RTO Insider
Your Eyes and Ears on the Organized Electric Markets
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Still 'Committed,' SPP Halts Mountain West Integration Effort

By Tom Kleckner

KANSAS CITY, Mo. — SPP CEO Nick Brown said last week the grid operator remains committed to making Mountain West Transmission Group's membership proposal work, despite Xcel Energy's surprise decision to pull out of the group and its pending integration into the RTO.

But integration work has been put on hold until the remaining Mountain West members decide what to do next.

"Obviously, the ball is in the court of the Mountain West participants," Brown told SPP's Board of Directors and Members Committee. "I've told them we remain committed to doing whatever it takes to come to a reasonable path forward, to create, again, the value that was expected from the previous agreement."

Representing about 40% of Mountain West's load and considered the group's most influential member, Xcel announced April 20 it was pulling its 1.4 million customers out of the agreement. That has left the Mountain West's smaller entities reviewing their options. (See Xcel Pulls out of Mountain West, Endangering SPP Integration.)

"It would be a shame for an individual participant of the Mountain West to unilaterally destroy the value I think would be afforded to the new SPP members of Mountain West and also destroy the value on the table for our current members," Brown said.

Board Chair Jim Eckelberger told directors and members the Mountain West entities had yet to sign a transition service agreement funding the integration work and approving a set of policy recommendations governing the terms of their RTO membership. In the absence of a signed agreement, Eckelberger said, the board's March 13 approval of the integration's funding and policy recommendations has been suspended.

SPP Chair Jim Eckelberger (L) and Harry Skilton are stepping down from SPP's Board after 18 years. (p. 26) | © *RTO Insider*

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PJM Seeks to Have Market Value Fuel Security

By Rory D. Sweeney

PJM wants to take a more holistic look at how the grid's supply chain works and factor the findings into its markets.

The RTO announced a plan Monday it thinks will help ensure the reliable delivery of both electricity and the fuel necessary to generate the electricity. The three-phased approach will analyze fuel security throughout PJM's footprint to identify vulnerabilities, develop criteria to address them and include those criteria in the models used for capacity auctions.

The result would be constraints on the grid that trigger clearing price differences in affected locational deliverability areas (LDAs) in the same way deliverability constraints already trigger price separation in base residual auctions (BRAs). Those price differences would signal opportunities for developers to build new infrastructure.

PJM will seek to identify locations where gas-fired generators are vulnerable to pipeline disruptions. | *Ohio Power Siting Board*

PJM hopes to have the process in place for the 2022/23 BRA in May 2019.

Avoiding Problems

In announcing the plan, CEO Andy Ott repeatedly reiterated that, while PJM's grid is currently reliable and has no fuel security issues, problems could materialize if cur-

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IN THIS WEEK'S ISSUE

COUNTERFLOW

BY STEVE HUNTOON

The Surreal, the Absurd and the Tragic

The Surreal

I'd like to apologize — on behalf of FirstEnergy — for dragging countless congressmen into the arcane world of the electric utility industry. You've had to listen to millionaire lobbyists — the quintessential swamp — talking about stuff so dry that we who toil in this world aren't allowed to talk to our spouses about it.

And biggest apology to Sen. Manchin because you're the biggest victim. Bailout for FirstEnergy via the Defense Production Act of 1950? OMG.

Do you think if there were a scintilla of national security threat we might have heard something from, hmm, let's see, maybe the Defense Department?

But here we are.

If you're just listening to FirstEnergy's lobbyists, you've missed a few key facts. FirstEnergy's plants are:[1]

- Not baseload.
- Old — not retiring prematurely.
- Inefficient.
- Unreliable.
- Not needed for a reliable and resilient grid.

In the tough competition for weakest bailout argument, the winner is the argument that if we didn't have all the coal plants we had last winter, there would have been an electricity problem, which is like saying if we didn't have all the Fords we had last winter, there would be a car problem. Duh.

All the Fords aren't disappearing overnight. And the Fords that do disappear are being replaced by better Fords.

A weaker argument for subsidizing old, inefficient and unreliable plants is hard to imagine. If it had prevailed 100 years ago, we'd still be driving Model T's.

Quick Quiz

Let's see if you've been conned with a quick quiz question: The Department of Energy projects in the year 2050, 32 years from now, there will be this much coal and nuclear generation in the United States:

a) 0 gigawatts
b) 10 gigawatts
c) 100 gigawatts
d) 274 gigawatts

The answer is d) 274 gigawatts.[2] Yes, Rick Perry's own Department of Energy projects a huge amount of coal and nuclear generation to be around for the *next 32 years*.

It's a con to pretend coal and nuclear plants will disappear quickly (or at all), causing any sort of reliability problem — and to premise a bailout on such fantasy.

The Absurd

The absurd is that all the responsible entities in the electric industry know there is no emergency. All the independent grid operators, the unanimous Federal Energy Regulatory Commission (where four of the five Commissioners are Trump appointees), former federal regulators, and all the independent analysts have repeatedly said that. These would be the first to warn of an emergency if one actually existed.

Compounding the absurdity, earlier this month FirstEnergy told the bankruptcy court that all its coal and nuclear plants would be operating throughout its bankruptcy proceeding.[3] That proceeding will take at least five to six years.[4] That means all the FirstEnergy plants will be operating for at least the next five or six years.

On top of that, Robert Murray, coal CEO and FirstEnergy's fellow traveler, told *The Wall Street Journal* earlier this month there was no longer any need for a bailout to save his company from bankruptcy because of increased exports to Asia.[5] He now "expects his company to thrive whether or not the Trump administration intervenes," the *Journal* reported.

There is no fire. Or even a puff of smoke.

The Tragic

FirstEnergy's customers paid it $6.9 billion in return for the company's transition from a regulated environment to a competitive environment. If that "bet" had turned out well, FirstEnergy would, of course, have kept the money. It hasn't gone as well as FirstEnergy anticipated, and now FirstEnergy wants customers to bail them out all over again.

I didn't realize just how outrageous that was until poring through the record of FirstEnergy's stranded cost proceeding in Ohio from almost 20 years ago. FirstEnergy's stranded costs were based on the difference between their regulated "net book value" and their net revenues in the future under market conditions.

Please bear with me. "Net book value" is the original cost of the plants reduced by the amount of capital that customers already have reimbursed the utility (a.k.a., depreciation). So, when FirstEnergy was paid net book value (less the future market revenues it would get to keep), it was paid the rest of the plant costs that customers hadn't already paid for.

In other words, customers have already paid for 100% of FirstEnergy's plants. FirstEnergy may retain legal title, but in equity the customers own the plants.

Can you imagine the tragedy of customers having to pay for those old, inefficient and unreliable plants all over again? Let's hope a surreal and absurd bailout and a tragic rate increase don't come to pass. And if they do, let's hope voters figure out who's responsible.

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] All of this is common knowledge in the industry. For my own takes, the non-baseload, old and inefficient nature of these plants is discussed here: http://www.energy-counsel.com/docs/Clunker-Poster-Child.pdf. The unreliable nature of these plants is discussed here: http://www.energy-counsel.com/docs/Cash-for-Clunkers-Redux-RTO-Insider.pdf. The lack of need for these plants is discussed here: http://www.energy-counsel.com/docs/Counterflow_More-Smoking-Guns-for-the-Clunkers_RTO-Insider.pdf.

[2] https://www.eia.gov/todayinenergy/detail.php?id=35572 (for coal, 195 gigawatts); https://www.eia.gov/outlooks/aeo/pdf/AEO2018.pdf (page 43, for coal, 79 gigawatts)

[3] https://www.usnews.com/news/best-states/ohio/articles/2018-04-04/utility-says-power-plants-will-stay-open-during-bankruptcy

[4] https://www.ohio.com/akron/business/breaking-news-business/firstenergy-solutions-bankruptcy-could-take-years-consumer-impact-review-begins

[5] https://www.wsj.com/articles/robert-murray-says-trump-administrations-help-not-needed-to-save-his-coal-company-1523570164?mod=searchresults&page=1&pos=3

CAISO NEWS

California Legislation Shields Utilities from Wildfire Costs

The La Tuna wildfire in September 2017 was the largest in the city of Los Angeles in 50 years. | *Wikimedia*

By Jason Fordney

A bill allowing utilities to recover wildfire costs if they conform to state-regulated safety plans moved through the California legislature last week, but it faces heavy opposition from some who say it lets utilities off the hook for their contribution to the blazes.

The relevant language in SB 1088, introduced by Sen. William Dodd (D), requires each electrical and gas utility to submit a biennial safety, reliability and resiliency plan to the California Public Utilities Commission (CPUC), beginning Jan. 15, 2019. It would require the CPUC to review the plans in a single consolidated proceeding and verify the plans comply with all rules, regulations and standards. The initial plan must be limited to addressing fire risks, with subsequent plans addressing risks associated with routine operation and all major events.

Calif. State Sen. William Dodd | *U.S. Army Corps of Engineers*

If utilities are found to be in "substantial compliance" with the plan, "the utility's performance, operations, management and investments addressed in the plan must be deemed reasonable and prudent for all purposes," a bill analysis said. The legislation would not protect utilities from civil lawsuits, which represent a separate area of liability for the fires.

The cost recovery issue is front and center for California investor-owned utilities, regulators and ratepayer interests as utilities try to recover costs of the devastating disasters.

The CPUC last December denied San Diego Gas and Electric's (SDG&E) request to recover $379 million from ratepayers for 2007 wildfires. (See *Besieged CPUC Denies SDG&E Wildfire Recovery*.) Commissioners at the time said the decision turned on a specific case of whether SDG&E had reasonably maintained its facilities, not on the cost recovery issue.

California law requires that any costs ratepayers incur on behalf of a utility must be just and reasonable, but the CPUC found SDG&E's management and control of its facilities prior to the 2007 Witch, Guejito and Rice Wildfires were unreasonable, mentioning poor vegetation management and other activities.

Seeing the writing on the wall for future cost recovery of last year's fires, the state's two other large investor-owned utilities, Pacific Gas and Electric (PG&E) and Southern California Edison joined SDG&E in requesting a rehearing of the CPUC decision and launched a fierce response on legislative, regulatory and legal fronts. (See *Sempra Joins 'Three-Pronged' Wildfire Front*; *PG&E Vows Fight over Wildfire Cost Recovery*.)

PG&E and other investor-owned utilities are being investigated for causing the 2017 fires, but utilities say they cannot be held solely responsible for the increasingly high-risk fire conditions in California, which most observers attribute to climate change. Sempra Energy CEO Debra Reed told shareholders in February she expected legislative action on the issue.

And state lawmakers such as Assembly Utilities and Energy Committee Vice Chair Jim Patterson (R) are sounding the alarm about IOU bankruptcies after utilities lobbied in Sacramento earlier this year for a legislative fix. (See *Wildfire Costs Ignite Worry at CPUC, Legislature*.)

In his author's comments on SB 1088, Dodd said that climate change will cause more frequent and intense storms, floods, mudslides and wildfires, and eight of the 20 most destructive wildfires in state history have happened since 2015, with five occurring in 2017. "Many scientists predict the 2017 fire season is not an anomaly, and similar wildfires are likely to continue into the future," he said.

Opponents of the bill include California Large Energy Consumers Association, California League of Conservation Voters, Consumer Attorneys of California, Consumer Federation of California, Environment California, Environmental Defense Fund, Silicon Valley Leadership Group and The Utility Reform Network (TURN).

TURN said the bill "would enrich utility shareholders at the expense of vulnerable households who would be forced to pay large rate increases for bloated programs of unproven benefit to safety risk reduction. TURN fully recognizes the increased risk of wildfires poses new challenges and financial threats to both ratepayers and utilities. Unfortunately, SB 1088 is fundamentally flawed and offers no such constructive solutions."

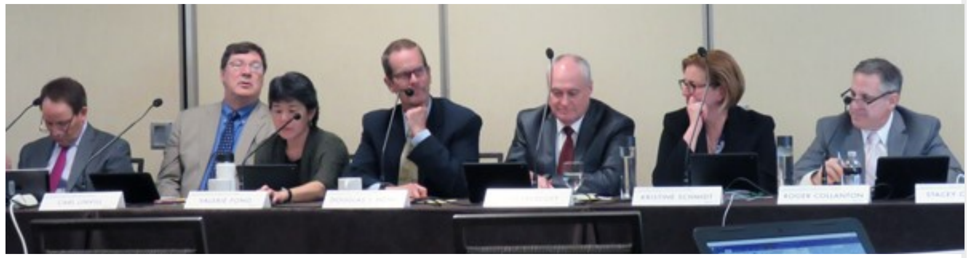
The Senate Governmental Organization Committee cleared the bill on April 24 on an 11-1 vote, and it now goes to the Senate Appropriations Committee.

The Senate Energy, Utilities and Communications Committee passed the measure on April 17 with a 9-1 vote.

CAISO NEWS

EIM Body Approves Imbalance Conformance Rules

By Jason Fordney



CAISO's Keith Casey (L) and Roger Collanton (R) surround EIM Governing Body members Carl Linvill, Valerie Fong, Doug Howe, John Prescott and Kristine Schmidt. | © *RTO Insider*

Western Energy Imbalance Market (EIM) leaders last week approved rule changes that would allow EIM balancing areas to manually adjust load forecasts during market operations to ensure the grid can support system conditions.

The five-member EIM Governing Body at an April 24 meeting in Vancouver, Canada, approved the ISO's proposed "imbalance conformance" rule changes, which allow operators to manually update the load forecast to account for changing grid conditions. Conformance is used to account for errors in the load forecast, CAISO Market Design Manager Brad Cooper told the body.

"A lot of times it is [used] because of supply deviations, whether it is generators deviating from their dispatch or renewable energy forecast error," Cooper said during a presentation. The body's decision conforms with CAISO's final proposal issued in mid-March, which clarifies that ISO and EIM balancing area operators can make imbalance adjustments, a clarification CAISO said it was making in the interest of transparency.

The proposal also includes alterations to the "imbalance conformance limiter," an ISO software tool designed to prevent price spikes caused by imbalance conformance adjustments. The adjustments can be imprecise, CAISO said, and the limiter keeps the market from trying to dispatch more supply than is available in a particular dispatch interval.

The Governing Body unanimously approved the tariff clarifications under its primary authority, while the imbalance conformance limiter changes fall under the body's advisory role. CAISO plans to seek approval from its Board of Governors on May 16 and then submit them to FERC.

The ISO said the changes were approved by all stakeholders, including Arizona Public Service, the Department of Market Monitoring, Pacific Gas and Electric, Public Generating Pool, Powerex, Southern California Edison and the Six Cities group of Southern California utilities.

CAISO initially announced the rule changes last November. Also called "load bias," the practice has drawn comment from some market participants that note CAISO is increasingly relying on it, particularly in early morning and evening hours when solar generation comes online and offline. (See *'Load Bias,' Prices Rise in CAISO Q3*.)

In its proposal, the ISO noted that imbalance conformance is imprecise because it uses an aggregated value since manually updating all the supply deviations every five minutes with 100% accuracy is not possible. Using the load forecast allows the conformance adjustments to be spread evenly across the system.

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CAISO NEWS

CPUC Approves $98M PG&E *Ex Parte* Settlement

CPUC members (left to right): Guzman-Aceves, Peterman, President Picker, Randolph, and Rechtschaffen at their Nov. 9, 2017 meeting in San Francisco | © *RTO Insider*

By Jason Fordney

Pacific Gas and Electric (PG&E) will pay $98 million in penalties for past improper communications with the California Public Utilities Commission (CPUC), but the years-old proceeding related to the controversy will continue to drag on because of new emails that came to light last fall.

The CPUC on Thursday approved the $98 million settlement with PG&E, but the *ex parte* proceeding remains open to consider emails divulged late last fall revealing additional improper communications between the utility and its regulators. (See *CPUC to Vote on $98M PG&E Settlement*; *Probe Reveals More CPUC-PG&E Contacts on Pipeline Blast*.) The penalties covered eight different CPUC proceedings, including one related to the 2010 San Bruno pipeline explosion that killed eight people.

The communications "have cast public suspicion on the integrity of the commission's regulatory process," the CPUC decision said. PG&E released 67,000 emails as part of the proceeding, including a new batch supplied to the agency in September that revealed more back-channel discussions. The *ex parte* proceeding was spurred by a public records request by the City of San Bruno in the wake of the September 2010 explosion.

None of the five commissioners who voted on the settlement Thursday were involved with the improper communications. Parties to the settlement include PG&E, the City of San Bruno, The Utility Reform Network (TURN), the City of San Carlos and the CPUC's Office of Ratepayer Advocates and Safety and Enforcement Division. TURN Executive Director Mark Toney on Thursday issued a scathing rebuke of the utility, saying "customers are tired of all the corruption at criminal corporation PG&E. And they want assurances that they are not paying even a penny of the costs of that corruption in their monthly bills, which is what this settlement provides." PG&E was convicted of a felony related to the 2010 San Bruno pipeline explosion and in April 2015 paid a separate $1.6 billion fine for safety violations.

The new fines approved Thursday will come from shareholders and not ratepayers and will pay $12 million into the state's general fund, $6 million each to the cities of San Bruno and San Carlos, and reduce by $10 million the revenue requirement in PG&E's next general rate case. The utility will also forgo collection of $64 million in revenue in 2018 and 2019.

"PG&E's failure to report these communications is an unacceptable violation of the CPUC's rules and justifies the remedy provided in this case," the CPUC said in a blog post. "Although these violations occurred more than four years ago, today's decision is an affirmation that all parties to the CPUC's proceedings must comply with the *ex parte* rules."

The settlement was originally crafted in March 2017, but a CPUC administrative law judge ruled that a proposed $1 million payment to the state's general fund was too low, and PG&E agreed to pay another $11 million to the state. The settlement agreement approved Thursday is the largest financial remedy ever imposed by the commission over violations of its *ex parte* rules.

EIM Body Approves Imbalance Conformance Rules

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Two Spots to Open

EIM Governing Body Chairman Doug Howe is due to step down from the panel at the end of June, when his first term ends. (See *'Hesitancy' Around Western RTO, EIM Chair Says*.) Body member Carl Linvill's term also ends on June 30, and it is not known whether he will seek re-nomination. Other members include Vice Chairs Valerie Fong and John Prescott, whose terms end in 2019, as well as Kristine Schmidt, whose term runs out in 2020. All five are original members of the panel overseeing the regional market, which is expected to incorporate CAISO's day-ahead market functions, a major change. (See *CAISO Says Changes Will Better Match Forecasting, Demand*.)

CAISO Regional Affairs Manager Peter Colussy told the board that an eight-member nominating committee and a third-party executive search firm are looking nationwide to fill two positions on the board. In-person interviews for new EIM Governing Body candidates are set for May 10-11 in Phoenix, Ariz. Relevant expertise is needed, as well as a familiarity with the Western Interconnection, and candidates must be independent of participants in the ISO and EIM markets or those who advocate for certain positions in the ISO stakeholder process, Colussy said in a presentation.

