the ISO has a number of DR program improvements underway, its past problems slowed payments to market participants. (See CAISO Resettling 2016 Demand Response Results.)

In 2016, the DR system was sometimes unaware that an event had occurred, or the system did not deliver settlement data, CAISO said. The system was not receiving the correct "payload" to identify that a DR event occurred, so the system was unaware of the event and no performance measurement was completed. But even when the event day and historic meter data were available, the DR system in some cases did not send the values to the settlement system, so no settlement occurred. The ISO's full resettlement should be completed in October.

The CAISO Board of Governors recently approved the second phase of a program meant to make distributed resource integration easier, dubbed the Energy Storage and Distributed Energy Resources (ESDER) Phase 2 proposal. (See New CAISO Rules Spell Increased DER Role.) ESDER includes a set of alternative energy usage baselines to assess the performance of proxy demand resources, one of a series of refinements to the DR program.

ERCOT NEWS

PUCT Briefs

ERCOT, SPP to Coordinate 2nd Load-Migration Study

The Public Utility Commission of Texas asked ERCOT and SPP on Thursday to coordinate a joint study on Rayburn Country Electric Cooperative's proposed transfer of most of its existing SPP transmission facilities and load into ERCOT (Docket 47342).

The East Texas co-op is an SPP member, but only about 150 MW (less than 20% of its load) and 160 miles of its transmission sit in the Eastern Interconnection. ERCOT estimates it will cost $38 million to connect the SPP load with the Texas grid.

Commissioner Ken Anderson said it would be "helpful" if the two RTOs would "give all of us — SPP, ERCOT and the commission — reasonable comfort as to what the costs, benefits and challenges are, if any — and to do it as quickly as humanly possible."

"We can do that," said Warren Lasher, ERCOT director of system planning. SPP was not represented at the meeting, but both RTOs are expected to report back with a study scope at the Aug. 31 open meeting.

The grid operators have already produced a similar, much larger study on Lubbock Power & Light's proposed transition of its 430-MW load from SPP to ERCOT. The study indicated the transition would cost them nearly $370 million. (See *Load Migrations Put SPP's Focus on Retention*.)

2nd Price Formation Workshop Scheduled

The PUC has scheduled a second staff-led workshop for Oct. 13 on price formation issues in the ERCOT market to pick up where the discussion left off earlier this month (Docket No. 47199). (See *ERCOT, Regulators Discuss Need for Pricing Rule Changes*.)

Stakeholders have been invited to submit alternate proposals and additional analysis in response to a report commissioned by independent power producers NRG Energy and Calpine, which asserts "a need for adjustments" to the market's pricing rules. The report, "Priorities for the Evolution of an Energy-Only Electricity Market Design in ERCOT," was the primary topic during the Aug. 10 workshop.

Staff on Friday filed a timeline for submitting comments, proposals and analyses. ERCOT's Independent Market Monitor will file a paper fleshing out its proposal to address reliability-must-run issues with a local reserve product by Sept. 15; the ISO's staff will submit a second filing on real-time co-optimization and scarcity pricing by Sept. 29.

Commission staff will then present a revised request for stakeholder comment during the PUC's Oct. 26 open meeting.

The commission agreed a second workshop would allow them to be more specific in addressing the recommendations and studies. They also plan to conduct their own workshop at a date to be determined.

"We could … give participants a stronger reference point of what we're working on, so their comments can be more targeted," Commissioner Brandy Marty Marquez said.

"While I enjoy workshops as much as anybody, I don't want this to devolve in an endless series," Anderson said. "It would be my hope the October workshop will include any and all ideas and the reports that come in by the end of September."

— Tom Kleckner

ISO-NE NEWS

Commenters Seek Broader Response on Millstone, Renewables

By Michael Kuser

© RTO Insider

HARTFORD, Conn. — Connecticut regulators got an earful at a public comment session Thursday on the future of Dominion Energy's Millstone nuclear plant, with multiple speakers opposing a state subsidy such as those adopted by New York and Illinois.

Instead, the speakers urged that any efforts to preserve the plant be part of a regional initiative that also includes other emission-free generation. Others questioned whether Millstone needed financial support in addition to its revenue from ISO-NE's energy and capacity markets.

The Aug. 17 hearing was in response to Gov. Dannel Malloy's executive order requiring state officials to assess the economic viability of Millstone and determine whether the state should provide it financial support. The governor also directed the Department of Energy and Environmental Protection and the Public Utilities Regulatory Authority to assess the viability of all forms of renewable energy and to report their findings by Feb. 1. (See *CT Gov Orders Financial Analysis of Millstone Plant*.)

Free to Solicit

PURA Chair Katie Dykes, who led the public meeting, reminded participants that they were not only to look at nuclear, but also at "large-scale hydropower, demand reduction, energy efficiency measures, energy storage and emissions-free renewable energy — all those different resources together — and how they could help Connecticut meet interim and long-term carbon and other emission targets. So there is a larger scope here."

The Connecticut General Assembly in June failed to pass a bill that would have allowed the 2,111-MW nuclear plant in Waterford to bid into the state procurement process (S.B. 106). Dominion had sought the legislation to boost the plant's revenues, which have suffered from low-priced natural gas, which often sets LMPs in New England.

Dominion has until Aug. 29 to respond to PURA's request for the company's financial records on Millstone, which supplies approximately 45% of Connecticut's electricity.

Tom Swan, executive director of the Connecticut Citizen Action Group, characterized Dominion's pleas of economic hardship as "BS" and said the regulators should also look at additional legislative remedies if the company wants to leave the business. While the state may need Millstone to meet its emissions reduction goals, "that doesn't say it has to be Dominion," he said.

State regulators have been given leeway to act by a 2nd U.S. Circuit Court of Appeals ruling in June that rejected claims that Connecticut's renewable energy procurement law intruded on FERC's authority. The court on Aug. 17 declined to revisit its decision.

The ruling affirmed a lower court decision on the law, which requires the state to solicit proposals for renewable energy projects and for utilities to sign contracts with the winners. Renewable energy developer Allco Finance challenged the law's implementation as discriminatory (16-2946, 16-2949). (See *Second Circuit Upholds Conn. Renewable Procurement Law*.)

Despite the court's support for state's rights, Peter Fuller, vice president of market and regulatory policy for NRG Energy, said, "We need to keep everything in the context of the regional context, the regional structure. ISO-NE and the New England markets are specifically tasked with maintaining reliability of the grid, are structured to achieve those reliability goals at lowest cost."

Connecticut's agencies need not "start from whole cloth" and worry about those issues, Fuller said. "We have those structures in place. Hopefully ISO-NE will be involved in assessing the various scenarios and so forth and assuring the various agencies on what is reliable."

Hydro on the Table

Michael Cuzzi, senior director of government relations for Brookfield Renewable, recommended that the study consider all hydropower resources in ISO-NE and adjacent control areas, not simply large-scale hydropower as stated in the governor's order and as currently defined under Connecticut statutes.

"The existing statutory definition — which contains both size and geographic limitations — prevents Connecticut from accessing existing, interconnected hydropower resources from both Canada and New York that can help Connecticut meet its energy needs and that are not currently accounted for in the state's greenhouse gas emissions inventory," Cuzzi said.

If the "hydro resources in New York and Canada aren't currently counted toward their renewable goals, are they currently counted towards other jurisdictions' goals?" Dykes asked him.

"It depends," Cuzzi replied. "As you know, in New York, the initial Clean Energy Standard did not incorporate existing clean energy resources, so I think there's a bit of a first-mover opportunity here to frankly claim those attributes and lock them into one jurisdiction or another."

Pricing Carbon

Fuller said that any targeted subsidy will distort markets, produce less-efficient outcomes and potentially increase risk to consumers.

He urged the regulators to "think about the multistate issues, think about the legislative proposal from a few months ago to place a broad, economy-wide carbon tax — those are the kinds of solutions either within the IMAPP [Integrating Markets and Public Policy] or within the broader economy we

Continued on page 11

ISO-NE News

Commenters Seek Broader Response on Millstone, Renewables

Continued from page 10

feel are going to be far more effective at getting the right answer."

The New England States Committee on Electricity (NESCOE) told the New England Power Pool in April that the states opposed "a FERC-jurisdictional tariff reflecting carbon pricing." (See *ISO-NE Two-Tier Auction Proposal Gets FERC Airing*.)

Cuzzi similarly recommended that the study "examine a uniform ISO-NE-wide carbon price."

On Aug. 11, NYISO and the New York Department of Public Service released a report that said a $40/ton carbon charge in the state would have "a relatively small impact" on customer costs, with bills dropping by 1% or rising no more than 2%. The analysis from the Brattle Group was prompted by the Public Service Commission's decision to subsidize upstate nuclear plants through zero-emission credits (ZECs) and penalize fossil fuel generators based on their level of carbon emissions. (See *NYISO Study Sees Little Cost Impact from Carbon Charge*.)

"The question of carbon pricing has come up a lot in the IMAPP context," Dykes said. "The executive order does highlight that we should consider best mechanisms, including potentially collaborating with other states, but we also have to consider how they would work [and] what the impact would be if Connecticut could not entice other New England states to participate with us: so as a one-state option versus how it would work if there was a multistate option."

Dykes added that "in an IMAPP context, the New England states' comments provided to NESCOE were not supportive of carbon adders, but I just wanted to highlight that this is one of the variables we'll be looking at as we assess mechanisms, one state versus regional implementation."

Regional, not Local Solutions

James Shuckerow, director of electric supply for Eversource Energy, said any recommended remedy should be least-cost and for the shortest duration possible.

"Because Millstone is a regional resource, if somehow there could be a regional remedy, I think that would be preferred by all," Shuckerow said. "I recognize the problem in New England. We have six different states versus the situation we have in New York."

In its written comments, Eversource said that Millstone is not a Class I, II or III renewable resource and "cannot simultaneously be a competitive merchant generator and receive state-sponsored financial support."

The company said that "any financial remedy that is developed to address a legitimate economic need should be based on cost-of-service principles with correspondingly limited returns on equity to reflect the reduction in risk resulting from Millstone's receipt of state financial support that is unavailable to other non-renewable merchant generators."

"Look at the costs affecting all customers and the overall impact not only on standard service customers or large customers, but all customers throughout Connecticut," Shuckerow said.

The cost-of-service approach would allow all types of customers through an appropriate charge to share the benefits, Shuckerow said. "Essentially, we'd sell the energy into the market, get credit for that energy and credit that against the cost of service."

Kerry Schlichting of the Acadia Center said that because the study results could influence Connecticut's long-term energy strategy, her organization asked DEEP and PURA to "issue a draft methodology and base case scenario sometime this fall for stakeholder review and comment" before the release of the draft report in early December. If the agencies wait too long it will be difficult to incorporate stakeholder feedback on modeling issues, she said.

Nancy Burton, director of the Connecticut Coalition Against Millstone, said "Millstone is hardly a zero-emissions facility. ... Every year they pile [DEEP] up with documents about their emissions, their continuous radioactive emissions into the air and the water, as well as their toxic discharges to the Long Island Sound."

John Erlingheuser, representing AARP, said: "How do we know what the problem is if Millstone doesn't release actual data? ... We're not opposed to nuclear or opposed to Dominion or to keeping the plant open. What we object to is devising solutions without proper information and without determination that there's an actual need."

Local construction worker John Thomson spoke as a consumer on the potential economic impact of losing Millstone. "I'm concerned about the economic impact of that area of the state," he said. "We've lost a lot of businesses already, so what's that going to look like going forward for taxpayers, not just ratepayers?"

Lynne Bonnet, a member of the New Haven Energy Task Force but speaking on her own behalf, said the Cross-Sound Cable was built as a two-way conduit but that so far the energy has only flowed from Connecticut to Long Island. "Why don't we ask Long Island now to generate power to help us to shut down Millstone?" Bonnet said. "And Long Island could also generate power to supply their own needs so they won't have to buy power on a contracted Cross-Sound Cable."

Bonnet also asked the regulators to be wary of the assumption that the state has already been penetrated with solar energy and energy efficiency. "If you pay attention to these situations where energy efficiency has decreased the load from residential use, New Haven is an untapped resource. It's not saturated and not even been penetrated," she said.

From left to right: Eric Annes, Kirsten Rigney and Mary Sotos of the Connecticut DEEP; Connecticut PURA Chair Katie Dykes; and PURA Director of Adjudications Victoria Hackett. | © *RTO Insider*

ISO-NE NEWS

Massachusetts Tightens GHG Limits for Generators

By Michael Kuser

Massachusetts regulators have issued new, stricter limits on greenhouse gas emissions from the state's fossil fuel power plants and ordered utilities to buy at least 16% of their electricity from clean energy sources in 2018.

The regulations, announced Aug. 11 in response to a 2016 court order, include a Clean Energy Standard (CES) that requires utilities and competitive suppliers in the state to procure increasing amounts of electricity from clean energy sources every year, with the minimum percentage increasing 2 points annually to reach 80% in 2050.

The new rules also set annually declining limits on aggregate CO_2 emissions from 21 large fossil fuel-fired power plants in the state, from 8.96 million metric tons in 2018 to 1.8 million metric tons in 2050. The regulations establish an allowance trading program for CO_2 emissions from generators, with allowance auctions beginning in 2019 and direct allocations for 2018. The rules offer flexibility in the form of limited allowance banking and a "deferred compliance" option to address electricity grid reliability.

The regulations also reduce allowable methane emissions from natural gas pipelines and distribution systems. They also tap the transportation sector by requiring state, city and regional transportation planning agencies to evaluate and report the aggregate GHG emissions of their facilities, fleets and programs.

The new procurement rules are like those of the Massachusetts Renewable Portfolio Standard, while the emissions targets are stricter than CO_2 limits under the Regional Greenhouse Gas Initiative, the cap-and-trade system agreed on by nine Northeastern states.

