RTO Insider

Your Eyes and Ears on the Organized Electric Markets

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

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GOP Tax Bill Would Trim PTC, Drop Credit for EVs

By Rich Heidorn Jr.

The tax bill introduced by House Republicans on Thursday would trim the wind production tax credit by more than a third and eliminate the credit for electric vehicles while maintaining the tax credit for Southern's Co.'s troubled Vogtle nuclear project.

The proposal would repeal the inflation adjustment for the PTC, effectively reducing the PTC from 2.3 cents/kWh in 2016 to 1.5 cents for projects begun after Nov. 2.

The American Wind Energy Association complained that the proposed Tax Cuts and Jobs Act "reneges" on the deal Congress made in 2015, which would phase out the PTC completely over five years.

AWEA CEO Tom Kiernan said the bill is "a retroactive tax hike" that would "pull the rug out from under 100,000 U.S. wind workers

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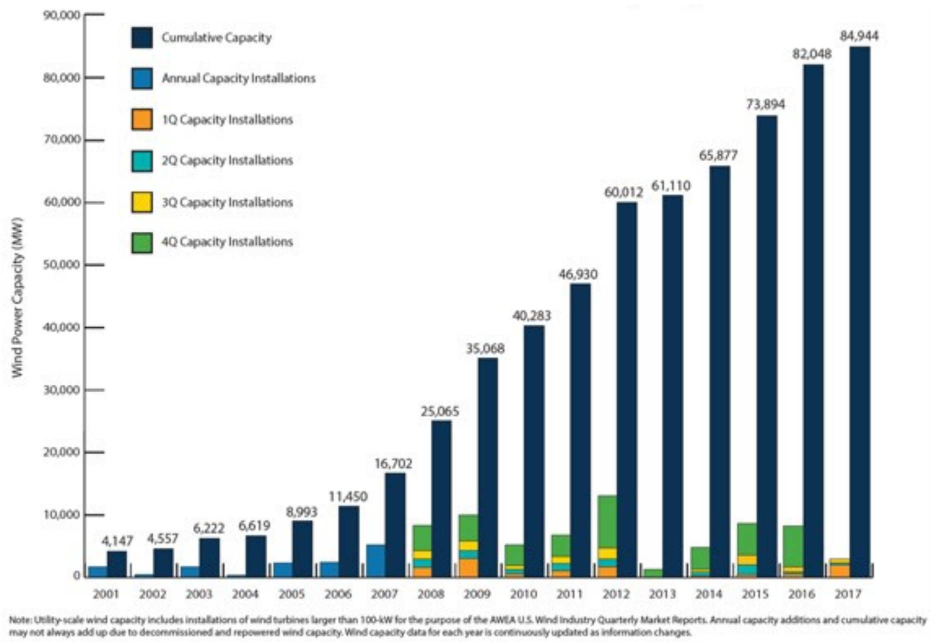

U.S. annual and cumulative wind power capacity growth | *AWEA*

McIntyre and Glick Confirmed to FERC

By Peter Key

The Senate on Thursday confirmed Republican Kevin McIntyre and Democrat Richard Glick to FERC, giving the commission a full panel for the first time in two years.

The two were approved on voice votes, putting them in a position to weigh in on Energy Secretary Rick Perry's controversial proposal to provide price supports to coal and nuclear plants in competitive markets (RM18-1).

McIntyre, the coleader of the global Energy Practice at the law firm Jones Day, will serve out the rest of a term that ends June 2018,

Continued on page 24

Federal Trade Panel Recommends Solar PV Quotas

By Michael Kuser

The U.S. International Trade Commission last week recommended that President Trump impose import duties as high as 35% on solar cells and modules.

The independent panel announced the recommendations following its unanimous ruling in September that increased imports of solar cells and components are harming domestic manufacturers, which supported the claims of solar manufacturers Suniva and SolarWorld under Section 201 of the 1974 Trade Act.

The commission will forward its injury determination, remedy recommendations, any additional findings and the basis for them to Trump by Nov. 13. The president will then have 60 days to decide on what, if any, measures he will take. (See *Trade Panel Rules PV Imports Hurting Domestic Manufacturers*.)

Three of the four commissioners recommended imposition of tariff-rate quotas. The fourth, Meredith Broadbent, recommended that the president impose a hard annual quantitative restriction on imports of crys-

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IN THIS WEEK'S ISSUE

Correction

In the Oct. 24 edition, *RTO Insider* incorrectly reported that MISO and PJM received nearly 100 stakeholder project suggestions during a proposal window for interregional projects as part of the RTOs' coordinated system plan study. PJM received a total of 96 proposals for regional market efficiency projects; MISO and PJM received eight stakeholder-originated proposals for potential interregional market efficiency projects. (See *MISO, PJM Reverse Support for Lone Interregional Tx Project*.)

COUNTERFLOW
BY STEVE HUNTOON

Clunkers Shoot Selves in Foot

By Steve Huntoon


Huntoon

The few supporters of the U.S. Department of Energy's proposal to FERC have promoted an insane rush to judgment in the absence of anything remotely resembling an emergency — or even a problem.[1]

In the reckless stampede imposed on the electric industry, these clunker owners have shot themselves in the foot. Twice.

First, they have largely accepted — and even refined — the provision of the DOE proposal that makes their nuclear units categorically ineligible for any subsidy.

Second, they have invoked the risk of electromagnetic pulses and geomagnetic disturbances as a basis for the DOE proposal when their coal and nuclear units are the most vulnerable to such risk.

Clunker Nuclear Units are Ineligible for Subsidies

The DOE proposal is amorphous on almost everything, but it is crystal clear that an eligible resource must be able to provide "ancillary reliability services," specifically including "frequency services."[2]

FirstEnergy suggested refining "frequency services" to "frequency response services" in order to "reflect terminology typically used by RTOs/ISOs." [3]

Thank you, FirstEnergy, for straightening the deck chairs on the Titanic.

Because here's the thing: Nuclear units can't and don't provide frequency response. The Nuclear Energy Institute, on behalf of its members like FirstEnergy, Exelon and Public Service Enterprise Group, was vehement in comments to FERC last year that nuclear units had no or limited frequency response capability, and for those few nuclear units that might be able to provide limited frequency response, the Nuclear Regulatory Commission doesn't allow it.[4]

In reliance on those nuclear industry representations, FERC proposed to exempt all nuclear power plants from providing frequency response.[5] You can't eat your cake and have it too.

By the way, in the significant frequency event in the Eastern Interconnection studied by NERC, nuclear units actually provided a *negative* response of 12 MW.[6] In other words, they made the reliability problem worse. No participation trophy for them.

Another required service is "operating reserves." This means a generating unit must change output on command to help cover the loss of another generator on the system. Nuclear units don't provide this service because they operate at 100% capacity (so no "headroom"), and because changes in output present unique safety problems, as described to FERC at a technical conference in 2010 by Jack Grobe, then deputy director of NRC's Office of Nuclear Reactor Regulation, now executive director at Exelon Nuclear (emphasis added):[7]

> "Power is not infrequently adjusted a few megawatts to deal with equipment issues. For example testing of valves, changing of rod patterns in the core, but those are just a few megawatts. More significant power changes introduce things like what Bruce [Mallett, NRC deputy executive director for reactor and preparedness programs,] was saying; those require a lot of equipment manipulations and it introduces the potential for human factors concerns. *Human errors, things of that nature.*
>
> *"From a safety perspective*, it also introduces changes in the dynamics of the core, because the neutrons that create fission also burn or destroy *poisons* in the core and the fission of the uranium nucleus creates poisons. There is a unique balance that goes back and forth when you make power changes to building in of *poisons* and burning out of *poisons* and different things of that nature. So, it changes the dynamics on how the fuel burns and this affects the efficiency in the fuel economy for the operator. Not a concern of ours, but it creates instabilities in the way, not unsafe instabilities, but just changes in the way the core behaves. *So, all of those things introduce the opportunity for perturbations to the safety of the core from the standpoint of the way the operators have to respond."*

Translation: Any nuclear unit that would vary output to provide operating reserves is taking a walk on the wild side. Ain't gonna happen.

Bottom line: DOE specified two "ancillary reliability services" that an eligible resource must provide, and nuclear units can't and won't provide them.

Coal, Nuclear Most Vulnerable to EMP/GMD

Exelon invokes EMP/GMD risk in support of the DOE proposal.[8]

Here's the thing: DOE's own Oak Ridge National Laboratory identified coal and nuclear units as the most vulnerable to EMP risk.[9] Coal and nuclear cooling tower motors have a particular vulnerability. And nuclear units have additional vulnerability due to "the extremely complex reactor control circuitry in control rooms."

So if EMP/GMD risk is important, that favors maximizing natural gas and renewable resources and minimizing coal and nuclear units. It's the diametric opposite of subsidizing uneconomic, unreliable coal and nuclear clunkers.

Isn't it Ironic?

In their reckless haste, the clunker owners overlooked the fact that their own nuclear units aren't eligible and that the EMP/GMD risk they invoked is greatest for their own coal and nuclear units.

Isn't it ironic, don't you think?

Steve Huntoon is a former president of the Energy Bar Association, with 30 years of experience advising and representing energy companies and institutions. He received a B.A. in economics and a J.D. from the University of Virginia. He is the principal in Energy Counsel, LLP, www.energy-counsel.com.

[1] My last column showed that the chance of a winter generation deficiency in PJM is much less than one in 5,000, and were that to occur, the chance of the deficiency being due to a fuel supply emergency is remote. And if these two remote circumstances were to coincide, PJM would still have reliability tools to avoid customer impact. There is no beef.

[2] Proposed 18 C.F.R. §35.28(g)(10)(i): "An eligible grid reliability and resiliency resource is any resource that: …(B) Is able to provide essential energy and ancillary reliability services, including but not limited to voltage support, frequency services, operating reserves, and reactive power;"

[3] https://elibrary-backup.ferc.gov/idmws/common/opennat.asp?fileID=14720893 (page 40).

[4] https://elibrary-backup.ferc.gov/idmws/common/opennat.asp?fileID=14213680. "… nuclear generating units have no or limited response to interconnection frequency changes." (page 3). "In summary, even if a nuclear unit does have the capability to provide a limited response (typically a maximum of 1% reactor thermal power) to a significant frequency deviation; the NRC licensed operators are not authorized to operate the unit above the maximum power level as specified in the NRC issued Operating License and they are required to take immediate actions to restore reactor power to less than 100.0% Reactor Thermal Power in the event of any transient." (page 4).

[5] https://elibrary-backup.ferc.gov/idmws/common/opennat.asp?fileID=14401057 (para. 51).

[6] http://www.nerc.com/docs/pc/FRI_Report_10-30-12_Master_w-appendices.pdf (page 96).

[7] https://elibrary-backup.ferc.gov/idmws/common/opennat.asp?fileID=12357307 (pages 43-44).

[8] https://elibrary-backup.ferc.gov/idmws/common/opennat.asp?fileID=14722658 (page 2).

[9] http://www.dtic.mil/cgi-bin/GetTRDoc?AD=ADA237104 (pages 20-22).

CAISO NEWS

Board Decisions Highlight CAISO Market Problems

By Jason Fordney

| © RTO Insider

FOLSOM, Calif. — In a move that met criticism from some stakeholders, CAISO's Board of Governors on Thursday approved two measures intended to prevent the early retirement of unprofitable — but needed — generation in California.

The board approved a reliability-must-run (RMR) contract for Calpine's Metcalf Energy Center, saying it was an undesirable but necessary measure to maintain electric grid reliability in the Silicon Valley.

Despite the unanimous vote, the board expressed unhappiness about approving the contract, an out-of-market payment to keep the 605-MW natural gas-fired plant from retiring.

Ashutosh Bhagwat | © RTO Insider

Governor Ashutosh Bhagwat said: "I am going to hold my nose very, very hard." He added that "I understand the problem, but I think this is going to be a recurring issue and we need to come up with a solution."

Governor Mark Ferron said he was tempted to vote against the RMR "because I am opposed to the process and the situation we find ourselves in." But, he added, "to vote against this contract is not a risk that we should play with."

The Metcalf RMR is the third such contract awarded to a Calpine plant this year, sparking concerns among industry participants that the CAISO market and California's resource adequacy (RA) process are not supporting generation needed for future reliability. Calpine in June told the ISO it planned to remove the plant from dispatch on Jan. 1, 2018. The RMR contract was developed in a relatively short time frame after the ISO determined Metcalf was needed for local reliability. (See *Metcalf Reliability-Must-Run Draws Scrutiny*.) Metcalf's designation as RMR follows similar contracts approved earlier this year for Calpine's Yuba City and Feather River plants. (See *CAISO RMRs Win Board OK, Stakeholders Critical*.)

Representatives from the California Public Utilities Commission, Pacific Gas and Electric and Cogentrix spoke against the agreement at the meeting.

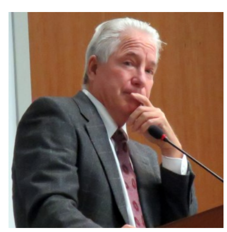
CAISO CEO Steven Berberich told the board that use of RMR "is not at all how we want to handle procurement." He added that "the RMR is symptomatic of a bigger problem, which is that resource adequacy is no longer able to meet the needs of the system." He said that the ISO does not want to frequently approve RMR agreements, and that procurement should be done through the RA process.

Board Approves CPM ROR Changes

In addition to the Metcalf RMR, the board approved a separate, broader program that will pay generators to stay in service to meet reliability needs. The Capacity Procurement Mechanism Risk-of-Retirement (CPM ROR) program expands the existing CPM process to include procurement of at-risk capacity needed for the next RA compliance year.

The program includes two application windows each year — in April and November — for three types of ROR designations. As the ISO developed the process, some stakeholders — including the PUC — raised concerns that inclusion of the April window gives resources undue insight into price discovery for the commission's RA program, which occurs in October. The commission was concerned "that moving a CPM ROR determination to a date prior to the conclusion of the year-ahead procurement process will result in front-running the RA bilateral procurement process." (See *CAISO Participants Question Retirement Program*.)

CAISO added the April window based on requests from generation owners, who said they needed the option of a designation earlier in the year for planning reasons. CAISO changed the proposal to require that a resource attest that it "reasonably believes" its annual fixed costs meet or exceed certain price thresholds. Some have criticized that the ISO would accept an attestation in that regard.



Keith Johnson | © RTO Insider

CAISO Infrastructure and Regulatory Policy Manager Keith Johnson told the board that the PUC's 2019 RA proceeding is an opportunity to address the issues that have been identified. The ISO will evaluate potential modifications to the RMR construct to better align with the current environment, he said in a presentation to the board.

No Time for Other Solutions

Keith Casey, CAISO vice president of mar-

Continued on page 5

CAISO NEWS

PacifiCorp, NV Energy Gain EIM Market-Based Rate Authority

By Robert Mullin

PacifiCorp and NV Energy can sell power into the Western Energy Imbalance Market (EIM) at market-based rates, FERC has ruled, reversing a previous finding that had restricted the companies to submitting only cost-based offers (ER17-2934).

The commission imposed the restrictions in late 2015 after finding the two Berkshire Hathaway Energy affiliates had failed to prove that they wouldn't exercise horizontal market power within the market. At the time, the EIM comprised only the CAISO, PacifiCorp-East (PACE), PacifiCorp-West (PACW) and NVE balancing authority areas (BAAs). It now includes Arizona Public Service, Puget Sound Energy and Portland General Electric.

In their August joint filing with FERC, PacifiCorp and NVE said that the bidding restrictions were "no longer appropriate" because both companies now meet conditions for EIM participation set out in previous FERC orders. They also contended that reliance on cost-based bids ran "contrary to organized market design" and presented the risk of unrecovered costs during some market intervals. (See *Berkshire Companies Request EIM Rate Authority*.) The utilities contended that the restrictions have created inefficiencies in how they manage hydroelectric resources and respond to intraday fluctuations in natural gas prices.

The companies also provided FERC with analysis by Charles Rivers Associates (CRA) demonstrating there has been little congestion between EIM BAAs since the entry of NVE into the market, supporting the argument that member BAAs should not be considered submarkets subject to market power — a key concern for FERC.

The CRA analysis examined EIM price data from December 2015 to November 2016 to determine the frequency of price discrepancies between CAISO and other EIM BAAs — an indicator of transmission constraints that could warrant concerns about local market power.

CRA's conclusion: In the 15-minute market, transmission paths appeared to be congested enough to create price separation only 0.7 to 2.4% of the time depending on the BAA; the five-minute market experienced congestion during 0.3 to 6.2% of all intervals, with the higher percentage representing periods when prices deviated by just 1 cent/MWh, what FERC called a "conservative" threshold to test for price separation.

In its Oct. 30 ruling, FERC said it had corroborated those findings.

"We have reviewed this analysis and determined the methodology to be acceptable for an EIM submarket analysis," the commission wrote. "The commission has previously found that binding constraints in 2.2% of all study hours during an 18-month study period is insufficient evidence to support the existence of a submarket. The price separation instances in this case, which are used here as an indication of binding constraints, are generally in the 2% range, which would indicate a lack of a submarket."

The commission additionally determined that, having demonstrated the lack of submarkets in the EIM, the two companies have prepared their pivotal supplier and wholesale market share screens consistent with FERC requirements.