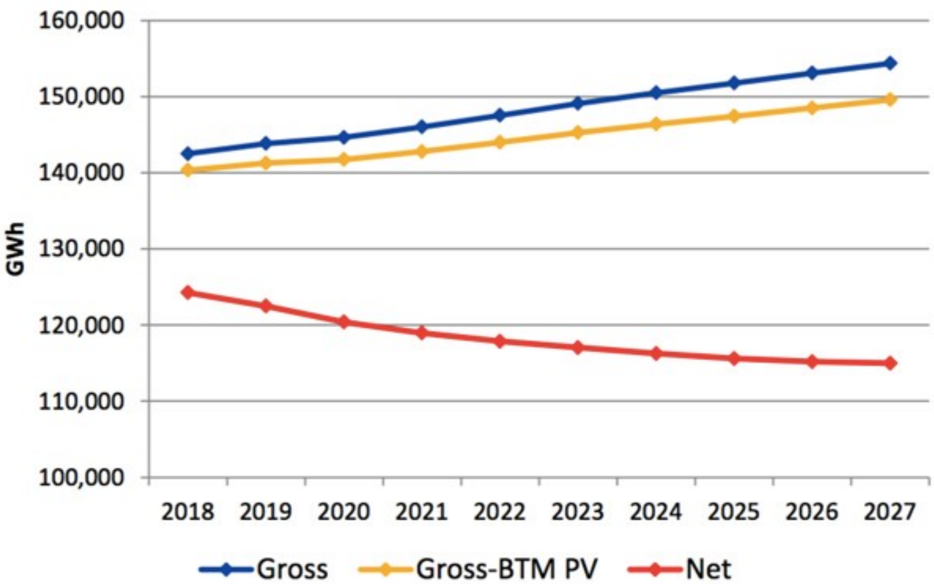
The approved slate of candidates is due for approval by the Governing Body on June 20. Terms are three years, beginning July 1 of each year and ending on June 30. In January, the EIM Governing Body rejected a proposal that would have changed how the board nominates members. (See *EIM Body Tables Nominating Process Changes*.) The rejected proposal would have eliminated the EIM Nominating Committee's obligation to use an executive search firm to help fill Governing Body vacancies, instead encouraging committee members to rely more on their own contacts.

ISO-NE NEWS

ISO-NE Planning Advisory Committee Briefs: April 26, 2018

Final 2018 CELT Forecast: Declining Load

MILFORD, Mass. — ISO-NE's 10-year Capacity, Energy, Loads and Transmission (CELT) forecast predicts 2026 annual net load will be about 3.7% lower than estimated in the 2017 forecast, Load Forecasting Manager Jon Black told the Planning Advisory Committee (PAC) on Thursday.



2018 CELT Forecast | *ISO-NE*

Net load forecasts, developed by subtracting energy efficiency and behind-the-meter solar from gross forecasts, are intended to be representative of energy and loads observed in New England in real-time.

The final 2018 CELT forecast update was changed slightly from the draft version presented at the March 15 PAC.

The behind-the-meter solar photovoltaic (PV) forecast is approximately 0.4% lower in 2026, slightly higher than the draft 2018 forecast, while the energy efficiency (EE) summer forecast is approximately 12.9% higher in 2026, down from the draft 2018 EE forecast. (See *ISO-NE Planning Advisory Committee Briefs: March 15, 2018*.)

Compared to last year's forecast for 2026, the 2018 CELT gross load forecasts show annual energy approximately 0.3% higher, gross summer 50/50 load about 2.7% lower and gross summer 90/10 load about 2.8% lower.

Net load forecasts, updated since March 15, show the net summer 50/50 forecast approximately 5.4% lower in 2026, with the net summer 90/10 forecast approximately 5.3% lower.

All forecast data will be posted on the RTO's load forecast website by May 1.

Winter Review Highlights Fuel Security Issues

The RTO's review of 2017/18 Winter operations showed stress on the grid from a severe cold snap around the turn of the year

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ISO-NE NEWS

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and from an exceptional chain of four nor'easters in March.

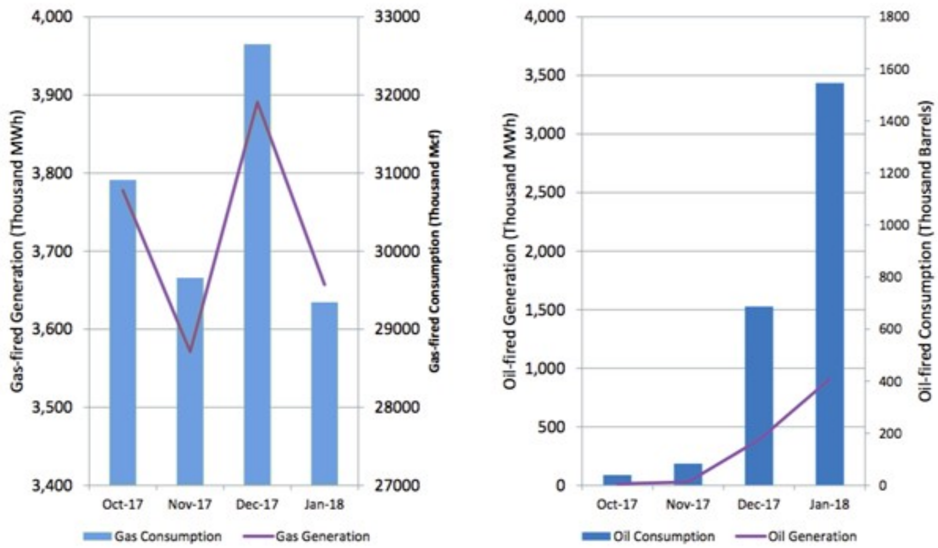
System Planner Mark Babula said the RTO avoided initiating emergency capacity deficiency procedures but did declare "Master/Local Control Center 2" procedures in early January and for each March storm, making them "hands-off" periods for regular generator maintenance or unnecessary outages.

As natural gas prices spiked, generators that could turn to oil did so, rapidly depleting the entire season's oil supply.

Sea and river ice hindered ship and barge deliveries to fuel oil terminals in New Hampshire and Maine and on the Hudson River, so the RTO "monitored ice with the U.S. Coast Guard, trying to get those icebreakers up the rivers to keep the natural gas supply lines open," said Babula.

The Winter 2017/18 Reliability Program started Dec. 1, 2017, and 86 generator units participated in the oil program for a total of 3.9 million barrels of oil. Approximately 2.9 million barrels of the total inventory on Dec. 1 are eligible for compensation according to winter reliability program rules, with total oil program cost exposure projected to be $29.62 million (at $10.33/barrel).

The reliability LNG program had no participants this winter, while three assets providing 7.5 MW of interruption capability participated in the demand response (DR) program, with the total program cost exposure projected to be around $23,000.



Winter oil and gas consumption vs. generation in New England | *ISO-NE*

Babula said daily communication with suppliers and pipeline operators is key to ensuring adequate fuel supplies, whether of oil, natural gas or LNG. (See *ISO-NE Sees Growing Fuel Security Risks* , *RTO Resilience Filings Seek Time, More Gas Coordination*.)

Natural Gas Rules Home Heating in Northeast

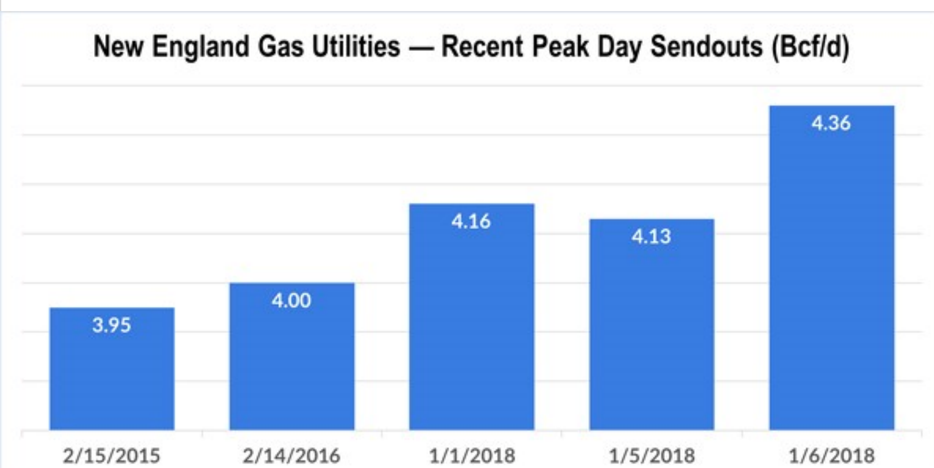
New England and neighboring states have seen household natural gas customers grow by 1 million since 2010, with gas increasingly fueling energy generation as well, Tom Kiley, president of the Northeast Gas Association, told the PAC.

Kiley's regional gas market update highlighted recent market growth, pipeline development and lessons learned from the winter cold snap from around the holidays.

The United States set a new gas sendout record of 150 Bcf on Jan. 1, 2018, while most local gas distribution companies in the Northeast set multiple sendout records in the first week of the year. New England natural gas utilities set three new sendout records that week — with a new all-time peak near 4.4 Bcf set on Jan. 6.

LNG played a key role in supplying generators during the cold snap, with the Distrigas terminal importing six cargoes totaling about 16 Bcf. Canaport LNG provided input into the Maritimes and Northeast Pipeline during the same period, with three cargoes in January, totaling about 9 Bcf.

Kiley cited a FERC report issued Apr. 19 that said "natural gas prices in New York City, New England and the Mid-Atlantic all set all-time record highs, with next-day trades reaching as high as $175/MMBtu in New York City on January 4. Although Operational Flow Orders limited shippers' flexibility to exceed their contractual obligations to meet varying natural gas demand, there were no pipeline outages or firm service curtailments."



| *Northeast Gas Association*

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ISO-NE NEWS

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The Natural Gas Act's gas supply task force has good communication protocols in place between gas pipeline control rooms and the power grids, Kiley said.

While gas utility demand continues to rise, New England has added nearly half a billion cubic feet per day of new pipeline capacity since November 2016, he said, with multiple projects planned to go into service through 2019. The Northeast region currently produces about 27 Bcf/d, with further growth expected; Pennsylvania is the second largest gas producing state in the U.S.

Updating Needs Assessments to Reflect Latest Forecasts

The RTO presented an update on the transmission Needs Assessments for Maine (ME), New Hampshire (NH), Southwest Connecticut (SWCT), Western and Central Massachusetts (WCMA) and Southeastern Massachusetts and Rhode Island (SEMA/RI).

Brent Oberlin, director of transmission planning, said the assessments attempt to balance the benefits of incorporating the latest load forecast against adding delays to each of the studies from including the data. A preliminary review shows the new forecasts could potentially eliminate some system needs.

The RTO has already posted a draft scope of work reports and intermediate study files for SEMA/RI and WCMA and will publish the SWCT scope of work in early May, with a finalized Needs Assessment due to be complete in September.

Maine and New Hampshire updated scope of work reports will also be published in early May, with final Needs Assessment reports slated to be delivered in October.

Cost Recovery in Flood Hazard Areas

Michael Drzewianowski, an ISO-NE lead engineer, outlined the RTO's new recommendations for regional cost recovery for transmission resources built in flood hazard areas. Large storms and other weather-related events in the past several years have changed the RTO's thought process on designing for flood hazard areas, he said.

Drzewianowski's report said the relevant Tariff clauses are defined on the Federal Emergency Management Agency Flood Insurance Rate Map.

In inland locations (defined as areas that have no chance for "wave action"), the RTO is now recommending cost recovery for infrastructure constructed to withstand the higher of the 100-year flood level plus two feet or the 500-year flood level.

For coastal locations, the RTO recommends adding another foot to the inland figure to account for sea level rise. For existing equipment that needs to be raised, the recommendation is to the bottom of sensitive equipment.

The RTO's previous recommendation was to construct to the 100-year flood level, plus an additional one foot, developed after review of national information available, including recommendations from FEMA and the American Society of Civil Engineers.

Comments on the plan can be submitted to PACMatters@iso-ne.com by May 10, ahead of the Reliability Committee review process anticipated to begin in June.

Eastern Conn. 2027 Needs Assessment Update

Jon Breard, associate engineer for transmission planning, presented an update on the Eastern Connecticut Needs Assessment results showing non-transmission options are not adequate to relieve the area's reliability criteria violations.

All updated needs are time-sensitive and based on the location of the reliability criteria violations; the RTO will work with participating transmission owners as needed. The final Needs Assessment report will be posted by May 31, and the PAC will be presented solution alternatives in the third quarter.

In addition, Kannan Sreenivasachar, principal engineer for transmission planning, presented an update on preferred solutions for SEMA/RI.

FCA 13 Zonal Boundary Determinations

Al McBride, director of transmission strategy and services, presented a review of interface transfer capabilities for a proposed capacity zone construct for the 13th Forward Capacity Auction (FCA 13, Capacity Commitment Period 2022/23).

The review showed no change to the interface transfer capabilities as a result of the new certifications for FCA- 3.

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ISO-NE NEWS

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The electrical limit of the New Brunswick-New England (NB-NE) Tie is 1,000 MW but drops to 700 MW when adjusted for the ability to deliver capacity to the greater New England control area.

The Hydro-Quebec Phase II interconnection is a DC tie with equipment ratings of 2,000 MW. Due to the need to protect for the loss of this line at full import level in the PJM and NY control areas' systems, the ISO-NE has assumed its transfer capability is 1,400 MW for capacity and reliability calculation purposes.

New York interface limits were modeled without the Cross Sound Cable and with the Northport Norwalk Cable at 0 MW flow and show that simultaneously importing into New England and SWCT or CT can lower the NY-NE capability by around 200 MW.

The Maine Load Zone will be evaluated as a potential export-constrained capacity zone, and a significant backlog of requests exists in the interconnection queue in Maine. FERC's Nov. 1, 2017, approval of the RTO's clustering proposal will enable the queue to move forward in Maine, which will allow more resources there to qualify for the FCA.

Northern New England will be evaluated as a potential export-constrained capacity zone that could be modeled either with or without Maine. The zone's potential boundaries will be tested and presented to the Power Supply Planning Committee in May.

Transmission Planning Technical Guide Update

ISO-NE is continuing to revise the Transmission Planning Technical Guide, which it reorganized last year into a new format. Revision 2 was posted on the ISO website on Nov. 14, 2017.

Steve Judd, lead engineer for system planning, presented the technical guide report and said staff is now updating the following sections for consistency with the RTO's style guide and publication template:

- All Sections – Changes to terminology with Price Responsive Demand (PRD)
- Section 2.2 – Clarification to system load level definitions and what is tested
- Section 2.8 – Simplified generic interface transfer levels section and moved detailed methodology to Section 4
- Section 2.11 (New) – Moved power flow solution settings to assumptions from methodology subsections
- Section 3.1.2.5 – Added maximum bus voltage limits for nuclear units to Table 3-2
- Section 4 – Split transmission Needs Assessments and Solutions Studies into a separate subsection 4.1 and Proposed Plan Application Testing into subsection 4.2 to allow for clarification in differences between study methodologies
- Section 4.1 – Detailed review to reflect current process for transmission Needs Assessments and Solutions Studies
- Section 4.2 – Moved previous description of stressed transfer levels from Section 2.8 to new subsection of PPA studies

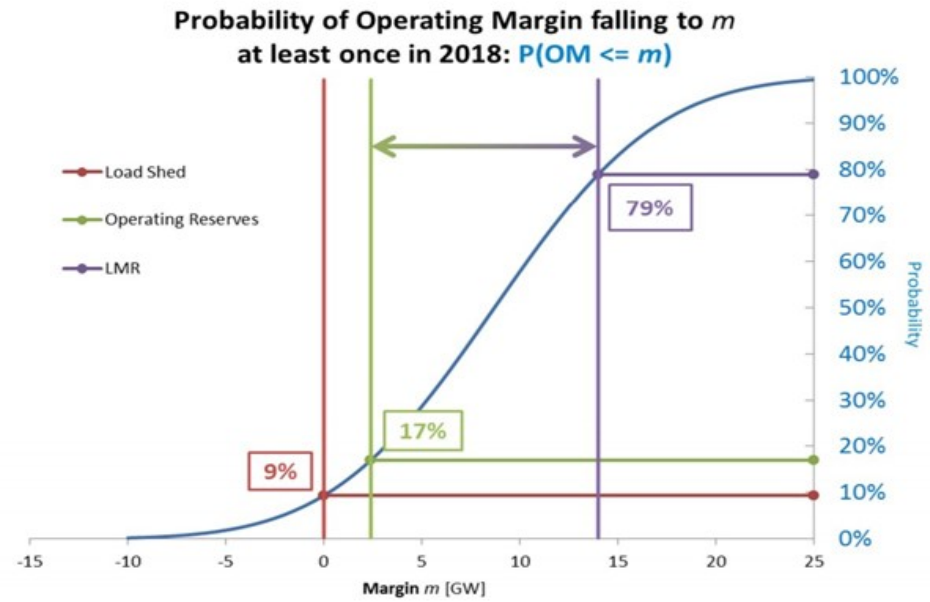
Proposed revisions to the Transmission Planning Technical Guide are to be posted to the PAC website, and stakeholders can provide comments by May 13 to PACMatters@iso-ne.com. Further detailed review of the guide will continue, with future revisions planned for 2018.

— Michael Kuser

MISO NEWS

MISO: Summer Reserves Adequate, but Emergency Likely

By Amanda Durish Cook



MISO summer probability of emergency | *MISO*

CARMEL, Ind. — While MISO says it's ready for a warmer-than-normal summer, RTO officials cautioned last week that operators will likely lean on demand response resources to manage loads at some point during the season.

During an April 24 summer readiness workshop, MISO officials stressed that summer capacity levels will exceed the forecasted 2018 summer peak demand and reserve margin requirement.

However, the RTO foresees a 79% probability it will call up load-modifying resources, a 17% probability of using operating reserves and a 9% chance it will be forced to shed load.

MISO predicts a 124.7-GW summer coincident peak with 148.6 GW in available supply and 11.4 GW in anticipated reserves after accounting for typical outages. Last summer, MISO predicted 148.5 GW worth of supply to meet a 125-GW peak demand, 4 GW shy of MISO's 121-GW actual peak load set in July.

"We have adequate supply to meet our expectations for this summer," MISO Senior Director of Systemwide Operations Rob Benbow told stakeholders.

Likewise, Kojo Sefah, a MISO resource adequacy engineer, said the RTO's transmission assessment showed no major constraints this summer.

However, MISO is predicting negative load growth combined with an increased use of behind-the-meter generation and demand response to meet the reserve margin.

"Negative load growth combined with an increase in behind-the-meter generation and demand response have increased our base reserve margin. What's that mean? We're going to use more [load-modifying resources] if we have to," said MISO shift operator Trevor Hines. " … That's what they're for."