Pushed to Act

The state acted in response to a 2014 lawsuit by the Conservation Law Foundation that accused Massachusetts officials of failing to enact regulations needed to meet the targets set by the 2008 Global Warming Solutions Act. The state's top court ruled in favor of CLF in May 2016.

CLF helped win passage of the climate change law, which requires Massachusetts to issue regulations to incrementally reduce greenhouse gas emissions each year.

"These rules re-establish the commonwealth as a national leader in developing sensible, enforceable standards to transition our economy to a low-carbon future," CLF President Bradley Campbell said in a statement. "Much more needs to be done, and Gov. [Charlie] Baker's leadership will be essential to getting neighboring states to take meaningful action to prepare New England for the energy future being shaped by the Paris Climate Agreement."

Last September, Baker issued an executive order that set a deadline of Aug. 11 for the secretary of energy and environmental Affairs and the Department of Environmental Protection to have "designed such regulations to ensure that the commonwealth meets the 2020 statewide emissions limit mandated by the GWSA."

That limit — a 25% reduction in emissions below 1990 levels — was established seven years ago by the state to meet the GWSA requirement of a minimum 80% reduction by 2050. Officials estimate that by 2014, Massachusetts had already cut carbon emissions by 21% from 1990 levels.

Continued on page 28

MISO NEWS

MISO Still Working Through New Queue Implementation Plan

By Amanda Durish Cook

MISO officials last week presented three proposals related to the implementation of the RTO's new generator interconnection queue for stakeholder feedback.

The proposals — dealing with retaining interconnection rights, changing dispatch modeling and updating a study coordination agreement — are part of MISO's effort to implement new interconnection rules approved by FERC in January (ER17-156). The new queue is intended to streamline a process that was plagued by restudies and backlogs. Last month, several stakeholders asked that some implementation details be fleshed out in discussions involving either the Planning Subcommittee or Planning Advisory Committee. (See *MISO, Stakeholders Differ on New Queue Plan*.)

MTEP Dispatch Modeling a Go

Shah

But planning manager Neil Shah told the PAC on Wednesday that MISO will immediately change the queue's dispatch modeling to match its annual Transmission Expansion Plan. Before, generators in the queue were modeled based on their expected level of output; now they will be modeled based on their maximum requested interconnection service level. Stakeholders attending last month's Interconnection Process Task Force had said the decision should not be made without soliciting stakeholder input during MISO planning committee meetings. (See *MISO Adopts New Dispatch Model for Queue Studies*.)

Shah said MISO sees a need for consistency between the MTEP dispatch modeling, which is used for baseline reliability studies, and the interconnection process.

Retaining Interconnection Rights

MISO is offering more flexibility on retention of interconnection rights. It is recommending that owners of retiring generation be allotted three years of continuing interconnection rights for replacement generation to begin commercial operations. However, some stakeholders said six years is a more realistic time period to allow generation to be built.

On Wednesday, stakeholders indicated that they would like MISO to allow for generator replacement instead of making owners of retiring generation re-enter the interconnection queue with their replacement plans. The RTO is considering executing a commercial agreement and conducting an out-of-cycle study with "reasonable study deposits" for such replacement scenarios.

Indianapolis Power and Light's Lin Franks said MISO should check in with replacing generators to see what progress is being made before terminating rights at the end of an inflexible three-year deadline.

"Interconnection rights are not scarce in this footprint," said Franks during an Aug. 15 Interconnection Process Task Force (IPTF) meeting. "If the rights are not scarce in the footprint — and they're not here — it doesn't make sense to put a definitive deadline on the project when they're working through it." She said although three years should usually be sufficient, she warned against the three-year deadline becoming an "unrealistic barrier to progress."

"We still propose three years, but if at the end of the of that three-year period, the construction is still in progress, [MISO could allow] a three-year extension for commercial operations," Shah said. He said MISO will consider the comments and bring back new queue implementation proposals in a few months.

Hwikwon Ham of the Minnesota Public Utilities Commission also pointed out that obtaining state approvals for generation construction can take time.

MISO will also allow generators to retain interconnection rights under an amended interconnection agreement when an owner upgrades equipment when it does not have a material impact on the grid.

New Study Coordination Agreement

MISO is also updating a coordination agreement with Manitoba Hydro and Minnkota Power Cooperative to improve the efficiency of generator interconnection studies under the revised queue. The agreement will be brought before the PAC in September.

Shah also repeated warnings about delays while MISO studies an unprecedented influx of queue projects under the definitive planning phase of the queue.

Continued on page 14

OMS Discusses Next Steps in DER Policy

After hosting a distributed energy resources conference early this month, the Organization of MISO States has formed a temporary work group to formulate ideas on incorporating DER into the grid.

The group will report to the OMS board, OMS Executive Director Tanya Paslawski said at a board meeting Thursday. She said the group will have a regional focus, studying how DER in one state affects other states. Members will also discuss with MISO analysts the potential needs on the system from increased DER use, she said.

OMS leadership said the Aug. 1 workshop was well-received by stakeholders, industry officials and regulators. (See *Stakeholders Hash out Future of DER at OMS Workshop*.)

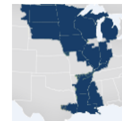
Missouri Public Service Commission Chairman Daniel Hall said the workshop sent a "very clear message to MISO and stakeholders" that DER is a very important topic that regulators are going to take an active role in shaping.

"I thought it was a really fantastic, thought-provoking day," Paslawski agreed. "It's opening up conversations about DER."

OMS, representing MISO's state regulating sector, will also weigh in on DER issues next month as part of the "hot topic" discussion during the RTO's quarterly Board of Directors week in St. Paul, Minn.

— Amanda Durish Cook

MISO NEWS



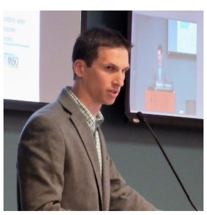
MISO Delays Removing MTEP Futures Weighting to 2019

By Amanda Durish Cook

MISO will pursue changes to its Transmission Expansion Plan futures weighting process in the 2019 cycle of projects, delaying the initiative by one year.

Starting with MTEP 19, equal weighting will be assigned to all four future grid and generation scenarios, effectively eliminating weighting of the 15-year futures. Staff initially said it would drop weighting beginning with MTEP 18. (See MISO Rethinks Weighting of MTEP 18 Futures.)

The RTO began reviewing its weighting process early this year after MISO South transmission owners and regulators of southern states asked for less emphasis in one MTEP 17 study on futures containing policy regulations and increased penetration of alternative technologies. The RTO granted the request. (See MISO Changes MTEP Futures Weighting for South.)



Ellis

MISO policy studies engineer Matt Ellis said the RTO is delaying the change because MTEP 18 futures were developed with the understanding that stakeholders would be involved in deciding their importance.

"It doesn't make sense to change something when it was implicitly understood at the beginning," Ellis said during an Aug. 16 Planning Advisory Committee meeting. He asked for stakeholder input on the unfinished MTEP 18 weighting process and said MISO still reserves the right to "put its thumb on the scale" if it thinks the stakeholder rationale for weighting is weak. Not surprisingly, MISO is recommending a 25% weighting for all four MTEP futures: a "limited," "continued" and "accelerated" fleet change and an emerging technologies scenario.

MISO is also considering using benefit-cost criteria in all four futures in MTEP 18 to determine which transmission projects are sent for Board of Directors approval. Projects may have to have an average 1.25:1 benefit-cost ratio across the four MTEP futures and earn at least a 1:1 cost-benefit ratio in at least two. Projects may also be rejected if a project earns a negative benefit of 0.8 greater in any one future.

Ellis said MISO will take a backward look at previously approved MTEP projects to further refine benefit-cost criteria and asked for stakeholder input on establishing benefit-cost floors.

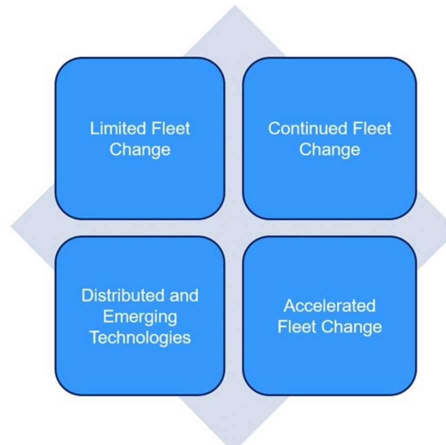
The new equal-footing weighting process in 2019 will make MTEP futures more predictable year to year and shift the focus from stakeholders' perceived likelihood of a certain future to how effectively a project can perform under varying scenarios, Ellis said.

"What we can all agree on is the old process wasn't very predictable. The MISO process should be very predictable, very cut and dried," he said.

Bill Booth of the Mississippi Public Service Commission asked if MISO was firm in its decision that all futures will have equal importance. "Seems to me that by eliminating weighting, you're eliminating stakeholder feedback," Booth said.

"We are firm on that. We are firm on even and equal weighting," Ellis said.

The PSC's David Carr asked if MISO viewed the Trump administration's rollback of environmental regulations — which sparked the requests for reweighting of MTEP 17 futures — as an "anomaly" that is not likely to occur again.



Proposed MTEP 18 futures | *MISO*

"We can tell you in the previous three [MTEP] cycles, we've gotten requests to reweight. So this is an issue that's been building for quite some time," Ellis said.

Going forward, Ellis said, MISO would only consider revising weights when all stakeholder sectors ask it to rethink the likelihood of a certain future. He also said that development of futures themselves will remain unchanged.

"As we go through the futures development process, we gather extensive stakeholder feedback. … We can tell you that all of our futures are very reasonable," Ellis said.

"Sectors aren't providing weights based on their expectations of the future, but on their advocacy of a particular business model," said Wisconsin Public Service's Chris Plante.

"That's a great point," replied Ellis.

Customized Energy Solutions' David Sapper said it was important to have MISO's "independent, unbiased" voice in the futures weighting process.

MISO Still Working Through New Queue Implementation Plan

Continued from page 13

"It's not set in stone. The timeline may change based on what we encounter," Shah said.

Meanwhile, IPTF Chair Randy Oye said MISO PAC leadership is considering extending the life of the task force beyond its December sunset date, an extension approved by Steering Committee members late last month. If the IPTF is not extended beyond December, the IPTF and Steering Committee may have to assign unfinished queue issues to other MISO committees.

MISO News

FERC Allows MISO Capacity Auction Withholding Rule

By Amanda Durish Cook

FERC on Thursday approved MISO's more stringent capacity withholding rule while also allowing the RTO to remove demand response and energy efficiency from market monitoring.

Commission staff had tentatively approved the changes in early spring but warned that the new rules could be overturned as unreasonable once FERC regained its quorum. (See *FERC Staff OKs MISO Mitigation Changes; Refunds Possible*.) With the quorum now restored, commissioners on Thursday approved the Tariff revisions retroactively Feb. 1 (ER17-806).

MISO's 50-MW minimum for physical withholding rules now apply to affiliated market participants collectively, rather than individually to each affiliated company. The RTO had already used the rule in April's annual capacity auction.

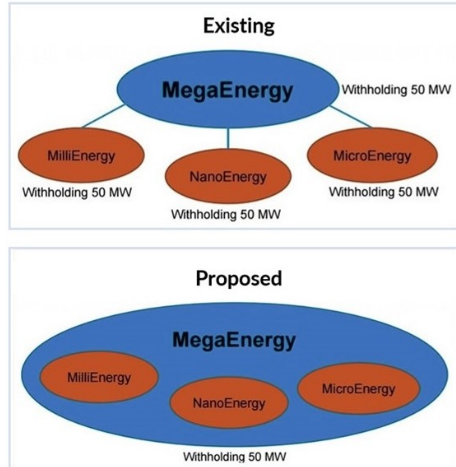
"We find that it is reasonable for the Tariff to clarify that the 50-MW physical withholding threshold will apply jointly to affiliated market participants. As MISO suggests, this will prevent large suppliers from distributing their planning resources among multiple market participants to withhold capacity from the auction," FERC wrote.

MISO's Independent Market Monitor first recommended the change in its 2015 State of the Market Report, saying that as "capacity margins fall in MISO, the market will become more vulnerable to physical withholding."

The order also allows MISO to exempt DR, EE and external resources from Planning Resource Auction mitigation measures. The RTO said DR and EE resources are too small to have market power. FERC agreed that encouraging the participation of such resources is "beneficial to the auction."

FERC's ruling also authorizes MISO to clarify that all planning resources "not otherwise exempted from market monitoring and mitigation" are eligible to receive a facility-specific reference level.

MISO has two bases for such proxies: going-forward costs for units that may consider retirement or mothballing, and the opportunity costs of selling capacity in the RTO, including the potential of selling for higher prices in bilateral trades.



Physical withholding framework | *MISO*

Previously, MISO's Tariff did not specify which resources were eligible to receive such reference levels. FERC said it was helpful for the RTO to establish that all planning resources except those explicitly exempted are "subject to potential mitigation for economic withholding and [have] the option to request a facility-specific reference level."

Great River Energy Seeks Test for Inverter-Based Generation

Great River Energy is urging MISO to account for the effects of inverter-based generation in the RTO's transmission planning studies.

Inverter-based generation — often new technology resources asynchronously connected to the grid via an electronic interface — can harm reliability in weak power systems, Great River Energy's Mike Steckelberg said at an Aug. 15 MISO Planning Subcommittee meeting. The Minnesota utility discovered the issue during a recent analysis, he said.

Steckelberg cited a June NERC report warning that such resources can affect dispatch and reliability — including voltage control, frequency response and ramping — when too many of them are interconnected into weak power systems.

The company said MISO's annual Transmission Expansion Plan study process should include screening for transmission with low short-circuit currents, comparing the megavolt-ampere level before a inverter-based resource is connected to the nominal power rating of that resource. If the calculation does not meet a certain threshold, MISO should remedy the transmission by modifying controls, connecting to a stronger source, planning for more transmission or reducing the size of the generation project.

Great River Energy

"This is a fairly easy screen to be doing ahead of time," Steckelberg said. While the screen would not have to be a "full-blown study," it does need to be incorporated into MISO's generation interconnection studies.