"Accordingly, we find it appropriate to lift the default energy bid restriction and allow the Berkshire EIM sellers to bid into the EIM at market-based rates without restriction," the commission said.

FERC's decision should help relieve the two companies' broader market restrictions in the interior West. Last year, the commission also revoked authorization for 21 BHE affiliates, including PacifiCorp and NVE, to sell power at market-based rates in the PACE, PACW, Idaho Power and NorthWestern Energy BAAs. (See *Berkshire Market-Based Sales Restricted in 4 Western BAAs*.)

While that order still stands, the two companies will immediately have a freer hand to effectively bid power into PACE and PACW through the EIM, and will gain similar access to Idaho Power's territory starting next April when that utility joins the market.

Board Decisions Highlight CAISO Market Problems

Continued from page 4

ket and infrastructure development, repeatedly took to the microphone on Thursday to rebut criticisms of both the RMR and CPM ROR. He acknowledged that the state's RA program and ISO markets need fixes, but there is not enough time to develop them in an adequate time frame.

Keith Casey | © *RTO Insider*

The ISO would normally let the RA procurement process run its course in October before signing an RMR agreement, but Calpine told it that the normal time frame would not be workable. Calpine also indicated it was not interested in the CPM ROR program, leaving the RMR as the best option, Casey said. "We don't want to be one wire away from blacking out Silicon Valley," he added.

"The issue for me is one of timing," Casey said. Changing the RA construct is going to be a long and difficult process, and with increasing retirements, "we have got to have some tools to ensure that resources that are critical on the system can be retained."

The board on Thursday also approved modifications to an incentive that is meant to ensure that RA resources can meet their must-offer obligations and provide replacement capacity if the resource has a forced outage. It changes the Resource Adequacy Availability Incentive Mechanism (RAAIM) calculation to separately calculate generic RA used for system load and flexible capacity, among other changes, according to an Oct. 25 letter from Casey to the board.

Lastly, the board voted to increase its retainer compensation to $40,000/year, which CAISO said is well below the retainers paid to the governing boards of the nation's other RTOs/ISOs.

CAISO NEWS

FERC Approves CAISO Black Start Changes

By Jason Fordney

FERC last week approved CAISO Tariff changes to establish a process for selecting and procuring black start resources needed to restore segments of California's transmission system in the event of regional outages.

Black start refers to the ability of a generating unit to begin operating without assistance from the electric grid. Such units are needed to restart other generation and restore the grid after widespread outages; they have certain requirements under the ISO's Tariff.

CAISO staff last year determined that additional black start capability was needed in the transmission-constrained San Francisco Bay Area, prompting staff to develop new procurement standards to be applied across the ISO. (See *CAISO Kicks off Effort to Procure Black Start Resources*.) The Board of Governors approved the proposed rules in May after an expedited initiative process. (See *CAISO Board OKs Black Start, TAC Area, EIM Charter Measures*.)

The changes reorganize and consolidate certain black start provisions, create rules for technical requirements and operating tests, and remove outdated provisions. They also designate the cost of incremental black start as a reliability cost and allocate it to the transmission owner in the area where the units are located (ER17-2237).

The new black start provisions entail significant involvement of the affected TO — in this case Pacific Gas and Electric — in drawing up technical specifications and vetting proposals from resources bidding into the solicitation. The ISO would have authority to accept or reject a TO's recommended resources. PG&E supported the changes and cost allocation method.

Under the new rules, CAISO will use a cost-of-service approach to compensate selected resources, rather than provide a capacity-type payment sufficient to support the operation of an otherwise unprofitable generator.

FERC said the revisions improve the reliability and clarity of the Tariff.

"Because individual black start capacity resources do not benefit all parts of the system equally, it is just and reasonable to recover these costs from a participating transmission owner where the resource is located and serves the reliability need," FERC said. No parties objected to the cost allocation, and the benefits were roughly commensurate with the costs, the commission said.

To comply with CAISO rules, black start generators must make a minimum number of starts, operate in standalone and parallel modes, be able to pick up load during start-up load, produce and absorb reactive power, and have communication and control equipment.

ERCOT NEWS

ERCOT: Sufficient Capacity for Winter, Spring

By Tom Kleckner

Despite the retirement of more than 3.5 GW of generation, ERCOT said Wednesday it has enough installed capacity available to meet forecasted peak demand through May 2018.

The ISO expects to have almost 81 GW of total capacity available this winter, more than enough to meet a projected peak of more than 61 GW. That would break the winter peak demand record of 59.75 GW, set last January.

ERCOT removed 3,551 MW of recently announced generation retirements from the final seasonal assessment of resource adequacy (SARA) report for the winter season (December-February). That includes 1,200 MW of capacity still being studied to determine whether it is needed to maintain system reliability.

Luminant accounted for most of the retired resources. The company said last month it will shut down three coal plants totaling 4.2 GW by the end of February. (See *Vistra Energy to Close 2 More Coal Plants*.)

"ERCOT still expects to have sufficient systemwide operating reserves for the winter season," Pete Warnken, the ISO's manager of resource adequacy, said Wednesday. "Our studies show this would be the case even with a much higher-than-expected peak demand."

The winter SARA includes nearly 1.4 GW of mostly renewable capacity. The wind and solar projects are expected to contribute 209 MW to the winter peak.

ERCOT Senior Meteorologist Chris Coleman said he expects a mild winter overall, with some very cold periods in mid-winter.

ERCOT operations center | © *RTO Insider*

The ISO's preliminary assessment for the spring months (March-May) was equally optimistic. Staff projects a season peak of more than 59 GW, and expects to have 80.7 GW of capacity available.

The final spring SARA report will be released in early March.

ERCOT's most recent Capacity, Demand and Reserves report indicated the ISO had an 18.9% reserve margin for next summer, with margins remaining above 18% the following three years. A revised CDR report incorporating the latest retirements will be released in December.

ISO-NE News

ISO-NE Bars Invenergy Plant from FCA 12

By Rich Heidorn Jr.

ISO-NE has barred Invenergy's planned Clear River Energy Center Unit 2 from offering into February's capacity auction because of permitting delays resulting from local opposition to the natural gas-fired plant in Burrillville, R.I.

Invenergy publicized ISO-NE's decision for Forward Capacity Auction 12 for 2021/22 in a filing Wednesday to the Rhode Island Energy Facility Siting Board.

The board was scheduled to hold its final evidentiary hearings on the $1 billion project this week but postponed them until December after calling for additional public comment hearings on the plant's water plan. The plant will have two 485-MW natural gas units with fuel oil backup.

Clear River Energy Center rendering | *Invenergy*

In September, the company announced it had reached agreements with the Narragansett Indian Tribe and water trucking company Benn Water & Heavy Transport to serve as supplemental water suppliers for the plant if it needs more than the primary supplier, the Town of Johnston, R.I., can provide. State regulators had required the company to identify the backup suppliers following a lawsuit by the Town of Burrillville and the Conservation Law Foundation challenging the Johnston supply contract.

The company said the plant will need about 15,000 gallons of water daily, which it says is "90% less than similar plants in the region."

Invenergy said ISO-NE cited the permitting problems and delays in ordering equipment, although the company said the current schedule would still have allowed it to begin operations by 2021.

"Although Invenergy considered appealing this decision to [FERC], Invenergy could not dispute that there have been permitting delays, and as such, the likelihood that the FERC would overturn ISO-NE's FCA qualification decision was determined to be remote," the company said.

Jerry Elmer, senior attorney with the Conservation Law Foundation, told the *Providence Journal* that "this shows that even the ISO agrees that [the plant] is not needed."

But in its filing with the siting board, Invenergy included an updated report from PA Consulting Group asserting that the need for the plant is unchanged. The company also said the RTO has told it that Unit 2 is eligible to participate in FCA 13 in 2019.

The report, which assumed a one-year delay in Unit 2's online date to June 1, 2022, said the delay had no impact on the four findings by the Rhode Island Public Utilities Commission indicating need: Unit 1's clearing of FCA 10; a significant amount of capacity at-risk for retirement; the state's location in an import-constrained zone; and the need for capacity above the RTO's net installed capacity requirement.

Unit 1 is scheduled for commercial operation no earlier than June 2020.

ISO-NE Plans for Hybrid Grid, Flat Loads, More Gas

By Michael Kuser

New England will see its grid integrate more renewable resources and increase its reliance on natural gas-fired generation over the coming decade, according to ISO-NE's 2017 Regional System Plan.

The plan, which forecasts power system needs through 2026, highlights increasing wind and solar penetration, flat load growth and fuel security concerns because of natural gas pipeline constraints. The forecasts are in line with those aired at a public hearing on the plan in September. (See *ISO-NE Forecast Sees Flat Loads, More Solar, No Congestion*.)

Declining Load, Increasing Retirements

With growing penetration of solar and energy-efficiency resources, the forecast shows the 10-year net energy for load decreasing from 126,786 GWh in 2017 to 119,680 GWh in 2026, a decline of 0.6% per year.

The 50/50 net summer peak forecast of 26,482 MW for 2017 declines to 26,310 MW for 2026. The 90/10 net summer peak forecast, which captures extreme heat waves, is 28,865 MW for 2017 and grows by 0.1% per year to 29,021 MW in 2026.

Retirements will likely be the key driver for new resources. From 2010 to summer 2020, power plant retirements will total approximately 4,800 MW, said the report, which notes that economic and environmental pressures are putting older oil, coal and nuclear generators at risk. Retiring resources are likely to be replaced by gas, wind and solar resources, resulting in a "hybrid" of renewable and conventional generation, the RTO said.

As of April 2017, nearly 13,000 MW of resources had applied to connect to the high-voltage grid, though the interconnection queue historically has had an attrition rate of 68% of the megawatts proposed. The most reliable and economic siting for new resources remains near load centers in southern New England.

Adequate Resources

The 11th Forward Capacity Auction, held in February 2017, procured sufficient resources to meet resource adequacy criteria through 2021, with about 264 MW of new generation, including 6 MW of wind, 5 MW of solar and 640 MW of new demand-side resources, including 515 MW of energy efficiency.

The regional net installed capacity requirement (ICR) is based on gross load and load reductions from behind-the-meter PV. The representative net ICR is expected to grow

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ISO-NE NEWS

FERC Approves ISO-NE Queue Clustering

By Michael Kuser

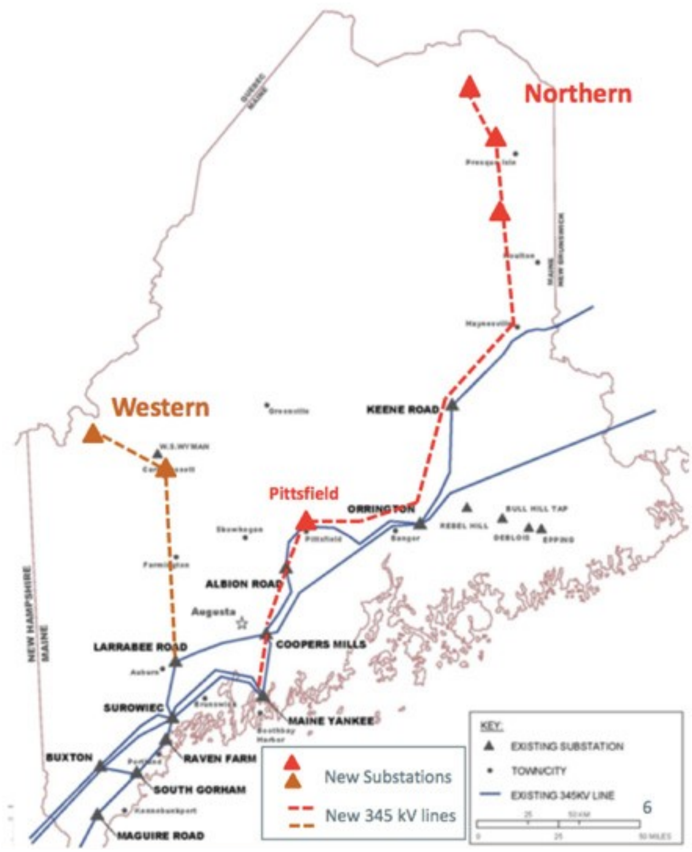
FERC last week approved ISO-NE's proposal to cluster interconnection requests to relieve a backlog in the queue for northern and western Maine.

The revisions, effective Nov. 1, will allow the RTO to consider interconnection requests and allocated network upgrade costs in groups rather than individually.

The commission's Oct. 31 order said that the changes "increase efficiencies, better inform the decisions of project developers and allow project developers to share the costs of the upgrades necessary to accommodate their interconnection" (ER17-2421). (See *ISO-NE Files Cluster Study Rules; Window to Open in Nov.*)

The RTO will use its new clustering procedure in addition to its "first-ready, first-served" serial interconnection request system. "When specific conditions are present in the ISO's interconnection queue, the proposed methodology would allow two or more interconnection requests to be analyzed in the same system impact study and for developers to share costs for certain interconnection-related transmission upgrades," ISO-NE said.

Together with the New England Power Pool's Participants Committee and the Participating Transmission Owners Administrative Committee, the grid operator proposed implementing the clustering methodology first to address the queue backlog in Maine, where more than 5,800 MW of proposed resources, mostly wind, want to connect to the grid.



Maine transmission upgrade concepts | *ISO-NE*

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ISO-NE Plans for Hybrid Grid, Flat Loads, More Gas

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from 34,300 MW in 2022 to 35,700 MW in 2026, the report said.

Fuel Security Concerns

The report cites fuel security risks from the failure of the natural gas pipeline infrastructure to keep up with the growth in gas-fired generation, a particular concern during winter.

ISO-NE is conducting an analysis to quantify the region's risk, the results of which will be discussed with stakeholders in 2018. The RTO delayed issuing the report in October following the Department of Energy's proposal to subsidize uneconomic coal and nuclear generators. (See *RTOs Reject NOPR; Say Fuel Risks Exaggerated*.)

Solar PV resources totaled 1,918 MW (nameplate capacity) at the end of 2016. The RTO projects that will more than double to 4,733 MW by 2026, producing about 6.2 GWh of energy that year. PV resources are estimated to reduce summer peak loads by 575 MW this year and by 1,035 MW in 2026.

New England has 1,300 MW of installed wind with about 5,400 MW more proposed as of April 2017. Massachusetts in July launched a solicitation for 400 MW in offshore wind, with proposals due in December.

The RTO sees the role of energy storage growing over the next decade as the technology's costs decline. The region's first grid-scale battery system, a 16-MW facility at Yarmouth Station in Maine, was placed online in 2016.

From 2002 to June 2017, the region spent $8.4 billion on 730 transmission upgrades to improve system reliability and reduce congestion. As of June 2017, an additional $4 billion in transmission investment for reliability was planned. The RTO expects the need for major transmission projects for reliability to decline through 2026 but said the integration of large-scale renewable energy resources could change that forecast.

ISO-NE NEWS

FERC Approves ISO-NE Queue Clustering

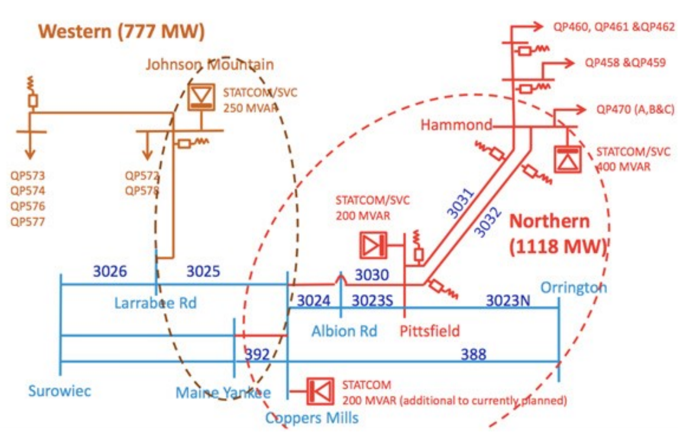
Continued from page 9

Long-Term Benefits

The commission rejected protests by RENEW Northeast, American Wind Energy Association, EDP Renewables and King Pine Wind, who argued it would be unjust and unreasonable to allow the clustering revisions to take effect before Massachusetts issues the results of its 2016 request for proposals. Owners of generation projects in northern and western Maine were among the respondents.

"Given the overall expected long-term benefits of the [revisions], we find that, on balance, it would be inappropriate to wholly reject the revisions to accommodate a subset of interconnection customers in the near term," FERC said.

RENEW asserted that solicitations like Massachusetts' determine which renewable generation projects are viable for interconnection construction and, thus, which projects execute power purchase agreements that include recovery of network upgrade costs. EDP said that ISO-NE could avoid such timing issues by aligning the implementation of the clustering with the timing of the Massachusetts RFP process.



Northern and western Maine cluster upgrades | *ISO-NE*

NEPOOL responded that RENEW provided an alternative proposal in the stakeholder process to synchronize the interconnection cluster study process with the state's energy procurement process, but only 40% of Participants Committee stakeholders favored the proposal.

The commission denied protesters' request to delay implementation of the clustering revisions until 30 days after the results of the Massachusetts RFP are released. FERC also rejected protests that the misalignment between the cluster study process and state procurement processes would cause the first cluster to collapse because interconnection customers not selected for the RFP will withdraw from it. FERC noted that the RTO's new rules "allow for full refund of the cluster participation deposit in such instances."