Hines | © *RTO Insider*

In a high-load, high-outage scenario, MISO expects to "rely heavily" on demand response, said Eric Rodriguez, of MISO's resource adequacy division.

Hines said in a high-load, high-outage scenario, MISO is "3.3 GW of demand response away from having to use operating reserves to serve load."

Beginning in June, MISO will have a 17.1% planning reserve margin, based on limiting the likelihood of shedding load to no more than one day in 10 years. Last year's margin was 15.8%. The RTO said the shrinking load growth and increasing DR and BTM generation use helped boost the planning reserve margin.

MISO said while negative demand growth has helped increase reserves, the percentage of reserves available beyond the minimum requirement has decreased. During the 2016/17 and 2017/18 planning years, MISO had an additional 3% of reserves on hand. This summer, the RTO predicts 2% in additional reserves.

MISO said its summer predictions were predicated on the megawatts available in this month's Planning Resource Auction. Additional non-firm generation support may be available but cannot be definitively counted, the RTO said. (See <u>*MISO Clears at $10/MW-day in 2018/19 Capacity Auction*</u>.)

Rodriguez said the number of planned, maintenance and forced outages this summer are expected to be consistent with outage levels over the past five years. Last year, MISO experienced roughly 15-17.5 GW in outages during summer peak times.

Customized Energy Solutions' David Sapper said he didn't understand why MISO was putting such a "spotlight" on mitigating outages in other stakeholder discussions when it did not expect outages to increase this summer. MISO officials have said outages have played a role in most of the RTO's maximum generation events since late 2016, and they are looking into forecasting the effects of planned and maintenance outages on peak in its loss-of-load expectation study by the 2019/20 planning year. (See <u>*MISO Looks to Address Changing Resource Availability*</u>.)

MISO officials nevertheless said they stood by their summer outage prediction for this year.

Summer 2018 Weather

Using forecasts from the National Oceanic and Atmospheric Administration, MISO is expecting a warmer-than-normal summer for the footprint — especially in MISO South, with normal precipitation levels in MISO Midwest but lower-than-normal precipitation in the South region.

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MISO NEWS

MISO Ops Easily Handle Quiet March

By Amanda Durish Cook

CARMEL, Ind. — MISO easily managed what turned out to be a "near-normal" March, the RTO said last week.

The RTO's load averaged 71.1 GW for the month, in line with the 70.8 GW average a year earlier. But the 85.3 GW monthly peak set on March 14 came up 2.5 GW short of last March's peak.

Benbow | © *RTO Insider*

During an April 24 Informational Forum, MISO reported relatively mild weather in most of the footprint during March, although cold conditions persisted in parts of MISO Midwest.

"I would say winter just won't go away this year," observed MISO Senior Director of Systemwide Operations Rob Benbow, who added that lower temperatures kept demand relatively low during the month.

"We did see a lot of diversity in our weather footprint," Benbow said, noting that one day in March saw snowstorms up north while parts of MISO South were under tornado warnings.

"When you span that far across the United States, you expect that," he added.

Real-time prices in March were about 14% lower than they were last year, averaging $25.40/MWh, while day-ahead averaged $25.55/MWh.

Benbow said the price drop was due to lower congestion and natural gas prices compared with last year. Gas prices in March averaged $2.48/MMBtu at Chicago Citygate and $2.66/MMBtu at Henry Hub, down from $2.84/MMBtu and $2.83/MMBtu, respectively.

Benbow said the month brought the usual onset of generation maintenance outages, with planned outages doubling to about 25 GW as February transitioned into March.

MISO also set a new, 15.6-GW record peak for wind generation on March 31, toppling its previous 15-GW wind record set in January.

Queue Progress

MISO also provided an update on its interconnection queue, with Benbow saying completion of affected systems studies continue to slow queue progress, a topic debated in early April at a FERC technical conference. (See *Renewable Gens Face Off with RTOs at Seams Tech Conference*.)

MISO's generator interconnection queue currently includes 561 projects, totaling 93.1 GW, and the April 2018 definitive planning phase queue cycle added 244 projects, representing 41.2 GW.

MISO said it is managing 14 ongoing queue cycles with five more queue cycles set to begin in the coming months. The lion's share of the queue is renewable generation, with 42.7 GW of wind, 37.4 GW of solar and 12.3 GW of natural gas generation.

MISO: Summer Reserves Adequate, but Emergency Likely

Continued from page 11

"Sustained high temperatures can have an impact" on day-to-day operations, Rodriguez said.

Hurricane Prep

MISO is preparing for at least one major storm to hit the Gulf Coast portions of MISO South.

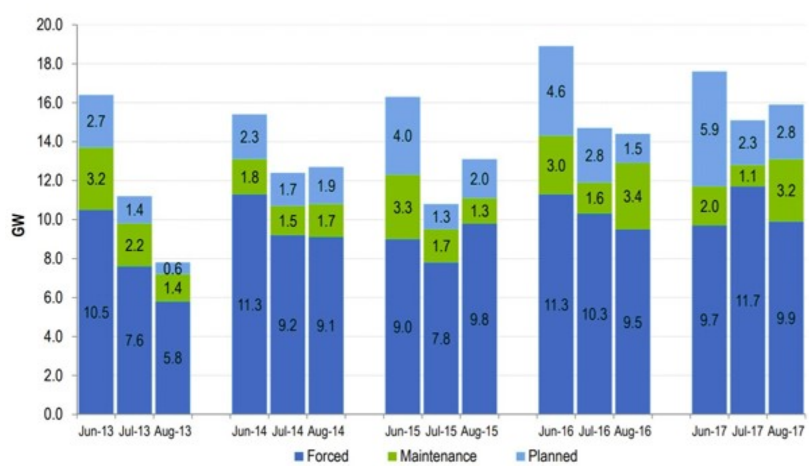
Colorado State University's Tropical Meteorology Project predicts 14 hurricanes for this summer, with seven of those developing into Category 3 or higher storms.

MISO South operations adviser Gerald Rusin said MISO will continue to use its hurricane action plan, which includes conducting a 31-hour, Category 4 storm simulation depicting multiple islanding events within the electric system.

Rusin said the university group sees a 38% chance of "at least one major hurricane making landfall along the Gulf Coast from the Florida Panhandle to Brownsville, Texas."

"There were four tropical weather events that took aim at MISO South last year," Rusin pointed out. Rusin said last year MISO maintained reliability through Hurricane Harvey's "unimaginable flooding" in the Lake Charles, La. area. Harvey submerged some substations and caused months-long generation outages in the Entergy footprint, he said.

MISO will hold a second hurricane preparedness drill with six MISO South market members May 16-17. A previous drill took place in mid-April.



Summer outage trends | *MISO*

MISO News

MISO Storage Group Takes on Order 845

By Amanda Durish Cook

CARMEL, Ind. — MISO's Energy Storage Task Force will now add to its to-do list storage-related aspects of FERC's recent rulemaking on generator interconnection procedures (Order 845).

The group said it will begin examining how MISO might need to alter provisions for energy storage interconnection to comply with the April 19 order, which prescribes more transparency and timeliness for RTOs' large interconnection agreements.

The order is expected to remove even more barriers to storage interconnection, according to MISO stakeholders. It explicitly revises the definition of a generating facility to include storage, permits interconnection customers to apply for interconnection service lower than the capacity of their generating facility and requires transmission providers to provide interim interconnection agreements for limited operation of a generating facility prior to completion of the full interconnection process, among other rules. (See *FERC Order Seeks to Reduce Time, Uncertainty on Interconnections*.)

"There are plenty of decisions in that order that are going to be impactful to storage," Energy Storage Task Force Chair John Fernandes said during an April 26 meeting.

Currently, there's just under 500 MW of energy storage in various stages of MISO's interconnection queue.

The task force began discussing the order after an April 25 conference call in which MISO's Steering Committee agreed to allow the group to explicitly consider both Order 841 and Order 845 when identifying discussion topics to recommend to other stakeholder groups. (See *Committee Ponders Expanded Role for MISO Storage Group*.)

MISO executives at the meeting said they are still reviewing Order 845 to identify how the RTO will be required to alter the interconnection process.

Executive Director of Resource Planning Patrick Brown said FERC's final order did not prescribe how to best model electric storage for the interconnection process, instead leaving storage modeling to be worked out between transmission providers and stakeholders.

Brown also noted the final order denied a request that energy storage be modeled as transmission assets in the interconnection process but said MISO is still determining whether the denial precludes storage from being treated as transmission.

"We're going to have to talk with our legal team about this," Brown said.

However, American Transmission Co.'s Bob McKee said he found nothing in the order preventing storage from being modeled as transmission.

"FERC is certainly still open to storage as a transmission asset," McKee said.

"Storage as transmission, that's kind of the next big thing in our industry to get FERC to make some rules around," Fernandes said. "I still think FERC is giving the green light to go ahead and do this; they're just not providing explicit rules yet."

Brown also said MISO may have to make a few tweaks to allow for interconnection service with surplus capacity, although the RTO's process for net-zero interconnection service requests could probably cover most of the directive.

"We believe that revisions to our net-zero provisions take care of that," Brown said, while conceding that some of MISO's net-zero rules may be too restrictive to meet FERC's compliance.

However, Wind on the Wires' Rhonda Peters said it's too "cumbersome" for projects to line up for net-zero interconnection service because of the requirement that customers must already be in the queue and provide milestone payments before they're able to respond to a request for proposal for net-zero service.

But Fernandes cautioned that while the Energy Storage Task Force could debate the interconnection queue as far as storage eligibility, queue improvements are the domain of MISO's Interconnection Process Task Force (IPTF).

"This task force is not assigned queue reform," Fernandes said.

Brown agreed a majority of work on Order 845 will be done at the IPTF. Fernandes said he would try to plan a joint conference call of the IPTF and the Energy Storage Task Force prior to mid-May to discuss how

AES Battery Storage | *AES*

FERC's order might make MISO's queue process more storage-friendly.

Brown said some work to comply with Order 845 will come down to finding language already included in MISO's business practice manuals and copying that language into the Tariff.

Some stakeholders asked if MISO would consider requesting an extension with FERC on the July compliance filing deadline for Order 845. Brown said MISO is judicious when requesting extensions, making sure it requests them only when necessary.

"It's a fairly short lead time," Brown conceded.

Process Holdup?

Stakeholders in attendance worried the July deadline would not provide enough time for the task force to identify Order 841/845 storage issues, then turn them over to the Steering Committee, which must then assign discussion to other stakeholder groups.

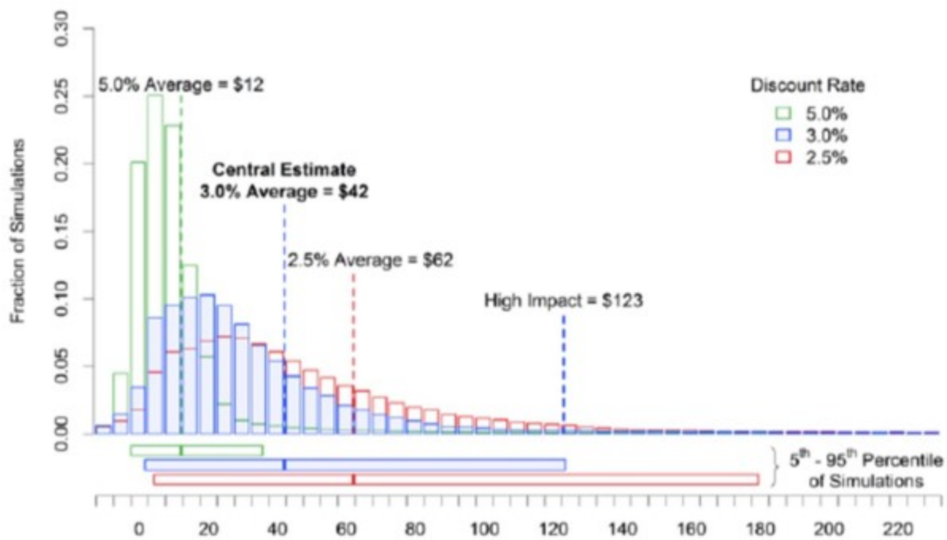
Customized Energy Solutions' Ginger Hodge said she was becoming "increasingly concerned" that the formal process of identifying issues and sending them to the Steering Committee was creating a roadblock to getting proposals written and vetted in other stakeholder groups.

Hodge said she didn't want the Steering Committee to become a place where "good ideas are quietly strangled."

NYISO NEWS

NY Task Force Looks at Social Cost of Carbon

By Michael Kuser



Frequency distribution of SC CO_2 | *Interagency Working Group on Social Cost of Greenhouse Gases*

To model the impacts of carbon pricing on dispatch, resource costs and emissions in its wholesale electricity market, New York would do well to start by estimating a social cost of carbon (SCC), experts told a state task force last week.

The Integrating Public Policy Task Force (IPPTF) heard three presentations April 23 on SCC and related topics as the group drilled further into technical details in its mission to reconcile the wholesale electricity market with state environmental goals.

The IPPTF is jointly run by NYISO and the state's Department of Public Service (DPS). The April 23 discussions were part of issue "Track 3" and "Track 5" in the group's five-track effort to price carbon emissions.

"Each and every ton [of CO_2] that's emitted contributes to harms that you and I face from climate change," Bethany Davis Noll, litigation director at the Institute for Policy Integrity at the NYU School of Law, said in explaining how the SCC attempts to put a monetary value on the damages associated with the incremental rise in carbon emissions each year. "What economists tell us is that if we can figure out a way to put a dollar value on those harms, it's easier for us to face or figure out what to do in response in order to stop them."

Davis Noll presented a report on the SCC determined by the Obama administration's Interagency Working Group (IWG) on Social Cost of Greenhouse Gases, which in 2016 estimated the SCC at $50 per ton of CO_2.

Numbers Game

President Trump in March 2017 signed an executive order disbanding the IWG and withdrawing its technical support documents, but federal agencies are still required to monetize climate harms, said Davis Noll.

Some agencies are still using the IWG's number, while EPA and the Bureau of Land Management have proposed to use an "interim" social cost of carbon.

"Basically, the interim estimate brings the $40 to $50 number down to $1," Davis Noll said.

The methodology used to get the $1 value obscures the global harm of emissions "and was rejected by the IWG as inappropriate for this type of analysis," Davis Noll said. "Agencies are not allowed to do lopsided analysis, putting a dollar value on the one side and not using a well-recognized tool on the other side."

David Clarke, director of wholesale market policy for Power Supply Long Island, contended the state has two approaches to consider: either a federally approved tariff or state regulation.

"What's your view on FERC and what kind of things they would consider when deciding whether a social cost of carbon is just and reasonable?" Clarke asked.

Davis Noll's position is as follows: Based on the "extensive research" already done on the SCC, the widespread support for the IWG number suggests it clearly is "just and reasonable" according to FERC standards.

"I think FERC is actually receptive to using it themselves in their decisions ... here all we have to do is figure out whether the ISO's proposal's going to be judged just and reasonable," Davis Noll said.

She added, "The executive order doesn't do anything, it really just disbands the working group ... and so far, there are so many states relying on this number — that's also supportive." States incorporating the IWG value into their environmental policies include California, Colorado, Illinois, Maine, Minnesota, New Jersey, New York and Washington.

New York Way

Warren Myers, DPS director of market and regulatory economics, presented a report recommending the task force use in its analysis the CO_2 value already adopted by the New York Public Service Commission (PSC).

The commission in its January 2016 Benefit Cost Analysis Framework Order (14-M-0101) relied on the IWG's "central value" SCC minus the Regional Greenhouse Gas Initiative (RGGI) allowance price, until Tier 1 renewable energy credit (REC) procurements were established later that year under the state's Clean Energy Standard (CES).

The PSC's March 2017 Value of Distributed Energy Resources (VDER) Order (15-E-0751) set compensation value at the higher of Tier 1 REC or SCC minus RGGI. Converted by DPS to dollar per ton, the latter figure would gradually increase over the coming decade from $40.74/ton in 2020 to $56.77/ton in 2030. (See *NYPSC Adopts 'Value Stack' Rate Structure for DER*.)

Myers said the precise dollars and cents values for each year could be a little misleading, since it is the order of magnitude

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NYISO NEWS

NYISO Board Rejects Appeals on Capacity Votes

By Rich Heidorn Jr.

The NYISO Board of Directors has rejected two appeals of Management Committee votes on capacity zones and locational capacity requirements.

The board declined to override the committee's Feb. 28 vote that fell short of the threshold for authorizing a Tariff change to create rules for establishing and eliminating capacity zones. The committee had voted 54.1% in favor, short of the 58% required. (See "MC Rejects On Ramp/Off Ramp Changes" in *NYISO Management Committee Briefs: Feb. 28, 2018*.)

The issue arose from Tariff revisions approved by FERC in 2012, setting rules for creating new capacity zones in the New York Control Area. The changes led the ISO to create a new capacity zone for the G, H, I and J load zones in the Lower Hudson Valley and New York City.

In denying an appeal by Central Hudson Gas & Electric and the New York Power Authority, the board said although some stakeholders called for developing rules for eliminating zones, FERC has not required them. The Independent Power Producers of New York (IPPNY), Cricket Valley Energy Center, Castleton Commodities Merchant Trading, Roseton Generating and the Long Island Power Authority (LIPA) opposed the appeal.

In 2017, ISO staff launched the "On Ramps and Off Ramps" project to consider rules for eliminating zones and concluded the deliverability-based approach used for creating zones was inappropriate for cancelling them. Staff said a reliability-based transmission security approach would be better for both creating and eliminating zones.

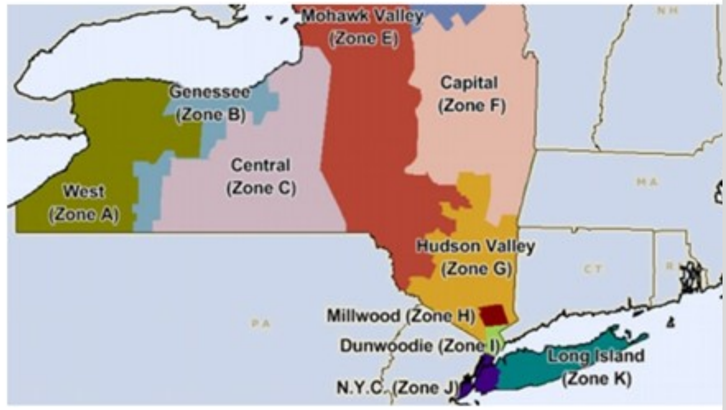
IPPNY said the change would distort market price signals and create uncertainty. Although it opposed the appeal, LIPA said it favors changes to the capacity zone rules.

"While we acknowledge the considerable time and effort NYISO staff and stakeholders spent developing the proposal, we deny appellants' request that the NYISO take the extraordinary measure of filing the proposal pursuant to [Federal Power Act] Section 206," the board said, calling "unpersuasive" the appellants' contention that current rules are unjust and unreasonable.