Steckelberg said MISO's Interconnection Process Task Force and Planning Subcommittee both need to address the issue, and transmission owners and planners should be able to review new interconnection requests for low short-circuit current issues.

Entergy's Yarrow Etheredge and American Transmission Co.'s Patrick Gerum said their companies shared GRE's concerns.

Customized Energy Solutions' Ginger Hodge asked for MISO's response on the issue.

MISO Director of Planning Jeff Webb said he and his staff would review the request and put together a response at the Planning Subcommittee's next meeting in October.

— Amanda Durish Cook

MISO NEWS

MISO to Conduct Long-Term Renewable Integration Study

By Amanda Durish Cook

MISO will conduct a study to identify the challenges of integrating growing volumes of renewable generation in its footprint.

The open-ended, multiyear study will be used to "facilitate a broader conversation about renewable energy-driven impacts on the reliability of the electric system," MISO said.

"We trying to look at the impacts over a much broader period of renewable penetration and quantify the impacts," said Jordan Bakke, of the RTO's policy studies group, at an Aug. 16 Planning Advisory Committee meeting. "If we look over the last decade of MISO, we started at very minimal [renewable] penetration … and we've grown quite steadily over that time frame."

Different types of renewables are growing at different rates throughout the MISO regions, Bakke said, and the RTO wants to identify "inflection points" at which the growth of renewables and the retirement of baseload units will require changes in the structure or operation of the system. With more projects moving through the interconnection queue, Bakke said MISO may soon have to begin forecasting for solar output.

The study aims to predict how and when reliability will be impacted under heavy renewable output; if there are limits to the amount of wind and solar generation MISO can support; how long before energy storage becomes a requirement; what parts of the grid will be stressed first; and how much renewable energy can be deployed before significant system changes are needed.

"We don't have a great idea of when certain things will have to take place to integrate renewable generation. We don't know at what mix that will have to take place," Bakke said.

MISO's current registered wind capacity is about 16.8 GW and current registered solar capacity is about 180 MW, but those figures could pale in comparison if all the prospective projects in its generation interconnection queue are realized. The RTO currently has about 31 GW of wind capacity and 15.7 GW of solar capacity advancing through various stages of the queue.

After some stakeholders cautioned MISO not to inhibit state jurisdiction over resource adequacy or renewable portfolio standards, staff stressed that the study will be limited to an impact assessment, and nothing will be built or changed as a direct result of the study.

"We're looking purely at the technical impacts of the system, and how those can change," Bakke said, adding that if something significant is discovered, study results will be passed to other departments.

Some stakeholders demanded to know if the study results would eventually inform modeling in MISO's annual Transmission Expansion Plan.

"It really depends. It's an exploratory study, and that's the nature of research," Bakke said.

Wind on the Wires' Natalie McIntire asked how this study would differ from other renewable studies the U.S. Energy Department has already conducted.

Bakke said that while national studies seek ways to incorporate targeted amounts of renewables, MISO's study will lack "a solution-oriented focus."

Indianapolis Power and Light's Lin Franks offered to share the company's data on its solar assets and Harding Street storage facility. "We've been trying to get MISO's attention now for a while to provide real PV data," Franks said. "We need to bring real data to the table before engaging in a worthless academic exercise."

Bakke agreed that renewable data for the footprint is hard to come by and said MISO may use IPL's data.

The RTO will return to the PAC in September with a study scope for stakeholders to review, he said.

MISO Revising Plan for Easing Retirement Decisions

By Amanda Durish Cook

MISO has developed a revised approach for providing owners of financially struggling generators more flexibility, saying it will treat Attachment Y filings as suspension notices while allowing owners 18 months to make a final retirement decision.

MISO adviser Joe Reddoch said staff has drafted near-final Tariff language to align the RTO's retirement and suspension process with the annual capacity auction.

In April, MISO said it would eliminate the temporary suspension provisions from its Attachment Y change of status rules in favor of a catch-all "economic shutdown" period.

But some stakeholders said the move to a binary status for generators — on or off — might nudge some owners into prematurely retiring units. (See "Removal of Temporary Suspensions will Provide Generators Flexibility, RTO says," *MISO Planning Advisory Committee Briefs*.)

With the revised language bringing the suspension concept back, retirement terminology would only come into play when generation owners waive their rescission rights or when the rescission period ends, giving asset owners time to decide, Reddoch said.

Under the proposal, all Attachment Y notices will be submitted as open-ended suspension requests without the estimated return date currently required by MISO. The temporary shutdowns would be limited to 18 months, with the RTO open to extending a suspension status to 30 months, aligned with the beginning of the planning year. MISO said that will allow an asset owner time to evaluate repairs in the case of a forced outage.

"By reorienting this process around suspensions, the process is a little more intuitive," Reddoch said, adding that asset owners would no longer be forced to decide when submitting an Attachment Y notice if their units will suspend or retire.

Reddoch asked for stakeholder feedback by Sept. 1 and said he would return to review final Tariff language at the September PAC meeting. MISO plans a FERC filing in October or November, he said.

MISO NEWS

SPP Disappointed as MISO Axes Last Interregional Project

By Amanda Durish Cook and Tom Kleckner

MISO's rejection last week of the last possible transmission project resulting from a coordinated study with SPP surprised the latter RTO and left officials wondering whether the neighbors will ever build an interregional project.

MISO staff told its Planning Advisory Committee on Aug. 16 that it was no longer recommending the $5.2 million Split Rock-Lawrence initiative in South Dakota, which would have been the RTOs' first-ever interregional project.

MISO now says an analysis of the project shows that congestion on the line can be managed for now and that another alternative project could provide the RTO with at least the same benefit at a lower cost.

MISO originally forecast that the 115-kV circuit project into Sioux Falls would have a 4.79 benefit-cost ratio. The project was the only contender to come out of MISO and SPP's coordinated system plan study last year, and MISO stakeholders voted in a non-binding ballot to recommend the project to officials in both RTOs in May. (See *MISO Stakeholders Give Go-Ahead on SD Interregional Project*; *MISO-SPP Coordinated Study Yields 1 Possible Project – For Now*.)

SPP Surprised

SPP COO Carl Monroe told *RTO Insider* Friday that the RTO only discovered MISO's recommendation through posted meeting materials and the ensuing coverage. "We're disappointed we can't find any of these types of projects," Monroe said. "We go through the Order 1000 process, which, from the joint study, seems to have some benefits. But it just doesn't seem like when we go to the individual [RTOs'] studies, it shows that type of benefits."

The project was halted before it could clear the Joint RTO Planning Committee — composed of staff with ultimate say over interregional issues — and before it would have been recommended for inclusion in MISO's 2017 Transmission Expansion Plan. The coordinated study was meant to focus on needs along the border of SPP's Integrated System in North Dakota, South Dakota and Iowa. Some MISO stakeholders expressed doubt at the beginning of the study that any projects would materialize.

MISO said the congested line in South Dakota is now operating as an open circuit under an operations guide proposed by Xcel Energy in May, which shifts some congestion to the nearby Sioux Falls–Split Rock 230-kV line. Had the project — which would have looped Xcel's existing Split Rock-Lawrence 115-kV circuit into the Western Area Power Administration's Sioux Falls station, crossing SPP territory — proceeded, Xcel would have been at risk of incurring SPP penalties for unreserved use of non-firm point-to-point transmission service, MISO said.

MISO recommends maintaining the status quo and operating the Lawrence–Sioux Falls line in an open state to relieve the congestion for now, Davey Lopez, MISO adviser of planning coordination and strategy, told the PAC. He added that the open state operation "provides MISO nearly the same adjusted production cost savings" as the interregional project at little to no cost.

However, MISO said it would continue to pursue upgrades to terminal equipment on the Lawrence–Sioux Falls line through joint efforts between MISO, Xcel, SPP and WAPA. The terminal upgrades would still represent a savings over the originally proposed loop project, MISO said.

Questions on Open Circuit

Monroe questioned MISO's use of an open circuit, which can reduce reliability when congestion is shifted from one line to another. "Normally, we don't run the system with open lines," he said. "In some regards, it increases the risk you're taking."

Continued on page 21

1 of 8 MISO-PJM Interregional Proposals Passes Preliminary Evaluation

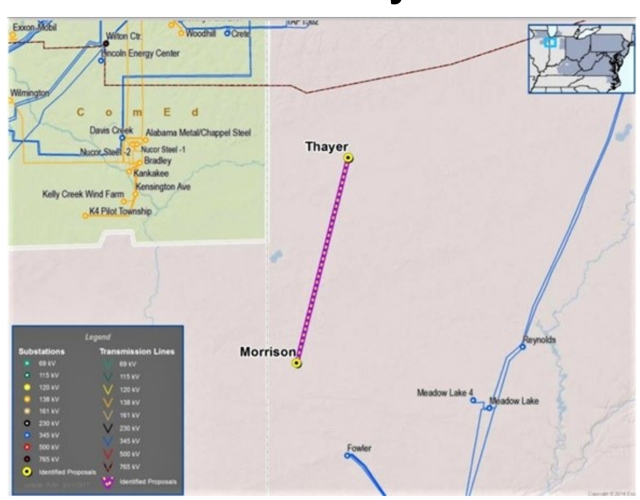
By Amanda Durish Cook

Seven of the eight stakeholder-originated project proposals evaluated by MISO and PJM are not expected to pass the RTOs' benefit threshold.

The sole project left standing is Northern Indiana Public Service Co.'s proposed new line section between its Thayer and Morrison 138-kV substations in northwestern Indiana, near the Illinois border. The greenfield project would be in service by 2022 at a $42.5 million cost, RTO stakeholders learned at an Interregional Planning Stakeholder Advisory Committee (IPSAC) meeting Aug. 18.

MISO would reap the lion's share of expected benefits at $75 million, while PJM would see $7.3 million in benefits; the costs would be split 91.1% and 8.9%, respectively. Staff said the project will now be evaluated in each regional process based on interregional cost allocation. PJM

Continued on page 19



NIPSCO interregional project map | *MISO, PJM*

PJM NEWS

PJM Stakeholders Begin Defining Capacity Design Needs

By Rory D. Sweeney

VALLEY FORGE, Pa. — After nearly a year of discussion on potential changes to PJM's capacity model, stakeholders have begun determining what components a new construct should have.

At another two-day meeting of the Capacity Construct/Public Policy Senior Task Force (CCPPSTF) last week, stakeholders began developing the criteria on which the nine construct proposals will be compared. It was a year ago that American Municipal Power and likeminded stakeholders pushed for a "holistic" review of the RTO's Reliability Pricing Model. (See *Co-ops, Munis Call for Reset of PJM Capacity Model*.)

Model Issues

PJM's Murty Bhavaraju presented a model that RTO staff created to compare results for each of the proposals. The model currently only includes the five repricing proposals but will eventually address the other four, PJM's Dave Anders said.

The model uses fictitious data in its comparisons, and Adrien Ford of Old Dominion Electric Cooperative asked if PJM could substitute data from recent Base Residual Auctions to give stakeholders a better indication of the real-world implications.

Staff balked.

"I think we probably need to explore what that would look like," Anders said. "I think to make the step between this modeling and taking a prior BRA, there's going to have to be a lot more assumptions."

"I am worried that the results of that will be taken as price forecasts," PJM's Adam Keech said.

"If there's concern about using the past, then what can we use?" Ford asked. "We also recognize that the supply stack in the examples isn't anything like the actual supply stack. I seek to understand if we do have an issue here and, if so, how big it is."

Ruth Ann Price of the Delaware Division of the Public Advocate asked PJM to identify if any proposals would discourage states from allowing resources within their borders to participate in the markets.

Susan Bruce, representing the PJM Industrial Customer Coalition, asked the RTO and its Independent Market Monitor to also report on how they believe the proposals would affect bidding behavior. "It would be helpful for us to understand what those concerns would be," she said.

PJM staff agreed to research potential solutions that address stakeholder concerns.

MOPR Issues

Attorney Mike Borgatti of Gabel Associates explained the standards FERC set out in its 1991 Edgar Electric Energy (ER91-243) and 2004 Allegheny Energy Supply rulings (ER04-730) to prevent utilities from self-dealing. The Edgar ruling required demonstration that long-term power purchase agreements that utilities sign with their marketing affiliates are reasonably priced compared to alternatives. The commission said such a demonstration could include evidence of competition between affiliated and unaffiliated suppliers or a showing of prices paid by non-affiliated buyers. FERC refined its guidance in Allegheny.

Left to right: Dave Scarpignato, Calpine; Tom Hoatson, LS Power; Adrien Ford, ODEC; Susan Bruce, PJM Industrial Customer Coalition; Ruth Anne Price, Delaware Division of the Public Advocate; Carl Johnson, PJM Public Power Coalition; Sharon Midgley, Exelon; Jason Barker, Exelon; Luis Fondacci, NCEMC; and Ken Foladare, Tangibl. | © *RTO Insider*

Borgatti said he brought up the rulings to propose a "conceptual framework" for considering changes to the minimum offer price rule (MOPR).

"If we were to go this route, that would need to be something we spend a lot of time on," he said.

John Hyatt of Monitoring Analytics, the IMM, said he believed that state-sponsored competitive and nondiscriminatory procurements are consistent with the Monitor's MOPR-Ex capacity proposal.

Roy Shanker, an industry consultant, expressed concern about using the rulings as guidance in this situation.

"Edgar certainly stands for the proposition of assuring there was not affiliate favoritism," Shanker said. "It's completely unacceptable to apply it without a thorough discussion of what nondiscriminatory means."

PJM staff agreed to review the current MOPR policies to determine if they should be revised.

Fixed Resource Requirement

PJM provided a refresher on its current fixed resource requirement (FRR) rules. FRR contrasts with RPM in that it can be used by a load-serving entity to meet a fixed capacity requirement, while RPM is variable. FRR resources don't receive RPM clearing prices and the LSE doesn't pay the RPM locational reliability charge.