The commission also was not persuaded by arguments that moving an interconnection customer that does not agree to join the cluster to the bottom of the queue is unjust and unreasonable.

"The clustering revisions appropriately aim to ensure that only those interconnection customers that are ready to move forward in the interconnection process participate in phase two of the cluster studies, [which] is consistent with the 'first-ready, first-served' approach that the commission discussed as a possible queue reform measure in RTO/ISOs as early as 2008," the commission said.

ISO-NE NEWS

FERC Denies Rehearing on ISO-NE Retirement Rule Changes

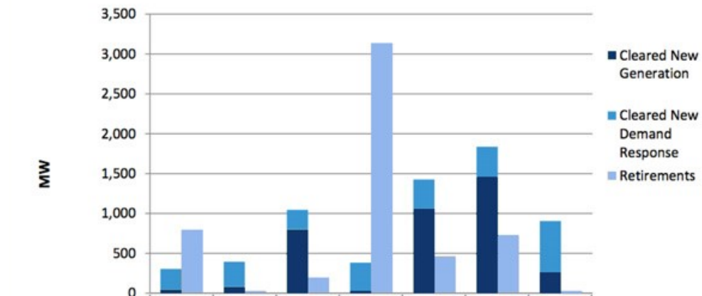
By Michael Kuser

FERC last week denied requests for rehearing of its April 2016 order that approved capacity market changes to prevent ISO-NE generation owners from retiring resources that are still economic (ER16-551-003).

The new rules changed how retiring generators declare their intention with de-list bids — the minimum capacity price that will keep the plant operating — and gave the RTO the power to keep a unit operating if needed for reliability.

ISO-NE said the changes were needed to prevent suppliers from retiring a generator to increase prices for the remainder of the supplier's portfolio. It followed an uproar over the closing of the 1,517-MW Brayton Point plant in Massachusetts. (See *FERC Approves Changes to ISO-NE Retirement Rules*.)

In a July 2016 order, FERC also approved a 10% mitigation threshold allowing ISO-NE to substitute the Internal Market Monitor's cost estimate in place of the supplier's de-list bid if the Monitor found the supplier had overstated the operating costs of the plant by 10% or more.



	FCA #5	FCA #6	FCA #7	FCA #8	FCA #9	FCA #10	FCA #11
New Generation	42	79	800	27	1,060	1,459	264
New Demand Response	263	314	245	355	367	379	640
Retirements	794	25	197	3,135	464	728	25

New capacity and retirement requests | *ISO-NE*

Section 205 Rights

The New England Power Generators Association, Exelon and NextEra Energy Resources asked FERC to reconsider the initial order, saying the rule changes forced them to cede to ISO-NE their Section 205 rights to file rates with the commission.

FERC concluded that although the Tariff changes add steps to the bid review process, they do not fundamentally alter the process in a manner that infringes on the suppliers' rights to file rates. "The Internal Market Monitor's mitigation is an input into a market-based capacity auction governed by ISO-NE's Tariff that generates the Forward Capacity Auction's clearing price," the commission said in its Oct. 30 order.

The commission said "this market construct is distinguishable from a supplier's right to file cost-of-service rates with the commission pursuant to Section 205 of the [Federal Power Act]. We reject petitioners' implicit contention that ISO-NE does not provide a jurisdictional service and that the Forward Capacity Auction is the suppliers', instead of ISO-NE's, rate."

The commission also disagreed with the generators' assertion that FERC provided no evidence that ISO-NE's proposal represented a balance between possible over-mitigation and the need to curb market power.

"On balance, we are persuaded that the need to address possible price distortion due to a retiring supplier potentially exercising market power to impact the market clearing price outweighs the risk of lower capacity prices resulting from possible over-mitigation," the commission said.

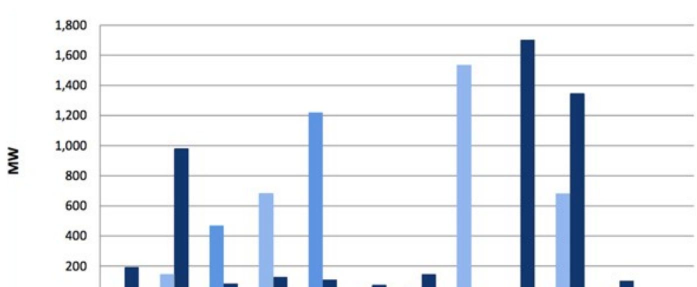
Two-Run Clearing

FERC also rejected the generators' complaint that the two-run clearing mechanism in the new rules — under which capacity needed to replace a retiring resource could receive a higher price — was discriminatory.

"To the extent that the second run yields a higher price than the first run, this would result from the Internal Market Monitor's determination that a resource has sought to retire uneconomically," the commission said. "Therefore, it is necessary to limit suppliers that cleared in the first run to that clearing price to ensure the auction's competitiveness and protect consumers from the exercise of market power. We find this mechanism is necessary to ensure that non-retiring suppliers themselves are not unduly discriminated against due to a retiring supplier's exercise of market power."

The commission dismissed as moot the generators' request that the mitigation threshold — which FERC's April 2016 order required the RTO to add — "is in addition to, and not a substitute for, flexibility with respect to forecasts and other inputs of exit bids."

The commission said its July order approving the threshold had already made that point clear.



	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total
Retirements	5	145	469	683	1,219	17	38	1,535	6	681	16	4,813
Additions	193	981	84	127	110	74	147	0	1,701	1,348	104	4,868

Actual and projected summer generation retirements and additions | *ISO-NE*

MISO NEWS

MISO: Tx Link from Ontario to Mich. UP not Cost Effective

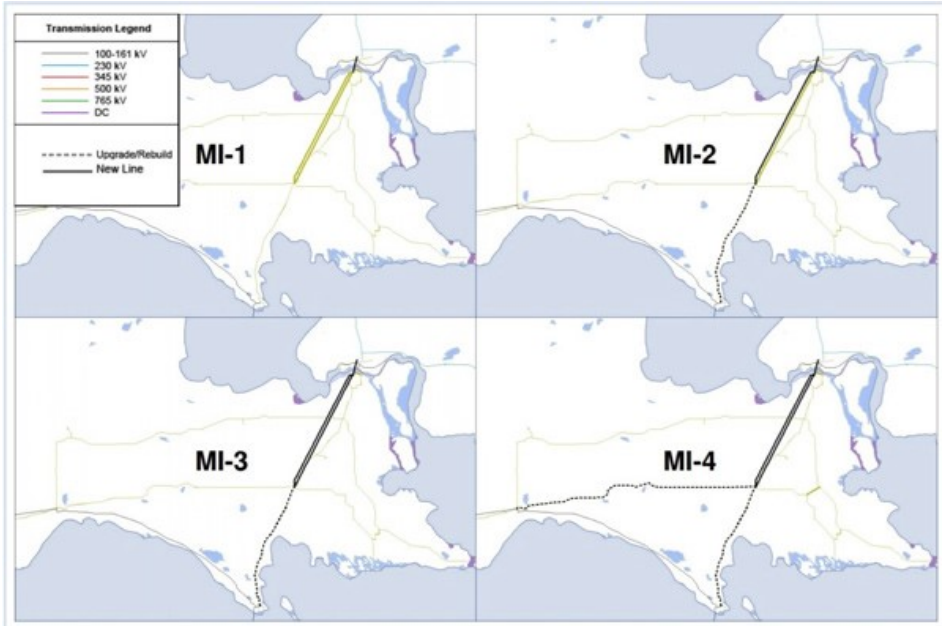
By Amanda Durish Cook

MISO has concluded there's little economic benefit to new transmission connecting Michigan's Upper Peninsula to Ontario.

Reporting on the results of a study requested by the state, MISO officials told a Nov. 1 Economic Planning Users Group call that none of several potential new lines through the twin Sault Ste. Marie cities on the U.S.-Canada border produces benefits commensurate with their costs over a 20-year span.

"Due to the relatively low transfer capability and relatively high construction cost, none of those transmission ideas provided enough benefit to cover its cost," said MISO Manager of Economic Studies Zheng Zhou.

Currently there's no transmission connection between Ontario and the UP, although the Lower Peninsula has connections to the province's hydropower system. Michigan Gov. Rick Snyder requested the study last August in search of solutions to alleviate persistently high power costs in the UP.



Lower-voltage options examined under MISO's UP-to-Ontario study | *MISO*

(See *Michigan Asks MISO to Study Tx Links to Ontario*.)

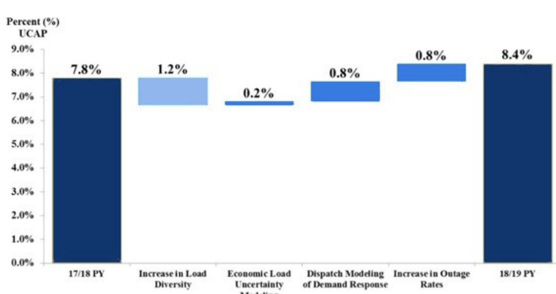
Continued on page 13

MISO 2018/19 Planning Reserve Margin Climbs to 17%

By Amanda Durish Cook

MISO predicts the 2018/19 planning year will require a reserve margin just more than 17%, a figure that's been steadily increasing over the years.

Based on its annual loss-of-load-expectation (LOLE) analysis, MISO expects the planning period to require a 17.1% reserve margin for installed capacity (ICAP) and 8.4% margin for unforced capacity (UCAP), the latter of which represents ICAP minus forced outage rates. MISO will use the margins along with the latest load forecasts to create its enforceable planning reserve margin requirement before April's capacity auction.



Waterfall chart of 2017 vs. 2018 planning reserve margin unforced capacity, including changes from a software change for the 2018/19 planning year. | *MISO*

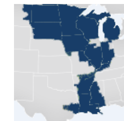
Systemwide, MISO predicts it has about 150 GW of ICAP and almost 139 GW of UCAP to meet a nearly 126 GW expected peak demand for the June 2018-May 2019 period. The RTO's planning reserve margin assumes the inclusion of 4,764 MW of firm UCAP and 2,331 MW non-firm UCAP from external resources.

MISO's needed reserve margin has been on the rise since 2013. Last year, MISO predicted 15.8% for ICAP and 7.8% UCAP reserve margin for the 2017/18 planning year, up from 2016/17's 15.2% and 7.6% values. (See *MISO 2017/18 Planning Reserve Margin at Nearly 16%*.) All local requirements increased from the 2017/18 planning year, the RTO noted.

Speaking during a Nov. 2 Reliability Subcommittee conference call, MISO senior engineer William Buchanan said the increase is primarily driven by an upswing in generation outages and a change in the dispatch model for demand resources, but it was partially offset by reduction in anticipated load growth. The RTO this year added a new modeling step to capture economic load uncertainty that increases the risk associated with high peak loads, also boosting the reserve margins.

Despite the yearly increases, MISO predicts reserve margins will begin to plateau. According to the LOLE analysis, they will largely hold steady because of similar forecasts over the next decade even as peak demand exceeds 129 GW by the 2023/24 planning year. The LOLE analysis found that through 2027, MISO's ICAP reserve margin will fluctuate between 17.1 and 17.2% while the UCAP reserve margin will oscillate between 8.3 and 8.4%.

MISO NEWS



MISO in 'Good Shape' for Winter Operations

By Amanda Durish Cook

CARMEL, Ind. — MISO expects to easily manage this winter's anticipated 103.4 GW of peak demand with an estimated 142 GW of available capacity, stakeholders recently learned during a trio of meetings focusing on winter preparedness.

"We certainly can't be complacent. … In winter, just like in every season, we have to be ready for anything thrown at us, but we're prepared," MISO Executive Vice President of Operations Richard Doying said during a Nov. 6 winter readiness workshop.

Using National Oceanic and Atmospheric Administration projections, MISO predicts this winter will be warmer than normal in its Central and South regions, while temperatures in the North region will be normal to below normal.

Darius Monson of MISO's resource adequacy coordination group said the RTO's winter reserve margin is expected to vary between 28.3 and 37.3% without factoring in outages.

"That's a fairly good position to be in," Doying said.

However, the reserve margin could range from 6.7 to 19.3% after taking possible outages into account, Monson said, compared with this year's footprint-wide 15.8% planning reserve margin requirement. The RTO used historical outage data to predict winter outage levels anywhere from the more probable 23.3 GW, to 28.7 GW in a high load, extreme outage scenario. MISO might need to rely on behind-the-meter generation and demand response resources to meet peak demand under that scenario, Monson said.

The RTO does not predict any major constraints or thermal and voltage issues during the winter.

Engineer Katherine Hulet said MISO did not uncover any potential issues through its biannual Coordinated Seasonal Assessment. The study evaluates a variety of stressed conditions across the MISO footprint and identifies potential limitations and issues on the system for the upcoming winter.

Hulet said the RTO studied possible transmission contingencies, potential transfer contingencies, voltage stability and possible phase angle differences, but found no cause for concern.

"It really looks like MISO's in pretty good shape. Not only are there capacity resources, but the transmission is in a position do well," Reliability Subcommittee Chair Tony Jankowski said during a Nov. 2 conference call.

Jankowski asked if MISO is considering performing seasonal studies for shoulder periods. Hulet said seasonal studies will continue to be limited to summer and winter.

Jankowski urged operators to ensure all generators are in good repair. "Eventually that arctic air will make it into our footprint," he warned.

Doying also said MISO is well-positioned for winter reliance on natural gas.

"We have access to just about all pipeline interconnections. Actually, most of the gas storage in the country is located within MISO," Doying said during an Oct. 31 Markets Committee of the Board of Directors conference call. The RTO expects gas storage inventories nationwide to peak at 3.8 Tcf this winter, slightly below the five-year average, and prices to continue hovering around $3/MMBtu into winter.

Independent Market Monitor David Patton said MISO's proximity to gas storage makes it easier to quickly ensure fuel supplies if a pipeline goes down, whereas the New England region doesn't have such supply backups, requiring more Northeast generators to have dual-fuel capability.

"We're ready until the next polar vortex presents a whole new realm of challenges," MISO Chairman Paul Bonavia remarked jokingly.

MISO: Tx Link from Ontario to Mich. UP not Cost Effective

Continued from page 12

MISO worked on the study with Ontario's Independent Electricity System Operator (IESO), which found it could reliably transfer a maximum of 125 MW to the peninsula. Beyond that amount, "significant reliability upgrades would be needed on both systems to increase that transfer capability," Zhou said.

Economic Studies Senior Engineer Tim Kopp said MISO studied 16 potential new lines, including 161-kV, 230-kV, 345-kV and DC options. It also found that the benefits of a new 400-MW combined cycle plant in Kalkaska County or a 100-MW plant at the nearby Pine River substation would not outweigh their costs either.

MISO did identify benefits over 20 years if a sub-345-kV transmission line allowed 400-MW transfers, but the scenarios showed the local 115-kV system couldn't reliably support that amount in its current state and would need expensive upgrades.

Final public results of the study will be posted in mid-December, Zhou said.

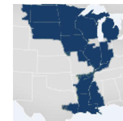
Customized Energy Solutions' Ginger Hodge asked if study results would be included in this year's MISO Transmission Expansion Plan. Zhou said the study was considered ad hoc and not an MTEP study.

Zhou agreed to a request by Michigan Public Service Commission staffer Bonnie Janssen to present the study's findings at the MISO Board of Directors' December meeting.

MISO's study results arrived a week after the PSC approved Upper Michigan Energy Resources Corp.'s $277 million plan to build two reciprocating internal combustion engine stations in the UP in spring (U-18224). Chairman Sally Talberg said the plants will result in a "more reliable and affordable" electric supply for UP customers, including the Tilden Mining operation. Tilden will cover 50% of the capital costs of the plants along with fixed operations and maintenance expenses.

The plants will replace the costly system support resource agreement that keeps the Presque Isle Power Plant running. In October, FERC ruled that ratepayers were overcharged by nearly $23 million for continued Presque Isle operations. (See *$23 Million Owed to Ratepayers in Presque Isle SSR Case*.)

MISO NEWS



MISO, PJM Respond to FERC's Pseudo-Tie Questions

By Amanda Durish Cook

MISO and PJM have responded to a FERC deficiency letter with a defense and clarification of their proposal to impose stricter rules on pseudo-ties.

In early August, the two RTOs filed identical proposals to permit them to terminate or suspend pseudo-ties that don't acquire transmission service or follow modeling rules by providing real-time data. The proposals would also allow a balancing authority the ability to redirect pseudo-tie output to avoid exceeding NERC operating limits.

In late September, FERC sent a deficiency letter asking how a native reliability coordinator would commit, de-commit or redispatch pseudo-tied generation to avoid operating limits. The commission also asked the RTOs to clarify rules for suspending terminating pseudo-ties. (See *2nd Deficiency Notice Issued for MISO-PJM Pseudo-Tie Effort*.)

In filings Oct. 30, the RTOs defended their proposals, with PJM saying redispatch and recommitment of pseudo-tied generation is essential to maintaining operating limits during localized thermal issues, voltage issues or islanding situations (ER17-2218). MISO also said a redispatch option is crucial during planned transmission outages, forced transmission outages or during periods of heavy system transfers (ER17-2220). PJM added that there would be no limit to the number of times a pseudo-tied generator could be recommitted or redispatched. MISO said pseudo-tied resources would still be eligible to provide reactive supply and voltage control service, a point PJM did not address.