"The NYISO has filed Tariff amendments pursuant to Section 206 only a few times in its history. The facts and circumstances presented here do not warrant that approach. Even if the board were so inclined, we do not believe the NYISO could satisfy the significant burden of proof required to implement the proposal pursuant to a Section 206 filing."

The appellants' arguments regarding price impacts on customers were not persuasive, the board said.

"Appellants assert that retaining a locality longer than needed causes undue price separation and would result in 'excess costs' for Zone J and Zones G-I customers. However, they calculate potential excess costs to consumers based on current system conditions in which there exists a continued reliability need for the G-J Locality to remain in place. Under system conditions that might support elimination of the zone, the cost impact of retaining the zone — if any — would be much lower," the board continued. "We note that NYISO staff performed an analysis that illustrated, among other scenarios, the potential for adverse consumer impacts of prematurely eliminating a capacity zone. Appellants' papers are silent on the NYISO's consumer impact analysis, offering instead a conclusory economic assessment that is based upon incorrect assumptions."



NYISO Capacity Zones | *NYISO*

The board declined to remand the issue for further work but said stakeholders could consider it during the annual issue prioritization process.

Locational Capacity Requirements

In a related matter, the board also rejected an appeal from LIPA, NRG Energy and Helix Ravenswood, which asked the board to override the Management Committee's Feb. 28 vote approving a change in how the ISO calculates locational capacity requirements (LCRs). The measure passed with a 77.55% vote. (See "Alternative Methods for Determining LCRs" in *NYISO Management Committee Briefs: Feb. 28, 2018*.)

NYISO calculates the LCRs to maintain the statewide installed reserve margin (IRM) set by the New York State Reliability Council (NYSRC) based on the one-day-in-10 years loss-of-load expectation (LOLE).

The LCR rule change replaces the "TAN 45" methodology adopted for the 2006/07 capacity year, before the creation of zones G-J. Loads in the Lower Hudson Valley complained that TAN 45 increases their local requirement while reducing requirements for New York City and Long Island.

The new rules, originating from an economic approach recommended by Independent Market Monitor David Patton, are based on the lowest cost-to-supply capacity.

Opponents of the change called for more study of the issue. LIPA contends that the new method underestimates the capacity costs for a new unit in its zone and that it is being forced it to subsidize New York City, noting that its LCR is expected to increase to more

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NYISO NEWS

NYISO Board Rejects Appeals

Continued from page 15

than 100% of peak load, while the city is expected at less than 80%.

New York City and 60 large industrial, commercial and institutional energy consumers opposed the appeal of the rule change.

In rejecting the appeal, the board said the rule change was a "significant improvement" that had been "carefully developed, thoroughly vetted and received widespread support from market participants."

"Contrary to appellants' assertions that the new approach would introduce volatility, analysis indicates that the alternative LCR methodology will provide results that are more stable than the current approach," the board said.

The board also turned aside arguments that the new methodology is flawed because it does not optimize the IRM calculation along with the LCR calculations, saying it "ignores the fact that the IRM is set by the NYSRC — not the NYISO." The board said the ISO will work with the Reliability Council to explore a co-optimized approach but the new rules should not be delayed by that effort.

The board said, "Concerns over 'rate shock' are unpersuasive."

"The NYISO is open to further discussion on [subsidization concerns and] … alternative approaches to cost allocation," it said. "Such discussion is outside the scope of the instant proposal, however, and should not delay [its] implementation."

Social Cost of Carbon

Continued from page 14

that really matters. So, while those precise calculations do reflect the IWG numbers adopted by the PSC, we should not conclude they are necessarily any more accurate than Davis Noll's $50/ton estimate, he said.

A portion of the SCC has already been internalized in the ISO's locational-based marginal pricing, Myers said, "and so what we would like is the externality, which we say is the SCC minus the relevant RGGI number."

One reason developers and environmentalists in the VDER proceeding "opposed using the Tier 1 RECs price only was that it just really doesn't triangulate at all; it isn't tied at all specifically to carbon; it's just a compliance cost of a program with certain program parameters," Myers said.

Howard Fromer, director of market policy for PSEG Power New York, said he appreciated the DPS's effort to send a consistent price signal to the market that clarifies "here is the value of avoiding carbon." However, he said state subsidies for large amounts of preferred technologies, such as the $180/MWh cost for the first 90 MW of offshore wind on Long Island, has the potential to undermine the price signal consistency.

"I would hope that we would not blindly lock ourselves into the [IWG] number, given that I have very little confidence in what today's interagency task force, if reconstituted, might produce, and I would much prefer to speak to the New York [Public Service] commission, frankly, with consistency with their policy," he said.

Modeling Resource Shift

Tim Duffy, NYISO manager of economic planning, presented a report addressing customer impacts via a proposed methodology for modeling and analysis. The ISO proposed starting from a base case using its Congestion Assessment and Resource Integration Study (CARIS) data, updated and extended, and carrying through to both a simple change case and a dynamic change case, which would add assumed changes to fleet and load.

"For the purpose of developing the system resource shift scenario or case, we assume achievement of CES in 2026," said Duffy. The CES mandates that New York get 50% of its electricity from renewable resources by 2030.

The ISO study aimed to define enough market scenarios to span the range of plausible impacts of a carbon charge throughout the state, as well as the key factors affecting marginal emission rates in various parts of the state, such as whether a new renewable resource is located upstate or closer to the load centers around New York City, he said.

"We're proposing to run multiple years here, 2020, 2025 and 2030, and all the data associated with each of those three years would be provided," said Duffy.

IPPTF co-chair Nicole Bouchez, NYISO principal economist, referred to the Brattle Group carbon pricing report from last August.

"We're looking at something in the same conceptual way that Brattle looked at this, which is first you look at what are going to be the direct price impacts, and then you look at these dynamic changes, how does investment change, how do the numbers change," said Bouchez.

Marc Montalvo of Daymark Energy Advisors, representing the state's Utility Intervention Unit, said, "The state is going to seek to meet its CES policy objectives with or without this carbon charge policy. So, if we add the carbon charge, will that be a successful thing to do? Analytically, how do we measure success?"

NY Dept. of Public Service
Proposed Net CO_2 Charges
($ Nominal/US-Ton)

Year	Gross Social Cost of Carbon	RGGI	Net
2020	$47.30	$6.56	$40.74
2021	$48.30	$6.98	$41.32
2022	$50.48	$7.39	$43.09
2023	$52.74	$7.81	$44.93
2024	$55.07	$8.45	$46.62
2025	$57.48	$9.09	$48.39
2026	$59.96	$9.73	$50.23
2027	$62.52	$10.35	$52.18
2028	$65.17	$10.96	$54.20
2029	$66.54	$11.58	$54.96
2030	$69.32	$12.55	$56.77

| New York Department of Public Service

The task force will next meet May 7 at NYISO headquarters to further cover issue "Track 5," which it will discuss again June 4 to complete the assumptions and scenarios. The study results are scheduled to be presented in September.

In a related move, the ISO has scheduled a public forum May 1 on analysis of transmission congestion on the New York state bulk power system and the potential costs and benefits of relieving transmission congestion through its CARIS process.

NYISO NEWS

NY Sets 40% Hike in EE Goal

By Rich Heidorn Jr.

The New York State Energy Research and Development Authority (NYSERDA) published a white paper Thursday outlining plans to accelerate the state's energy efficiency (EE) goal by 40%.

The paper calls for 185 trillion British thermal units (TBtu) of cumulative annual site energy savings relative to forecasted 2025 consumption. The agency said that would deliver almost one-third of the emissions reductions needed to meet the state's goal of reducing greenhouse gas emissions 40% from 1990 levels by 2030.

NYSERDA said this would include a 30,000-GWh reduction from forecasted 2025 electricity sales — a 3% reduction in investor-owned utility sales in 2025 and average savings exceeding 2% of IOU sales between 2019 and 2025.

The new target is based on savings in buildings and the industrial sector across all fuel sources (electricity, natural gas, heating oil and propane).

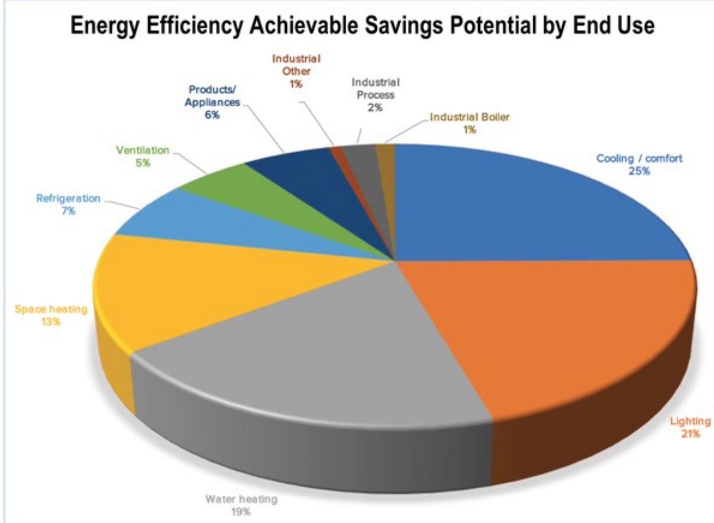
"This paper proposes a portfolio of accelerated actions to drive an additional 41 TBtu of aggregate efficiency savings statewide by 2025 or a 40% increase above the state's current commitments for the 2019–2025 period," NYSERDA said.

NYSERDA said it will spend an additional $36.5 million to train more than 19,500 people for energy efficiency and other "clean energy" jobs.

"The path to delivering on New York's 2025 energy efficiency target recognizes that a mix of strategies will be necessary, focusing on the approaches best suited for specific markets and their needs and on the mix best suited for long-term cost-effectiveness," the report said. "The portfolio will include a good measure of innovation, testing those approaches with the best promise, then scaling those that take hold."

NYSERDA said it will seek to meet the 2025 target by:

- "Accelerating and shifting" utility energy efficiency programs by increasing market-based EE, more leverage of public funds and more effective programs. "This includes the proposed development of a shared savings approach that provides greater opportunity and reward for utilities to advance energy efficiency as a business and as a resource." (See *NY Fine-tuning CES; Phasing out EE Program*.)
- Dedicating at least 20% of any additional public investment in EE to low- to moderate-income consumers.
- Strengthening laws on building codes and appliance standards by increasing EE requirements.
- "Driving deep energy savings" through building retrofits and construction and cost-effective heat pump adoption. "If New York is to achieve the 40 by 30 … climate goals, it will be essential to retrofit the state's existing building stock to dramatically reduce energy consumption, so that most buildings are able to reach passive house or net zero energy performance levels. This presents an imperative to develop deep (i.e., 30-40-50% energy savings) and replicable retrofit strategies … In the absence of government mandates, [efficient construction practices] will only reach true scale when market players view them as sound financial investments." (See *Lovins: We're Only Scratching the Surface on Energy Efficiency*.
- Leading by example with EE in state facilities.



Utility EE programs have had success in reducing energy use in lighting, but major savings remain in cooling and water heating. | *NYSERDA*

The agency noted the state's 2015 energy plan identified lighting as one of the biggest EE opportunities.

"Since then, utilities' efficiency programs have focused heavily on lighting. At the same time, costs of high-efficiency lighting products have come down and natural adoption [has] increased, resulting in a greater portion of the lighting savings potential being achieved in the years since this study was published as compared to other end uses.

"However, this data shows several other high-potential, end-use opportunities in addition to lighting — specifically, cooling and water heating. This highlights a need to broaden the scope of utility programs to address other cost-effective efficiency measures and to encourage approaches that pair lower-cost opportunities like lighting with other efficiency improvements to achieve deeper savings."

The state Public Service Commission will take steps to implement the white paper, beginning with a technical conference. "Following the initial technical conference, DPS Staff will initiate and define a process and schedule supporting further development of the jurisdictional aspects of the white paper," NYSERDA said. "This is expected to include additional technical conferences, as well as topical working groups and a formal written stakeholder comment process with the goal of developing an adequate record for commission action, including benefit, cost, and practical implementation information."

NYISO NEWS

FERC Orders Deadline on NYISO Market Power Reviews

By Rich Heidorn Jr.

NYISO must set a deadline for completing final market power reviews on retiring generators, FERC ruled.

The commission's April 23 ruling came on a rehearing request by Entergy Nuclear Power Marketing but denied the company's request that it set a 120-day deadline for the ISO's review of its Indian Point nuclear plant (ER16-120-004, EL15-37-003).

The issue stems from the commission's 2015 order that found the ISO's Market Administration and Control Area Services Tariff wanting because it did not include rules on the retention and compensation of generators needed for reliability. (See *FERC Orders NYISO to Standardize RMR Terms in Tariff*.)

Entergy sought rehearing or clarification of the commission's November 2017 ruling approving the ISO's second compliance filing in the docket, in which the ISO added a 90-day deadline for completing reliability studies related to plant shutdowns. Entergy said the ISO's lack of a deadline for the market power review left it without certainty about its authorization to exit the market.

The Services Tariff says the ISO can perform a market power review for capacity suppliers seeking to retire to determine whether the "decision has a legitimate economic justification" or is intended to withhold capacity to increase prices.

Entergy asked the commission to require NYISO to complete its final market power review of Indian Point by March 13, 2018, 120 days after receiving Entergy's complete generator deactivation notice. The company contended FERC had previously approved the 120-day deadline, which it said reflected the ISO's statements concerning when it plans to conduct the analysis and how long it takes to complete. (See *Entergy Asks FERC to Clarify Indian Point Retirement Process*.)

The ISO's market power reviews determine whether retirement decisions have "a legitimate economic justification" or are intended to withhold capacity to increase prices.

The commission said it had not approved the 120-day deadline but agreed with Entergy that the lack of a deadline "could impede the generator's ability to make informed decisions about deactivating." It gave the ISO 30 days to make a compliance filing proposing a "reasonable timeline" for completing the market power reviews.

"Although NYISO's [Open Access Transmission Tariff] states that it will determine whether a generator is needed for reliability within the first 90 days after the generator gives notice of its intent to deactivate, neither NYISO's OATT nor Services Tariff provide a timeline for NYISO to complete a final market power review (if needed), which impacts the ability of that generator to 'be deactivated as planned,'" the commission said.

"NYISO should set a deadline for completing final market power reviews (if needed) working back from the proposed deactivation date rather than starting from the submission of a complete generator deactivation notice," it continued. "This is because the final market power review may be less effective with data and assumptions too far removed from a generator's actual deactivation date."

Entergy plans to shutter Indian Point Unit 2 by April 30, 2020, and Unit 3 within a year after that.

Indian Point nuclear plant | *Wikipedia*

PJM NEWS

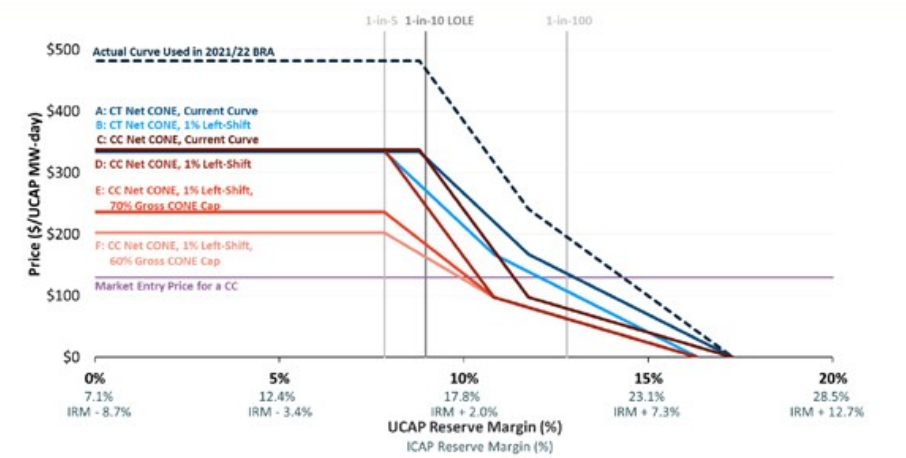
PJM to Consider Revisions to Demand Curve Design

By Rory D. Sweeney

When stakeholders begin considering potential changes to PJM's demand curve next month, one of the main debates will likely center on whether combustion turbines (CTs) should remain the reference technology for estimating the cost of new entry (CONE) or be replaced by combined-cycle gas turbines (CCGTs).

PJM will take up the issue of revising its variable resource requirement (VRR) curve at its Market Implementation Committee meeting on May 2.

The review, which occurs every four years, must be completed by Aug. 31 to be filed for FERC approval by Oct. 1 and put in place for use in the 2019 Base Residual Auction (BRA). PJM has until May 15 to recommend proposed Tariff revisions, which are based on an analysis by the Brattle Group, who provided recommendations of its own, some of which differ from PJM's.



Brattle's recommendation to use a combined cycle generator as the reference technology would also move the curve to the left. | *The Brattle Group*

Brattle's Analysis

PJM hired the Brattle Group to analyze the shape of the VRR curve, the CONE for areas used in the VRR Curve and the methodology for determining the net energy and ancillary services (E&AS) revenue offset for the region PJM serves and for each zone. Brattle representatives presented their findings to stakeholders on Wednesday.

Brattle's analysis found the Capacity Performance (CP) rules PJM implemented in 2016 would not significantly impact the curve it recommended in its 2014 report, but the net CONE has decreased "substantially" compared with the parameters that will be used this May in the 2021/22 BRA. CP flattens lower-priced offers in the supply curve but doesn't affect the higher-priced side of the curve.

"This reduces instances of very low prices and volatility but does not change results under high-priced, low-reserve-margin conditions that drive reliability performance," the report said.

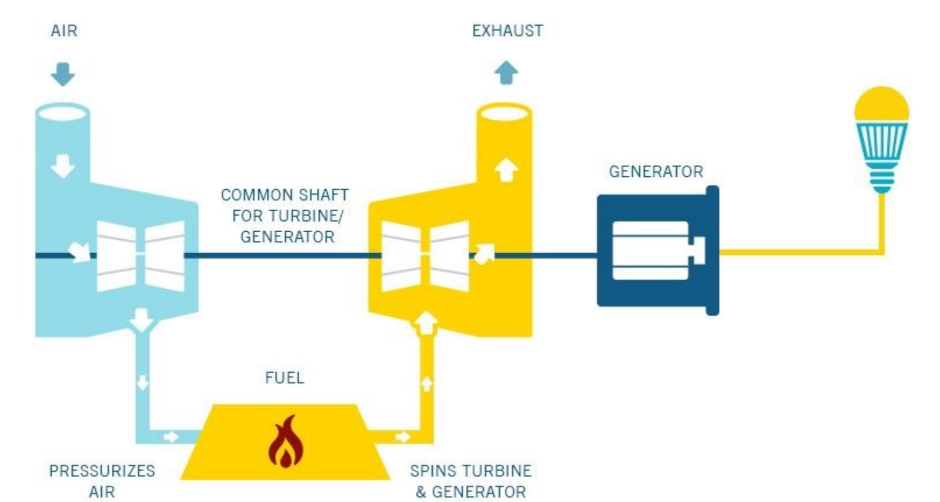
However, reducing net CONE would shift the VRR curve substantially down, such that the cost to procure PJM's installed reserve margin (IRM) would be potentially cheaper by hundreds of dollars per MW-day.