The education came in response to a proposal from Dayton Power and Light's John Horstmann that would allow LSEs to choose acquisition from FRR, RPM or any combination of the two to address their capacity requirements. Horstmann acknowledged that his proposal has many factors that would have to be addressed, but he argued that it also resolves many issues stakeholders have identified.

"I'd say look at the things you don't have to worry about, including two-tiered auction design compromises, creation of a reference

Continued on page 19

PJM NEWS

PJM Stakeholders Begin Defining Capacity Design Needs

Continued from page 18

price and auction participant bidding concerns," he said.

Social Science Experiment

The nine proposals fall into three categories: Some completely redesign the capacity construct; some add to the RPM a repricing mechanism to avoid subsidized offers influencing clearing prices; and the last group would expand the MOPR to effectively prohibit subsidized units from offering into auctions.

In what he called a "social science experiment for stakeholders," Anders split meeting attendees into three groups and directed each of them to identify the positive and negative aspects of one of the categories and develop potential questions for a poll of stakeholder interests.

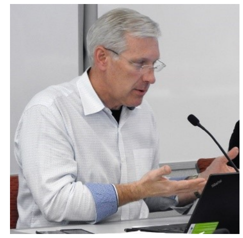
Stakeholders found that the MOPR was straightforward and easy to understand, but that it could be subjective and fails to accommodate state policy actions. The task force's charter called for developing RPM rule changes "that could accommodate/address both capacity construct objectives and state actions."

The redesign proposals would give load and resources more flexibility in decision-making but could increase market volatility if enough buyers and sellers opt out. The repricing options all attempt to address price influence from subsidies but could incentivize undesirable behavior, such as bid suppression or additional pursuit of subsidies, stakeholders said.

Next Steps

The task force's next meeting is scheduled for Wednesday, when Anders said stakeholders should be prepared to provide input on identifying the traits of an offer that would trigger repricing.

AMP's Steve Liebermann said he plans to have revisions to discuss for his organization's proposal — which focuses on encouraging long-term bilateral contracts — based on feedback he's received.



Anders

Keech

"States with retail choice might have some difficulties with the bilateral-contract concept," he said. "We think we have a workable solution."

Other sponsors have already offered revisions or addendums to their proposals, including LS Power and Exelon. Both focus on repricing.

Jennifer Chen of the Natural Resources Defense Council promised some revisions as well. The NRDC's proposal focuses on including seasonal resources that can't meet Capacity Performance's requirement to be always available.

1 of 8 MISO-PJM Interregional Proposals Passes Preliminary Evaluation

Continued from page 17

engineer Alex Worcester said the RTOs still plan to return to an October IPSAC meeting to discuss all eight projects and their final benefit-cost ratios, however dismal.

In May, the RTOs revealed three upgrade and five greenfield proposals from stakeholders, ranging from $1 million to $198 million, for three congested flowgates around the borders of Michigan, Indiana and Ohio.

Most proposals' effectiveness was undercut by American Electric Power's recently announced plans for a supplemental project for the Olive–Bosserman constraint near the western Indiana-Michigan border. AEP plans to remedy the problem by increasing voltage and rerouting nearby PJM circuits dating back to the 1930s with two new 138/120-kV distribution stations. (See *MISO, PJM Weighing 8 Interregional Tx Proposals*.)

All but two of the project proposals concentrated on the Olive–Bosserman constraint. Another NIPSCO proposal — an $8 million plan to reconductor a NIPSCO line between AEP's Bosserman and Olive 138-kV substations and reconductor a NIPSCO line between Bosserman and AEP's New Carlisle 138-kV substation — was found to benefit neither PJM nor MISO after the AEP proposal was factored in.

NIPSCO's Clark Gloyeske asked if PJM had plans to refund the project submission fees the RTO charged to consider the proposals. "The supplemental came along and wiped out all of these proposals," he said.

PJM Manager of Interregional Planning Chuck Liebold said it may conduct additional analysis to explore the possibility, but he did not elaborate on an expected timeline.

Meanwhile, MISO engineer Adam Solomon said the RTOs still have five targeted market efficiency projects (TMEPs) at the ready should FERC approve the regional cost allocations for the new category. MISO filed for regional allocation Aug. 4 (ER17-2246), and PJM filed its allocation on April 11 (ER17-1406).

Commission staff tentatively approved the TMEP category in a delegated order in June but said the decision was subject to review by the commission once it regained the quorum it lost in February (ER17-721). (See *FERC Tentatively OKs New MISO-PJM Project Type*.)

"Pending FERC approval, we are still ready to recommend the five TMEPs that we've had on our hands for a while now," Solomon said.

The RTOs will not conduct a new TMEP study this year. The TMEP process was originally intended to be performed annually, but Solomon said MISO and PJM are still undecided if they will undergo a study even in 2018.

"Closer to the end of the year is when we'd try to make that decision," Solomon said.

PJM NEWS

Ohio PUC Upholds FirstEnergy Subsidy

By Rich Heidorn Jr.

Ohio regulators on Wednesday rejected challenges to their order awarding FirstEnergy a subsidy worth more than $600 million, assistance the company said it needed to avoid having its credit rating reduced below investment grade.

The Public Utilities Commission of Ohio also rejected some rehearing requests by FirstEnergy while also granting others (14-1297-EL-SSO).

Opponents of the rider immediately vowed to appeal to the state Supreme Court.

In October, the commission unanimously rejected FirstEnergy's request for an eight-year retail rate stability (RRS) rider totaling $4.46 billion, which the company said it needed to ensure its financial health at a time in which its coal- and nuclear-fueled generation is challenged by low natural gas prices.

Instead, the commission approved a three-year distribution modernization rider (DMR) totaling about $612 million for subsidiaries Ohio Edison, Cleveland Electric Illuminating and Toledo Edison. The commission said the additional money would allow the company to make investments in grid modernization. (See *PUCO Rejects FirstEnergy's $558M Rider, OKs $132.5M*.)

In December, the commission agreed to consider FirstEnergy's rehearing request, along with challenges by environmentalists, independent power producers, large customers and the Ohio Consumers Counsel (OCC).

In its unanimous ruling Wednesday, the commission said that it had already "thoroughly addressed" issues raised by OCC, the Northwest Ohio Aggregation Coalition, Cleveland Municipal School District and the Sierra Club. Commissioner Lawrence K. Friedeman recused himself.

It said the risk of FirstEnergy's and its subsidiaries' credit ratings dropping to below investment grade was "sufficient to constitute an emergency that threatens the utility's financial integrity," rejecting opponents' claim that it should rely on the current credit ratings of the companies.

The commission also approved FirstEnergy's request to strike portions of filings by the Ohio Manufacturers' Association Energy Group, saying "new information should not be introduced after the closure of the record." It also struck news articles included in filings by the Northeast Ohio Public Energy Council, which it said were hearsay.

In response to a request from FirstEnergy, it clarified its earlier ruling, saying that if Electric Security Plan (ESP) IV is terminated, the Rider Delivery Capital Recovery (DCR) revenue cap increases currently in place will continue until the commission establishes a new standard service offer (SSO). "If FirstEnergy exercises its right to terminate ESP IV at some point in the future following rehearing or an appeal, the Rider DCR revenue cap increases yet to be implemented at the time of termination will also be terminated along with the remaining provisions of ESP IV. However, FirstEnergy will be permitted to continue to recover costs already incurred under Rider DCR," it said.

PUCO said it was "not persuaded by FirstEnergy's assertion that DMR revenue could be recovered through a base distribution rate case. We do agree that certain costs of grid modernization, specifically the costs of any acquisition and deployment of advanced metering, including the costs of any meters prematurely retired as a result of the advanced metering implementation, may be recovered outside of an ESP [electric security plan]. Moreover, we also agree that the $568 million annual economic impact of the retention of the FirstEnergy Corp. headquarters is an economic benefit under the ESP and should be included as a consideration in the ESP versus MRO [market rate offer] test."

Opponents of the rider reacted sharply, saying they will take their arguments to the Ohio Supreme Court.

"There is simply no basis in Ohio law to force utility customers to pay for a slush fund for FirstEnergy Corp. and its shareholders," said Shannon Fisk, managing attorney at Earthjustice.

"We are very disappointed in the commission's continued unwillingness to shield customers from FirstEnergy's poor business decisions," said Dan Sawmiller, senior representative for Sierra Club's Beyond Coal Campaign. "The PUCO has missed yet another opportunity to focus the company on real efforts to modernize our electric grid and invest in new, clean energy technologies and instead has forced customers to pay up for unwise investments in outdated coal and nuclear plants."

The Environmental Defense Fund said it was "confident the Ohio Supreme Court will … reject the regulators' latest giveaway to dirty energy."

FirstEnergy spokesman Doug Colafella said the ruling "affirmed the commission's previous order that will help support future investments to modernize our electric system."

"Grid modernization will benefit our customers and competitive suppliers by enhancing service reliability and enabling new products and services," he said.

Ohio Edison switchyard | *FirstEnergy*

SPP Disappointed as MISO Axes Last Interregional Project

Continued from page 17

Monroe said SPP has offered to go beyond FERC's Order 1000 process to find "mechanisms and ways to share costs" to ensure both RTOs benefit from interregional projects, "but we haven't found one of those."

"It's hard to say whether it's the process or stakeholders or something," Monroe said, "but we just haven't been able to get across the goal line from the perspective of their regional review."

SPP stakeholders have questioned the desire of MISO to develop interregional projects with its western neighbor. The two RTOs have now conducted two coordinated joint studies and failed to agree upon a single interregional project.

Adam McKinnie, utility economist for the Missouri Public Service Commission, said he had "severe concerns" that MISO was allowing a temporary operations plan to become a long-term solution for congestion.

"We couldn't justify subjecting our customers to a $5 million project when there's a no-cost solution available," Lopez explained.

Seeking a 'Willing Partner'

McKinnie also questioned if the SPP-MISO seam is receiving the same level of interregional coordination as the MISO-PJM seam. "I'm kind of tired of refereeing fights between MISO and SPP because my ratepayers pay for those fights," he said, adding that SPP officials seem more receptive to interregional planning than those at MISO.

MISO staff countered that the RTO is looking for the most economic and efficient solution to the congestion.

MISO's interregional project cost and voltage thresholds with SPP remain unchanged at $5 million and 345 kV, respectively. FERC ruled at the beginning of the year that MISO and SPP were not bound by its directive to PJM and MISO to remove identical thresholds. SPP had asked FERC last year to apply the same directive to the MISO-SPP seam.

Had the 115-kV Split Rock-Lawrence project won approval, MISO would have had to designate its portion of the project as "miscellaneous," unable to qualify for cost allocation, because it does not meet the 345-kV voltage threshold required of its market efficiency projects.

"We just haven't seen that ability, whether it's because they don't want to do it, or they don't feel like they can do it, or the stakeholders don't want it," Monroe said. "I just don't know where the resistance is. If you feel like these [projects] are good to do and you want to get them done, you can work through these issues, hopefully, and even demonstrate the rigidness of the problems that Order 1000 creates. We just haven't found a willing partner on the other side to negotiate those issues."

SPP's Seams Steering Committee was to present the South Dakota project to the Markets and Operations Policy Committee in October, but that is unlikely to happen now, Monroe said. "You could probably believe we don't have much hope that our members want to go ahead with this either, if MISO doesn't want to," he said.

It's unclear how soon the RTOs will embark on another joint study. Last spring, MISO staff originally decided against a coordinated study, explaining that it was hoping to improve the process behind coordinated studies before taking up another one. Staff later reversed course and agreed to the 2016 coordinated study. A 2014-15 MISO-SPP coordinated study ran over deadline by three months and left both RTO staffs frustrated and empty-handed. (See SPP, MISO Try to Bridge Joint Study Scope Differences.)

Clean Line Ponders Options After Grain Belt Rejection

By Tom Kleckner

Clean Line Energy Partners said Thursday it is considering legal appeals and other options following the Missouri Public Service Commission's third rejection of its proposed Grain Belt Express.

The PSC on Wednesday rejected Clean Line's request for a certificate of convenience and necessity (EA-2016-0358). The commission previously denied the $2.3 billion project last year on a procedural error, and in 2015 for not proving the project's necessity and worth.

Skelly

Mike Skelly, Clean Line's founder and president, said the company will review the PSC's order to determine its next course of action.

"We are currently assessing all existing authorities available to move the Grain Belt Express project forward, including, but not limited, to legal appeals," Skelly said in a statement. "The PSC's decision … sends a clear message that investors contemplating new infrastructure projects should not come to Missouri."

Clean Line's other options, said spokesperson Sarah Bray, include asking the PSC for a rehearing, working with the state's legislature to revise pertinent laws or seeking U.S. Energy Department approval under Section 1222 of the 2005 Energy Policy Act. The latter would authorize the department to take part in "designing, developing, constructing, operating, maintaining or owning" new transmission.

"The project is certainly not dead," Bray said.

Following the PSC's 2015 rejection of the Grain Belt Express — when the commission determined there weren't enough benefits for Missouri consumers and cited landowner opposition — Clean Line signed up more than three dozen cities to purchase about 100 MW of power from the project. The Houston-based company projects ratepayers in those cities will see annual savings of $10 million.

Four of the commission's five members said in a concurring opinion Wednesday the project is needed, economically feasible and beneficial to the public.

However, they referenced a March state appeals court ruling on an unrelated case involving Ameren Transmission Company of Illinois, which found that infrastructure projects must first secure approvals from each county it crosses.

In 2012, Clean Line won permission from the commissions of eight counties to construct the line along and across their public roads. But the company was tripped up in Caldwell County, after a court ruled in 2015 that county officials had violated the state Sunshine Law when they approved the line.

"It was in the public interest to approve the line," PSC Chairman Daniel Hall said. "Unfortunately, because of the structure of this commission and because of the legal system in this state, we were unable to act in the public interest."

Commissioner Steve Stoll did not sign the order, saying "the court has spoken."