PJM said its 42-month notice to terminate a pseudo-tie is rooted in its three-year advance capacity auction and would give "planning engineers sufficient time to take into consideration the impact of the termination" and pointed out that it is "consistent with the notice requirement that a capacity market seller must give to PJM when it intends to deactivate a generator."

MISO and PJM said they would only terminate a pseudo-tie under the circumstances described in their respective Tariffs and both would generally try to impose a suspension period first, during which the resource is decommitted or manually dispatched. PJM said termination conditions are "for the most part … tied to a situation in which a pseudo-tie is causing instability on the bulk power system or raising or causing reliability concerns."

In identical language, MISO and PJM also said they would use a case-specific approach to termination, and would work with generators to address problems and avoid terminations, which they called a "last resort."

The RTOs have said that they would suspend a pseudo-tie when they are "reasonably" found to pose a reliability risk or don't follow the rules of their attaining balancing authority. PJM added that the RTOs "expect suspensions to be very exceptional events."

MISO and PJM proposed that suspensions occur without FERC approval, and that a contested suspension remain in force pending a commission decision.

Meanwhile, MISO is still awaiting final word on its *pro forma* pseudo-tie agreement for PJM. The agreement was conditionally approved by FERC staff in August before the commission regained its quorum (ER17-1061). The proposal also was the subject of a deficiency notice in the spring. (See *FERC Conditionally OKs MISO's Pseudo-tie Pro Forma*.)

NYISO NEWS

FERC Clarifies Ruling on NYISO Capacity Change

By Michael Kuser

FERC on Oct. 25 denied NRG Energy's request for rehearing of a January order concerning NYISO Tariff revisions intended to correct a pricing inefficiency in the ISO's capacity market (ER17-446-003).

NYISO proposed the revisions last November to address situations in which a generator exports power out of an import-constrained locality, creating increased counter-flow on the transmission constraints between that locality and other zones in the New York Control Area (Rest of State).

The ISO proposed to use a locality exchange factor, reflected as a percentage, to calculate the amount of Rest of State generation that can be imported into the locality to replace a portion of the exported capacity. The ISO would multiply this factor — 47.8% for the G-J locality — by the amount of exported capacity to determine the additional capacity that can be procured from outside the locality as a result of the export.

NRG protested the Tariff changes, expressing concerns about NYISO's "apparent" assumption that an exporting resource would indefinitely continue to provide capacity benefits to its locality through counter-flows produced by its exports. The company noted that, under the Tariff, any resource that ceases to participate in the capacity market — by continuously exporting for three years — loses its capacity resource interconnection service (CRIS) rights and therefore can no longer provide a capacity discount to the locality in which it resides.

In its January order, FERC rejected NRG's protest, but the company's request for rehearing alleged that the commission erred in approving NYISO's filing without fully addressing its concerns on how a generator that loses its CRIS rights should be considered for purposes of the locality exchange factor methodology.

NRG also asked FERC to clarify that a resource cannot claim resource adequacy benefits once it loses its injection rights in New York. In the alternative, the company sought clarification that a continuously exporting unit that loses its CRIS rights cannot be counted in the ISO's installed reserve margin modeling.

Clarifying Order Language

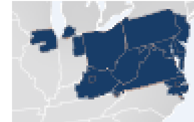
FERC's Oct. 25 order denied NRG's rehearing request, but granted — in part — what NRG was seeking.

"The express relief [NRG] seeks is for the commission to clarify a statement in the Jan. 27 order rather than to change the commission's determination," the commission said.

FERC acknowledged that its Jan. 27 order "may cause confusion" in how it addresses the relationship between the locality exchange factor and CRIS rights. That order meant to convey that, under the existing NYISO Tariff, the locality exchange factor does not apply to the exported capacity of a generator that has failed to maintain its CRIS rights, the commission said. The factor should be applied only to locational export capacity, and by definition would not apply to exports from a resource that has lost its CRIS rights.

But the commission demurred on NRG's alternative request for clarification.

"It is our understanding that a unit that exports and loses its CRIS rights after three years would not be counted in installed reserve margin modeling," the commission said. "However, installed reserve margin modeling is performed by the New York State Reliability Council, not NYISO, and we find questions regarding the establishment of the installed reserve margin to be beyond the scope of this proceeding regarding NYISO's proposed revisions to its [capacity] market design."



PJM Stakeholders Look to Slow Capacity Redesign Process

By Rory D. Sweeney

VALLEY FORGE, Pa. — PJM and its Independent Market Monitor provided updates to their capacity market redesign proposals at last week's meeting of the Capacity Construct/Public Policy Senior Task Force (CCPPSTF), but the discussion was dominated by the question of when the group should recommend any rule changes.

Proponents for load — including American Municipal Power, Old Dominion Electric Cooperative, the PJM Industrial Customer Coalition (ICC) and the PJM Public Power Coalition (PPC), the Organization of PJM States and the Consumer Advocates of the PJM States (CAPS) — argued that the decision should be delayed until after FERC responds to the Department of Energy's Notice of Proposed Rulemaking for coal and nuclear price supports. The commission has said it expects to take some action on the proposal within 60 days after its Oct. 10 publication in the *Federal Register*.

Generators urged staying on the task force's current timeline of having a proposal selected to file with FERC by the end of the year. "By putting things off, we just slow down the process," Calpine's David "Scarp" Scarpignato said.

Monitor Joe Bowring called for stakeholders to take the lead on how FERC responds to the NOPR.

"What you say does affect the process," he said. "I would urge you all not to think of yourselves as passive consumers of what FERC is doing. They're looking for guidance as well."

Load representatives, however, said they didn't have enough information to make an informed choice.

"Boy, I don't have anything among any of these proposals that I can say, 'This is what's going to be best for the market and my customers' future,'" said Carl Johnson, who represents the PPC.

Joe DeLosa, of the Delaware Public Service Commission, said there has been some difficulty in evaluating proposals. "We feel the time is not appropriate to move forward with proposals," he said.

Modeling of Proposals

Morris Schreim | *© RTO Insider*

Morris Schreim, of the Maryland Public Service Commission, asked about a commitment he said PJM made to perform an analysis of the most popular proposals. At a meeting in August, staff agreed to research possible solutions to several stakeholder concerns, including a request from ODEC's Adrien Ford to substitute data from recent Base Residual Auctions into PJM's model of the proposals. (See *PJM Stakeholders Begin Defining Capacity Design Needs*.)

PJM's Adam Keech responded to Schreim that he remembers another meeting where staff "pretty clearly" said they would not be performing modeling.

RTO officials acknowledged the concerns of load but remained focused on the current timeline.

"I believe it's important for this group to keep working forward," PJM's Suzanne Daugherty said.

PJM Revises Reference Price

PJM revised the reference price in its proposal for undefined subsidies. Previously, it was calculated using a formula for a competitive offer: the net cost of new entry multiplied by the expected average balancing ratio for the delivery year. The RTO has revised it to a "capacity repricing value" that is based on resource type and whether it's new or existing. That value is used to resort the generation offers in the second, price-setting stage of PJM's proposal.

The RTO presented its methodology for calculating the default values along with example values for delivery year 2021/22 measured in gross dollars. An existing combined cycle gas turbine's value would be $84 per ICAP MW-day, while a new unit would be $501. Onshore wind would be $65 and $998, respectively.

"What we're trying to do is determine what the market price should be for that year," PJM's Rich Brown explained.

Rich Brown | *© RTO Insider*

Stakeholders asked Brown to provide a comparison of how reference prices change under PJM's previous proposal and the new "capacity repricing values."

Bowring didn't need any comparisons.

"This is entirely inconsistent with the Capacity Performance paradigm," he said.

IMM Revisions

The Monitor revised its proposal to expand one of the exemptions to its extended minimum offer price rule (MOPR) proposal. The renewable portfolio standard exemption would be extended to all competitive, non-discriminatory, state-mandated programs and not just competitive auctions. The IMM is also planning to adjust its public power exemption to allow supply to be "slightly" greater than 105% of demand for a year "to recognize that investment can be lumpy," Bowring said.

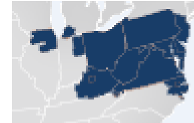
Several load proponents, including Ford, AMP's Steve Lieberman and Susan Bruce, representing the PJM ICC, thanked Bowring for his willingness to adjust his proposal.

"We don't think repricing is the right answer," Ford said, acknowledging that ODEC's proposal, which has been retracted, included repricing. "We're really appreciative, Joe, that you're listening to some of the concerns expressed here in the CCPPSTF and finding ways to modify what we think is a fairly pure market proposal as opposed to an administrative, two-stage approach."

"Certainly, we continue to believe that the time is not appropriate to move forward, especially with the NOPR out there, but we appreciate the efforts that have been made to try to frame the issue," Bruce said. "I am not at all suggesting that the time is never. … We live in a time of more uncertainty than I've seen. … We're going to see some guidance from FERC soon, and I think that is going to be an important touchstone."

Continued on page 17

PJM NEWS



PJM Members Still Split on Capacity Sell-Back, Excess Commitments

By Rory D. Sweeney

VALLEY FORGE, Pa. — While stakeholders remain divided on changes to PJM's Incremental Auctions, hope remains for reaching a compromise that can be implemented in time for next year's Base Residual Auction. (See Consensus Fades on PJM Incremental Auction Solution.)

Stakeholders at last week's meeting of the Incremental Auction Senior Task Force defined where they will and will not budge on their positions. The three main sticking points are the number of IAs per delivery year, at what price PJM should sell excess capacity and what to do about excess commitment credits (ECCs).

Number of Auctions

Stakeholders appear closest to consensus and willing to negotiate regarding the number of auctions. PJM's Brian Chmielewski presented the results of a recent poll that found more than two-thirds of voters strongly supported the status quo of an IA for each of the three years between the BRA and the delivery year.

However, most respondents were willing to consider proposals to reduce the number to two. A majority of voters were neutral about an option to have PJM sell capacity in either IA, with 41% opposed. A proposal to limit PJM to selling capacity in the final IA was strongly supported by 38% and opposed by 44%, with 18% neutral.

James Wilson of Wilson Energy Economics, a consultant to consumer advocates for several PJM states, said there's no reason to reduce the number of IAs, but reducing to two could be acceptable. Carl Johnson, who represents the PJM Public Power Coalition, agreed that his membership was "not willing to fall on our sword" over the issue.

Sell-Back Price

Stakeholders remain divided over the sell-back pricing approach. PJM's Jeff Bastian argued that the price must be at least what the RTO paid for it in the BRA. "If I'm going to excuse someone from a BRA commitment, why should I pay them?" he asked.

Calpine's David "Scarp" Scarpignato agreed it must be at "or close to" the BRA price. It is a position on which "we can't move," he said.

Wilson and Jeff Whitehead of GT Power Group argued PJM should sell for whatever the market will bear. "You may sell some capacity [at the BRA price], but you're basically pricing yourself out of the market," Whitehead said.

PJM's position "doesn't make much sense," Wilson said, because the capacity is not as valuable in the IA if the load forecast has been reduced following the BRA. He has argued that PJM needs more accurate load forecasts prior to the BRA.

Bastian later floated an idea that was developed during a meeting break to allow market participants out of their capacity obligations but not excuse them from the daily capacity-shortfall penalties, which equal 120% of the capacity payments. Wilson and Adrien Ford of Old Dominion Electric Cooperative pointed out that the idea is analogous to selling the capacity at the BRA clearing price. Bastian agreed, adding, "you'd have a cleaner settlement report."

EnerNOC's Katie Guerry was concerned the idea would reduce liquidity in the IAs because those with capacity obligations could walk away and decide they "won't even bother" attempting to replace them in the IAs.

Whitehead said the IAs would have to clear above the BRA price for load to benefit. "I think, mathematically, load is better off under what [Bastian] just described," Whitehead said.

> **"You may sell some capacity [at the BRA price], but you're basically pricing yourself out of the market."**
>
> **Jeff Whitehead, GT Power Group**

Split over Excess Commitments

Stakeholders were also split on what to do with ECCs, which are allocated to load-

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PJM Stakeholders Look to Slow Capacity Redesign Process

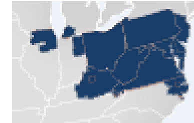
Continued from page 16

Greg Poulos, the executive director of CAPS, said some state advocates are questioning why stakeholders are "all of a sudden" focused on revising the capacity market after nuclear units in one PJM state — Illinois — received price support, particularly when they believe there will not be any new subsidies for generators. He said there is "growing support" among the advocates for the Monitor's revisions. "It's definitely getting more favor from the advocate groups," he said.

The remaining proposals — from NRG Energy, LS Power, Exelon, AMP, Northern Virginia Electric Cooperative and the Natural Resources Defense Council's Sustainable FERC Project — had no new revisions.

Poulos expressed advocates' concerns about "gaming" the repricing structures, and asked representatives from LS and NRG, who have also submitted repricing proposals, whether they have examined how their proposals prevent gaming and how their protections compare to other repricing proposals. The representatives said they have not noticed or been alerted to any concerns.

"We don't see a meaningful distinction between all the repricing proposals," Bowring said. "We think they're all subject to the kinds of issues that were raised by [Poulos]."



AMP Questions $400M in Added PJM Tx Upgrades

By Rory D. Sweeney

PJM is "planning on making these recommendations no matter what comments were provided."

Ryan Dolan, AMP

PJM's announcement on Thursday of plans to recommend more than $400 million in transmission upgrades — just weeks after the RTO's Board of Managers authorized $1 billion in spending — sparked pushback from American Municipal Power, which said the RTO ignored questions about the effectiveness of several of the projects.

Staff plan to recommend adding the projects to PJM's Regional Transmission Expansion Plan at the board's Dec. 4 meeting.

AMP's Ryan Dolan questioned PJM's analysis of several of the reliability projects, arguing that the proposed solutions fail to address all issues at the nodes in question and will necessitate additional construction in the future. He was displeased that PJM plans to recommend the projects even though, he said, concerns were raised about their effectiveness from a "holistic planning" perspective at a sub-regional RTEP discussion the previous day.

"For some of these projects, basically … [PJM is] planning on making these recommendations no matter what comments were provided," Dolan said. "I think it would be useful to give time between when we make recommendations to when the last review of a project is to ensure any of the comments … that were brought up … can actually be accounted for."

PJM's Mark Sims responded that all information underlying the RTO's recommendation has been available throughout the planning process and that recommendations can change as additional information is added to the analysis.

"We've been transparent with all the steps along the way," he said.

The $400 million in additional projects will be recommended as the result of a reliability analysis for the 2021/22 delivery year, Sims said. They include eight projects from the first RTEP proposal window for 2017, along with 13 projects that were previously identified.

The recommendations also include one market efficiency project proposed by American Electric Power to address a thermal constraint on the Tanners Creek-Dearborn 345-kV circuit. PJM's Nick Dumitriu explained that AEP's $600,000 solution would upgrade equipment at the Tanners Creek station, removing price separation in the Duke Energy Ohio/Kentucky (DEOK) locational deliverability area in the 2020/21 Base Residual Auction Capacity Emergency Transfer Limit (CETL) study.

PJM rejected two other proposals for the same constraint that estimated costs at $4.9 million and $12.7 million.

RTO staff confirmed the upgrades will be included in the model for the 2021/22 BRA.

AMP has become increasingly critical of transmission spending in PJM. In September, the company released a report showing that more than half of the $24.3 billion in transmission spending in the RTO since 2012 were supplemental projects by transmission owners and were not needed to comply with RTO or federal reliability requirements. (See *Report Decries Rising PJM Tx Costs; Seeks Project Transparency*.)

PJM Members Still Split on Capacity Sell-Back, Excess Commitments

Continued from page 17

serving entities when reliability requirements decrease below commitments. Currently, LSEs can use ECCs to replace resource commitments. Load has proposed eliminating the ECCs so that the excess committed megawatts, if not otherwise sold in an IA, are retained. The proposal also removes an opportunity for market participants to bypass the intent of any new IA sellback-pricing approach, Susan Bruce, who represents the PJM Industrial Customer Coalition, told *RTO Insider* in an email.

Johnson said public power organizations "feel entitled" to the ECCs and find them "helpful" for covering EFORd (equivalent forced outage rate – demand) deficiencies while adhering to their business models. As nonprofit entities, public power has a "distaste" for "making money" on the commitments by selling them back, Johnson said. Ford said she agreed with Johnson.

Guerry said that LSEs incur costs to secure commitments. "It's not all necessarily profit" when they are sold back, she said.

Bruce said she "can appreciate [public power's] perspective when you have self-supply obligations," but that "load is getting the short end of the stick." She also questioned how auditable ECCs would be if customers attempted to negotiate for their proportionate share of them in a retail transaction. She acknowledged some "wiggle room here" to negotiate a different solution but said the "status quo is not an option from a load perspective."

Chmielewski asked stakeholders to develop new proposals for the task force's next meeting on Nov. 10.

The IASTF is also charged with resolving a second problem statement and issue charge on the potential for profiting off of replacement capacity. Chmielewski said the issue will be a focus of the next meeting as well. (See "Stakeholders Quibble with, but Eventually Endorse, Replacement Capacity Investigation," *PJM Markets and Reliability and Members Committees Briefs*.)