Removing CT Base

Brattle recommended using the net CONE for CCGTs as the reference technology in conjunction with localized adjustments. PJM currently uses the net CONE for CTs, but Brattle's analysis showed the construction cost for a CCGT has dropped as much as 40% so that it is just slightly higher than that of a CT. Net CONE for CTs also dropped in the updated calculations but not as much as net CONE for CCGTs, which Brattle estimates is between 44% and 76% lower than PJM's 2021/22 parameters and between 25% and 63% lower than its updated CT Net CONE estimates, depending on location.

"CCs are more economic because their much higher net E&AS revenues more than offset slightly higher plant costs on a per-kW basis," the report found.

"In reality, net CONE has declined substantially, especially for CCs, and this has major implications for the VRR curve," Brattle continued. "... If in spite of that reality, PJM maintained a CT as the reference technology for anchoring the VRR curve, [but] continued low-priced entry of CCs would maintain average reserve margins substantially above target."



Combustion turbine diagram | *Duke Energy*

Continued on page 20

PJM to Consider Revisions to Demand Curve Design

Continued from page 19

Brattle estimated that using a CC as the reference technology, along with adjustments to compensate for triggering an alternative price cap provision, would achieve average reserve margins 1.4% above the IRM target and decrease annual average procurement costs by $212 million compared with the current CT-based curve and $138 million compared with adjusting the current curve 1% to the left to account for the expected over-procurement.

Brattle also determined that if its analysis underestimated the CONE by 20%, the average loss of load expectation (LOLE) would rise to 1.6 events every 10 years rather than its target of 1 event every 10 years.

That said, Brattle didn't reject using the CT basis.

"We also see an argument for a CT-based curve if PJM and stakeholders are highly risk-averse about ever procuring less than the target reserve margin, since the incremental cost is modest in context," the report said. "Even a $140-million difference in cost is less than 0.5% of PJM's total annual wholesale costs."

Additional Recommendations

Brattle also recommended changes to PJM's methodology for calculating net E&AS revenues:

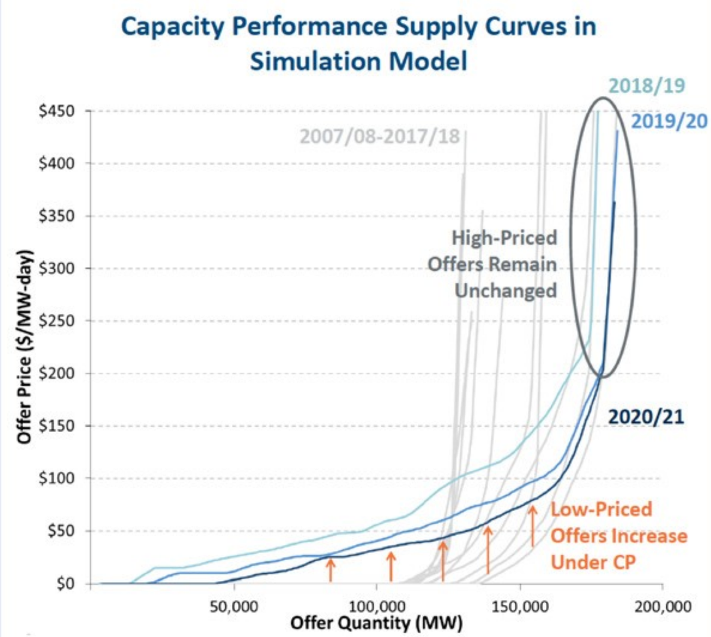
- Update gas-pricing points for six locational deliverability areas (LDAs).
- Update unit operating characteristics, such as heat rates.
- Include net CP payments.
- Move maintenance costs from variable operations and maintenance (O&M) costs into the fixed O&M cost component of CONE in the current cost development guidelines.
- Implement forward-looking estimates of E&AS revenues rather than the current three-year historical calculations.
- Calculate E&AS margins for RTO and other multizone LDAs based on median across zones.

PJM's Recommendations

In a letter to stakeholders, PJM recommended updating the CT used as the reference technology to a GE Frame Model 7HA, which Brattle used in its analysis based on project development trends, improved efficiency and lower costs. Stu Bresler, PJM's senior vice president of operations and markets, noted in the letter that NYISO, ISO-NE and the Alberta Electric System Operator all use CTs as their reference technology.

"The combustion turbine continues to provide the lowest CONE, shortest time to market, and derives the most significant portion of its revenue from the capacity market as compared to other resources.

"The fact that the CT receives the smallest amount of its revenue from the energy market means that its Net CONE value is the least likely to be significantly perturbed by potential changes in energy market prices," Bresler wrote. "PJM's certainty is provided through the use of a peaking unit as a reference resource because it minimizes the exposure to short-term energy revenue offset volatility."



Capacity Performance rules have flattened the lower-priced portion of the supply curve but left the higher-priced portion largely untouched. | *The Brattle Group*

Maintaining the CT-based VRR curve with updated values for net CONE "will continue to provide long-term reliability at reasonable cost," Bresler argued.

PJM agreed with Brattle's CT estimates for all CONE areas except for the "rest of RTO," which it felt was too low. PJM recommended $282/MW-day in that that zone, Cone Area 3, rather than Brattle's recommendation of $269/MW-day.

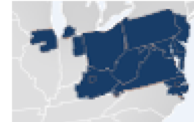
PJM also agreed with several of Brattle's recommendations on E&AS, including the update to unit operating characteristics and gas pricing hubs and using the median to determine net E&AS offset. It also recommended a 10% adder "to account [for] potential uncertainties in measurement" and to maintain dispatch flexibility.

But it differed on the methodology for calculating generator revenues, recommending use of the sum of the median monthly revenues from the last three calendar years rather than annual revenue averages.

"This approach provides a less volatile year-over-year determination of an annual net E&AS value than that provided by a three-year average by dampening distortion caused by a single anomalous month of unusual weather or fuel market conditions," Bresler wrote.

PJM has scheduled additional meetings on the VRR curve updates, starting with an afternoon session on May 25. Subsequent meetings are planned for June 22, July 6 and July 27.

PJM NEWS



PJM Seeks to Have Market Value Fuel Security

Continued from page 1

rent trends continue for too long. The percentage of gas-fired generation has been growing quickly in PJM's fleet. The RTO determined last year it wouldn't have reliability concerns even with a high percentage of gas generation, capping its analysis at 86% of the fuel mix because the current 14% share of demand response and hydro and biomass production is not likely to change, but the analysis didn't address the security of the gas plants' fuel supplies. Because they are beholden to gas pipelines, gas plants can have — and pay for — a wide range of contracts, from receiving uninterruptable service to being cut off first if there's not enough gas in the pipeline. Other plants maintain backup supplies of liquid fuel, such as oil or LNG, onsite or are connected directly to Marcellus shale gas wells. (See *PJM: Increased Gas Won't Hurt Reliability, Too Much Solar Will*.)

Ott called the plan a "narrow" portion of the resiliency initiatives going on at PJM and throughout the nation. He pointed to pipeline constraints in ISO-NE as justification for the plan to get "ahead of those issues in a timely manner."

"At some point in the future, we may be overdependent on one pipeline or one set of fuel-delivery infrastructure," he said. "Our approach is to develop these criteria to make sure that we're monitoring those trends."

Plan Mechanics

It's unclear how the mechanics of the plan will work, as the transmission-constraint pricing it would be modeled on raises prices in areas that have issues. That would suggest the price signals would also reward fuel-insecure units within those LDAs.

"If we see a fuel security problem, the price would elevate in that area," Ott confirmed in his Monday morning briefing.

PJM spokespersons said the question is beyond RTO staff's current analysis, but Robbie Orvis of the clean energy consulting firm Energy Innovation predicted it might be designed as a shadow price that calculates what the price would be without the insecure resources and offers them as an adder for secure ones.

Ott appeared to corroborate that in describing the price separation as an "adder."

"The increased cost to fix that would be adding more onsite fuel tanks or other types of fuel-secure resources," he said. "The idea is not to give units more money. The idea is to look at the exposure that we have."

He noted wind, solar and batteries could qualify as fuel secure, but a renewable resource alone "would probably [qualify at] a much smaller amount than its nameplate capacity" in capacity auctions.

Impact

Ott | © *RTO Insider*

PJM said part of the study is to determine what, if any, new construction is necessary and where. Orvis added it's unclear whether it would create demand for new coal and nuclear units, but "it seems rather unlikely" given the net revenues for those technology types calculated by PJM's Independent Market Monitor in its 2017 State of the Market Report are "well below" their respective costs of new entry calculation.

"Given just how short these units would be on revenue recovery, it would take a very high price from some kind of new market product for fuel security to cause new coal and nuclear builds," he said. "It's worth noting that those low revenues are consistent across zones, so it doesn't look like there are even any specific constrained areas where those plants are especially attractive."

The adder would make the threshold easier to reach but require significant additional action.

"Over time, with a high enough price, large retirements, and in constrained zones, it is possible that some kind of fuel security price adder could tip the scales and incent new capacity, but it would take a significant deviation from today's prices," Orvis said. "PJM's high reserve margins in the near- and medium-term, based on its cleared capacity in the capacity market, indicate that it's unlikely

Continued on page 22

PJM NEWS

PSEG to Pay $39M to Settle FERC Investigation

By Rich Heidorn Jr.

Public Service Enterprise Group's energy trading arm has agreed to pay $39.4 million to settle an investigation into violations of PJM's energy market bidding rules over nine years (IN18-4).

The commission's April 25 order approving a consent agreement with PSEG Energy Resources & Trade, which markets the output of PSEG Power's generation fleet, both praised and criticized the company's actions in the matter.

The non-public investigation was disclosed earlier this month, when FERC's Office of Enforcement issued a Notice of Alleged Violations charging PSEG with violating PJM's Tariff and FERC regulations by submitting incorrect cost-based bids into PJM's daily energy market between 2005 and 2014, when the company self-reported the violations to the commission. (See *FERC Investigation Shows PSEG Violated PJM Bidding Rules*.)

PSEG agreed to a civil penalty of $8 million and to pay PJM disgorgement of $26.9 million and $4.5 million interest. It also will submit annual reports to ensure future compliance. The company did not admit any wrongdoing.

In April 2014, PSEG told FERC of inaccuracies in the cost-based offers for some of its fossil units due to the inclusion of incorrect environmental adders for the prior two years. The company later provided the commission self-reports that identified incorrect cost-based offers dating to 2005.

Among PSEG's "errors," as FERC described them in its order approving the consent agreement, were: including CO_2 adders in its cost-based offers after New Jersey withdrew from the Regional Greenhouse Gas Initiative; including seasonal NOx adders in offers outside the NOx compliance season; incorrectly stating the amounts of fuel required for minimum operations at Unit 2 of its 1229-MW natural gas and kerosene Bergen Generating Station; and providing inaccurate heat rate data for some units.

The commission said it decided on the $8 million penalty considering "that PSEG self-reported the violations, cooperated fully and comprehensively throughout the investigation and has no prior history of violations. The remedy also reflects that although PSEG had a compliance program in place, it was not sufficiently robust to detect or prevent the violations."

"In addition to responding to Enforcement's data requests, PSEG provided extensive data, conducted extensive data analyses regarding the cost-based offers and demonstrated exemplary cooperation during the investigation," the commission added.

But the order also noted, "PSEG's compliance program and existing compliance procedures did not detect the errors in the cost-based components of the offers, in some cases, for multiple years."

After the self-report, FERC said PSEG adopted new procedures requiring that daily offers be double-checked for accuracy and revised its fuel policy "to more clearly articulate the calculation of cost-based offers in accordance with PJM's rules."

The company also added staff to its internal audit department and hired an independent audit company to help develop additional compliance procedures.

It also made unspecified personnel changes in the trading and asset optimization groups "to impose additional accountability and focus attention on compliance issues," FERC said.

FERC directed PJM to disburse the disgorgement and interest *pro rata* to affected market participants.

PJM Seeks to Have Market Value Fuel Security

Continued from page 21

there will be a capacity shortfall to push capacity market prices up."

Orvis noted the modeling parameters PJM plans to use will likely underestimate the generation fleet and therefore might indicate a fuel delivery constraint when there are actually many more resources available.

"It is possible PJM will charge its customers for a service or attribute that is not needed. It would be better if they modeled the system based on what is actually expected to be available rather than their required reserve margin since they have in the past and will in the future continue to come in well above that reserve margin," he said.

Reaction

Paul Bailey, CEO of the American Coalition for Clean Coal Electricity, praised PJM's action and urged other grid operators to follow suit. "We are also encouraged that PJM is following a work plan consistent with the urgency necessary to address lack of fuel security," he said. "Over the next three years, more than 6,000 MW of fuel-secure coal-fueled generating capacity in PJM are expected to retire."

Meanwhile, NRG Energy spokesman David Gaier noted PJM on Monday also said that FirstEnergy's announced retirements of its Davis-Besse, Perry and Beaver Valley nuclear plants will not cause reliability problems.

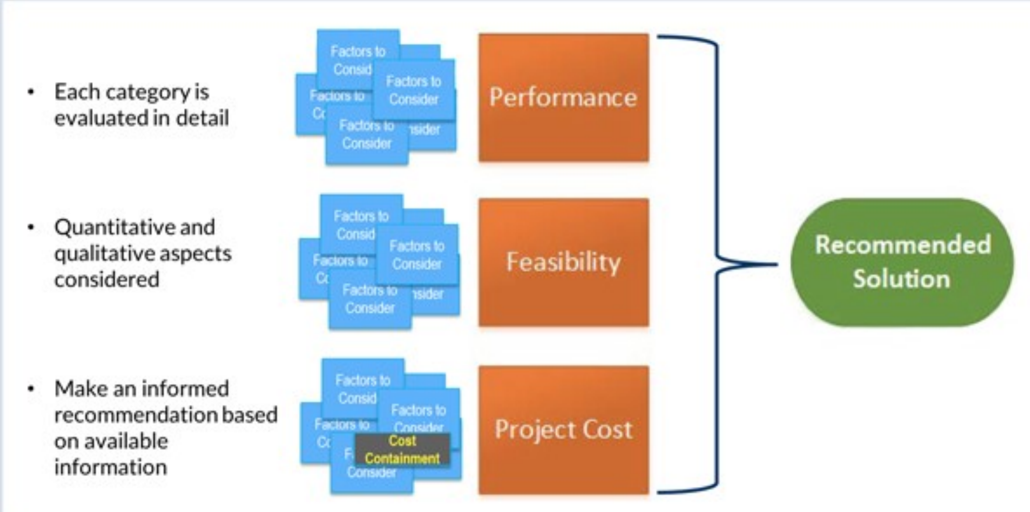
"Units can retire as scheduled" PJM said in a presentation for the May 3 Transmission Expansion Advisory Committee meeting. "Operational flexibility allows [us] to bridge any delays with the transmission upgrades."

Gaier said the RTO's analysis undermines FirstEnergy's request that the Department of Energy declare an emergency to keep the plants running. "Clearly, the attempt by FirstEnergy to keep open its uneconomic nuclear plants on the backs of ratepayers is a subsidy in search of a crisis — one that doesn't exist," Gaier said.

PJM NEWS

PJM Stakeholders Clash Over 'Heart' of Containment Provisions

By Rory D. Sweeney



PJM is considering a realignment of how it considers competitive transmission proposals to include cost-containment provisions. | *PJM*

Stakeholders last week plowed through several hours of material at a special PJM Planning Committee session on whether the RTO should include cost containment provisions in its analysis of competitive bids for new transmission, but they ended up tabling what has become the most important issue.

The wide-ranging discussion covered the results of a stakeholder poll and related comments, PJM's proposal templates, proposed contract language regarding revenue requirement provisions and proposed changes for evaluating Order 1000 projects. However, stakeholders were unable to reach consensus on whether PJM's criteria for selecting projects should weigh a developer's commitment to a cap on the return on equity (ROE) it will seek during its ratemaking process at FERC. The issue received a significant amount of contentious discussion, including a consumer advocate presentation on the importance of such caps, but no decision was reached.

Alex Stern with Public Service Electric and Gas (PSEG) said he didn't think the idea is consistent with applicable law and called it "a complete end-around" of Section 205 of the Federal Power Act.

"I am very concerned about enforceability," he said.

Erik Heinle of Office of the People's Counsel for the District of Columbia, who presented on the value of ROE caps, disagreed that the voluntary proposals ran afoul of FERC's authority.

"We are very clear that FERC is the rate-maker. They should be the rate-maker," he said. "I don't think this makes it some sort of coercive issue where everybody has to do it."

LS Power attorney Mike Engleman of Washington, D.C., firm Engleman Fallon also took issue with objections to the provisions.

"We completely disagree that this is outside what PJM can look at or do. PJM isn't setting the rates. PJM is accepting a voluntary commitment of what the developer will do in filing at FERC," he said. "The entire purpose of Order 1000 is to get the benefits of these types of proposals to ratepayers. … Nobody's forcing PPL or PSEG or anybody else to make a proposal they don't want to make."

Representatives from fellow transmission owners PPL and Duquesne Light Co. backed Stern's position, noting legal precedents for why the provisions wouldn't stand. However, Ruth Ann Price, who represents the Delaware Division of the Public Advocate, challenged them to provide their cases.

"At the right time, they'll be provided," Stern responded. "That's what we do when we go to FERC. This is not a legal proceeding."

"What right time? Now is the right time. We're discussing it," Price said.

PJM staff attempted to reach agreement that everyone favored additional transparency and move on from the topic, but LS Power's Sharon Segner insisted that it continue to be addressed.

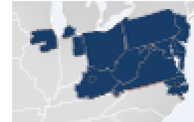
"The ROE discussion is at the heart of what this discussion is supposed to be about," she said. "It is not a discussion solely about transparency."

The issue will be addressed again at the next special session on the issue on May 11.

Segner acknowledged some very "positive developments" in the proposal templates PJM presented, particularly on aspects regarding clear disclosures of cost commitments. PJM's templates would create clear, uniform and organized proposal submissions that would make project comparison easier. Segner, with strong support from several consumer advocates, has largely led the push for cost-containment considerations and templates, having proposed her own set in recent meetings. (See *PJM Stakeholders Explore Cost Containment Complexities*.)

Segner also noted that LS has backed away from proposing any caps on operations and maintenance costs and won't include them in its proposal to the Markets and Reliability Committee on May 24.

"We weren't able to find any evidence that the market was responding robustly to [operations and maintenance] caps" in other RTO/ISO competitive windows, she said. "These other issues are bigger-ticket items to the ratepayers, so why not focus discussions there?"