Bray told *RTO Insider* that Clean Line was "encouraged by the PSC's determination that the project is in the public interest and will benefit the State of Missouri."

The "ruling is inconsistent with good government and sound public policy, and it is our hope that moving forward, Missouri will work to remove barriers to building new critical infrastructure projects," Skelly said.

> ***"The project is certainly not dead."***
>
> **Sarah Bray, Clean Line**

James Owen, executive director of Renew Missouri, which supports renewable energy and energy efficiency, said the PSC ruling is based on a misreading of state law and undermines Gov. Eric Greitens' promise to eliminate "job-killing regulations."

"The [appellate] opinion now says that a few county commissioners have absolute veto power over the regulatory decisions of the federal and state government," Owen said in a statement. "This multibillion-dollar project spanning four states is now stalled due to a baseless objection from a single Missouri county. … In the face of this absurd result, Gov. Greitens' silence is deafening."

The Grain Belt Express would deliver approximately 4,000 MW of wind power from western Kansas through Missouri and Illinois to the Indiana border over 780 miles of DC lines. Kansas and Illinois regulators approved the project within their states in 2013 and 2015, respectively.

Clean Line said the decision would be "devastating" for Missouri ratepayers and workers "who will be deprived of good paying local jobs."

The company had support from a number of the state's companies and organizations, including the Missouri Joint Municipal Electric Utility Commission, the Missouri Department of Economic Development, the International Brotherhood of Electrical Workers, the Missouri AFL-CIO, The Wind Coalition and Wind on the Wires.

Sempra Outmuscles Berkshire Hathaway for Oncor

Continued from page 1

proposed transaction, "which provides substantially greater recoveries to all creditors of Energy Future than the proposed Berkshire transaction."

Including debt, BHE's bid valued Oncor at $18 billion, while Sempra's values the utility at $18.8 billion.

Sempra CEO Debra Reed said the acquisition will "enhance our earnings beginning in 2018 and further expand our regulated earnings base, while serving as a platform for future growth in the Texas energy market and U.S. Gulf Coast region."

Reed

Debt and Equity

The company said it expects to fund the transaction using a combination of its own debt and equity, third-party equity, and $3 billion of expected investment-grade debt at the reorganized EFH. Sempra will hold about a 60% equity ownership of EFH and projects the transaction to be completed in the first half of 2018.

BHE, which had said last week it would not increase its $9 billion all-cash offer for Oncor, announced Monday that EFH had terminated its proposed acquisition. Warren Buffet's company is renowned for its fiscal discipline and avoids bidding wars.

The Nebraska-based company is eligible for a $270 million breakup fee, but it would have to be approved by the court overseeing EFH's bankruptcy case in Wilmington, Del.

On late Friday, Berkshire said it had reached a settlement agreement resolving "all issues" with Public Utility Commission of Texas staff, the Texas Office of Public Utility Counsel, the Steering Committee of Cities Served by Oncor, Texas Industrial Energy Consumers and International Brotherhood of Electrical Workers Local 69.

Oncor CEO Bob Shapard praised Sempra as a "well-respected and experienced utility operator with a quality workforce and management team."

"The announcement today is just another

Continued on page 24

Calpine Going Private in $5.6B Deal

Continued from page 1

PJM and ISO-NE).

In addition to its generation assets, Calpine also has two retail businesses — Calpine Energy Solutions and Champion Energy — which operate in 25 states, Canada and Mexico.

M.J. Bradley & Associates ranked Calpine as the nation's 10th largest power producer in 2015. Calpine claims to be the top-ranked generator in gas-fired capacity in Texas, with a No. 2 ranking in California and No. 3 rankings in the Mid-Atlantic and New England states.

Undervalued

During a call to discuss second-quarter results before the deal was announced, CEO Thad Hill explained the rationale for going private, saying "the public equity markets have undervalued our business and underappreciated our strong track record of executing on our financial commitments and our stable cash flows."

Hill, who became COO in 2010 was promoted to CEO in 2014, said the acquisition will not change the company's operations. The company will maintain its headquarters in Houston and its current management team, he said.

The sale will allow the company to "continue to strengthen our wholesale power generation footprint, while benefiting from ECP's support, industry expertise and long-term investment horizon," Hill said in a statement.

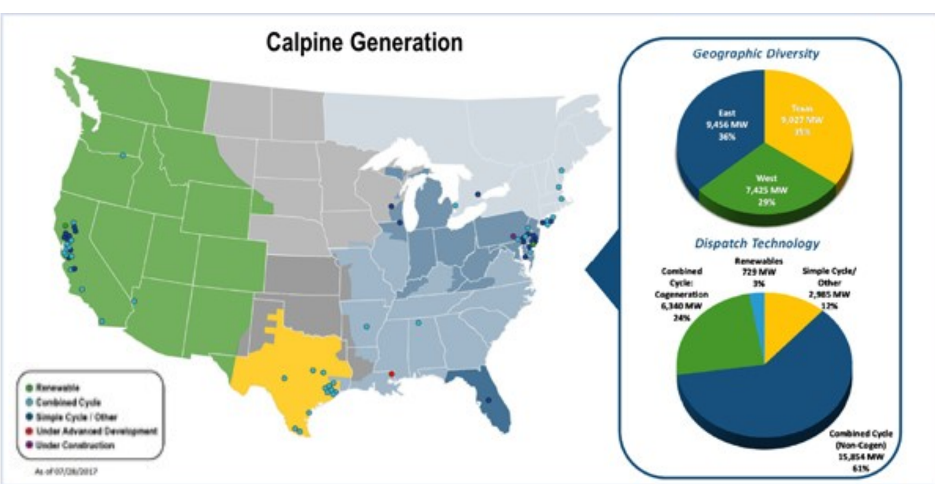
ECP partner Tyler Reeder confirmed that the deal would not result in operational changes, saying that the investors "see significant value in Calpine's operational excellence and strong and stable cash flows, and have been impressed by the company's exceptional leadership and talented employees."

"We do not intend to make any changes to the company's financial policy or previously announced $2.7 billion deleveraging plan," he added, referring to plans to pay off the debt in full by 2019.

Including debt, *The Wall Street Journal* reported, the deal's enterprise value is $17 billion.

The deal allows Calpine a 45-day "go-shop" period to seek a higher offer. The company would have to pay the ECP group a $142 million termination fee for canceling the deal. The fee would be reduced to $65 million if Calpine terminates the agreement within 106 days.

"We don't think it is likely there is a topping bid," Greg Gordon, an analyst at Evercore ISI, wrote in a research note, according to Bloomberg. "It was probably very hard to pull together an equity consortium for this size of a deal and it was a competitive process."



Continued on page 24

Sempra Outmuscles Berkshire Hathaway for Oncor

Continued from page 23

example of how our 3,900 employees have made Oncor one of the most sought-after companies in the energy sector today."

At a previously scheduled bankruptcy court hearing Monday, EFH creditors expressed their support for the Sempra deal. Judge Christopher Sontchi set a Sept. 6 date for an expedited hearing on Sempra's merger agreement. The deadline for filing objections is Aug. 31.

"This is a big change, clearly a change to the benefit of the estate and the creditors," said Sontchi, thanking the parties for "freeing up his day." The judge had scheduled up to eight hours of testimony and arguments on Elliott Management's opposition to the Berkshire offer.

Oncor is the sixth largest transmission and distribution utility in the nation, serving more than 10 million Texans through more than 122,000 miles of wires and 3.4 million meters. It has been the subject of a tug-of-war since parent EFH, saddled with almost $50 billion in debt after poor bets on energy prices, declared bankruptcy in April 2014.

Dallas' Hunt Consolidated and Florida-based NextEra Energy had separate bids fall apart in the face of the Texas PUC's strict ring-fencing measures and demands that Oncor be run by a "truly independent" board with control over decisions on capital expenditures and operating expenses. (See *NextEra-Oncor Deal Meets Third Denial*.)

PUC Concerns

Although it was rejected by Elliott Management, Berkshire's offer was received positively by PUC staff.

During the PUC's open meeting Thursday, Commissioner Ken Anderson restated his insistence that Oncor be protected from incurring any additional debt from EFH's bankruptcy proceeding. Anderson's focus is on the billions in debt owed by Oncor stemming from the 2007 leveraged buyout of EFH's predecessor, TXU.

That debt "was all incurred either in connection with the original [leveraged buyout] or refinancing the 2007 leveraged buyout," Anderson said. "None of it ever was, nor can it be, an obligation, directly or indirectly, or legally implied of Oncor. None of either the principal or interest can go into rates."

Anderson alleged that the suitors before BHE intended to use Oncor's profits to pay

Continued on page 35

Calpine Going Private in $5.6B Deal

Continued from page 23

The acquisition is subject to approval by Calpine stockholders, antitrust regulators, FERC and state regulators, including those in New York and Texas, the company said. Closing is targeted for the first quarter of 2018.

Seesaw Ride for Investors

Founded in 1984, Calpine went public in 1996 and grew steadily over the next several years before falling into bankruptcy in 2005. It moved its headquarters from California to Houston after exiting bankruptcy in 2008.

Like other independent power producers, Calpine has been pinched by low power prices and competition from renewables.

NRG Energy, which lost $626 million last quarter, is planning to sell as much as $4 billion of its assets, and last month it ordered an undisclosed number of layoffs. Dynegy, which lost $296 million in the second quarter, is reportedly considering an acquisition by Vistra Energy. (See *Report: Vistra Energy Suggests Takeover of Dynegy*.)

Calpine's 2016 profit of $92 million was a 60% drop from 2015. It reported a second-quarter loss of $216 million after losing $56 million in the first quarter. Rising gas prices have resulted in reduced capacity factors for the company's non-peaker plants, falling to an average of 43.6% in the first six months of the year from 48.8% a year earlier.

After peaking at almost $25/share in late 2014, Calpine's share prices fell as low as $10 in April before news of a potential deal. Shares closed Friday at $14.92.

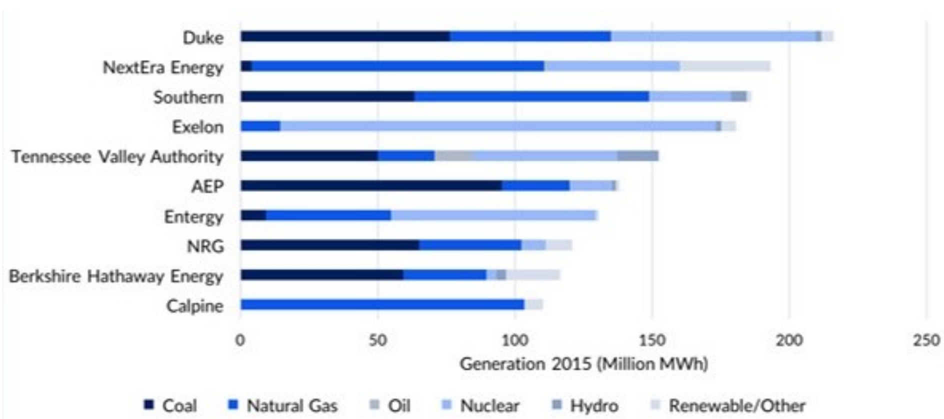
Energy Capital's Plans

Based on its history, ECP may not keep Calpine for very long.

In 2015, it sold EquiPower — a company it created five years earlier to oversee a portfolio of fossil generators in the eastern U.S. — to Dynegy. In 2008, two years after acquiring it, ECP sold FirstLight Power Resources, a 1,440-MW portfolio of mostly hydro generation, to a subsidiary of GDF SUEZ, now ENGIE.

The firm also helped Dynegy finance its $3.3 billion acquisition of 17 U.S. power plants, selling its stake to Dynegy last year for $750 million. The company was Dynegy's largest stakeholder as of June, according to Bloomberg.

ECP's current holdings include Wheelabrator Technologies, which generates power from municipal solid waste and other renewable waste fuels.



Fuel mix for top 10 electric generators | *M.J. Bradley and Associates*

FERC News

FERC Has More Questions on Frequency Response NOPR

By Rich Heidorn Jr.

FERC last week asked for additional comments on the rule it proposed in November that all newly interconnecting generators provide primary frequency response.

The Notice of Proposed Rulemaking, which reflected both reliability concerns and the technological advances of renewable generators, proposed revising the *pro forma* Large Generator Interconnection Agreement (LGIA) and Small Generator Interconnection Agreement (SGIA). (See *FERC Proposes Frequency Response Requirements for Renewables*.)

On Friday, the commission issued a notice requesting supplemental comments on electric storage and small generators (RM16-6).

The commission said it was prompted by the Energy Storage Association (ESA) and other commenters who said that the NOPR failed to address storage's "unique technical attributes" and could discriminate against them.

ESA said that the proposed use of nameplate capacity as the basis for primary frequency response service and the fact that electric storage resources can operate at the full range of their capacity — without a minimum set point — would require them to provide a "greater magnitude of [primary frequency response] service than traditional generating facilities."

"In light of these concerns, the commission seeks additional information to better understand the performance characteristics and limitations of electric storage resources, possible ramifications of the proposed primary frequency response requirements on electric storage resources, and what changes, if any, are needed to address the issues raised by ESA and others," the commission said.

FERC also asked for more information on commenters' concerns that small generating facilities could face disproportionate costs in providing frequency response.

Commenters including the Sierra Club, the Sustainable FERC Project and the National Rural Electric Cooperative Association said that the NOPR failed to prove the commission's conclusion that "small generating facilities are capable of installing and enabling governors at low cost in a manner comparable to large generating facilities."

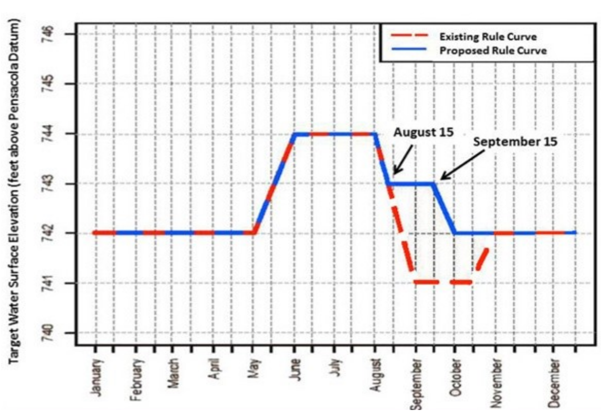
Comments will be due 21 days after publication of the notice in the *Federal Register*.