To get the proposals implemented in time for the next BRA in May, they will need to be presented at the January meeting of the Markets and Reliability Committee, he said.

SPP NEWS

Board of Directors/Members Committee Briefs

Z2 Fix Allows Short-Term Service Agreements to Expire

LITTLE ROCK, Ark. — SPP's Board of Directors last week approved a cleanup of Tariff language that may have put much of the RTO's troublesome Z2 process in the rearview mirror.

During the board and Members Committee's quarterly meeting Oct. 31, stakeholders approved an option put forward by Kansas City Power & Light, altering a previously approved revision request (RTWG-RR244) to align with the original intent of the task force producing the revision.

The original measure passed the Markets and Operations Policy Committee earlier in October with minimal discussion and only two abstaining votes. One of those was cast by KCP&L's Denise Buffington, who chaired the task force that worked to simplify Attachment Z2 of SPP's Tariff, in which financial credits and obligations are assigned for sponsored transmission upgrades.

In July, MOPC and the board accepted the Z2 Task Force's recommendations to eliminate credits for non-capacity upgrades, such as substation facilities, and for short-term transmission service of less than a year. (See "Z2, Two Other Task Forces Expire," *SPP Board of Directors/Members Committee Briefs: July 25, 2017*.)

However, the Regional Tariff Working Group's language in RR241 would have cut off those credits for existing service agreements upon the effective date of the Tariff revision, rather than let them expire when the service did.

Buffington said the first time she realized there was an issue with the Tariff language was during the MOPC meeting, and she offered two options to correct the oversight. "Option 1" ensured that short-term firm and non-firm point-to-point transmission service granted prior to the effective date would "continue to be used to pay revenue credits … for the duration of term of that service."

"I don't believe the RTWG implemented the intent of the task force," Buffington said. "We specifically talked about short-term reservations and when credits would end. Our intent was that if reservations were granted, they would continue to receive credits for the life of that service."

Asked how the RTWG's language had slipped by unnoticed, Oklahoma Gas & Electric's Greg McAuley told the board and committee, "It was a matter of not enough of this discussion taking place, or not enough time when this came about."

SPP's Charles Locke said the task force's proposed language was "administratively more difficult."

"Staff does have a preference for the MOPC recommendation, because it can be implemented sooner," Locke said. "It reduces the risk resettlements will happen. Short-term credit flows create uncertainty. Not only are there additional administrative challenges for staff, but also settlements and for member companies."

SPP's Charles Locke updates members on the Z2 process. | © RTO Insider

"I hear there is some risk today," Buffington countered, "but I don't hear concrete reasons you can't implement one of these options."

"There's an argument to be made that this is retroactive ratemaking," said NextEra Energy Resources' Aundrea Williams, referring to the potential premature end to transmission service agreements.

Locke eventually offered that all three options before the board would fulfill the Z2 task force's recommendation.

"All three could also be filed at FERC and accepted, because they're prospective in nature," he said. "In terms of Option 1, it's essentially a staggered implementation. Assuming a Feb. 1 implementation date, [short-term] reservations would run for various periods of times. Eleven months might run into the fall of 2018."

"We've done a lot of work here, and good things, with reaching an agreement on non-capacity upgrades," said MOPC Chair Paul Malone, who also served on the Z2 task force. He reminded stakeholders that non-firm service only accounts for about 2% of the credits.

"Let's do the right thing here and avoid potential trips at FERC," Malone said. "Let's not have this one be where a filing gets thrown back in our face."

In the end, the board accepted the Members Committee's unanimous approval of KCP&L's first option.

"There's been a lot of discussion about the potential for a burdensome administrative effort to do this," Buffington said. "But now, we're hearing that maybe it's not so difficult."

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SPP NEWS

Board of Directors/Members Committee Briefs

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SPP to Seek FERC Input on Behind-the-Meter Load

With members unable to reach agreement on how to report behind-the-meter network load, the board directed staff to reach out to FERC for clarity, in the hopes of settling the matter during SPP's January membership meetings.

The RTWG ended several years of work in early October when it presented new Tariff language to the MOPC. The measure would have established a 1-MW threshold for BTM output at a discrete delivery point and in front of the retail customer's meter, but it drew only 54.6% of votes in favor. (See "Stakeholders Unable to Reach Consensus on Network Load," *SPP Markets and Operations Policy Committee Briefs*.)

Southwestern Public Service appealed the rejection to the board, saying "consistent reporting of network load among all entities … is critical to ensuring that the costs of network service are fairly distributed to SPP network service customers."

SPS said without the consistent reporting, some SPP customers would be subsidizing network service used by other customers.

David Hudson | © RTO Insider

"This issue has been circling the airport for the last four years. We feel like it's time we resolve this issue," said SPS President David Hudson. The company has been following FERC Order 890 in reporting all BTM load, he said.

"What we're finding out is more and more people are not reporting these loads," Hudson said. "We want consistency that everyone is receiving the same billing determinants."

"Order 890 is relevant, but subsequent orders that directly and indirectly addressed this order said that some exclusions are relevant and can be made," McAuley, making it clear he is not a lawyer, said in responding to the concerns of SPS and others. OG&E makes that exclusion and does not report BTM load.

"The overarching idea is that if a generator does not impact the transmission system, it should not be included for calculating that load," McAuley said.

"People are admitting they're inconsistent," said Bill Grant, SPS regional vice president of regulatory and strategic planning. "It's been four years. When are we going to make a decision?"

Board Chair Jim Eckelberger brought the discussion to a close when he asked staff to gather definitions from FERC to gain a better understanding of the problem. General Counsel Paul Suskie said staff are already working to lay out the commission's explanations of what is and what isn't net metering.

"Let's make sure that at the January MOPC we have an answer we can work with," Eckelberger said. "Let's ensure everyone understands what the rule is."

Director Larry Altenbaumer added that the board should make "an absolute commitment … to take action in January."

That seemed to satisfy the members. Said Westar Energy's Kelly Harrison: "We may not like it, but at least they make a decision."

Brown Looks Back to Move Forward

Left to right: NPPD's Tom Kent; SPP CEO Nick Brown; and SPP Board Chair Jim Eckelberger. | © RTO Insider

SPP CEO Nick Brown told the board and committee that in drafting a speech for a member company's annual meeting, he looked back at 2007 and future predictions for the industry.

"Quite clearly" no one would have predicted what has come to pass since, he said.

"We passed the 10-year view for wind energy in a year and a half," Brown said. "Transmission expansion we got horribly wrong. Gas prices were horribly wrong. Even in the most perverse, extreme scenario, no one would have contemplated the natural gas prices we're seeing today."

Brown recalled gas prices were at $7/MMBtu, peaking above $13, and then settling into the $2 to $3 range.

"None of us saw that coming," he said.

Nor did the RTO anticipate investing $10 billion in transmission within the footprint, consolidating its various balancing authorities into one, or the advent of financial transmission rights.

Still, Brown said, "I would argue we've been pretty strategic in what we've accomplished."

Brown took advantage of the opportunity to let the board and stakeholders know he had ordered each director and committee representative copies of Craig Roach's recently released book, "Simply Electrifying: The Technology that Transformed the World, from Benjamin Franklin to Elon Musk."

Roach is a nationally recognized expert on electricity, and the founder and president of electricity consulting firm Boston Pacific. Last year it joined Bates White's energy practice, for which Roach collaborated on SPP's annual forward-looking report.

Brown also noted that SPP will on Dec. 19 mark 20 years as a reliability coordinator within its footprint. The RTO plans to celebrate the milestone on or around that date.

Finance Committee Proposing 1-Cent Increase in Admin Fee

Altenbaumer, chair of the Finance Committee, said he will be proposing a 1-cent increase in the system administrative fee at December's board meeting, when SPP's budget is typically voted on.

The director said the committee has suggested an increase to 42.9 cents/kWh, up from the current 41.9 cents, because of a systemwide loss of load and SPP's commitment to absorb former staffers of the soon-to-be-dissolved SPP Regional Entity (RE), he said.

Altenbaumer also said the committee is

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SPP NEWS

Regional State Committee Briefs

Committee Begins Engagement in Mountain West Integration

LITTLE ROCK, Ark. — SPP's Regional State Committee will later this month begin taking a lead role in Mountain West Transmission Group's integration into the RTO, with the first of what will likely be many calls and meetings on the subject.

| © RTO Insider

SPP has identified the RSC as one of the key stakeholder groups in Mountain West's pursuit of membership. The committee has primary responsibility for cost allocation, financial transmission rights, resource adequacy and remote resources planning within the RTO's current 14-state footprint.

Staff played up the importance of the RTO's role during a recent appearance before the Colorado Public Utilities Commission. (See Col. Regulators Talk Governance with SPP, Mountain West.)

"This is a wonderful strategic opportunity for SPP," CEO Nick Brown told RSC members Oct. 30. "Expanding our market and lowering our administrative rates both carry significant benefits to SPP members and significant benefits to the Mountain West Transmission Group.

"Now's the time to engage … please stay that way," Brown implored. "The next couple of months will be critical."

SPP will use a commissioners' forum to work through several policy issues as the integration process moves into more open forums. Some work will still take place behind closed

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taking advantage of Mountain West Transmission Group's integration to possibly restructure the manner in which SPP is paid for its expenses. Any changes would be coordinated with the integration process, he said.

Directors, Members Committee, RE Trustee Elections

The board re-elected three directors and four Members Committee representatives to three-year terms, beginning Jan. 1, during the annual meeting of members.

Elected to new board terms were Altenbaumer, Joshua W. Martin III and Bruce Scherr. Martin has served on the board since 2003, Altenbaumer since 2005 and Scherr since 2016.

Arkansas Electric Cooperative's Duane Highley, SPS' Hudson, Oklahoma Municipal Power Authority's David Osburn and NextEra's Williams were all re-elected to the committee. Elected for the first time to the committee were McAuley and Omaha Public Power District's (OPPD) Joe Lang.

Lang replaces OPPD's Jon Hansen, who is retiring after 34 years in the industry.

Gerry Burrows was re-elected to the RE's board of trustees. The RE will be dissolved by December 2018.

Revision Request to Address Potential Gaming Passes

The board approved a measure targeting potential gaming related to the regulation deployment adjustment settlements charge type. MWG-RR243 eliminates market participants' ability to use energy offers to game incentive payments by using the lesser of the as-dispatched energy offer curve and mitigated energy offer curve for the regulation-up adjustment, and the greater of the as-dispatched offer curve and mitigated energy offer curve for the regulation-down adjustment.

Dogwood Energy's Rob Janssen, who abstained during the MOPC's vote two weeks earlier, said he intended to vote for the change, as it was a "good enough answer" to a "problem in need of a solution."

Addressing member concerns about the measure's $119,220 implementation cost and suggestions that the Market Monitoring Unit simply monitor the potential gaming, MMU Executive Director Keith Collins noted manipulation of regulation-down offers has cost the market about $1 million in recent years.

"If only it were that simple," Collins said. "What can happen at times is there's usually a dialogue, there's an observation… Is this potentially an issue, or is it not? That cost can outweigh the concerns we're having here of the implementation costs or an inefficient solution."

Westar was the only member to oppose RR243, while two others abstained.

The board's consent agenda included three additional RRs:

- MWG-RR231: Removes locally committed resources from economic mitigation tests and creates a 10% cap for resources committed for local reliability. Addresses the practice among some resources of "self-mitigating" to pass the conduct threshold test and avoid possible mitigation by submitting competitive energy offers 10% above the mitigated offer.
- ORWG-RR240: Removes Section 7 of the SPP Operating Criteria and creates a standalone SPP Reserve Sharing Group Operating Process for BAL-002-2's annual maintenance process, which becomes effective Jan. 1.
- RTWG-RR238: Addresses the financial exposure to SPP and its market participants stemming from a defaulting transmission customer avoiding responsibility for the full amount owed for the full term of a service agreement. The change also restricts the ability of SPP, transmission owners and transmission customers from recovering attorney's fees related to performance of a service agreement, and clarifies that each party to an arbitration under the Tariff is responsible for its own fees.

— Tom Kleckner

SPP NEWS

Regional State Committee Briefs

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doors, with the Strategic Planning Committee holding executive sessions Nov. 21 and Dec. 4. (See SPP, Mountain West Integration Work Goes Public.)

Mountain West has asked SPP to expand the RSC to include a group consisting of just the Western states, resulting in a single committee with two regional divisions. It has also proposed a Westside Transmission Owners Committee that would have decision-making authority over cost allocation, zonal changes and transmission revenue requirements in what would become the west side of the RTO.

Wind Likely to be SPP's No. 2 Fuel in 2017

SPP Vice President of Operations Bruce Rew told the RSC that the Integrated Marketplace continues to work "very well," despite the growing influence of wind energy in the RTO's footprint.

Rew said wind will likely become the No. 2 fuel source for 2017, behind only coal. Coal has accounted for 46.9% of the RTO's fuel mix year-to-date, with wind averaging 22.0% and gas 19.4%, respectively.

Almost 16.7 GW of wind energy is installed and operational in SPP, with another 690 MW registered but not yet operational.

Rew said the RTO came close to setting new records for both wind production and summer peak demand during the third quarter. Wind production peaked at 13.32 GW on Sept. 21, just short of the record of 13.34 GW set in April. On Sept. 22, SPP averaged just more than 12 GW of wind energy for the entire day, Rew said.

Wind penetration during the quarter peaked at 49.41% of system load on Sept. 8. SPP's record is still 54.47% wind penetration, set in April.

Summer demand peaked at 50.57 GW in July, not far off the all-time peak of 50.62 GW set in 2016.

Rew said 197 market participants are currently active in the markets. Of those, 130 are classified as financial-only and 67 as asset-owning. He said the day-ahead market was delayed from posting once in the last 12 months, and the real-time balancing market has successfully solved 99.87% of all intervals.

Kansas' Albrecht Elected as RSC's 2018 President

The RSC's leadership (left to right): South Dakota's Kristie Fiegen, Missouri's Steve Stoll, Kansas' Shari Feist Albrecht . | © *RTO Insider*

The RSC unanimously elected the Kansas Corporation Commission's Shari Feist Albrecht as its president for 2018, replacing Missouri Public Service Commissioner Steve Stoll. Albrecht currently serves as the committee's vice president.

South Dakota Public Utilities Commissioner Kristie Fiegen will become the committee's vice president next year, with Dennis Grennan of the Nebraska Power Review Board replacing Fiegen as the RSC's secretary and treasurer.

The committee also approved a 2018 budget of $370,500, with the understanding that $50,000 to $150,000 could be allocated for consulting expenses for its Mountain West work.

— Tom Kleckner

FERC NEWS

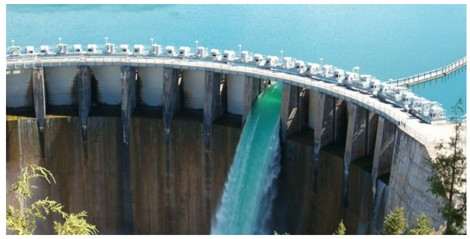
FERC May Consider More Hydro License Changes

By Rich Heidorn Jr.

FERC may consider additional changes to its hydropower licensing rules following a review prompted by President Trump's March 2017 executive order to eliminate burdens on domestic power production.

Executive Order 13783, "Promoting Energy Independence and Economic Growth," required executive branch officials to review their regulations, orders and policies and eliminate those that "unduly burden the development of domestic energy resources."

On Nov. 1, FERC published in the *Federal Register* a 30-page report in response, saying it had found several potential changes involving its hydropower rules that the commission may consider. Commission staff emphasized that, as an independent agency, it was not required to respond to the order but was doing so voluntarily.



Kerr Dam in Montana

The report said "the vast majority of agency actions relating to the commission's hydropower program do not present a material burden."

But it said the commission "could consider" revising its regulations to:

- Make optional the integrated licensing process (ILP), which is currently the default — requiring applicants to justify the use of the traditional licensing process or the alternative licensing process;
- Make optional the requirement to submit a draft license application or preliminary licensing proposal before submitting a final license application as part of the prefiling process;
- Reducing comment and filing deadlines to save three months in the three- to three-and-a-half-year process for obtaining an integrated license;
- Increasing the threshold — currently 5 MW — for eligibility for the "simplified and expeditious licensing procedure for small hydroelectric power projects" under the Public Utility Regulatory Policies Act;
- Removing the requirement that facilities eligible for license exemptions under PURPA Section 405 install or increase the capacity of their facilities;
- "Explicitly" allow applicants for small hydropower exemptions to convert their

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GOP Tax Bill Would Trim PTC, Drop Credit for EVs

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and 500 American factories, including some of the fastest growing jobs in the country."

Under the 2015 legislation, wind projects that started construction in 2015 and 2016 receive the full PTC of 2.4 cents/kWh. Projects that begin construction in 2017 receive 80% of the credit, with those beginning in 2018 reduced to 60% and those in 2019 getting 40%. The credit would be eliminated for projects begun in 2020 and beyond.

Eliminating the inflation adjustment would boost tax receipts by $12.3 billion through 2027, according to a summary released by Republicans on the House Ways and Means Committee.