PJM NEWS

Stakeholders Oppose PJM PFR Mandate for Existing Units

By Rory D. Sweeney

VALLEY FORGE, Pa. — Although FERC has required almost all new generating units to provide primary frequency response, PJM stakeholders are strongly opposing any move by the RTO to require existing units to follow suit.

That disapproval became clear last week at a meeting of the Primary Frequency Response Senior Task Force (PFRSTF), during which staff reviewed the results of a non-binding poll that revealed stakeholder support for the only PFR proposal that does not impose a mandate on units that don't increase their output.

The proposal from American Electric Power (AEP) would apply PFR capability requirements on new units and existing units that modify their interconnection agreement to increase their output. Units that already provide PFR would be "encouraged to continue to do so" and can seek compensation at FERC. Units would annually confirm whether they will continue to provide the service, and PJM and transmission owners would revise system restoration plans accordingly.

A 10% dip in the system-wide aggregate PFR would trigger reconvening the task force "to analyze and suggest, if necessary, possible solutions."

Stakeholders strongly opposed all three other proposals, two of which came from PJM and the third from the Independent Market Monitor. They all applied PFR capability on existing units but differed on minimum size or use thresholds and cost-recovery mechanisms.

"Part of the hang up we have with PJM's initial proposal is the universal requirement for all. Where we get concerned is ... if there's compensation involved, we've got to foot the bill here," explained Dave Mabry, who represents the PJM Industrial Customer Coalition (ICC). "I think the AEP proposal gets us a little bit closer to looking at: Does it make sense for a unit to have it?"

The PJM ICC believes existing units already have an avenue to be compensated for PFR costs through the capacity market, Mabry said, and would support provisions that develop a cost-benefit analysis for whether units should make those investments.

Carl Johnson, who represents the PJM Public Power Coalition, said he was "a little confused" by the lack of support for PJM's "option B" proposal, which would require PFR only for units involved in system restoration plans and would offer them a one-time capital recovery method.

"On behalf of my members who both represent load but also self-serve load and have a lot of generation ... we have concerns about anything that's going to add costs for a service that we think maybe you should be providing anyway, but at the same time we have concerns about being audited and reported for failure to provide it, [including] the possibilities of selective enforcement. So, we're of two minds on this," he said. "I think we still need to work out a lot of issues with regard to what a broad requirement for PFR would be."

GT Power Group's David Pratzon and Tom Hyzinski voiced concerns about "retroactive ratemaking" and unfair demands on generators.

"If you take a look at those existing resources, a lot of them are resources that are financially challenged in the market right now. So, on one hand, to say they're absolutely critical to the integrity of the system but then to turn a blind eye to the fact that they're challenged in the market and to not make any attempt to compensate the vast majority of them for this critical value that they bring to the table" is unfair, Hyzinski said.

Package Criticism

PJM's Glen Boyle said staff heard feedback that the proposals weren't aligned with FERC Order 842, which some stakeholders believe specifically exempts existing resources from PFR requirements — the opposite of PJM's interpretation. Stakeholders also said that exempting nuclear units — in harmony with the exemption of any new nuclear units in FERC's order — was discriminatory.

The requirement would be an "unfunded mandate" and wouldn't support capital cost recovery, stakeholders said. Calpine's David "Scarp" Scarpignato agreed.

"If you have to go through a complex, very expensive, tedious process in order to get paid back for something, and there's no kind of internal rate of return, I think some people might view those as unfunded," he said.

Primary Frequency Response Senior Task Force meets April 26. | © *RTO Insider*

Finally, RTO staff heard they did not satisfactorily make the case for the requirement, a criticism they attempted to address with presentations on a recent report from the Lawrence Berkeley National Laboratory and the importance of PFR in system restoration. PJM's presentation detailed the many uses of PFR during such events, while the laboratory study emphasized the importance of having as many generators as possible provide the service.

Pratzon noted the possibility that some units may find it's not worth the investment to provide PFR if they're required to do so, weighed against a related concern that, without such a mandate, those who continue to provide PFR will be unfairly overcompensating for those who don't.

"There are problems going down either direction," he said.

Next Steps

Johnson noted that FERC is awaiting a report from NERC in July on the availability of existing facilities to provide PFR and suggested that discussions should continue but hinge on the report's publication.

Scarp said he plans to offer an alternative package based on the feedback from the meeting.

PJM staff decided against moving for a binding vote until the group comes to a consensus or FERC responds to a request for rehearing of Order 842. The task force's next meeting is May 23.

PJM NEWS

Izzo: Nukes Outside NJ Likely Eligible for State ZECs

By Peter Key

PSEG's Hope Creek nuclear plant | *NRC*

A recently passed New Jersey law could lead to the state subsidizing nuclear plants outside its borders, Public Service Enterprise Group (PSEG) CEO Ralph Izzo said during his company's first-quarter earnings call Monday.

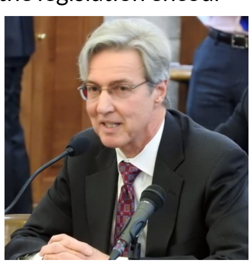
"The bill simply says that New Jersey wants 40% of its power supplied by nuclear energy and it does not limit it geographically," Izzo said.

Izzo made the statement in response to a question from Morningstar's Director of Energy Research Travis Miller, who said he thought nuclear plants outside New Jersey could be eligible for the zero emission credits (ZECs) authorized by the legislation.

In addition to the Salem and Hope Creek nuclear plants that PSEG operates in Salem County, N.J., Izzo said the Peach Bottom nuclear plant in Pennsylvania, of which PSEG is half owner, could compete for ZECs. So, he added, could two other Pennsylvania nukes: Talen's Susquehanna and Exelon's Limerick.

Ranking System

The ranking system the legislation encourages the New Jersey Board of Public Utilities (BPU) to use in determining which plants get ZECs is driven by their impact on the state's air quality, Izzo said.



Izzo | © *RTO Insider*

Gov. Phil Murphy has not signed the legislation, which was passed April 12. He has 45 days from then to sign it into law; veto it, which both houses of the legislature could override with two-thirds majorities; conditionally veto it, which amounts to sending it back to the legislature with changes requiring majority approval; or not sign it, in which case it would become law after the 45 days pass. (See NJ Lawmakers Pass Nuke Subsidies, Boosted RPS.)

Izzo declined to opine on what he thinks Murphy will do — "You never, ever want to pretend to be constraining your governor," he said — but he also said the governor has been outspoken about nuclear power being a bridge to a future with much more renewable generation capacity and supportive of the jobs at PSEG's two nuclear plants in the state.

Two-Stage Capacity Auction

As for PJM's efforts to improve its capacity market, Izzo said PSEG supports the RTO's two-stage capacity repricing proposal over the Independent Market Monitor's plan to expand the minimum offer price rule. PJM earlier this month filed both plans with FERC, asking it to choose one and outline what aspects of it should be revised. (See *PJM Capacity Proposals to Duel at FERC*.)

Izzo said PSEG prefers the status quo to either option because it doesn't interfere with the ability of states to price attributes that markets aren't currently pricing, which, in PSEG's case, are the emissions-free generating capabilities of its nuclear fleet.

PJM's two-stage approach would at least continue to allow states to value carbon-free generation, but what's really needed is a price on carbon, he said.

"The market's just got these inherent inconsistencies built into it," he said. "If we could get a price on carbon … capacity markets could do what they're supposed to do."

PSEG CFO Dan Cregg addressed the company's recent agreement to pay $39.4 million to settle an investigation into violations of PJM's energy market bidding rules over 9 years. (See *PSEG to Pay $39.4M to Settle FERC Investigation*.) He said PSEG's Power unit recorded an incremental $5 million pretax charge to income in the first quarter that will conclude the issue. "We do not believe the order will have any ongoing impact" on PSEG Power, he said.

PSEG earned $558 million ($1.10/share) in the first quarter, up from $114 million ($0.22/share) in the first quarter of last year. Last year's results included costs related to the early retirement of the Hudson and Mercer generating stations and a reserve for the impairment of leveraged leases.

As part of his effort to promote renewables, Gov. Murphy issued an executive order that began moving the state towards a solicitation of 1,100 MW of offshore wind capacity.

Izzo said PSEG has a lease and a partner, which he didn't name, for offshore wind development, but said since his company has no experience in that area, it "would be interested in the transmission component as much as, if not more than, the actual wind farms."

"If we could get a price on carbon … capacity markets could do what they're supposed to do."

Ralph Izzo

SPP NEWS

Eckelberger, Skilton Step Down from SPP Board

By Tom Kleckner

KANSAS CITY, Mo. — For 18 years, Jim Eckelberger and Harry Skilton have been a steady presence on SPP's Board of Directors, providing strategic direction and financial guidance.

The men joined the board in 2000 as two of its first seven independent members, helping to oversee SPP's classification as an RTO in 2004. Until last week, they were the only two original directors still active on the board.

No more. SPP CEO Nick Brown began the board's April 24 meeting by telling the Members Committee that Eckelberger and Skilton would be moving to emeritus status, although they will continue to remain under contract with the board.

"They will continue to bring the tremendous amount of experience and institutional knowledge they've gained over 18 years of service to this organization," Brown said.

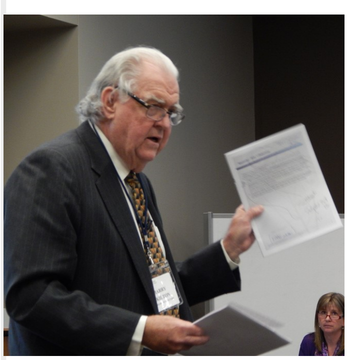
Vice Chair Larry Altenbaumer replaces Eckelberger as chair, while Graham Edwards takes over as vice chair. The moves became effective following the board meeting's conclusion.


Altenbaumer (L), Edwards (R) | © *RTO Insider*

Eckelberger, who was first elected board chair in 2004, took his final moments in the role to reflect on his time with SPP and to thank everyone around him. He said he was only following the Jesuit philosophy of serving others.

"Instead of being in a leadership role, I will be in a resource role. I love that," Eckelberger told the board and members. "I think that's a wonderful opportunity for me to be a benefit to others. Thank you for allowing me to go beyond age 80 into this resource position.

"Bottom line, if you look at the last few months, October onward, the [prices] in our footprint have been phenomenal, lower than they've ever been," he said. Referring to his audience, Eckelberger said, "We've done a wonderful job for the organization's members and the consumers in the footprint. It's been a win-win situation all around."


Skilton | © *RTO Insider*

Eckelberger heaped praise on staff, his fellow board members, and the Regional State Committee and Markets and Operations Policy Committee. "The success is all about you," he said.

"I've watched over the years as people with very disparate ideas have found a way, without going to Washington, to make progress we can all agree to. Everyone has to represent their organization, but it's been a phenomenal ability of everyone to bring about evolutionary change and a relationship-driven and member-driven organization. I appreciate the Members Committee for finding a way to do that.


SPP CEO Nick Brown listens as Chairman Jim Eckelberger speaks at April 25 board meeting. | © *RTO Insider*

"To SPP, you said you've wanted an independent board. I can say I've pissed off every member of the staff in one way or another," Eckelberger said, drawing a laugh.

"Then I look at the board and the Members Committee. I'm surrounded by peers for whom I have great respect," he said, as his eyes filled with tears. "I want to say to you, the members who have made all this possible … Thank you, thank you, thank you."

SPP's directors, members and staff rewarded Eckelberger with a standing ovation.

Now composed, he turned to Altenbaumer, shook his hand and said, "And to my successor, whom I have great respect for … Good luck!"

With that, Eckelberger's tenure as board chair was over.

Brown said Eckelberger and Skilton will be honored with "much more fanfare" during SPP's Annual Meeting of Members in October.

A 30-year veteran of the U.S. Navy, Eckelberger rose to the rank of rear admiral before entering the corporate world and joining SPP. He served in the first Gulf War during his last year of active duty.

Skilton spent 25 years in senior executive and general management positions, including CEO of American Meter Company and treasurer for Celanese Corporation.

Altenbaumer was elected to the SPP board in 2005 and recently succeeded Skilton as chair of the Finance Committee. He served as president of Illinois Power, a regulated electric and natural gas delivery company, and was executive vice president of regulated energy delivery for Dynegy.

SPP hopes to select replacements for Eckelberger and Skilton before the annual members meeting in October.

SPP NEWS

Texas Commissioners Approve 478-MW SPS Wind Farm

By Tom Kleckner

Commissioner Arthur D'Andrea questions witnesses. | © *RTO Insider*

AUSTIN, Texas — The Public Utility Commission (PUC) of Texas on Friday orally approved Southwestern Public Service Company's (SPS) request to build a wind farm in West Texas, clearing the way for a 1.23-GW project that will provide renewable energy and economic benefits to SPS customers in the Lone Star State and New Mexico.

"It's hard for me to look at this and do something different than what" benefits ratepayers, said PUC Chair DeAnn Walker.

Walker and Arthur D'Andrea requested additional information from SPS during the commission's April 12 meeting, expressing doubts as to whether they had a "legal basis" to grant an application for new generation when the company already has sufficient capacity. (See *Texas Regulators Seek More Details on SPS Wind Project*.)

Walker | © *RTO Insider*

"I'm sorry if we kind of freaked out, but it's a big question, and we don't have a ton of time to review it," D'Andrea told SPS representatives and the consumer groups with whom they had reached a unanimous settlement.

"I think you've done a nice enough job … for the ratepayers," D'Andrea said. "You've certainly done a great job of getting everyone's finger on the trigger."

SPP staff had also previously stamped its approval on the SPS proposal. Walker instructed staff to reflect Friday's several minutes of discussion in its draft order. The final order will be approved during the PUC's May 10 meeting (Docket No. 46936).

"It's been a very cooperative effort, with both local stakeholders and statewide stakeholders," SPS President David Hudson told *RTO Insider* after the April 27 open meeting. "This project will bring tremendous economic value to the region for three decades."

The commission's approval allows SPS parent Xcel Energy to proceed with construction of a 478-MW wind farm near Plainview, Texas, and a 522-MW facility near Portales, N.M., both in SPP's footprint. Xcel will begin construction in Texas in June and in New Mexico next year. The company, which will own both facilities, will also purchase 230 MW of energy from two NextEra Energy Resources in Texas.

SPS received approval for the New Mexico portion of the project from the state's Public Regulation Commission in March.

Xcel says the project will save customers hundreds of millions of dollars in production costs over a 30-year period. SPS will receive 100% of the available production tax credits for 10 years, passing the savings directly to its customers.

Xcel also expects the project to generate more than $150 million in local property tax payments over the next 25 years in Texas and New Mexico.

PUC Lowers CenterPoint's Tx Rates

The commission also approved CenterPoint Energy's request to revise its wholesale transmission rates to reflect the reduction of the federal income tax corporate rate from 35% to 21%, thanks to the Tax Cut and Jobs Act of 2017 (Docket No. 48065).

The revision reduces CenterPoint's transmission rate base from $2.11 billion to $2.08 billion and its wholesale transmission revenue requirement from $389.5 million to $347.8 million. Its interim wholesale transmission rate drops from $5,753.91/MW to $5,138.64/MW.

Texas PUC conducts an open meeting on April 27. | © *RTO Insider*

SPP NEWS

SPP Regional State Committee Briefs: April 23, 2018

RSC Approves Study Scope for Cost Allocation Study

KANSAS CITY, Mo. — SPP's Regional State Committee (RSC) last week approved the scope for a study of cost allocation in wind-rich areas, a problem that grows along with the RTO's wind generation.

The study will work with SPP staff to review correlations between generation and load flows on systems below 300 kV and identify potential rate approaches, selecting up to three for further review. Final recommendations are due back to the RSC in April 2019.

"We're not throwing the highway/byway out," said Cost Allocation Working Group (CAWG) Chair John Krajewski, who represents the Nebraska Power Review Board, during the RSC's Apr. 23 meeting, referring to the methodology by which SPP allocates transmission costs according to project size.

Under highway/byway, facilities of 300 kV or more are considered highway facilities and their costs allocated on a regionwide, postage stamp basis; facilities between 100 kV and 300 kV are categorized as byway facilities, with two-thirds of the costs assigned to the host zone and one-third allocated regionwide. Projects under 100 kV are allocated entirely to the host zone.

The RSC in January directed the CAWG to study the issue, following a presentation by Sunflower Electric Power on cost allocation issues in wind-rich areas. (See "Committee Takes on Cost Allocation Issues" in *Mountain West, Cost Allocation Top SPP RSC Concerns*.)

Sunflower's Al Tamimi told the RSC in January transmission projects used to be based on changes in load or in designated resources in the same geographical area where the facilities are built. Today's renewable generation is built at great distances from load centers, with many wind projects in small load zones exported elsewhere, he said.

While the local zones don't necessarily benefit from the reduced energy costs from the additional wind, they are saddled with the byway costs in the highway/byway methodology, Tamimi said.

Regional State Committee gathers for its April meeting. | © *RTO Insider*

CAWG to Get HITT Liaison

The RSC determined the CAWG should have a liaison on the Holistic Integrated Tariff Team (HITT), given that the group's work overlaps with the HITT's proposed scope. "HITT's work touches on everything the RSC does," said Oklahoma Corporation Commissioner Dana Murphy.

The committee left the recommendation on a CAWG liaison to HITT Chair Tom Kent.

The RSC also voted unanimously to suspend "until further notice" the CAWG's work on the new member cost allocation review process.

The committee had asked the group in January to draft a report on the effect of new members on existing cost allocations, a reaction to the Mountain West Transmission Group's pending integration into SPP. Xcel Energy's sudden departure from the group has temporarily rendered the report moot.

Committee OKs Tx Cost Triggers

The committee approved a Tariff change that memorializes as a business practice the current practice of using triggers to stop the annual escalation of transmission projects' undefined baseline costs.

The Markets and Operations Policy Committee approved the Project Cost Work Group's (PCWG) revision request on Apr. 10. PCWG-RR255 adds triggers when a designated transmission owner provides 1) SPP a letter of commercial operation; 2) notification that an upgrade is in-service; and 3) notification that an upgrade is complete.

— Tom Kleckner

South Dakota's Kristie Fiegen, Kansas' Shari Feist Albrecht share a laugh. | © *RTO Insider*

SPP NEWS

SPP Board of Directors/Members Committee Briefs: April 24, 2018

Board Forced to Table NDVER Conversion Change

KANSAS CITY, Mo. — SPP's Board of Directors was last week forced to table the appeal of a rejected revision request, cutting short the discussion when they realized the supporting documentation was not included in the background materials.

The Tariff change (MWG-RR272) requires non-dispatchable variable energy resources (NDVERs) to register as dispatchable variable energy resources (DVERs) within a multiyear transition period. It failed to receive the Markets and Operations Policy Committee's (MOPC) endorsement by a handful of votes. (See *Vote to Make Variable Resources Dispatchable Falls Short at MOPC*.)