GRDA Granted 2-Foot Rise in Reservoir Level

By Tom Kleckner

FERC last week granted Grand River Dam Authority's (GRDA) request for a permanent 2-foot increase in the reservoir level of the 105-MW Pensacola Project in northeastern Oklahoma, despite opposition from a nearby Native American tribe (Project Nos. 1494-437, 1494-441).

The Miami Tribe charged that FERC had not lived up to its obligations under Section 106 of the National Historic Preservation Act, which requires federal agencies to conduct a review to determine how a proposed project may affect historic properties and to seek ways to avoid, minimize or mitigate any "adverse effects."



Proposed Pensacola Dam rule curve adjustment | *GRDA*

The tribe asserted the commission never engaged in a Section 106 review with respect to tribal cultural properties in and around the hydropower project, which includes a 5,950-foot-long, 147-foot-high dam and the 46,500-acre Grand Lake reservoir. The review would have included gathering information from tribes, identifying historic properties of relevance to the tribes and assessing the effects that the project has already had on historic tribal properties.

FERC disagreed, saying the Miami Tribe relied on assertions made by Oklahoma agencies "that have since been revised," and pointed out that the state agencies did not object to the commission's finding that the reservoir-level change would not affect historic properties.

GRDA, an SPP member, last year requested maintaining the reservoir level at the dam on the Grand River at 743 feet between Aug. 16 and Sept. 15, 2 feet above current levels. It also requested a 742-foot level between Sept. 16 and Oct. 31, 1 foot above current levels. The company proposed returning to the project's existing surface elevation or "rule curve" for the remainder of the calendar year.

The project's dedicated flood storage is listed at 745 to 755 feet. When reservoir levels are within the flood pool, the U.S. Army Corp of Engineers can direct releases from the dam.

FERC NEWS

FERC Denies NRG Waiver in NY Emissions Case

By Michael Kuser

FERC last week denied NRG Curtailment Solutions' request for an exemption from NYISO penalties for nonperformance and invalid generator registrations on approximately 13% of its New York capacity obligations in May 2016 (ER17-834).

NRG argued that uncertainty about EPA emissions regulations compromised its ability as a Special Case Resource (SCR) to help the New York grid operator balance shortfalls in delivered capacity contracts.

SCRs are demand-side resources that agree to reduce load at the ISO's instruction, using either curtailments or "local" generators — ones intended to self-supply a load and that do not supply the distribution system. As a "responsible interface party," NRG Curtailment aggregates individual SCRs for the ISO.

An EPA rule change in 2013 allowed reciprocating internal combustion engines (RICE) providing emergency DR to run without extra emissions controls for up to 100 hours per year in emergency demand response programs, up from the previous limit of 15 hours annually. In 2015, the D.C. Circuit. Court of Appeals vacated and remanded the 100-hour exemption. (See *Appellate Court Rejects EPA Rule on Back-Up Generators*.) EPA was granted a stay of the D.C. Circuit's decision until May 1, 2016.

On April 15, 2016, EPA issued guidance that RICE generators may not operate for *any* period of time unless they meet emission standards for nonemergency engines. On May 2, 2016, the D.C. Circuit issued a mandate implementing its earlier decision.

NRG said it only enrolled generators in the May 2016 installed capacity auction that would participate for 15 hours or less because it believed that the 15-hour rule would be reinstated with the elimination of the 100-hour rule. The company said it had no ability to withdraw resources that no longer complied with the revised emissions rule but that it stopped selling capacity from DR resources with noncompliant generators for the June 2016 auction.

Increasing Emissions Stringency

NYISO opposed NRG's waiver request in a filing in February, arguing that EPA's intent to apply more stringent emissions requirements was apparent beginning in July 2015, contrary to the company's contentions. The ISO said EPA's motion to stay indicated that the agency clearly intended not to revert to its 15-hour limit.

While NRG may not have intended to enroll ineligible resources, NYISO said, if the company was unsure, it could have waited until EPA had clarified its position. The ISO believes that NRG assumed the risk of noncompliance and therefore should be subject to the penalty provisions of its Tariff.

NYISO said that while it had not yet determined whether penalties were "appropriate" for NRG's capacity sales for May 2016, "sales by invalidly enrolled SCRs would be subject to a penalty." In addition, an aggregator can be penalized when its unforced capacity sales exceed the greatest quantity megawatt reduction achieved during a single hour in a performance test or event called by the ISO.

FERC ruled that granting the waiver "would have undesirable consequences, as it would effectively serve only to relieve NRG of the financial consequences of its market commitments ... and could encourage similarly risky bidding behavior that market participants seek to remedy after the fact through a waiver."

FERC Denies Extension of CAISO Intermittent Resource Program

By Robert Mullin

FERC last week rejected a CAISO proposal to extend the life of a program designed to protect some renewable energy resources from being assessed uplift costs associated with their variable output (ER17-1337).

The ISO established the Participating Intermittent Resource Program (PIRP) in 2014 as part of enhancements to its real-time market under FERC Order 764. PIRP provided older variable energy resources (VERs) a three-year transition period in which to acquire the capability to respond to dispatch instructions, during which they would avoid being assessed for startup costs for conventional generation needed to respond to uninstructed, intermittent output.

The program also accommodated renewable resources that needed additional time to renegotiate long-term power purchase agreements that expressly prohibited them from responding to real-time price signals.

CAISO earlier this year proposed to extend PIRP for an additional year until Apr. 30, 2018, contending that several resources operating under the program required more time for the transition. The ISO contended that the nine resources using the program had received a net benefit of $5.6 million between 2014 and 2016, an amount that was not expected to increase significantly with a one-year extension. The cost of extending the measure would continue to be allocated across all ISO scheduling coordinators.

In denying the extension, FERC said that "CAISO has not argued that the three-year transition period was an unreasonable time frame, or that circumstances have changed since the commission originally accepted" PIRP. The commission also noted that extending the program would expose market participants to additional uplift charges for another year while not guaranteeing that the protected resources would resolve their challenges during that time.

"Further, CAISO does not assert and the record does not indicate that allowing the protective measures to expire on April 30, 2017, would pose a risk to reliability, or that the relevant VERs would suffer significant financial losses as a result of their expiration," the commission said.

The commission also agreed with Pacific Gas and Electric that allowing PIRP to remain in place would not give the relevant resources an "economic incentive" to respond to CAISO dispatch signals.

"CAISO itself has highlighted the need for resources to respond more quickly to CAISO dispatch instructions to curtail generation during oversupply conditions," the commission said.

STATE NEWS

New NARUC Head Calls for NEPOOL Transparency

Will Focus on Water-Energy Issues

By Michael Kuser

Jack Betkoski talks about storm-related outages on a TV program in November 2013. | *Connecticut Public Utilities Regulatory Authority*

Connecticut regulator John W. "Jack" Betkoski III, the new president of the National Association of Regulatory Utility Commissioners, last week called for more transparency at the New England Power Pool and said he plans to focus his NARUC tenure on the "water-energy nexus."

Betkoski, vice chairman of the Connecticut Public Utilities Regulatory Authority, had been serving as NARUC's first vice president before assuming the presidency on Aug. 14 from former Pennsylvania regulator — now FERC Commissioner — Robert Powelson. He will complete Powelson's term and in November begin a full 12-month term.

In an interview, Betkoski told *RTO Insider* about his priorities at NARUC.

"You usually roll [priorities] out in November, but I'm probably going to [do] something with the whole water-energy nexus," he said. "That's certainly very important to what we do as regulators. You need both water for energy and energy for water. It's something that we as regulators could highlight. I've always felt very passionate about the water cases that I've been involved in."

NARUC committees set up to explore the issue would be divided equally between electric and water utility regulation, he added.

"Thank goodness that we have iPads and computers and everything else, because I can certainly fill my responsibilities here in Connecticut with my dockets but also be doing the great work we have to do with the national organization," Betkoski said. "There's so much going on, and the whole re-composition of [a quorum] at FERC, that's going to be something that in my new role we'll be getting reacclimated to, a fully staffed FERC organization within the next couple months."

Betkoski declined to comment on dockets currently before PURA, on the state-federal tensions that prompted a FERC technical conference in May or on PURA's role under Gov. Dannel Malloy's executive order to assess the economic viability of Dominion Energy's Millstone nuclear plant. "Katie is the lead commissioner on that joint proceeding," he said, referring to PURA Chair Katie Dykes. (See related story, *Commenters Seek Broader Response on Millstone, Renewables*, p.10.)

Betkoski also demurred on elaborating on his plans for NARUC and the water theme: "It's not even a week since I took over, so it's really transitional right now."

NEPOOL Transparency

Betkoski was surprised to learn last year that most stakeholder meetings of the New England Power Pool, which advises ISO-NE, are closed to the public and the press. Most meetings of the other six RTOs and ISOs are open.

NEPOOL is "doing something that impacts ratepayers, and anything like that should be as transparent as possible," Betkoski said. "I know that's certainly the way we operate here. I've been a commissioner for 20 years, and certainly I encourage people to come to public hearings and certainly have never kicked journalists out of public hearings, and I think the same should hold true for them."

If a discussion concerns proprietary information, the regulatory agency can go into executive session, but other than that the meetings should be open, he said.

Betkoski will be formally installed as president in November at NARUC's Annual Meeting and Educational Conference in Baltimore. Wisconsin Public Service Commission Chair Ellen Nowak will also be formally installed as first vice president in Baltimore, while the second vice president position she is vacating will be filled at the same meeting.

A Democrat from Beacon Falls, Betkoski has served on Connecticut's utility regulatory authority since 1997, when it was known as the Department of Public Utility Control. Malloy appointed Betkoski to the newly created PURA in 2011 and reappointed him to a four-year term that began in 2015. He is a past president of the New England Conference of Public Utilities Commissioners.

He has served on NARUC's executive committee since 2012 and is currently chairman of the Connecticut Water Planning Council and a member of the American Water Works Association Research Foundation's Public Council on Drinking Water Research. He previously served as a member of the EPA National Drinking Water Advisory Council's Water Security Working Group.

State News

NY Clean Energy Commitment Spurs Procurement

By Michael Kuser

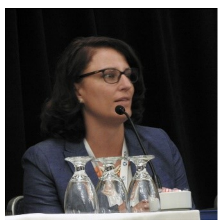
NEW YORK — While timelines for completing large power projects can be especially long in New York, developers are finding it easier to invest here now that the state is providing more predictability around clean energy procurement and market fundamentals.

That was the consensus of panelists discussing the impact of the state's Clean Energy Standard (CES) on procurement at the Infocast New York Energy REVolution Summit held earlier this month at Times Square.

Gov. Andrew Cuomo's Reforming the Energy Vision (REV) and its associated CES aim to meet two goals by 2030: a reduction in New York's greenhouse gas emissions to 40% below 1990 levels and that renewables generate 50% of the state's electricity.

To support those objectives, the governor in June announced the largest-ever state-mandated clean energy procurement, authorizing the New York State Energy Research and Development Authority (NYSERDA) and the New York Power Authority to oversee up to $1.5 billion of investment in major renewable energy projects, including offshore wind and solar.

Noah Hyte, Cypress Creek Renewables; Karlis Povisils, Apex Clean Energy; Jack Godshall, Invenergy; Dennis Phayre, Entersolar; Doreen Harris, NYSERDA; and moderator Sean Garren, Vote Solar. | *© RTO Insider*



"We're encouraged by the number of projects, both in the interconnection queue at the ISO, and also in the pipeline of projects that are moving through Article 10," said **Doreen Harris**, director of large scale renewables at NYSERDA. Article 10 is New York's primary permitting process for authorizing the construction and operation of all utility-scale power projects 25 MW and above.

"It's a good signal to us of the interest in New York and the supply that's to come."

Steady Wind

Harris said NYSERDA is focusing on three main areas around renewables: solicitation of long-term contracts; behind-the-scenes work running tracking systems and working with 152 load-serving entities; and aggressive pursuit of offshore wind.

Cuomo in January called for the development of 2,400 MW of offshore wind projects by 2030, starting with the 90-MW South Fork Project off Montauk, Long Island. (See *New York Seeks to Lead US in Offshore Wind*.)

"The way we are evaluating proposals is

Continued on page 29

Massachusetts Tightens GHG Limits for Generators

Continued from page 12

"These regulations will help ensure the commonwealth meets the rigorous emission reductions limits established in the Global Warming Solutions Act in order to protect our residents, communities and natural resources from the effects of climate change," Baker said.

Limited Effect on Consumers

The DEP concluded that the emissions targets and clean procurement rules would likely increase customer electricity bills by 1 to 2% per year.

The Bay State has been busy this year ramping up its environmental regulations. Officials earlier this summer announced that the state's electric distribution utilities must procure a combined 200 MWh of energy storage by Jan. 1, 2020. (See *Massachusetts Underwhelms with 200-MWh Storage Target*.)

In late July, the state received more than half a dozen proposals to meet its call for 9.45 TWh a year of renewable generation. Projects will be selected next January, with contracts to be submitted in late April. (See *Hydro-Québec Dominates Mass. Clean Energy Bids*.)

In response to public comment, the final CES included limited grandfathering to accommodate electricity sold in 2018 and 2019 under existing contracts. For the next three years, the alternative compliance payment rate is being increased to 75% of the RPS amount, but it will drop to 50% of the RPS amount in 2021. The use of banked clean energy credits is not allowed until 2021.