AWEA also said the law would unfairly change what constitutes the start of project construction. "Investors who put billions of dollars into factory orders and construction contracts cannot go back in time to meet the revised requirements," it said.

Under current rules, a project is deemed to have commenced construction when it has passed a "physical work" test or shown that 5% or more of the total cost of the facility was paid or incurred. The physical work test is met by activities such as the beginning of excavation for turbines' foundations or work on step-up transformers.

Developers are required to make "continuous progress" toward completion once construction has begun and must complete the project within four calendar years after the year in which it began construction. The new bill would eliminate the 5% "safe harbor," disqualifying projects "unless there is a continuous program of construction."

The wind industry is just one of the potential losers in the bill, which also eliminates the $7,500 tax credit for purchasers of electric vehicles. That would be more bad news for Tesla, which on Wednesday reported a $619 million quarterly loss and said it would not meet its goal of producing 5,000 Model 3 cars per week in 2017. Tesla shares dropped 6.8% Thursday.

The bill also would eliminate the permanent 10% investment tax credit for commercial-scale solar and geothermal power.

But there are also some energy winners.

The Treasury Department would forgo $1.2 billion through 2027 by "harmonizing" the expiration dates and phase-out schedules for ITCs on solar, geothermal, fuel cell, microturbines, combined heat and power system and small wind facilities.

In addition, the bill would remove a 2020 deadline for nuclear plants to claim the 1.8 cents/kWh nuclear production tax credit, a change needed to allow Southern's over-budget and behind-schedule Vogtle Units 3 and 4 to claim it.

The credit applies to the first 6,000 MW of new nuclear capacity. Because the Vogtle project totals 2,200 MW, and South Carolina Electric & Gas' V.C. Summer Units 2 and 3 have been canceled, it "will leave a significant amount of remaining capacity that future small modular or advanced reactor projects will be able to access," the Nuclear Energy Institute said.

FERC NEWS

FERC May Consider More Hydro License Changes

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exemption applications to a license application if the exemption is rejected; and

- Allow hydro operators whose license applications are rejected to resubmit their applications once the deficiencies are corrected.

Next Steps up to Commission

FERC spokeswoman Mary O'Driscoll emphasized that the response is a FERC staff report. "The commission itself will determine what steps to take on any and all matters related to this," she said in an email. "We cannot predict, nor can we surmise, what the commission will do in the future."

The response to the executive order also says the commission "currently is considering comments" on its policies on the length of hydropower licenses, an apparent reference to the responses to its 2016 Notice of Proposed Rulemaking (RM17-4).

O'Driscoll explained that the staff response was due Sept. 27, before the commission's Oct. 19 meeting, at which it approved a policy statement setting a 40-year default license term. The commission said the change will reduce administrative costs and encourage dam owners to upgrade capacity and make environmental or recreational investments (PL17-3). (See *FERC Sets 40-Year Term for Hydro Licenses*.)

Prefiling Requirement for LNG Terminals

Commission staff also reviewed but found no rules to recommend changing regarding LNG terminals; natural gas pipeline and storage facility siting; generator interconnection policies; and electric capacity markets in PJM, ISO-NE and NYISO.

For example, staff examined the prefiling process for LNG terminals and related facilities but ultimately decided "there is no need for the commission to consider any revision."

Commission regulations require applicants to use its prefiling process for at least 180 days before filing an application. Staff said that although the Natural Gas Act only requires prefilings for terminals and not "related" facilities, gas pipelines and the terminals they serve need to be evaluated together to avoid segmentation under the National Environmental Policy Act.

"Further, the prefiling process allows stakeholders to become involved in the overall project at an early stage, and applicants can benefit from stakeholders' early identification and resolution of issues that may overlap with the LNG terminal. Without using the prefiling process for related jurisdictional natural gas facilities, delays could occur during the application review, when issues are first identified and need resolution," staff said. "Thus, although this regulation may result in delays or additional costs to the applicant early on in a project's development, its overall result is a more timely application review."

McIntyre and Glick Confirmed to FERC

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and then serve a full term that ends June 2023. Glick, the general counsel for Democrats on the Senate Energy and Natural Resources Committee, will serve a term that ends in June 2022.

The nominations of McIntyre and Glick were approved by the Senate Energy and Natural Resources Committee in September, but their confirmations were blocked last month by Sen. Jim Inhofe (R-Okla.), who complained Senate Democrats were blocking several of President Trump's other nominees. (See *Senate Panel Clears McIntyre, Glick for FERC*.)

The two were among more than two dozen appointees approved Thursday.

Once they are sworn in, FERC will have its full five members for the first time since October 2015, when Republican Philip Moeller left the commission. FERC was without a quorum between February, when former Chairman Norman Bay resigned, and August, when Republicans Neil Chatterjee and Robert Powelson joined Commissioner Cheryl LaFleur on the commission. (See *FERC Quorum Restored as Powelson, Chatterjee Confirmed*.)

Chatterjee welcomed the two in a statement released by FERC. "I've enjoyed getting to know Kevin through the confirmation process and am eager to start working with him, and it will be great to reunite with Rich Glick, my former Senate colleague," he said.

The addition of the two ensures, however, that Chatterjee would need to attract at least two votes for a majority in support of the Department of Energy's Notice of Proposed Rulemaking to provide "full recovery" of nuclear and coal plant costs. (See *FERC Chair Praises Perry's 'Bold Leadership' on NOPR*.)

Chatterjee said at a luncheon Wednesday that the federal government may "cast a lifeline" to coal and nuclear power plants while it conducts a long-term review of the country's power grid. Chatterjee said he was worried that short-term market pressures would force the owners of coal and nuclear plants to close them and later on the country would realize it needed the power they produced.

Although DOE put no price tag on its proposal, estimates of its cost range into the billions. (See *Cost Estimates on DOE NOPR: $300 million to $32 billion*.) In a conference call with Kentucky reporters Thursday, Chatterjee acknowledged that the policy could result in higher electric bills for some customers.

Additional revenue to keep struggling coal plants running "would come from customers in that region, who need the reliability," he said, according to the *Courier Journal*. "It's in these customers' interests to keep these plants open."

Chatterjee, like his former boss, Senate Majority Leader Mitch McConnell, is from Kentucky.

During his confirmation hearing, McIntyre said, "FERC is not an entity whose role includes choosing fuels for the generation of electricity." (See *McIntyre to Senate: 'FERC does not Pick Fuels'*.)

FERC NEWS

Federal Trade Panel Recommends Solar PV Quotas

Continued from page 1

talline silicon photovoltaic (CSPV) products into the U.S. for a four-year period. That restriction would be set at 8.9 GW in the first year, increasing by 1.4 GW each subsequent year.

Tariffs and Quotas

Chair Rhonda Schmidtlein sought tariffs as high as 30% on imports of cells that exceed annual quotas of 0.5 GW, recommending that in-quota levels be incrementally raised and the tariff rate incrementally reduced during a four-year remedy period.

For CSPV modules, Schmidtlein recommended a 35% duty to be incrementally reduced during a four-year remedy period.

Vice Chair David Johanson and Commissioner Irving Williamson joined in recommending measures similar to Schmidtlein's: "For imports of CSPV products in cell form, we recommend an additional 30% *ad valorem* tariff on imports in excess of 1 GW. In each subsequent year, we recommend that this tariff rate decrease by 5 percentage points and that the in-quota amount increase by 0.2 GW. The rate of duty on in-quota CSPV products in cell form will remain unchanged. For imports of CSPV products in module form, we recommend an additional 30% *ad valorem* tariff, to be phased down by 5 percentage points per year in each of the subsequent years."

U.S. International Trade Commission headquarters

Who to Blame?

Schmidtlein also recommended that Trump initiate international negotiations to address the underlying cause of the increase in imports of CSPV products.

Broadbent said that surging imports and a global oversupply of CSPV products resulted "from the subsidization of manufacturers in China in the context of targeted industrial policy programs. I believe the president intends to address China's non-market economic policies that have contributed to global oversupply as part of broader bilateral negotiations with the government of China, and I support those efforts."

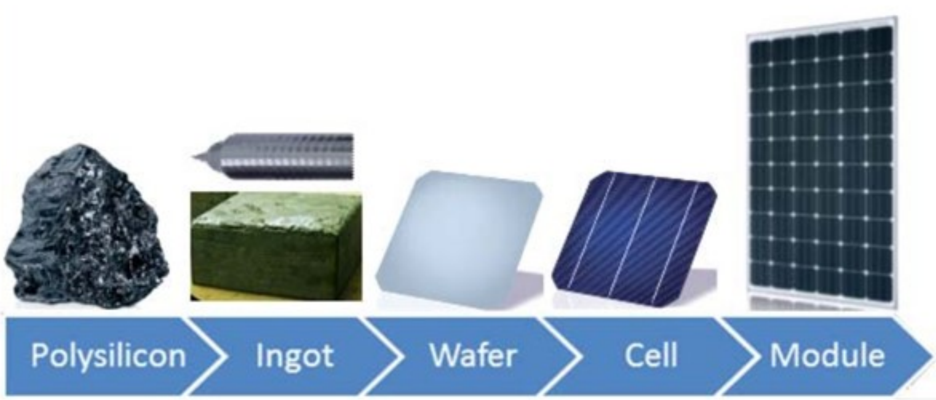
She said her recommended quotas "are consistent with the market share held by imports in 2016, adjusted to reflect projected changes in demand for photovoltaic products over the next four years. Therefore, they are set at levels that will not disrupt expected growth in CSPV demand but will help address the serious injury to the domestic industry by preventing further surges in imports."

Where the Buck Stops

Timothy Fox of ClearView Energy Partners said in a research note that the commission's recommendations for trade remedies represent another step toward final action, not final action itself.

"We regard today's vote as another significant step towards trade action likely to raise the cost of solar domestically, potentially blunting solar power deployment over the next four years," Fox said, adding that Trump's decision could be driven more by politics than by economics.

"President Trump measures economic success in terms of bilateral trade balances and manufacturing jobs," Fox said. "This solar trade proceeding could give President Trump a way to 'win' on both fronts. Economic nationalism appears alive and well within the White House, including in renegotiations of the North American Free Trade Agreement and Korea-U.S. Free Trade Agreement. As such, we think this solar proceeding could serve as a prototype for future protectionist efforts, including those concerning aluminum and steel (especially steel)."



CSPV production process | *International Trade Commission*

Q3 EARNINGS

CEOs See Dollar Signs in ZECs, PJM Price Formation

By Rory D. Sweeney

The CEOs for three of the largest companies that stand to gain from proposed price supports for nuclear and coal generators used their third-quarter earnings calls last week to praise FERC, the Department of Energy, PJM and states for their attention to the issue.

Exelon's Chris Crane, Public Service Enterprise Group's Ralph Izzo and Dominion Energy's Thomas F. Farrell II all made a point to thank the RTO, states or federal agencies who have made — or are considering — changes to funnel additional money to the generators, which the companies argue are critical to the grid but undervalued in markets.

Chris Crane | *© RTO Insider*

And they had good reason to. Crane said "each dollar [per] megawatt-hour of distortion caused by a flawed market design" costs the company $135 million per year. Izzo said each dollar change in per-megawatt-hour revenue from PJM is worth $55 million pre-tax to his company.

"We commend [Energy Secretary Rick Perry] for focusing attention on the need to reform the energy markets, and ensure that our customers continue to benefit from the resilient system," Crane said. "Between these efforts and state initiatives, we're optimistic about the path to preserve nuclear power plants. … We are confident that the FERC actions around resiliency will facilitate needed power price reforms in PJM that will fairly compensate our generating assets."

The DOE's Notice of Proposed Rulemaking "is aimed at protecting our customers from outages resulting from manmade and natural interruptions on the gas system by preserving resilient generation sources, including nuclear," he said.

PSEG is "on track … to reduce the all-in cost per megawatt-hour of its nuclear operations by 10% from the average cost experienced during the prior three years," Izzo said. "But energy prices influenced by the availability of natural gas have declined by a greater degree during this time frame.

Ralph Izzo | *© RTO Insider*

"We believe that the DOE NOPR is necessary. … We recommend that measures adopted in response to the DOE NOPR should be viewed as an interim [solution] until effective mechanisms can be developed that recognize these attributes in the market," he said. "State action also remains critical to prevent the loss of these units. We believe state action can be done [in a] way that both maintains the integrity of the wholesale market and serves as a bridge until a regional [or] federal solution is in place."

State ZEC Programs

Farrell didn't want to speculate on the outcome of the NOPR, but said "Connecticut certainly hasn't been willing to depend on it." He said he expects Connecticut lawmakers to follow Illinois and New York in establishing a zero-emission credit program to support nuclear units.

Thomas F. Farrell II | *© RTO Insider*

Last week, Gov. Dannel Malloy signed a bill that could allow Dominion's Millstone nuclear plant in Waterford, Conn., to compete in a state-sponsored solicitation for zero-carbon electricity if officials conclude it is in the best interest of ratepayers. Malloy, however, said he believes the plant is profitable and does not need a subsidy.

"Dominion Energy thanks the General Assembly for giving Millstone this opportunity and is grateful to the Malloy administration for his work in negotiating the current form of the legislation," Farrell said.

"We weren't surprised" by approval of the legislation, he added. "We've been working on it for two years and been deeply involved in it for that period of time."

Joe Dominguez, Exelon's vice president of governmental and regulatory affairs and public policy, also praised the Connecticut legislation and said that his lobbying efforts aren't done.

"We have been [in] very productive discussions both in Pennsylvania and New Jersey. We'll continue to do that," he said.

He said that the ZEC programs are designed to decrease if energy-market reforms happen, so "it will not be a double-dip here."

Izzo said PSEG is lobbying as well.

"Depending on what happens at the federal level, there remains the opportunity for New Jersey to recognize certain attributes that perhaps are not explicitly identified at the federal level," he said. "We are just in a series of conversations with people right now. We are just making sure they understand what our nuclear plants mean to New Jersey."

FERC Action

Izzo and Crane agreed FERC should order PJM to revise its price formation methodology, a move Izzo called a "no brainer" and "long overdue." Crane anticipated changes by as early as mid-2018.

In its comments to FERC on the NOPR, PJM suggested such reforms in arguing that large, inflexible units should be able to set LMPs. (See *Critics Slam PJM's NOPR Alternative as 'Windfall'*.)

Defining "resiliency" has been an ongoing debate, but Dominguez said PJM's Capacity Performance design makes the discussion quantitative.

"We were able to value the cost of incremental reliability associated with dual fuel, so if the design basis ultimately ends up being we need 90 days of fuel, we have a mathematical way of calculating what's the market solution to get dual-fuel resources to 90 days of fuel with it," he said. "That would probably be $8 or $10/MWh in terms of doing that based on the cost we saw in CP."

A rule from FERC that boosted power prices could also leave smaller retail competitors

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Q3 EARNINGS

CEOs See Dollar Signs in ZECs, PJM Price Formation

Continued from page 26

who have been "aggressive" in their pricing vulnerable to acquisitions by large, integrated energy companies like Exelon, Crane said.

"Any time we've seen a volatility event … we've had opportunities to acquire companies in that type of environment," Crane said.

Izzo said he was wary of projections that rules on price formation will increase PJM energy prices by $2 to $4/MWh, saying it ignores other factors that can have an impact.

"What [is the impact] of pipelines that may change the basis differential of gas in Western PJM versus Eastern PJM? What [is the impact of] future carbon constraints that may or may not be part of a subsequent administration in Washington?" he said. "Some people on this call may want to go see their children in their Halloween parades; otherwise I would list a thousand other factors that should go into people's thought process before making those kind of investment decisions."

Earnings

Crane said the Illinois Power Authority's decision last month to delay the finalization of the procurement of the ZEC contracts from December 2017 to January 2018 will shift 9 cents of earnings per share from 2017 to 2018.

Exelon earned $824 million ($0.85/share) in the third quarter, missing expectations by 1 cent but improving on the 53 cents/share earned in the same quarter a year ago. Revenue of $8.77 billion beat expectations by $90 million but was down from $9 billion a year ago. Operating earnings were 85 cents/share, compared to 91 cents/share for the third quarter of 2016.

While Exelon hasn't escaped the industry's cyclical nature, "we've gained greater flexibility with programs like the ZEC," Crane said.

Dominion posted operating earnings of $672 million ($1.04/share) for the third quarter of 2017, which beat expectations by 2 cents but was down from $716 million ($1.14/share) for the same period in 2016. Revenue of $3.18 billion missed expectations by $110 million but was up from $3.13 billion in the third quarter of 2016.

PSEG reported third-quarter operating earnings of $417 million ($0.82/share), which missed estimates by 2 cents and was down from $444 million ($0.88/share) a year ago.

Seeking Alpha provided the earnings calls transcripts for this article.

Q3 EARNINGS

Weather Leaves Alliant Profit Down Despite Rate Hikes

Despite two rate increases that took effect earlier this year, Alliant Energy's third-quarter results were down year over year because of mild weather this summer.

The Madison, Wisc.-based company announced a quarterly profit of $174.3 million ($0.75/share), down from $179.7 million ($0.80/share) a year earlier. Alliant attributed the slump to mild conditions, higher depreciation expenses and higher energy efficiency cost recovery amortization at subsidiary Wisconsin Power and Light (WPL).