However, additional information on the measure was not part of the 638 pages of background material for the Apr. 24 meeting, leading Director Phyllis Bernard to move to table the measure "until we have further background information in front of the Members Committee before we vote."

The Members Committee agreed with Bernard. Oklahoma Gas & Electric abstained from the vote.

The rejection was appealed by members, SPP staff and the Market Monitoring Unit (MMU).

Director Larry Altenbaumer, in one of his final comments before assuming the board's chairmanship, told directors and members to plan on making a decision during their next meeting in July.

"If you have ideas to improve the process, you've got a quarter to make that decision," he said.

In bringing forward the revision request, the Market Working Group said it would increase reliability and market efficiency through the reduction of manual out-of-merit energy orders to mitigate constraints.

The proposal applies to about 6 GW of NDVERs, which are generally older wind resources. However, it exempts about 2 GW of resources that don't have direct interconnection agreements with SPP or are registered as qualifying facilities under the Public Utility Regulatory Policies Act (PURPA).

MMU Executive Director Keith Collins argued for the change, saying it's a "global market efficiency issue" and would help reverse the recent growth of negative real-time pricing in SPP's markets.

"To the extent resources are not flexible and capable of availing themselves to the system, we see an increase not only in frequency but [also] the magnitude of prices when we are unable to dispatch those resources," Collins said. "Operators have to skip over the NDVER and find another resource."

He pointed out that recent SPP analysis has found that dispatchable resources classified as non-dispatchable have "significant effects on the market congestion we're seeing."

The measure found resistance from stakeholders with renewable interests who said the rule change would add costs to existing power purchase agreements.

"If we can address the rule change, we're taking a negative from the system, and that has a lot of global benefits," Collins said. "We don't deny some resources will face increased costs, but we believe the whole market can benefit from that."

SPP Operations Vice President Bruce Rew said the rule would lead to a more efficient market through better management of congestion.

"It's a much smoother operation for us to be able to dispatch those resources that may be down at the time, rather than the generator making that decision when to come on and off," Rew said.

Directors Approve Previously Tabled Sponsored Upgrade

While the board was forced to table one voting item, it took another one off the table when it approved a sponsored upgrade of an OG&E transmission line that MOPC was unable to take action on.

OG&E requested MOPC delay a vote until it could address its concerns about the upgrade with SPP. The project is sponsored by EDF Renewable Energy, which wants to upgrade terminal equipment and rebuild an 11-mile, 138-kV line near Ponca City and its 154-MW Rock Falls wind farm, which became operational in December. (See "OG&E Raises Concerns over Third-party Tx Line Upgrade" in *SPP Markets and Operations Policy Committee Briefs: April 17, 2018*.)

SPP answered all 23 of the questions submitted to it by OG&E, but the utility said it still has questions about the project's cost allocation and asked for additional time to get answers.

"This is a small project, in and of itself. It' not going to break the bank for anybody," OG&E's Greg McAuley said. "The precedent here is what some of the [transmission owners] are concerned about. If you had a $100 million to $200 million project, you would see a much different amount of concern. We're continuing to work to close the gaps in the Tariff we think exist, so we still ask for additional time to get those questions answered."

EDF has said it will seek cost recovery

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SPP NEWS

SPP Board of Directors/Members Committee Briefs: April 24, 2018

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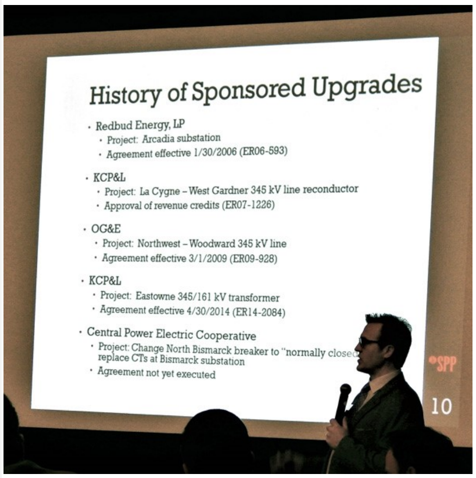
through SPP's Attachment Z2 revenue crediting or incremental long-term congestion rights. Attachment Z2 of SPP's Tariff assigns financial credits and obligations for sponsored transmission upgrades, with directly assigned Z2 network upgrades allocated to SPP's base plan.



Engineering VP Lanny Nickell reviews SPP's history of sponsored upgrades. | © *RTO Insider*

"A project like this, if it just remains between EDF and OG&E, I don't think it will have impacts," said Nebraska Public Power District's Paul Malone, who chairs the MOPC. "But to the extent this project qualifies for Z2 credits, we're all going to end up paying for that. Thus, the vested interest."

Attorney Dan Simon represented EDF and said he saw no legal reason for members to delay their endorsement of the project.

"We've gone through the process as dictated by the Tariff and the staff," Simon said. "We understand OG&E has a number of important questions," but "all of those questions are things that are already dictated by the current language in the Tariff," and therefore do not provide a justification to delay the request.

Simon said EDF worked with OG&E to develop a cost estimate before it submitted its official upgrade request to SPP, noting OG&E did not raise concerns until the MOPC meeting.

"It's been based on that information that we've continued to proceed through the transmission process to submit this request. We don't think it's appropriate to allow these questions coming so late in the process to delay our upgrade request," he said.

"This project is time-sensitive. The sooner this gets placed into service, the sooner it will relieve congestion, and we all realize economic benefits from that," Simon said.

The measure passed the Members Committee by a 14-3 margin, with OG&E, American Electric Power and the Omaha Public Power District voting in opposition. The Oklahoma Municipal Power Authority abstained.

MMU Shares Draft of State of the Market Report

Collins shared the MMU's draft of its annual State of the Market Report with the board and members. He declared the market to be "competitive and efficient," citing low energy prices, declining mitigation and make-whole payments, along with declining levels of excess online capacity and the alleviation of a congestion bottleneck.

Collins said total market costs last year approximated $24/MWh, a 7% increase from 2016, driven by a 14% rise in natural gas prices. As an example, the MMU pointed to the Panhandle hub, where the average gas price increased from $2.32/MMBtu in 2016 to $2.65/MMBtu in 2017.

Wind resources accounted for about 70% of the SPP footprint's 2.2 GW increase in nameplate generation capacity last year, but the rate of new additions has declined significantly. SPP added about 11.4 GW of generation in 2015 and 3.9 GW in 2016.

"Even so, wind generation continued to increase as it represented almost 23% of system generation, up from 18% in 2016 and 14% in 2015," the MMU said. In contrast, coal-fired units saw their share of total generation continue to slide, from 55% or more before 2016 to 46% last year.

Collins said SPP has a reserve margin of about 30%. "That can contribute to the high levels of competition we see," he said.

He noted several issues that bear watching in the months ahead:

- Self-commitment has declined but is still high overall.
- Wind generation is under-scheduled in the day-ahead market.
- The frequency of negative prices has doubled.
- Real-time price volatility has increased.
- Congestion has increased significantly.
- Very few resources are being retired.

The final report will be released later in May.

Director Josh Martin, who chairs the Oversight Committee that oversees the MMU, said the monitor is fully staffed "for the first time in a long time." The MMU added CAISO's Adam Swadley as its lead economist to reach its full staffing level.

Finance Committee Looks to Engage Stakeholders

Finance Committee Chair Larry Altenbaumer told the board and members the committee has been studying a recovery mechanism that "appropriately" reflects the administrative fee as it tries to maintain a simple rate-design structure.

The committee has determined membership's "full engagement" is necessary, Altenbaumer said, and will work with MOPC's leadership in July to involve a broader stakeholder group.

The board unanimously approved three recommendations from the Finance Committee:

- Accepting BKD's 2017 financial audit, which noted "no issues or material/significant weaknesses."
- Engaging BKD to perform the 2018 financial audit and Thomas & Thomas to audit the employee benefit plan's financial statements.
- Taking out an $80 million bank loan with a 5-year maturity and floating rate pricing on outstanding balances under the guidance line.

SPP RE Tying Up Loose Ends

"As you all know, we're going out of business," said Dave Christiano, chairman of the

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SPP News

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SPP Regional Entity's board of trustees, as he delivered what is likely to be the final RE update to the board.

Christiano said the RE will cease its compliance and enforcement activities by the end of June and be officially dissolved by September. The RE has already successfully transferred 25% of its data to NERC, the Midwest Reliability Organization and the SERC Reliability Corporation, he said, but it still has a number of loose ends to resolve.

"It's pretty complicated, as you can guess," Christiano said

SPP said last July it would dissolve the RE, ending a reliability oversight role that has been a source of concern at NERC and FERC. NERC approved the dissolution in February. (See NERC Board Approves Dissolving SPP Regional Entity.)

The RE's staff of two dozen has dwindled to 17 employees, with all but five either having already found work within the RTO and other organizations or having decided to retire.

Christiano also recommended members read a joint report from the FBI and Department of Homeland Security, "Russian Government Cyber Activity Targeting Energy and Other Critical Infrastructure Sectors."

SPP's 2017 Annual Report: 'Focus'

As it does every April, SPP handed out copies of its 2017 annual report during the meeting.

The report, titled "Focus," highlights the "people, milestones, accomplishments, and challenges that made 2017 another exceptional chapter in [SPP's] story."

The report includes comments from a broad section of SPP staffers and how they work with their members.

Last Board Meeting for Westar's Harrison

The board meeting was the last for Westar Energy's Kelly Harrison, who represents public transmission-owning members on the Members Committee.

Harrison, who is nearing 60 years of age, said he is taking advantage of the Westar-Great Plains merger to take retirement. He said he would miss the SPP meetings, as well as the people who attend the meetings — who treated Harrison to a standing ovation.

SPP Board and members meet April 24. | © *RTO Insider*

"I, for one, am extremely appreciative of the care and the intellect Kelly has brought to the Members Committee," Brown said, singling out Harrison's financial acumen and participation on the Oversight Committee. "I couldn't begin to count all the task forces and working groups Kelly has worked on over the years. Thank you, Kelly, from the bottom of my heart."

Consent Agenda Clears Sponsored Upgrade, 7 Tariff Changes

Members unanimously approved the consent agenda, which included the re-baselining of a Nebraska Public Power District 69-kV and 161-kV project from $37.8 million to $27.5 million; a sponsored upgrade with the addition of a second 161/69-kV transformer at City Utilities of Springfield's (Mo.) James River Power Station; funding the SPP retirement and post-retirement healthcare plans; and seven revision requests.

- GIITF RR267 eliminates the "standalone scenario," which considers each interconnection request by itself, from the definitive interconnection system impact study process. This will free SPP resources to focus on binding cluster study results, permitting their earlier availability. Staff will provide the standalone equivalent study models through existing confidentiality provisions to customers seeking to conduct a standalone scenario of their own.
- MWG RR252 assigns an out-of-merit energy (OOME) cap and/or floor, allowing staff to economically dispatch the resource down or up within the ranges.
- MWG RR259 modifies the market settlement posting and dispute timelines being implemented with the new settlement system, reducing the number of resettlement postings and manual processes resulting from revisions to meter and bilateral settlement schedules.
- MWG RR273 automates several of the market settlement system's charge types that are not yet part of revenue neutrality uplift processing, resulting in rounding/residual amounts that must be manually processed and distributed through miscellaneous charges. The new system is scheduled to go live in May 2019.
- ORWG RR268 clarifies or removes outdated language from the operating criteria, improving SPP's ability to perform reliability coordinator, balancing authority, transmission service provider and reserve sharing group functions.
- ORWG RR269 clarifies language and removes antiquated and redundant

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SPP NEWS

Still 'Committed,' SPP Halts Mountain West Integration Effort

Continued from page 1

SPP also announced on last week that all Regional Tariff Working Group meetings previously scheduled to address the integration have been canceled through the end of May. The stakeholder group had scheduled 17 meetings before the July 31 board meeting to work on at least a dozen Mountain West-related revision requests.

On April 23, the Regional State Committee (RSC) approved the Cost Allocation Working Group's request to suspend its work on the new member cost allocation review process. The RSC in January directed the group to draft a report on how new members affect existing cost allocations. (See *Mountain West, Cost Allocation Top SPP RSC Concerns*.)

The board and single representatives from each SPP member met in an executive session April 24 to discuss next steps in the Mountain West integration. The group also discussed recent letters sent to SPP asking for more stakeholder involvement in new member negotiations. (See *SPP Group Balks at Mountain West Concessions*.)

SPP pointed to Brown's earlier comments to the board when asked if any decision had been made on next steps.

Several members said their concerns were heard in the follow-up discussion, and SPP said it would respond to each of the members' letters.

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language in SPP's operating criteria and describes the existence of multiple standalone documents.

- ORWG RR270 converts the operating criteria Appendix OP-2 to a standalone document, clarifies language and adds formatting improvements.

— Tom Kleckner

Q1 Company Earnings

AEP 'Halfway There' to Wind Catcher Approval

By Tom Kleckner

Wind Catcher site | *Invenergy*

Buoyed by recent positive developments, American Electric Power (AEP) CEO Nick Akins had several reasons Thursday to proclaim the company "in better shape than in the first quarter of last year."

Not even falling pennies short of the Zacks Consensus Estimate for first-quarter earnings could dampen his mood. AEP posted earnings of $473.2 million and $0.96/share, similar to 2017's first quarter ($474.3 million, $0.96/share) but missing the Zacks estimate of $1.00/share.

Paraphrasing Jon Bon Jovi, one of the Rock and Roll Hall of Fame's newest inductees, Akins, who sits on the Hall's board of directors, told analysts during a conference call, "This phrase will stick with you the rest of the day: We're halfway there, living on a prayer, take our hand and we'll make it, we swear.

"So, enjoy the ride with American Electric Power."

Just this week alone, AEP saw FERC approve a settlement reducing the base return on equity for its PJM transmission companies to 9.85% (See "AEP ROE Reduced to 9.85% in Settlement" in *Company Briefs*.) and its Public Service Company of Oklahoma (PSO) subsidiary reach a settlement with several consumer groups over its Wind Catcher project.

"Wind Catcher is finally feeling some tail winds," Akins said, referring to the massive 2-GW, $4.5 billion wind farm in the Oklahoma Panhandle. "We have accomplished settlements in Arkansas, Louisiana and now Oklahoma … that provides the framework for the various commissions to bless this significant project and its benefits for our customers."

Akins said AEP is working to add other parties in Oklahoma to the settlement, including Oklahoma Corporation Commission staff. The state's attorney general, Michael Hunter, opposes the project, saying PSO did not follow a competitive bidding process and doesn't need the generation.

Akins admitted AEP is not likely to get Hunter "on board" but said the outreach will continue. He said the company is also continuing efforts to reach a settlement in Texas and hopes to have regulatory approvals in May and June.

"I think [the project] is framed up pretty well because a lot of work's been done in the background," Akins said. "As far as I'm concerned, we're in a very good place."

During AEP's annual stockholder meeting April 24, Akins said the Columbus, Ohio-based company plans to invest $17.7 billion in capital ($12.8 billion in wires infrastructure, $1.7 billion in renewable energy) over the next three years. That capex does not include Wind Catcher.

AEP's share price closed at $69.77/share Thursday, up 1.1% from its open.

Xcel Welcomes Approval of Texas Wind Farm

Xcel Energy CEO Ben Fowke correctly predicted Thursday that the Texas Public Utility Commission would approve its Southwestern Public Service (SPS) subsidiary's request to build a 478-MW wind farm in West Texas.

At their April 13 meeting, the commissioners had questioned SPS and parties to a unanimous settlement on the proposal about the legal justification for a project when there is no apparent need for the capacity. (See *Texas Regulators Seek More Details on SPS Wind Project*.)

But the commissioners said Friday they were convinced the project would benefit ratepayers. (See *Texas Commissioners Approve 478-MW SPS Wind Farm*.)

"We think the project's driving tremendous benefits for consumers," Fowke said during Xcel's quarterly earnings call. "There were some questions asked [by the PUC], and they've been answered."

The company's proposal has been endorsed by PUC staff, who are also part of the settlement between the utility and various consumer groups.

SPS announced last year it intends to build 1.23 GW of wind generation through a pair of wind farms in Texas and New Mexico and a long-term contract from another facility as part of parent Xcel's multistate investment in wind. Xcel said the projects will save the region's customers about $2.8 billion over a 30-year period.

New Mexico's Public Regulation Commission has already approved the facility.

Minneapolis-based Xcel reported first-quarter earnings of $291 million ($0.57/share), up from $239 million (0.47/share) a year ago. That beat analysts' projections of $0.51/share.

Fowke borrowed lyrics from Minnesota rockers Prince ("sometimes it snows in April") and Bob Dylan (" … trees, bent over backwards in a hurricane breeze") to illustrate recent severe weather that drove up profits.

Xcel's share price gained 71 cents Thursday, finishing at $46.53/share after opening at $45.67/share.

— Tom Kleckner

Q1 COMPANY EARNINGS

Avangrid Posts Steady Q1 Income, Highlights Renewables

By Michael Kuser

Avangrid said last week that its first quarter earnings rose slightly on new rate plans and increasing output from its wind fleet, and the company highlighted its growing opportunities in renewable energy — particularly offshore wind.

The company posted net income of $244 million for the quarter ($0.79/share), up 2% from the same period a year ago.

CEO James P. Torgerson said in an analyst call April 23 that "earnings improved primarily due to the implementation of our multiyear rate plans [and] increased wind production, mainly from the 534 MW of capacity that came on line in 2017."

Torgerson noted Avangrid subsidiary Central Maine Power (CMP) is set to sign a contract with Massachusetts by the end of this month for the state's 9.45-TWh clean energy solicitation, which was awarded to CMP's New England Clean Energy Connect (NECEC) transmission project after the original winner was rejected by siting officials in New Hampshire. (See *Mass. Picks Avangrid Project as Northern Pass Backup*.)

CMP partnered on the project with Hydro-Québec, which will deliver up to 1,200 MW of Canadian hydropower to the New England grid via a 145-mile transmission line. The partners estimate the project will cost $950 million and will soon file with the Massachusetts Department of Public Utilities, said Torgerson.

Avangrid also completed the sale of its gas trading business last quarter and expects to sell off its gas storage business in May.

The company said it has 497 MW of onshore wind and solar under construction, to be operational by the end of 2019. Avangrid's Vineyard Wind partnership with Copenhagen Infrastructure Partners bid 400-MW and 800-MW projects into Massachusetts' offshore wind solicitation, the winners of which will be announced in May. (See *Mass. Receives Three OSW Proposals, Including Storage, Tx.*)

Vineyard Wind in the first quarter also submitted a bid for 190 MW of offshore wind in Connecticut, with selection scheduled for June.

Regulatory Update

Torgerson expressed muted optimism about a FERC administrative law judge's March ruling that municipal utilities and commission staff failed to prove the New England Transmission Owners' base return on equity of 10.57% (11.74% with incentives) is unjust and unreasonable, rebuffing requests to reduce it. (See *ALJ Rules New England Tx Owners' ROEs not Unjust.*)

"We feel that's positive, but the commission will still ultimately need to decide, and there's really no time frame at this point to make that decision," said Torgerson.