The RGGI emissions cap represents a regional budget for CO_2 emissions from the power sector, with each CO_2 allowance representing an authorization to emit 1 short ton from a regulated source. The nine RGGI states agreed on a 2014 cap of 91 million short tons. The CO_2 cap declines by 2.5 percentage points each year from 2015 to 2020.

STATE NEWS

NY Clean Energy Commitment Spurs Procurement

Continued from page 28

more complex than it used to be under the [renewable portfolio standard] in the sense that, first of all, we are looking to signal through some new threshold criteria the desire to really move projects through the pipeline in New York state," Harris said.

Having the state replace goals with actual standards to achieve over five to 10 years "enhances the ability of developers to focus specifically on development of the best possible assets, with appropriate timelines," said **Jack Godshall**, vice president of origination at Invenergy, the largest renewable energy provider in North America.

Firm procurement targets allow companies to spend time and capital developing assets for which they know there will be a market in coming years, Godshall said. "And that's great for the state and also for the developers."

Beneficial Load

Corporate clients deciding to "go solar" have shifted toward more and more larger procurements and off-site developments, according to Dennis Phayre, director of business development for EnterSolar, the top solar developer in New York.

"New York state now is limited to 2 MW on the distributed generation level, soon going up to 5 MW, but in our world, with the clientele we deal with, we certainly have to be looking at what comes beyond that," Phayre said. "Having appropriate maturity barriers, so that we don't have churn in awards, is super important to ensure that NYSERDA isn't rebidding the same 100,000 MWh over and over again."

NYSERDA Director of Policy and Regulatory Affairs **John Williams** said people tend to think of the DG outcomes of REV, but the program "always envisioned the supply side needing to undergo some pretty dramatic changes as well, and the Clean Energy Standard is the primary mechanism. When planning for a dynamic grid, we always imagined that there's going to be a lot of dynamic activity on the supply side."

Why all the focus on the power generation sector when it only represents about 20% of GHG in New York? Over the past decade, New York has nearly halved the sector's GHG emissions, with an accompanying shift in load, according to Williams.

"The CES actually needs to take account of the shift of load," Williams said. "We like to call it beneficial load, but clean energy-powered load only becomes beneficial to the degree that we can get consistent and continuous emissions reductions and a shift in that emissions profile in that electric generation sector. The value in an aggressive, continuous focus on power generation sector emissions is necessary because it winds up being the solution to emissions reductions that we need to see in other sectors."

COMPANY BRIEFS

Goldman Lost $100M Betting On Marcellus Gas Prices

Goldman Sachs Group lost more than $100 million this spring in a mistaken bet that natural gas prices in the Marcellus Shale region would rise, a big reason for the bank's weak second-quarter performance.

Goldman reportedly bet that gas prices in Ohio and Pennsylvania would rise because of new pipelines. But prices fell sharply in May and June following pipeline construction delays.

Goldman, the seventh-largest marketer of natural gas in North America, said the second quarter was the worst ever for its commodities unit.

More: The Wall Street Journal

Palmco to Pay $5M to Settle Claims of Deceptive Practices

Electricity supply company Palmco Power has agreed to pay $5 million to Connecticut and give up its license to sell electricity in the state for five years to settle allegations that it engaged in deceptive and abusive marketing tactics.

State agencies had been investigating Palmco since February 2015 for consumer complaints including allegations of high-pressure tactics, misrepresentation, threats that customers' power would be shut off if they didn't sign up with Palmco, and that sales agents switched customers to Palmco without authorization.

Under the settlement, Palmco officials did not acknowledge liability or guilt.

More: Hartford Courant

Home Depot Installing Rooftop Solar at 50 Stores

Home Depot announced Thursday that General Electric's Current unit and Tesla will install rooftop solar systems at 50 of its stores.

The installations are part of the company's plan to get 135 MW of clean energy by 2020 and will cut each store's grid demand by one-third.

Home Depot will buy output from each of the systems under power purchase agreements in New York, New Jersey, Connecticut, California, Maryland and D.C.

More: Atlanta Business Chronicle; Bloomberg Markets

Talen Downsizing Pa. HQ; Opening 2nd Office Near Houston

Talen Energy is moving and downsizing its Allentown, Pa., headquarters and will open a second office outside Houston.

CEO Ralph Alexander last week sent an email to employees saying that the Allentown office will be one of two "center locations." The other will be in The Woodlands outside Houston. Both centers will be smaller than the historic "Talen 1.0" HQ, said Alexander, who is based in Houston.

More than 500 people worked for Talen in its current headquarters, but the Allentown workforce will reportedly be reduced to less than 200 employees by next year when the company moves. The independent power producer, created in 2015 as a spin off from PPL, was acquired by private equity firm Riverstone Holdings last year.

More: The Morning Call

SCANA: Unlikely V.C. Summer Construction Will Restart

SCANA's CEO does not see much chance of restarting construction at the scrapped V.C. Summer nuclear plant expansion, notwithstanding last week's withdrawal by its subsidiary of a request to regulators that it be allowed to abandon the project.

Speaking to analysts in a conference call Wednesday, SCANA CEO Kevin Marsh said he considers the withdrawal by South Carolina Electric & Gas to be a temporary suspension. He also said he isn't sure when SCE&G will move forward with plans to charge ratepayers for the project.

South Carolina Gov. Henry McMaster has been trying to find a new partner for the project, the costs of which have ballooned from an initial $9 billion in 2008 to at least $18 billion now.

More: Charlotte Business Journal; The Post and Courier

DTE Turning off Power for Smart Meter Opponents

DTE Energy is shutting off power for customers who have resisted installing new digital electric meters in their homes.

DTE spokeswoman Randi Berris said the utility is close to completing its conversion to smart meters and expects to finish the project, which began in 2008, by the end of this year. Customers can opt out of the smart meter program for an initial fee of $67.20, plus $9.80/month.

Linda Kurtz, director of the Smart Meter Education Network, is concerned that electromagnetic fields generated by smart meters pose health hazards. Dozens of people gathered at her Ann Arbor, Mich., home last week to protest the expected shutoff of her electricity.

More: MLive

Washington Regulators Deny Rate Increase for Avista

Washington regulators denied a request by Avista for a 2.9% rate increase that would have amounted to an additional $15 million in revenue.

Avista had requested the increase to begin Sept. 1, citing higher power costs.

The Utilities and Transportation Commission's refusal in December to grant Avista a rate increase for 2017 led to an earnings shortfall of $20 million to $30 million for the year, Kelly Norwood, the company's vice president of state and federal regulation, wrote in a letter to the commission.

More: The Spokesman-Review

ScottMadden Forms New Practice; Bob Hevert to Lead

Energy consulting firm ScottMadden announced it has formed a new rates, regulation and planning practice and tapped

Continued on page 31

COMPANY BRIEFS

Continued from page 30

Bob Hevert to be its leader.

The new practice will assist clients with rate development, regulatory policy and strategy, rate case preparation and management, market and risk assessment, resource planning, and demand forecasting.

Hevert joined the firm in 2016 and has provided expert testimony on more than 150 occasions for energy companies and financial institutions. He previously served as managing partner at Sussex Economic Advisors.

More: *ScottMadden*

Coal Company Warns It May File for Chapter 11

Armstrong Energy may need to seek Chapter 11 protection, according to a filing it made Friday with the U.S. Securities and Exchange Commission.

The company, which operates five coal mines in western Kentucky, reported a $17.2 million second-quarter loss on revenue of $60.9 million. It didn't make an $11.75 million interest payment that was due on June 15, and a forbearance agreement by holders of the debt was set to expire last Monday.

More: *St. Louis Post-Dispatch*

Duke Entering NY with Purchase Of Invenergy Solar Project

Duke Energy Renewables is making its New York entrance by acquiring the 24.9-MW Shoreham Solar Commons project on Long Island from Invenergy.

The project, which is currently under construction, is expected to be complete in the second quarter of 2018. The Long Island Power Authority will purchase the power under a 20-year agreement.

More: *Duke Energy*

FEDERAL BRIEFS

Clean Energy Groups Launch Lobbying Blitz

In an effort to appeal to the Republican-controlled government, 10 clean energy associations are organizing a lobbying and advertising push that emphasizes creating jobs and providing reliable electricity, rather than combating climate change.

The groups — including Advanced Energy Economy, Nuclear Energy Institute, Biomass Power Association, American Wind Energy Association, Business Council for Sustainable Energy, Clean Energy Business Network, Solar Energy Industries Association, National Hydropower Association, American Council on Renewable Energy and Citizens for Responsible Energy Solutions Forum — have dubbed the week of Sept. 25 "National Clean Energy Week."

More: *Axios*

DOE Funds 2 Projects for Recovery of Rare Earth Minerals

The Energy Department announced Wednesday that it will give $17 million to researchers for two projects to advance the recovery of rare earth minerals from abandoned coal mines and coal waste.

West Virginia University and North Dakota Institute for Energy Studies will receive $6 million each to develop "bench-scale technology" to separate, extract and concentrate mixed rare earth elements from coal and coal byproducts. University of Kentucky Research Foundation and private Massachusetts company Physical Sciences will get less than $6 million to focus on "pilot-scale technology to economically separate, extract and concentrate mixed rare earth elements from coal and coal byproduct solids."

Silicon Valley's demand for rare earth elements has grown significantly over recent years, according to the department.

More: *Washington Examiner*

NYU Will Help AGs Fight Trump Environmental Rollbacks

The New York University School of Law plans to launch a new center to help state attorneys general fight federal efforts to roll back renewable energy, environmental protections and climate policies.

The State Energy and Environmental Impact Center, funded by a nearly $6 million grant from Bloomberg Philanthropies, will provide assistance to states regardless of party.

David J. Hayes, who served as the Interior Department's deputy secretary under the Obama and Clinton administrations, will serve as the center's executive director.

More: *The Washington Post*

NRC Greenlights Uprate for Browns Ferry Nuclear Plant

The Nuclear Regulatory Commission has approved Tennessee Valley Authority's request for a 14.3% increase in generating

capacity for all three of its Browns Ferry Nuclear Plant reactors.

The change will raise each reactor's capacity by about 155 MW.

TVA plans to implement the extended power uprate during the spring 2018 refueling outage for Unit 3, the fall 2018 refueling outage for Unit 1 and the spring 2019 refueling outage for Unit 2.

More: *The News Courier*

Report: North American Tx Market Exceeds $31.6B

The North American electric transmission market topped $31.6 billion in 2016, growing 1.2% from 2015, according to a report released last week by The C Three Group.

The "2017 North American Electric Transmission Market Forecast" found the market's U.S. component grew 5.5% during the 2015 to 2016 period.

Substations were the fastest growing segment, with U.S. substation spend up 16.9%.

More: *The C Three Group*

Continued on page 32

Federal Briefs

Continued from page 31

Judge Blocks Expansion Of Montana Coal Mine

A federal court issued an order last week blocking Signal Peak Energy from mining in an 11-square-mile expansion area at its Bull Mountain coal mine in Montana pending further environmental studies.

The order by U.S. District Judge Donald Molloy says the Interior Department's Office of Surface Mining must consider the environmental impact of shipping the fuel to customers in Asia and from the greenhouse gases and other pollutants emitted when burning the coal.

Montana Environmental Information Center, Sierra Club and Montana Elders for a Livable Tomorrow filed suit in 2015 claiming the government did not properly examine the effects of the 176-million-ton coal mine expansion on waterways, air pollution and the health of people who live along the coal's shipping routes.

More: *The Associated Press*

DC Circuit Rejects Challenge to Freeport LNG Export Terminal

The D.C. Circuit Court of Appeals on last week ruled that the Energy Department conducted the necessary environmental and economic reviews before it approved the Freeport LNG export terminal in Texas, due to come online in 2018.

The Sierra Club challenged the agency's review of the project, claiming the agency didn't comply with federal environmental laws before issuing its approval in 2014 and that it erroneously determined the project was in the public interest.

The court found the agency followed procedures under the National Environmental Policy Act even though it declined to make specific projections about environmental impacts, and it properly considered domestic economic impacts, foreign policy goals and energy security measures in its public-interest determination.

More: *The Hill*

Sierra Club Sues DOE for Info on Grid Study Experts

The Sierra Club sued the Energy Department last week in the hopes of identifying groups and experts the department consulted in preparing its electric grid study that has yet to be released.

The suit, filed in the U.S. District Court for the Northern District of California, says the agency ignored a Freedom of Information Act request Sierra Club filed in May. The request sought the release of communications between staff and outside groups the department consulted, in the belief it relied primarily on fossil fuel backers.

A draft of the study that was leaked to the media last month said intermittent renewable power hasn't harmed the grid. But a department spokeswoman said the draft was "outdated" and had not been reviewed by political or career staff.

More: *Reuters*; *Washington Examiner*

Fitch: Solar Projects Beating Projections; Wind Missing the Mark

Solar projects around the world are exceeding estimates for electricity generation, while wind projects are failing to meet them, according to a report released last week by Fitch ratings.

The ratings agency found solar projects across Europe, Africa, the Middle East, and North and South America since 2010 met or exceeded their early estimates 70% of the time. But about 75% of wind projects failed to meet early projections.

Fitch attributed the success of solar to "better-than-expected solar irradiance and plant availability." It attributed the underperformance of wind to technological challenges in forecasting, natural resource volatility and equipment problems.

More: *Houston Chronicle*

EPA Plans to Revise Rule Increasing Treatment for Plant Wastewater

EPA plans to revise 2015 guidelines mandating increased treatment for wastewater from steam electric power plants, according to a letter it filed last week as part of a legal appeal.

The letter by Administrator Scott Pruitt was filed with the 5th U.S. Circuit Court of Appeals, which is hearing legal challenges to the Obama-era rule. Because Pruitt wants to rewrite the standards, EPA is asking the court to put the litigation on hold.

EPA estimates that if the rule is implemented, power plant pollution would decrease by 1.4 billion pounds a year. About 12% of U.S. steam electric power plants would have to make new investments to meet the higher standards.