CEO Patricia Kampling said earnings would have been on target with earlier estimates had summer temperatures been on par with historical averages.

"This quarter, we continued to produce solid financial and operational results," Kampling said. "With three quarters of the year behind us, I am pleased to report that our anticipated … temperature-normalized earnings for fiscal year 2017 are in line with the original midpoint of our 2017 earnings guidance. However, taking into account year-to-date temperatures, which resulted in an estimated 6 cents/share of lower earnings, we are updating 2017 adjusted earnings per share guidance to a midpoint of $1.93."

Alliant provided year-end guidance between $1.89 and $1.97/share.

The earnings announcement follows regulatory approval of two Alliant rate hikes this year. Interstate Power and Light's interim electric base rate increase was approved in April, while WPL's electric and gas base rate increases were implemented in January. They will boost annual revenues by $102 million and $18 million per year, respectively. Also in January, Alliant discontinued WPL's practice of offering winter rates that are lower than summer rates.

— Amanda Durish Cook

Calpine Profits down 24%

By Jason Fordney

Calpine reported Wednesday that it earned $225 million in the third quarter ($0.63/share), down 24% from $295 million ($0.83/share) a year earlier.

The decrease was primarily due to "an unfavorable variance in mark-to-market gain/loss, net, and increases in plant operating expense and depreciation and amortization expense," Calpine said. The decline was partially offset by a higher commodity margin, which the company said was driven by hedge revenues from retail operations and higher regulated capacity revenue.

The company, which has agreed to go private in a $5.6 billion deal with Energy Capital Partners and an investors group, lost $47 million in the first nine months of this year, compared with a profit of $68 million in the same period a year ago. Company officials issued the earnings with no previous public notice and no conference call to take questions from analysts. (See *Calpine Going Private in $5.6B Deal*.)

In a news release announcing the results, CEO Thad Hill said the merger is on track to be completed in the first quarter of 2018. He focused on the company's response to natural disasters in California and Texas.

"Since our last earnings call, we endured Hurricane Harvey in Texas and the wildfires in Northern California safely and without any material damage to our facilities," Hill said. "I am particularly proud of team members on the front lines who kept our plants and operations going in the face of adversity."

Operating revenues were $2.6 billion for the quarter, compared with about $2.4 billion in the same quarter last year. Operating revenues in the first nine months of 2017 were nearly $7 billion, compared with about $5.1 billion in the same period last year.

The company said cash from operating activities rose 21% to $807 million over the first three quarters, "primarily due to a decrease in working capital employed resulting from the period-over-period change in net margining requirements associated with our commodity hedging activity, partially offset by a decrease in income from operations, adjusted for non-cash items."

Con Ed Earnings Fall 8%

Consolidated Edison's third-quarter earnings fell 8% to $457 million ($1.48/share), a drop the company attributed to changes in its rate plan and regulatory charges, as well as the impact of weather on steam revenues. The new rate plan includes changes in the timing of recognition of annual revenues between quarters.

"This is an exciting time in the energy industry," CEO John McAvoy said during a Nov. 2 earnings call. "We're incorporating renewables into the grid at an increasing rate, we're using data analytics to provide customers with more information about the way they're using energy and how they can save, and we're working on programs to increase electric vehicle use and access to charging stations. At the same time, our $1 billion storm hardening program after Superstorm Sandy has made our system more reliable than ever five years later, having already prevented 250,000 power outages due to our investments."

The company updated its guidance on adjusted earnings per share for 2017 slightly to $4.05 to $4.15/share. The previous range was $4 to $4.15/share.

Con Ed also said it is unable to estimate the amount or range of possible costs related to an April 21 subway power outage in New York City.

After investigating the outage, the New York Public Service Commission in August issued an emergency order requiring the company to inspect electrical equipment serving the Metropolitan Transportation Authority's system, analyze power supply and power quality events affecting subway signaling services, provide new monitoring and other equipment, and file monthly reports with the commission on all activities related to the subway system. The commission last month approved another order extending the subway outage oversight beyond its original 90-day limit but has not yet issued the second order.

— Michael Kuser

Q3 Earnings

CenterPoint, OGE in 'Late-Stage' Talks over Enable Midstream

By Tom Kleckner

CenterPoint Energy executives Friday said the company is in "late-stage discussions" over its Enable Midstream Partners gas-gathering and processing joint venture but offered few details beyond that.

"Should these discussions not come to fruition, we will evaluate the sale of units in the public market place," CenterPoint CEO Scott Prochazka said during a conference call with analysts.

Prochazka also said the Houston-based company "continues to believe Enable is well positioned for success."

CenterPoint owns a 54.1% share of Enable. Oklahoma City's OGE Energy holds a 25.7% limited-partnership interest and a 50% management interest.

In August, OGE accepted a right of first offer for CenterPoint's shares. Any competing offer CenterPoint accepts for its interest would have to be at least 5% higher than OGE's, CFO Bill Rogers said.

Enable's status has been the prime subject of the two companies' earnings calls for more than a year. (See OGE, CenterPoint Earnings Calls Focus on Enable Midstream.)

"This has been admittedly a long process," Prochazka said. "As we come to the end of this, we will communicate the outcome, irrespective of what it is."

CenterPoint reported quarterly earnings of $167 million ($0.38/share), down from $177 million ($0.41/share) a year ago. A Thomson Reuters survey of analysts had projected earnings of 39 cents/share.

The company said revenue for the quarter rose 11.1% to $2.10 billion, up from $1.89 billion for the same quarter last year.

Rogers said CenterPoint's Hurricane Harvey restoration efforts have cost the company between $110 million and $120 million. A third of that will be covered by property insurance claims, with the rest recovered through capital mechanisms or regulatory assets in the company's next rate case, he said.

CenterPoint's electric utility operations added 46,000 metered customers during the quarter, a 2% growth rate.

Wall Street reacted to CenterPoint's announcement by driving down the company's share price by 79 cents, to $28.96/share, when the market opened Friday. The stock recovered to $29.59/share by the market's close.

OGE Q3 Earnings Unchanged from 2016

OGE on Thursday reported net income of $183 million ($0.92/share), compared to $184 million ($0.92/share) the same period a year ago. Third-quarter revenue was $717 million, down from $744 million the year before.

Analysts surveyed by Zacks Investment Research had projected earnings of 93 cents/share.

OGE said its Oklahoma Gas & Electric subsidiary expects to file a rate case with the Oklahoma Corporation Commission by the end of year. The utility is seeking to recover $390 million in expenses to retrofit its Mustang power plant with seven 66-MW combined cycle gas turbines.

"It's a much simpler case" than previous rate proceedings, CEO Sean Trauschke told analysts. "The plant will be finished and in service, so there's no question about the cost."

OG&E also expects to file another rate case with the OCC in 2018 to recover $542 million in environmental upgrades at its Muskogee plant.

OGE shares, which closed Wednesday at $36.75, were down to $35.97/share in Friday afternoon trading, a loss of 2.1%.

Profits up, Edison Talks Clean Energy Goals

By Jason Fordney

Edison International says its grid will help California meet its clean energy goals, but infrastructure and market improvements are still needed.

The company, parent of utility Southern California Edison (SCE), "must be a key enabler of California's ambitious renewable policies," CEO Pedro Pizarro said during an earnings call last week. He mentioned renewable integration, customer technology choice, adoption of distributed energy, vehicle electrification and energy efficiency. Achieving those goals will require strengthening the existing electricity grid, he said.

Edison said it would soon issue a whitepaper on a framework for the state to meet its energy goals, building on existing policies and summary results of different scenarios. The paper will discuss carbon-free electricity with storage, increased electric vehicle integration and improved building efficiency.

The company earned $470 million ($1.44/share) during the third quarter, compared to $421 million ($1.29/share) a year earlier. Net income for the nine months ending Sept. 30 came in at $1.1 billion ($3.41/share), compared to $982 million ($3.01/share) during the same period last year.

SCE's net income through Sept. 30 increased by $73 million, or 23 cents/share, from the same period in 2016, primarily because of an earlier rate case decision, the company said.

The utility is in the midst of its 2018 rate case with the California Public Utilities Commission, having recently filed reply briefs, with public hearings slated for November. It does not expect a decision from the commission this year. Another proceeding with the PUC regarding electric vehicles and energy storage could increase SCE's investment forecast by $1 billion, Edison said during the earnings release.

Company executives said last week they continue to support the existing settlement over the San Onofre Nuclear Generating Station. SCE has been unable to reach agreement with settling parties and recently urged the PUC to support the existing settlement. (See CPUC Orders Renegotiation of San Onofre Settlement.)

"Folks have different ideas as we walk down the pathway here," Pizzaro said of the proceeding.

Q3 EARNINGS

Eversource Q3 Earnings Flat on Mild Weather

By Michael Kuser

Eversource Energy last week reported third-quarter earnings of $260.4 million ($0.82/share), down nearly 2% from the same quarter in 2016. Earnings for the first nine months of 2017 were $750.6 million, up 5% from earnings of $713.1 million in the same period last year.

"The primary drivers of our [quarterly] results were higher electric transmission earnings being offset by lower electric distribution results," Eversource CFO Phil Lembo told analysts in a Nov. 2 conference call.

A higher rate base boosted transmission earnings by 10.7% to $99 million, the result of the company investing $600 million in its transmission system this year through September, with just less than $1 billion planned for the full year, Lembo said.

He attributed a 7.4% drop in earnings for the company's electric distribution and generation division to lower sales reflecting mild weather in July and August. Cooling degree days in Boston were down nearly 34% for the quarter compared with last summer and 8% below normal, he noted.

In addition to lower electric revenues, the company recorded higher property tax, depreciation and interest expense in the quarter, but was able to offset much of the negative impact by controlling costs, Lembo said. Eversource's natural gas distribution segment posted a net loss of $6.2 million in the third quarter and earnings of $49.1 million in the first nine months of 2017, compared with a net loss of $7 million in the third quarter of 2016 and earnings of $51.9 million in the first nine months of 2016.

"For the long term, we continue to project 5 to 7% [earnings per share] growth," Lembo said. "We are pleased with our results today and remain comfortable with our 2017 guidance, although I'd like to see some very cold weather in November and December, and that would really help us reach the higher end of our earnings range for '17."

Future Developments

Lembo noted that Eversource last month filed with the New Hampshire Public Utilities Commission to sell its remaining 1,200 MW of generation assets in the state for $258 million, and expects the two sales to be completed late this year or in early 2018. On the company's proposed merger of subsidiaries NSTAR Electric and Western Massachusetts Electric Co., he said state regulators should issue a decision by Nov. 30 on the merger and grid modernization, and a decision on performance-based rate design by Dec. 29, with rates to become effective in January 2018.

Lee Olivier, Eversource executive vice president for business development, said the company's Northern Pass transmission project achieved an important milestone Nov. 1 when utility subsidiary Public Service Company of New Hampshire filed a settlement agreement on the lease terms for most of the 192-mile route for the line.

"The settlement was reached with New Hampshire PUC staff and the Office of Consumer Advocate, the two principal intervenors in the case," Olivier said. "We expect the New Hampshire PUC approval of the settlement by the end of the year. Taken together, we are very pleased with our current position in the siting process, with significant progress being made in all venues."

Eversource has also partnered with Ørsted, formerly DONG Energy, to form Bay State Wind for the offshore wind solicitation in Massachusetts.

"We are preparing our bid into the Massachusetts offshore wind [request for proposals], which is due Dec. 20," Olivier said. "Given the vast experience of Ørsted in European offshore wind and our knowledge of New England markets and transmission, we believe we will be able to submit a highly compelling set of proposals for review by the evaluators."

SDG&E's Wildfire Costs Undercut Sempra Profits

By Jason Fordney

Sempra Energy's third-quarter financial results were hobbled by an administrative law judge's preliminary decision to deny subsidiary San Diego Gas & Electric's request to recoup losses stemming from wildfires a decade ago.

A California Public Utilities Commission ALJ in August recommended the commission deny SDG&E's request to recover $208 million in costs related to the 2007 Witch, Guejito and Rice wildfires, ruling that prior to the fires, the utility "did not reasonably manage and operate its facilities." The ALJ decision is not binding, and the PUC is due to vote Nov. 9 on SDG&E's request to recover the costs.

During an earnings call last week, Sempra executives said they are prepared to take the matter to court if they are not allowed to recover the money.

Traditional accounting measures require the company to reflect the preliminary decision in its financial results, but Sempra said that on an adjusted basis, earnings increased to $265 million ($1.04/share), from $259 million ($1.02/share) a year ago. Unadjusted earnings came in at $57 million, compared with $622 million last year.

For the first nine months of the year, Sempra's earnings were $757 million, compared with $991 million over the same period last year.

Sempra is also attempting to acquire Texas-based utility Oncor in a deal worth nearly $10 billion. The Public Utility Commission of Texas last week issued a preliminary order that calls for Sempra to prove it is financially fit to own the state's largest utility. (See *Texas Regulators Seek More Details on Sempra Oncor Bid*.)

SDG&E recorded a net loss of $28 million in the third quarter, compared with earnings of $183 million a year earlier, "due primarily to the $208 million after-tax impairment related to cost recovery for the 2007 San Diego wildfires."

The utility's earnings were $276 million for the first nine months of 2017, compared with $419 million in the same period last year. Earnings for the first nine months of 2017 included the third-quarter 2017 wildfire-related impairment. In last year's second quarter, SDG&E recorded an after-tax charge of $31 million, refunding to ratepayers the benefits from tax deductions related to the final 2016 rate case decision.

Q3 EARNINGS

NRG Optimistic Despite Q3 Profit Decline

By Michael Kuser

A cool summer and the impact of Hurricane Harvey drove NRG Energy third-quarter earnings sharply lower, but the company still sees bright days ahead, according to CEO Mauricio Gutierrez.

NRG earned $171 million ($0.53/share) last quarter, compared with $402 million ($1.27/share) in the same period last year. Revenues were down 10.9% to about $3 billion.

Gutierrez said during a Nov. 2 earnings call that although the company is "on track" to transform itself through cost-saving measures, the third-quarter results led the company to lower its full-year earnings before interest, tax, depreciation and amortization (EBITDA) guidance to $2.4 billion to $2.5 billion from the previous $2.56 billion to $2.76 billion.

"In Texas we saw both a major hurricane and the coolest August since 2004, with cooling degree days 13% below normal, and in the Northeast, cooling degree days were on average 8% below normal for July and August," Gutierrez said. He noted that ERCOT summer wholesale prices fell 43% below expectations. Mild weather across the East and in Texas eliminated any opportunity to benefit from scarcity pricing.

NRG attributed one-time financial impacts of $40 million to Hurricane Harvey, evenly divided between its generation and retail operations in Texas. About 80% of the company's baseload generation on the Gulf Coast was available during the worst part of the storm, and 95% has been restored to date.

Brighter Side

NRG's retail business continues to improve its operating efficiencies, customer acquisition and retention, which partially offset the impacts of milder summer weather, especially in ERCOT, Gutierrez said.

He said certain cost and margin enhancements will start impacting the company's bottom line next year, as well as the sale of subsidiary NRG Yield and its renewables assets, which is expected to be completed this year and return up to $4 billion. The company continues to use excess cash to deleverage itself, he said.

"Since our second-quarter call, we have taken another $600 million of debt out of our capital structure, completing our 2017 capital allocation," Gutierrez said.

He also pointed to improving market conditions in Texas as a particular bright spot for the company.

"Despite the absence of extreme weather this summer, ERCOT fundamentals remain strong. ERCOT's 2017 peak load of 69.5 GW was up nearly 2% over the five-year average and came in just shy of the 2016 peak," he said.

The recently announced retirement of more than 4 GW of generating capacity in ERCOT puts further pressure on a market with already strong fundamentals, Gutierrez said. Vistra Energy on Oct. 6 announced plans to retire three aging coal-fired units in East Texas with a combined capacity of 1,880 MW, rendered obsolete by ERCOT's record low prices. (See *Vistra Energy to Close 2 More Coal Plants*.)

"For summer of 2018, these new retirements and asset delays alone will put ERCOT at the lowest reserve market on record, which is suspected to be somewhere between 10 and 11%," Gutierrez said. "Other changes, such as delayed new builds and new industrial demand, could lower these numbers even further."

But while the retirements are nudging up forward markets, prices are still below what is needed to justify new builds, he pointed out.

Calls to Action on Market Reform

In response to an analyst question about whether NRG would consider selling parts of its Texas portfolio, Gutierriez said, "Right now we're very comfortable with our Texas portfolio." He said the capability of NRG's generation fleet aligns well with its retail loads.

But while the recent retirements are improving market health, ERCOT must do more to strengthen markets and should recognize the locational value of power plants, he said.

"Reliability and resiliency are important attributes to the grid, and we will continue to work with ERCOT to ensure that generators close to load centers are compensated for all the benefits they provide."

Beyond the positive developments in ERCOT, Gutierrez said NRG sees several other "calls to action" occurring for market reform.

"As the power grid continues to undergo significant change — low gas prices, renewable penetration and attempts for out-of-market subsidies for uneconomic generation — regulatory bodies and other stakeholders are taking note," Gutierrez said.