More: *Associated Press*

State Briefs

COLORADO

300 EV Charging Stations Coming to Denver

Three hundred electric vehicle charging stations will be installed in Denver's metro area over the next two years, city officials said Wednesday.

Lawsuit settlement money paid by Volkswagen after its diesel emissions cheating scandal will help fund the effort, which may include changes to the city building code to encourage installation of more charging stations near apartments and condos.

More: *The Denver Post*

Continued on page 33

STATE BRIEFS

Continued from page 32

MASSACHUSETTS

Solar Parking Lot Canopy Coming to County Jail

The Department of Energy Resources is investing $545,000 to install a 436-kW solar canopy above the parking lot of the Franklin County Jail and House of Corrections.

The canopy is expected to offset more than a quarter of the facility's consumption and save about $92,000 in annual energy costs.

More: The Republican

OHIO

AEP to Begin Installing Smart Meters

American Electric Power last week began rolling out what will eventually be 900,000 smart meter installations in homes across the state.

The initiative, which will begin in the central part of the state, will continue until 2021. Residents who refuse the smart meters will have a charge of $24 per month added to their bill.

The Delaware area will see the first installations. Lewis Center, Sunbury, Johnstown, Galena, Westerville, New Albany, Pataskala, Powell, Worthington, Dublin, Amlin and Plain City also are scheduled for smart meters this year.

More: The Columbus Dispatch

PENNSYLVANIA

API Poll: State Voters Oppose Nuclear Plant Bailouts

Eighty-four percent of the state's voters oppose legislation that would impose a special fee to bail out or fund Exelon's nuclear power plants, according to a poll released Wednesday by API Pennsylvania.

The poll conducted by the American Petroleum Institute division also found that 77% of voters agree the electricity market should be based on the marketplace, rather than special treatment for one corporation, and 60% believe electricity prices are lower with competition.

More: API Pennsylvania

SOUTH DAKOTA

Judge Approves Three-Quarter-Mile Setback for Wind Towers

A 400-MW wind farm planned for Clark County must keep towers a minimum of 3,960 feet from residences, according to a decision last week by the state's Third Circuit Court.

If completed, Geronimo Energy's Crocker Wind Farm would be the state's biggest wind farm. Geronimo had challenged a decision by the Clark County Commission approving the project, but requiring towers be placed a minimum of three-quarters of a mile from residences.

Commissioner Francis Hass said the commission didn't do enough homework before allowing a 2,000-foot minimum setback for an 11-tower project built a few years ago.

More: Watertown Public Opinion

TEXAS

PUC Staff Look to Cut Low-Income Bill Assistance

Public Utility Commission staff filed a report Wednesday suggesting changes to state law that would slash benefits that help low-income residents afford their utility bills.

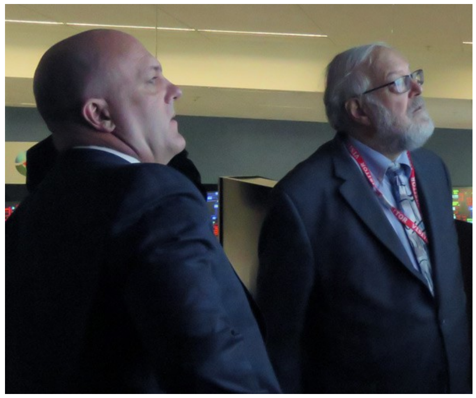
Among the suggestions were cuts to programs that offer reduced electric rates and help pay utility deposits. The reductions would follow the lapsing of the so-called System Benefit fund, which helps poor residents pay for electricity.

Consumer advocates are worried that a list paid for by retail electric providers and used by the commission to identify people eligible for certain protections will be discontinued after a deadline passed for companies to sign up and pledge compensation. As of this month, 43 of an estimated 50 to 60 retail electric providers in the state agreed to pay for and receive the list.

More: Houston Chronicle

Grid Operators Manage Solar Eclipse

Continued from page 1



California Energy Commission Chair Robert Weisenmiller (right) and CAISO CEO Steve Berberich study generation output during the eclipse. | *© RTO Insider*

Tennessee Valley Authority's Watts Bar nuclear plant, located in Spring City, Tenn., experiences totality. | *TVA*

CAISO said it would not be able to provide precise figures for how much solar generation dropped off its system until later this week.

"We forecasted 4,200 MW of utility-scale solar coming off. We believe that the actual will be more in the 3,000 to 3,500 MW range," CAISO spokesman Steven Greenlee said.

Grid operators had to deal with two solar ramp-ups rather than just one.

About 10:50 a.m. PT, after totality, load was about 30,500 MW and solar generation was about 4,100 MW, with the grid stable. When the sun was nearly clear of the moon about 11:30, CAISO said load was about 29,300 MW and solar generation was at about 6,800 MW. By about 1:30 p.m., solar generation in the ISO was back up to around 9,000 MW. There is about 10,000 MW of solar capacity on the ISO system.

CAISO had to manage not only the rapid loss of solar but also a steeper-than-usual climb of that resource compared with a normal day as the sun returned. CAISO predicted it would lose about 51 MW/minute, and as the blockage waned, solar generation came back at a rate of 93 to 100 MW/minute. On a normal morning, solar ramps about 29 MW/minute.

Wholesale prices briefly went negative as solar returned, as they regularly do when there is excess generation on the grid. CAISO said that the 1,000-mile East-West span of the Western Energy Imbalance Market (EIM) allowed it to call on available resources as other areas ramped down.

About 860 MW of solar went off the grid in the EIM.

SPP, ERCOT See Little Impact

SPP had anticipated a peak load of approximately 45,000 MW across its system Monday but saw demand about 2,500 MW below that as air conditioning usage dropped and manufacturing facilities closed while employees observed the eclipse.

"In preparation for the relatively sudden and not entirely predictable drop in load, SPP utilized its day-ahead market processes beginning Aug. 20 to commit adequate reserves to accommodate load swings and the resulting impacts to frequency and interchange," SPP said. The RTO increased its regulation service in preparation. An eclipse also slows wind speed by cooling air, causing a 1,200-MW swing in the RTO's wind generation that also had to be managed.

"By increasing our regulation requirements, we essentially 'widened the lanes' of our system and operated more conservatively than we might have on a normal day to accommodate any unpredictable occurrences during this rare event," Director of System Operations CJ Brown said.

This was a great learning opportunity for SPP," said Vice President of Operations Bruce Rew. "And I'm proud that our staff and systems were able to ensure that, despite so many variables and the rarity of the solar eclipse, it was essentially a non-event electrically speaking."

Utility-scale solar in the ERCOT system dropped from a peak of 760 MW to a low of 299 MW during the eclipse, while total system load dropped from 60,824 MW to 60,163 MW. The ISO said a number of factors could have contributed to the load decrease, including reduced air-conditioning demand.

Duke Loses 1,700 MW in NC

In North Carolina, Duke Energy reported that it lost about 1,700 MW of capacity during the height of the eclipse. "Given the weather conditions, we should have expected 1,808 MW of solar output during the afternoon. But at the height of the eclipse, we were getting only about 109 MW," said spokesman Randy Wheeless.

North Carolina is the nation's No. 2 state for

From left to right: CAISO Executive Director of Operations Nancy Traweek, CAISO Vice President of Operations Eric Schmitt and California Energy Commission Chair Robert Weisenmiller brief reporters at CAISO. | *© RTO Insider*

Continued on page 35

Grid Operators Manage Solar Eclipse

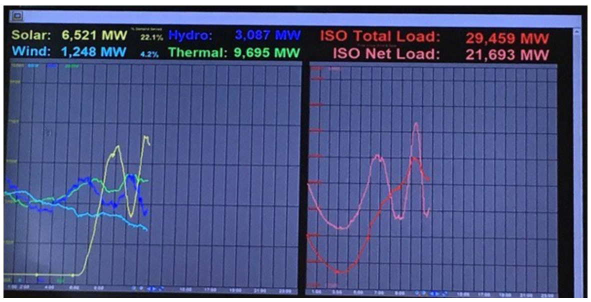
Continued from page 34

solar capacity, with 2,500 MW connected to the Duke system.

Peak demand for Duke Energy Carolinas and Duke Energy Progress in North Carolina is about 22,500 MW on a typical summer day.

MISO has no Issues

MISO said it navigated the eclipse without reliability problems as it crossed its 15-state footprint, but operators did see a significant drop in load.



Electronic board in CAISO control room displays solar generation (left) and load (right) during and after eclipse. | *CAISO*

"Around 1:15 p.m. ET, demand for electricity in the region flattened out and then dropped during a two-hour period as the moon passed in front of the sun. Load began steadily increasing after 3 p.m.," said spokesman Mark Adrian Brown. "Cooler-than-expected temperatures likely contributed to the drop in load as storms rolled through the Upper Midwest Monday afternoon. Decreased solar generation during the eclipse did not have a major impact on the numbers."

Currently, MISO has about 180 MW of grid-scale solar and an estimated 350 MW of distributed solar in its footprint.

The RTO said before the event that it would be monitoring its distributed generation and learning lessons for the eclipse on April 8, 2024, when solar will make up more generation in the region.

Clouds in PJM

In the eastern half of the country, cloud cover and rain dampened the eclipse's effects. At PJM headquarters in Valley Forge, Pa., more than 50 people filtered through an onsite auditorium to try and view the eclipse as it passed across the continent and approached its footprint, the RTO said.

Peak load was expected to be 137,800 MW on Monday, with temperatures near 90 degrees Fahrenheit across much of the Mid-Atlantic.

"Substantial cloud cover largely obscured the event at PJM's offices, but stakeholders and staff gathered outside with special glasses and homemade viewing apparatuses to catch whatever views were available," PJM said. The grid operator carried about 1,000 MW of regulation service instead of the usual 800 MW.

PJM saw grid solar generation drop by about 520 MW from before the eclipse until its peak. Behind-the-meter solar dropped by 1,700 MW. Solar represents less than 1% of PJM's 185,000 MW of generation capacity.

The RTO had expected the drop in solar production to result in an increase in net load. But "because of a variety of potential factors, including reduced air conditioning, increased cloud cover and changes in human behavior related to the event," it saw a net decrease in demand of about 5,000 MW during the eclipse.

Temperatures dropped by an average of 2 degrees Fahrenheit, with the Chicago area hit by storms after the eclipse began.

Continued on page 36

Sempra Outmuscles Berkshire Hathaway for Oncor

Continued from page 24

off what he viewed as "imprudently incurred debt" by the utility's holding company.

"The continued existence of any material amount of debt above Oncor will be a concern," Anderson said. "One of the most important aspects is the cash flow generated out of Oncor must be protected. It needs to be available to Oncor's management and to Oncor's board to put it back into the business."

The debt "is not Oncor's problem. It is the problem of the commission now, but when the dust settles, I don't want it to be the problem of either this commission or future commissions."

Sempra has committed to support Oncor's plan to invest $7.5 billion of capital over a five-year period to expand and reinforce its existing system.

New CEO

When the transaction is completed, Shapard will become executive chairman of the utility's board of directors. Allen Nye, currently the utility's general counsel, will succeed Shapard as CEO. Both have been asked to serve on the board, which will consist of 13 directors, including seven independent directors from Texas, two from existing equity holders and two from the new Sempra-led holding company.

The transaction is subject to customary closing conditions, including the approval of the PUC, FERC, the bankruptcy court and antitrust regulators at the U.S. Justice Department.

"It is important for Oncor to remain financially strong," Sempra's Reed said. "Our proposal will help bring a satisfactory resolution to Energy Future's bankruptcy case, keep Oncor financially strong and protect Oncor customers, while addressing the needs of Texas regulators, creditors and the U.S. bankruptcy court."

The deal would allow Sempra to regain a foothold in Texas, where it once owned and operated 10 power plants and currently maintains a 200-person office in Houston to support marketing and development activities. A Fortune 500 corporation that includes San Diego Gas & Electric and Southern California Gas, Sempra had 2016 revenues of more than $10 billion.

Sempra's announcement was not a complete surprise. Word began leaking out last week that a mystery bidder had emerged to take on BHE's offer. During a bankruptcy hearing Friday, legal counsel for Elliott identified the new competitor for Oncor as "a large investment-grade utility."

Elliott's representative also told the court that EFH was considering pursuing talks with the new competitor. EFH's board met Friday and Sunday before accepting Sempra's offer.

Rory Sweeney reported from Wilmington, Del.

Grid Operators Manage Solar Eclipse

Continued from page 35

PJM will use lessons from Monday's event for April 8, 2024, when the RTO's footprint will be in the path of a total eclipse between Texas and Maine.

Minimal Effects in New England

ISO-NE had sufficient resources available to meet the rise in electricity demand resulting from a drop in output from the region's 2,000 MW of solar PV systems during the partial eclipse. New England saw peak obscuration about 2:45 p.m., when the moon blocked about 65% of the sun. Skies were generally clear across the region during the eclipse.

ISO-NE reported in June that PV generation would face a less extreme reduction in output because the angle of the sun is lower in late August than earlier in the summer, and the eclipse would occur almost two hours after the solar noon peak.

"To precisely balance electricity supply and demand minute-to-minute during the partial eclipse, ISO system operators must consider three major factors that will affect PV output," said the report: obscuration percentage, angle of the sun and cloud cover.

The grid operator cited human behavior as another factor that could dampen the dip in solar output: "When there's an eclipse, people typically stop what they're doing and watch," which lowers demand for electricity, it said.

New York not Fazed

New York experienced the partial eclipse under clear skies. NYISO said it had minimal impacts on electric load and that it did not need to take any special transmission operating actions.

NYISO Vice President of Operations Wes Yeomans on Friday posted a YouTube video in which he explained that peak totality of roughly 80% would be strongest from 2:30 to 2:45 pm.

New York has approximately 850 MW of rooftop solar, but solar generation peaks at 625 MW because the panels are not aligned in the same direction, Yeomans said. Solar output peaks between noon and 1 p.m. on very sunny days.

The last significant solar eclipse in New York occurred on May 10, 1994, when there were very few solar devices in the state.