"These have led to several significant catalysts, from the [Department of Energy] staff report on competitive markets and [Notice of Proposed Rulemaking], to PJM's proposed market reforms. I cannot recall another time when there has been such urgency and reach across ISOs to improve competitive energy markets." (See *Market Summit Tackles Ongoing PJM Changes*.)

Gutierrez said NRG has been optimistic about market developments in PJM, especially around the introduction of Capacity Performance.

Asked to rank the most promising areas for growth, Gutierrez responded that NRG aims to balance its generation and retail businesses and is focused on perfecting an integrated platform.

"A lot of the generation is going to be driven by our retail needs and how we grow retail, and a lot of our retail will be driven by where we have generation," he said.

"We're still long in generation in PJM. We have a ways to go before we have a balanced portfolio like we have in Texas. ... Just in terms of market structure, I would put PJM No. 1, New England No. 2 and New York No. 3."

Q3 Earnings

PG&E Earnings up 42% on Lower Expenses

By Jason Fordney

Pacific Gas and Electric earnings jumped 42% to $550 million during the third quarter ($1.07/share), boosted in large part by reduced expenses and realization of one-time income. Year-to-date profits for the utility have more than doubled to $1.5 billion, compared with $711 million last year.

Operating revenues for the electric side were $3.6 billion for the quarter, out of total revenues of about $4.5 billion.

"The quarter-over-quarter increase reflects lower expenses primarily due to the absence of disallowed charges related to the San Bruno penalty decision, which impacted the third quarter of 2016, and also due to insurance proceeds in the third quarter of 2017 related to the court-approved settlement of the shareholder derivative suit, with no similar amount in 2016," PG&E said during an earnings call Thursday.

During the first nine months of the year, the utility incurred $71 million in costs associated with in fines and penalties, including disallowed expenses of $32 million, related to an April 2015 decision by the California Public Utilities Commission regarding the San Bruno pipeline explosion.

PG&E CEO Geisha Williams also discussed the wildfires that blazed across the state in the third quarter, saying "we also remain focused on continued investment in vital infrastructure and technology to increase the resilience and the sustainability of California's energy economy for the future."

The utility restored service to 360,000 electric customers and 42,000 gas customers during the disasters, saying it is aiding the PUC and California Department of Forestry and Fire Protection in their investigations.

PG&E updated its 2017 guidance range to $3.36 to $3.56/share because of the reinstatement of the company's liability insurance following the wildfires and an increase in the expected third-party claims associated with the 2015 Butte fire, partially offset by insurance recoveries.

More than 12 victims of the recent wildfires have filed suit against PG&E for this season's blazes, which claimed 43 lives and burned thousands of homes and commercial buildings. The company told the Securities and Exchange Commission on Oct. 13 that "the causes of these fires are being investigated by the California Department of Forestry and Fire Protection (Cal Fire), including the possible role of power lines and other facilities of" PG&E. The company said it is unknown whether it will have any liability, but it has $800 million in liability insurance for potential losses from the fires.

Pinnacle West Capital Profit Rises on Customer Growth

Arizona Public Service parent company Pinnacle West Capital earned $276 million ($2.46/share) in the third quarter, compared with $263 million during the same period in 2016.

"Our service territory experienced solid customer growth of 1.9% as new customers moved to Arizona for job opportunities and an improved quality of life, our employees continued to demonstrate superior customer service and operational performance, and we successfully settled our rate review," Pinnacle CEO Donald Brandt said.

The Arizona Corporation Commission allowed APS to raise its rates for the first time in five years. The company said the increase will allow it to invest in cleaner infrastructure and provide customers with new rate options.

Customer growth lifted profits by 2 cents/share compared to a year earlier despite milder temperatures. Pinnacle raised its earnings guidance to $4.25 to $4.45/share for 2017 and $4.15 to $4.30/share for 2018.

APS' rate base is expected to grow about 6% annually, to a projected $8.2 billion in 2019.

— Jason Fordney

Company Briefs

Duke's Earnings Hurt by Hurricane Irma

Damage caused to Duke Energy's infrastructure by Hurricane Irma caused the company to post lower third-quarter earnings than a year ago and lower its 2017 earnings estimate.

The company still posted adjusted earnings above the consensus Zacks Investment Research estimate, although its revenue fell short.

Duke cited lower income tax expense and higher retail revenues from increased pricing as helping to offset negative factors in the quarter.

More: *The Charlotte Observer*

PPL Earnings Beat Estimates Despite Drop

PPL's third-quarter earnings and revenue were down from a year ago, but its adjusted earnings beat the average estimate of five analysts surveyed by Zacks Investment Research.

The company said its results were hurt by mild weather in Pennsylvania and helped by higher rates in Kentucky and the U.K.

PPL raised the midpoint of its 2017 earnings guidance because of stronger-than-expected earnings from its Western Power Distribution subsidiary in Great Britain.

More: *The Morning Call*

Continued on page 33

COMPANY BRIEFS

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NextEra Leading in Early Bidding for Santee Cooper

NextEra Energy has made a "substantial offer" that is the early leader in bids for Santee Cooper, *The Post and Courier* reported, citing a source with knowledge of the negotiations.

Duke Energy and Southern Co. have submitted more informal bids, and Dominion Energy is expected to send a proposal within two weeks.

Santee Cooper is owned by the state of South Carolina, which put it up for sale after it and South Carolina Electric & Gas spent $9 billion on an expansion of the V.C. Summer Nuclear Station that they were unable to complete.

More: *The Post and Courier*

Southern Trying to Sell Nuclear Settlement, Part of Solar Business

Southern Co. said Wednesday it is trying to sell a $3.7 billion nuclear settlement and part of its solar generation business to raise cash.

The $3.7 billion is owed to Southern by Toshiba as a result of the latter company's failing to complete the expansion of Southern's Vogtle nuclear plant in Georgia.

Southern needs to raise cash to cover about $1.4 billion in added costs to complete the Vogtle expansion and to bail out its Mississippi Power unit, which regulators forbade from recovering the costs of a failed coal-gasification power project from ratepayers.

More: *Bloomberg*

Empire Files to Build $1.5B Wind Project, Close Coal Plant

Empire District Electric last week filed an application with the Missouri Public Service Commission seeking permission to build a $1.5 billion wind power project in southwest Missouri and close its Asbury coal plant in April 2019, more than 15 years ahead of schedule.

Empire said it planned to pursue an equity partnership that would take advantage of more than $800 million in federal tax incentives for the project, meaning it would only have to invest $700 million in the project itself.

On Thursday, however, U.S. House Republicans unveiled a tax bill that would cut federal tax credits for the wind industry, possibly rendering those numbers obsolete.

More: *The Joplin Globe*

Clean Line Asks Missouri Supreme Court to Hear Grain Belt Case

Nixon

Clean Line Energy Partners last week asked the Missouri Supreme Court to hear its appeal of the Missouri Public Service Commission's rejection of its application to build the Grain Belt Express, a 780-mile transmission line that would deliver 4,000 MW of wind power from western Kansas through Missouri and Illinois to the Indiana border.

Lawyers for Clean Line, led by former Missouri Gov. Jay Nixon, had appealed the commission's decision to the Missouri Eastern District Court of Appeals in September.

In its appeal, Clean Line asked the Supreme Court to take the case to prevent the project from experiencing a lengthy delay, which it said could have financial consequences for the project and the customers that have agreed to buy the power it would carry.

More: *Columbia Daily Tribune; WTAD*

SCANA Execs Stepping Down

Marsh

Kevin Marsh is retiring as chairman and CEO of SCANA and its South Carolina Electric & Gas subsidiary at the end of the year, SCANA said last week.

Stephen Byrne, an executive vice president with SCANA who is SCE&G's chief operating officer, also will retire at the same time.

SCANA has been under pressure to make executive changes since it and Santee Cooper pulled the plug on two reactors they had hoped to build at the V.C. Summer Nuclear Station.

More: *The Associated Press*

Lawmakers Seek to Cut off Recouped Costs from SCANA

A special committee of the South Carolina House of Representatives voted last week to draft legislation to cut off the $37 million a month SCANA's customers pay to finance two reactors that the company and state-run Santee Cooper had hoped to build at the V.C. Summer Nuclear Station.

The committee also discussed amending a 2007 law that allows SCANA to charge its customers between $2 billion and $4 billion more for the reactors.

SCANA, which is the parent of South Carolina Electric & Gas, and Santee Cooper decided in July not to complete the reactors.

More: *The Post and Courier*

Statoil Aims to Sign PPA with US Utility to Develop Offshore Wind

Statoil aims to sign a power purchase agreement with a U.S. utility to develop an offshore wind farm off New York, Stephen Bull, a senior vice president with the Norwegian oil and gas company, said last week.

Statoil submitted a winning bid of $42.5 million in a lease sale of 79,350 acres off the coast of New York last December. The site could accommodate a wind farm of up to 1 GW capacity.

More: *Reuters*

FEDERAL BRIEFS

New EPA Science Advisers more Conservative than Predecessors

EPA Administrator Scott Pruitt appointed 66 experts to three different scientific committees on Friday.

Many of the experts come from industry or state government and espouse more conservative views than their predecessors, making it likely that they'll change the agency's research objectives and recommendations for regulations.

Two of the new chairs — Texas' top toxicologist Michael Honeycutt, who will helm the Scientific Advisory Board, and consultant Louis Anthony "Tony" Cox, who will chair the Clean Air Scientific Advisory Committee — have harshly criticized the agency.

More: *The Washington Post*

Federal Report on Climate Change Contrasts with Trump Admin Stance

The federal government on Friday released the National Climate Assessment, and its conclusions about climate change were at odds with views expressed by members of the Trump administration.

The report affirms that climate change is driven almost entirely by human action, warns of a worst-case scenario in which seas could rise as much as 8 feet by 2100 and details the climate-related damage already unfolding across the U.S. as a result of an average global temperature increase of 1.8 degrees Fahrenheit since 1900.

"The climate has changed and is always changing. As the 'Climate Science Special Report' states, the magnitude of future climate change depends significantly on 'remaining uncertainty in the sensitivity of Earth's climate to [greenhouse gas] emissions,'" White House spokesman Raj Shah said in a statement.

More: *The Washington Post*

USDA Makes $2.5B in Loans for Rural Electric Infrastructure

The Department of Agriculture is providing loans totaling $2.5 billion for rural electric infrastructure improvements in 27 states through its Rural Development Electric Program.

The largest loan, $382.5 million, is to the Western Farmers Electric Co-Op in Oklahoma for building 144 miles of transmission, improving 42 miles of transmission and making other improvements to its system.

More: *U.S. Department of Agriculture*

EPA Admits Clean Power Plan Would Save Lives

In a draft analysis of its repeal of the Clean Power Plan, EPA said implementing the plan could prevent up to 4,500 premature deaths per year by 2030.

That's more than the 1,500 to 3,600 premature deaths annually by 2030 that the agency under the Obama administration predicted the plan could prevent when it unveiled it in 2015.

EPA's revised prediction is based on the Energy Information Administration's Annual Energy Outlook 2017.

More: *The Washington Post*

PREPA Asks FEMA for $10M to Pay Whitefish

The Puerto Rico Electric Power Authority is asking the Federal Emergency Management Authority for $10 million to pay Whitefish Energy for its work rebuilding the territory's grid, which was destroyed by Hurricane Maria.

The contract, which PREPA has said it is canceling, called for a $3.7 million initial payment, followed by up to $300 million for satisfactory work. A PREPA spokesman, however, said it would honor the terms of the deal.

More: *CNN*

FBI Looking into Whitefish Contract To Rebuild Puerto Rican Grid

The FBI has opened a preliminary inquiry into the $300 million contract that Whitefish Energy secured from the Puerto Rico Electric Power Authority to repair the territory's power grid, according to a source with knowledge of the inquiry.

The contract, which was signed Sept. 26 and canceled Sunday by Puerto Rico Gov. Ricardo Rosselló, is also being investigated by the House of Representatives, the Senate, Puerto Rican officials and the Department of Homeland Security.

Whitefish, which only had two employees when it signed the contract, is based in the hometown of Interior Secretary Ryan Zinke, who said he had nothing to do with the company getting the contract.

| Whitefish Energy

More: *CNN*; *Vox*

UN Exec Says US Will Meet Paris Commitments Despite Trump

U.N. Environment Programme Executive Director Erik Solheim said last week the U.S. likely will meet its commitments under the Paris Agreement despite President Trump's plan to withdraw the country from the pact.

Solheim said he expects the U.S. to meet the commitments because "all the big American companies" are making their operations greener.

He made the comments as UNEP presented its latest "Emissions Gap" report, which gives a scientific assessment of how national efforts are affecting greenhouse gas emissions trends.

More: *The Associated Press*

DOD Spending on Microgrids to More than Triple by 2026

| Black & Veatch

Defense Department spending on microgrids will reach $1.4 billion in 2026, up from $453.3 million this year, according to a new report by Navigant Research.

Navigant says shifting from relying on backup diesel generators to large-scale microgrids could save the department, which is the single largest consumer of petroleum in the world, $8 billion to $20 billion over the next 20 years.

More: *Microgrid Knowledge*

STATE BRIEFS

CALIFORNIA

Lawmakers to Introduce Bill Restricting Wildfire Costs in Rates

Four state lawmakers said they plan to introduce in January a bill that would prevent electric utilities found culpable in wildfires from passing the costs for claims not covered by insurance, as well as fines or penalties they incur, on to their customers.

The bill is being authored by State Sens. Jerry Hill, Mike McGuire and Scott Wiener, and State Assemblyman Marc Levine, all Democrats.

In explaining the need for the bill, the lawmakers cited San Diego Gas & Electric's request to recoup $208 million in costs stemming from wildfires a decade ago. A California Public Utilities Commission administrative law judge in July recommended that the PUC deny SDG&E's request.

More: *Rohnert Park-Cotani Patch*

CONNECTICUT

Governor Signs Bill to Study Millstone Finances

Gov. Dannel Malloy last week signed legislation that allows state regulators to study and ultimately determine whether the electricity produced by the Millstone Nuclear Power Station should be sold on the clean energy market like solar, wind and hydroelectric power.

The legislation allows nuclear power to participate in the market if regulators determine it is in the best interest of the ratepayer.

Malloy said he signed the bill despite a preliminary study showing the plant will be profitable for the foreseeable future. The plant's owner, Dominion Energy, has argued that access to the clean energy market is necessary to keep the plant profitable.

More: *Hartford Courant*

Eversource Seeks Rate Increase Amid Criticism of Storm Response

Eversource Energy has asked the Public Utilities Regulatory Authority to approve a rate increase that would boost its revenue by $336.8 million over three years.

The increase would provide Eversource with additional revenue of $255.8 million in the first year, $45 million in the second year and $36 million in the third year.

The rate-hike request came as Eversource was facing criticism for its efforts to restore service to hundreds of thousands of customers left without power from a storm that hit the state Oct. 29-30.

More: *The Hartford Courant*

KENTUCKY

Q3 Coal Employment up from Year Ago, Down from Q2

The state's coal industry employed 6,438 people in the third quarter, up 2.1% from the same period last year but down 5.1%, or 350 workers, from the second quarter of this year.

Coal production was down in the third quarter from both the second quarter and the third quarter of 2016.

Tyler White, president of the Kentucky Coal Association, said losses in coal jobs and coal production have slowed from the double-digit drops of some earlier periods but haven't stopped.

More: *Lexington Herald-Leader*

NEW YORK

Weatherization Assistance Program to Get $59M

Gov. Andrew Cuomo said last week that $59 million will be made available through the Weatherization Assistance Program to help cut utility costs for approximately 9,200 income-eligible families and seniors across the state.

The money will be released to a statewide network of nonprofits to conduct energy-efficiency work including air sealing, insulation, upgrading heating systems and diagnostic testing to identify hazards such as carbon monoxide and mold.

More: *Andrew Cuomo*

OHIO

PUCO Staff Recommend Rate Cut for Duke

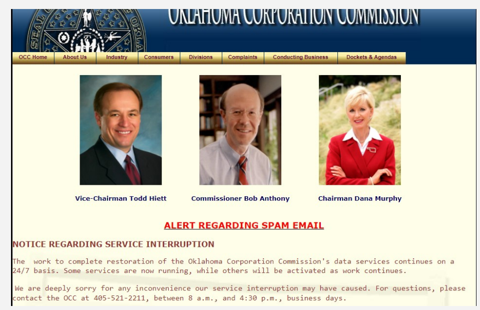
Public Utilities Commission technical staff are recommending that the commission cut Duke Energy's distribution rates and reject the utility's request for an increase of almost 1%.

Staff didn't object to the returns sought by Duke, but they disagreed with the math the utility used to attain them.

More: *Cincinnati.com*

OKLAHOMA

OCC Website, Network Restored from Cyberattack



The website and most of the network operations of the Corporation Commission were restored last Tuesday being offline since a cyberattack on Oct. 23.

The state Office of Management and Enterprise Services and Cyber Command handled the restoration and said the attackers used malware called "Zero-day."

More: *The Oklahoman*

PENNSYLVANIA

PUC Looking into Making Gas, Power More Affordable

The Public Utility Commission is conducting a statewide study on how to make gas and electricity more affordable.

The study was prompted by an increase by the state's utilities in the number of service shut-offs to customers who fall behind on payments.

The PUC's initial survey of affordability issues is due at the end of November.

More: *WHYY*