The corporate tax cuts passed by the Trump administration in December created benefits for the company, and Avangrid is working with state regulators in New York and New England to offset major storm recovery and advanced metering infrastructure (AMI) costs through the windfall before passing benefits to customers.

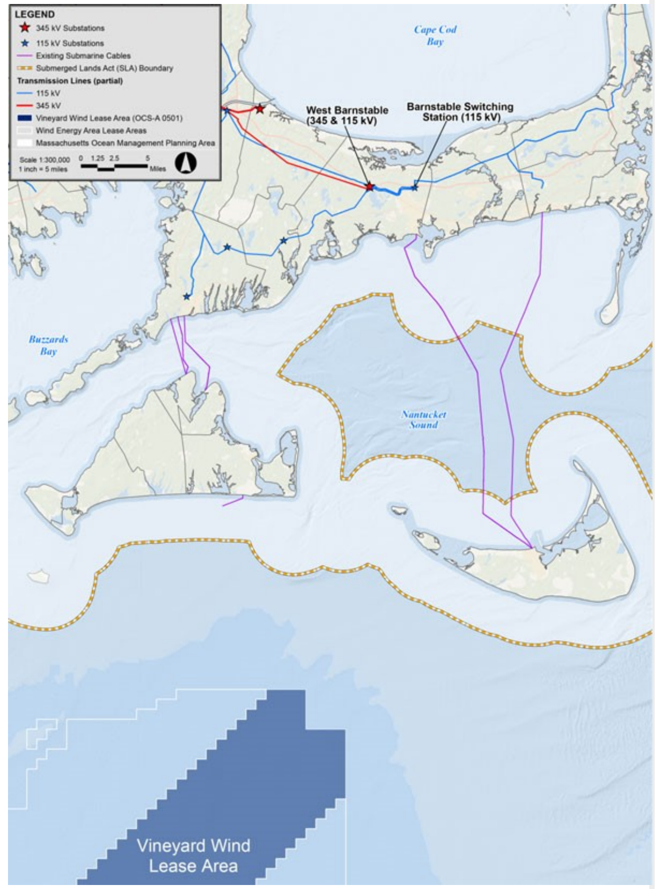
The AMI discussions are ongoing in New York and the company anticipates approval later in 2018. "The earnings adjustment mechanism discussions have been impacted by the ongoing storm activity and the AMI discussions and other things, so that's been delayed somewhat," said Torgerson.

Offshore Potential

After establishing its offshore wind business last year, Avangrid quickly won a Bureau of Ocean Energy Management (BOEM) lease auction off Kitty Hawk, N.C., an area that could produce up to 2.5 GW of energy. The company also last year acquired its 50% partnership in Vineyard Wind.

Torgerson also highlighted upcoming opportunities in offshore wind.

"In New York, they are looking for 800 MW in the fall and 2,400 MW by 2030," he said. "Rhode Island is evaluating or looking to evaluate the implications from the Massachusetts RFP and want information on that, how it could impact Rhode Island. So, there is an expectation that Rhode Island may be looking for some offshore wind as well."



Vineyard Wind Project, Nantucket Sound | *Vineyard Wind*

Offshore wind got a boost on two fronts earlier this month when U.S. Interior Secretary Ryan Zinke announced two new proposed offshore wind leases for Massachusetts, while the Interior Department's BOEM issued a call for commercial interest in four wind energy areas in the New York Bight. (See *Interior Plans Would Boost Mass., NY Offshore Wind.*)

"We will be looking at those very closely," said Torgerson. "And Governor Phil Murphy in New Jersey is said to be looking for about 3,500 MW offshore of New Jersey."

Earnings call transcript courtesy of Seeking Alpha

Q1 Company Earnings

NextEra Beats Wall Street's Expectations


Next Era's 75-MW River Bend Solar Energy Center in Alabama is under a 20-year contract with Tennessee Valley Authority. | *TVA*

NextEra Energy beat analysts' expectations and shattered last year's first-quarter performance, reporting earnings last week of $4.4 billion and $9.32/share, up from $1.6 billion and $3.37/share, respectively.

The Florida-based company's reported adjusted earnings April 24 of $1.94/share, beating the Zacks Consensus Estimate of $1.78/share. The GAAP results reflect the deconsolidation of NextEra Energy Partners from NextEra's financial statements and the impacts of tax reform, the company said.

"NextEra Energy delivered strong first-quarter results and is off to a solid start toward achieving our overall objectives for the year," said CEO Jim Robo.

NextEra CFO John Ketchum told analysts the company now expects its Florida Power & Light (FPL) subsidiary to achieve its target regulatory return on equity of 11.6% "either late in the second or early in the third quarter." He said NextEra may begin "partially restoring" FPL's reserve amortization balance through tax savings later this year, and it continues to expect the utility will end 2020 "with a sufficient amount of surplus to potentially avoid a base rate increase for up to two additional years."

The Florida Public Service Commission has opened separate dockets to address tax reform for FPL and each of the other Florida investor-owned utilities, Ketchum said.

"We look forward to working with the [commission] and other interested parties to further explain how FPL's prompt actions within the terms of the settlement agreement benefit customers," Ketchum said.

NextEra said the eight solar energy centers it has brought on line this year will generate more than $100 million in total savings for FPL customers during their operating lifetime. The utility has also announced the creation of the largest combined solar-plus-storage project in operation in the U.S., a 10-MW battery project with 40 MWh of storage capacity at Babcock Ranch in southwest Florida.

The company's share price gained $2.50 after April 24's open but finished Wednesday at $160.31, down 77 cents from Monday's close.

— Tom Kleckner

Entergy Earnings Up, But Fall Short

Entergy posted first-quarter earnings Wednesday of $211 million, or $1.16/share, up from $178 million, or $0.99/share, over the same period last year. Zacks had projected earnings of $1.31/share.

The New Orleans-based company credited the performance to the lower federal income tax rate, favorable weather and a new financial reporting guidance that requires the mark-to-market of equity investments in the nuclear decommissioning trust funds at Entergy Wholesale Commodities (EWC).

EWC has shut down its Vermont Yankee nuclear unit and is planning to retire Pilgrim in 2019, Indian Point in 2021 and Palisades in 2022.

— Tom Kleckner

Q1 COMPANY EARNINGS

DTE Highlights Renewable Efforts, Wins Gas Plant Approval

By Amanda Durish Cook

Pinnebog Wind Park | *DTE Energy*

DTE Energy is focused on plans to double its renewable energy capacity by the early 2020s and build a new, controversial $1-billion gas-fired plant recently approved by regulators, company executives told analysts during an earnings call last week.

First-quarter earnings fell nearly 10% to $361 million ($2.00/share) compared with 2017, but operating earnings jumped $20 million to $342 million. The utility posted revenue of $3.75 billion for the period.

During an April 25 call, DTE Energy CEO Gerard Anderson revealed more detail about the company's plan to double its current renewable energy capacity primarily through new wind projects built over the next few years. DTE filed its plan with the Michigan Public Service Commission (PSC) last month.

"If approved, this will drive increased investment in new wind and solar projects," Anderson said.

DTE last year said it would transition to cleaner energy sources and reduce carbon emissions by more than 80% by 2050.

The company's $1.7-billion proposes about 1 GW of new wind and solar projects in Michigan to be completed by 2022.

" …This plan is another significant step toward our carbon emission reduction goals, and those goals can be met in a way that continues to deliver reliable and affordable power for our customers as well," Anderson said.

The plan includes two central Michigan wind farms providing 330 MW of new capacity: Pine River, set to be completed later this year, and Polaris, slated for completion by 2020.

Anderson said the two wind farms will be DTE's largest and most efficient to date.

The plan also includes an additional 300 MW of new wind capacity by 2020 to support a new voluntary renewable energy program for DTE's large business customers interested in reducing emissions, Anderson said.

Finally, DTE will complete another two wind farms in 2020/21 that will provide a combined 375 MW of capacity, Anderson said.

He also expects DTE to begin investing in more solar generation in the coming years.

"Along with the increased wind capacity, we're also planning on adding 15 MW of solar power. Wind today is clearly lower cost than solar in Michigan, and thus we're really concentrated on wind capacity in the near-term. But solar costs are improving, and we expect that by the mid-2020s, solar will be ready to play a more prominent role in our mix," Anderson said.

He added that DTE plans to add more renewable energy generation beyond that outlined in the plan submitted with regulators.

Anderson's comments on solar development come at a time when DTE has twice been accused of withholding interconnection data from independent solar developers seeking to connect new generation to DTE's grid, as well as overcharging for studies requested to start on new projects. Both Cypress Creek Renewables and a Geronimo Energy subsidiary this month filed similar complaints with the Michigan PSC, claiming DTE's responses violate a provision of the Public Utility Regulatory Policies Act (PURPA) that qualifying facilities have a right to interconnect with the host utility's grid (U-20151, U-20156).

DTE representatives did not respond to a request for comment on the complaints.

Regulators Approve Controversial New Gas Plant

Still, DTE's renewable plans will not match the output of its proposed $1 billion, 1.1-GW natural gas plant to be built in St. Clair County near the Canada border, which Michigan regulators approved Friday after concluding it "was the most reasonable and prudent means of meeting DTE's future energy needs" (U-18419). The company wants to begin construction in 2019.

"DTE Electric's recent and planned investments in energy waste reduction, renewable energy and energy storage, when coupled with this highly efficient gas plant, demonstrate that Michigan is a great example of an 'all of the above' strategy to meet our energy needs in a reliable, affordable manner that protects the environment," Michigan PSC Chairman Sally Talberg said in a statement.

During the earnings call two days ahead of the approval, Anderson said he expected a "constructive outcome" in the proceeding.

Environmental advocates such as Sam Gomburg with the Union of Concerned Scientists have questioned the need for the plant, saying DTE's commitment to the environment rings hollow when pushing such a large fossil fuel plant.

"There is plenty in the record to justify not approving this. [This was] a matter of how much backbone this commission has," Gomburg said in a telephone interview with *RTO Insider*.

Continued on page 37

Q1 Company Earnings

Dominion: 'No Flexibility' on SCANA Bid

By Rory D. Sweeney

South Carolina legislators continue to maneuver as if there is some room to negotiate the terms of a deal to sell SCANA to Dominion, but Dominion CEO Thomas Farrell emphatically rejected that presumption on a Friday conference call to discuss the company's first-quarter earnings.

"No flexibility," Farrell said. "We've made our offer, and it's going through the political process now."

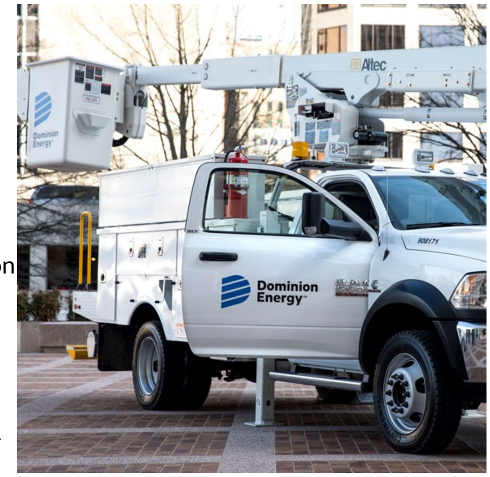
The state legislature must approve the nearly $8 billion takeover bid, which includes controversial provisions for customers to continue paying on a failed nuclear plant in the state. He noted that the legislature's session ends on May 11.

Dominion reported first-quarter operating earnings of $741 million ($1.14/share), which beat analysts' estimates by $0.08/share and improved on earnings of $611 million ($0.97/share), for the same period in 2017. Revenue of $3.47 billion improved 2.7% from the same period last year but missed expectations by $50 million.

The company's unadjusted earnings were $503 million ($0.77/share), compared with $632 million ($1.01/share), for the same period in 2017.

Paul Koonce, Dominion's executive vice president and CEO of the Power Generation unit, was also upbeat about the prospects for its Millstone nuclear plant to receive subsidies through a Connecticut procurement process previously reserved for renewables. State officials will be issuing requests for proposals for renewable generation in May, he said. Bids will be open through September and approved by year end. The company plans to pursue an "at-risk" designation for the plant that will allow it to include non-price factors in its offer, including zero carbon emissions, fuel diversity and grid reliability, he said.

"They have a report … that showed what it would cost consumers if Millstone were to retire, so I think there is some recognition of



| Dominion Energy

the value of Millstone, so really [all those developments are] supposed to play out between now and September with bids being approved by year end," he said.

DTE Highlights Renewable Efforts, Wins Gas Plant Approval

Continued from page 36

Gomburg said a combination of renewable generation and storage, energy efficiency measures and demand response could meet DTE's needs more efficiently and inexpensively. He said DTE's assessment in justifying the natural gas plant failed to explore alternatives.

"Even using their own tools, we find ways to meet their goal with cheaper options," Gomburg said.

Gomburg warned about a future spike in natural gas prices or new regulations putting more emphasis on staving off the effects of climate change, making the plant costlier.

"I see a very high risk that ten years from now, as we're paying this off, we're [going] to regret this," Gomburg said. "I see putting all your eggs into this billion-dollar basket as very risky."

While Gomburg said DTE seems "disingenuous" in its goal to double renewable capacity while planning a large natural gas plant, he didn't want to denigrate DTE's goal of reducing emissions by 80% in little more than 30 years.

"I don't want to say that the goal they've put forward is meaningless, but we can do more sooner. What matters is what carbon dioxide and mercury we emit now until 2050," Gomburg said.

Power Up Michigan, a coalition of nine clean energy groups, said the plant is unnecessarily expensive, fails to create the level of jobs that new renewable sources could generate and is a "failure of innovation" to transition to clean energy sources.

However, in filings leading up to the approval, DTE said those who "suggest that there might be some other combination of resource options that might somehow be preferable from their self-interested perspective" ultimately failed to submit an alternative proposal.

"It again bears emphasis that DTE Electric presented the only specific proposal to meet the power need … established on the record," the company wrote.

DTE said its analysis found that the gas plant would "appropriately" balance six characteristics, including reliability, affordability, cleanliness, compliance, reasonable risk and flexibility.

COMPANY BRIEFS

AEP Plans $17.7B in Capital Investments Over Next Three Years

American Electric Power plans to invest $17.7 billion in capital over the next three years — including $12.8 billion in its transmission and distribution systems and $1.7 billion in renewable energy — Chairman, President and CEO Nicholas Akins told shareholders at the company's annual meeting April 24.

Akins said the investments will continue to support AEP's operating earnings growth rate of 5% to 7%.

The renewable energy figure doesn't include the Wind Catcher Energy Connection project, which AEP plans to invest $4.5 billion in.

More: *American Electric Power*

Duke Overcharged Fayetteville, N.C., FERC Rules

FERC ruled April 23 that Duke Energy Progress has overcharged Fayetteville, N.C., for energy and capacity since 2014 because of an improper accounting change. The commission ordered Duke to refund the overpayments and resubmit its FERC Form 1 filings for 2014, 2015 and 2016 (ER17-1553-001).

The commission granted Fayetteville's challenge to Duke's 2015 formula rate true-up, which alleged its electric costs increased $1.4 million (2%) after the company moved $395 million in materials and supplies (M&S) inventory from a construction account — which is not part of its formula rate base — into an operations and maintenance (O&M) account, which is included in the formula rates. Duke provides all the electric capacity and energy requirements of Fayetteville's retail customers, other than those met by the city's other generation resources.

FERC agreed with Fayetteville that the change was improper. "The purpose of designating M&S inventory as construction or O&M is to provide the commission with information about how the M&S inventory ultimately will be used, which has significant ratemaking implications," the commission said. "… Because DEP does not designate any portion of its M&S inventory as construction-related, DEP fails to provide the commission with needed information about its anticipated future use of the M&S inventory."

FERC OKs Settlement on ODEC Gas Plant Rates

FERC on April 23 approved an uncontested settlement reducing the reactive power revenue requirement for Old Dominion Electric Cooperative's new Wildcat Point Generating Facility by more than 20%. ODEC, which had proposed a $2.7 million annual revenue requirement for reactive power and voltage control, will be paid $2.1 million instead (ER17-2290-001). The 950-MW combined cycle plant went into commercial service earlier this month.

Google Gives $1 Million to Coal Community Nonprofit

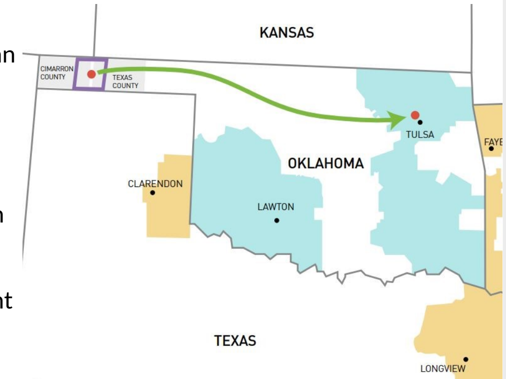
The Just Transition Fund said April 24 it has received a $1 million grant from Google.org to help it create a resource guide for communities and workforces affected by the coal industry's decline.

The grant was one of several announced by the philanthropic arm of Google as part of Google's $50 million initiative on the future of work. It supports the Just Transition Fund's technical assistance to and fieldwork with communities that are grappling with economic problems due to the shuttering of the coal mines or coal-fired generation plants that provided much of their employment base and tax revenue.

More: *Just Transition Fund*

PSO Files New Wind Catcher Agreement in Oklahoma

Public Service Company of Oklahoma (PSO) said April 24 that it, Oklahoma Industrial Energy Consumers (OIEC) and Walmart have reached a settlement agreement on the proposed Wind Catcher Energy Connection project and are asking the Oklahoma Corporation Commission (OCC) to approve the project under the agreement's terms.



Wind Catcher Project | *AEP*

PSO said the agreement, which was filed with the OCC, replaces an agreement that it and Walmart reached and filed with the OCC in March. OIEC, a membership organization that includes some of PSO's largest power users, wasn't a party to the previous agreement.

The Wind Catcher project, which will cost $4.5 billion, consists largely of a 2,000-MW wind farm being built in the Oklahoma Panhandle and a dedicated line to transmit power from the wind farm to the Tulsa area. The project is a partnership between PSO and Southwestern Electric Power Co., both of which are American Electric Power subsidiaries.

More: *Public Service Company of Oklahoma*

AEP ROE Cut to 9.85% in Settlement

FERC has approved a settlement reducing the base return on equity for American Electric Power's PJM transmission companies to 9.85%, from 10.99%, effective Jan. 1, 2018 (ER17-405, ER17-406).

In addition, the equity component in the AEP companies' capital structures will be the lesser of each company's actual equity capital component or 55%. Affected are AEP subsidiaries Appalachian Power; Indiana Michigan Power; Kentucky Power; Kingsport Power; Ohio Power; Wheeling Power; AEP Appalachian Transmission; AEP Indiana Michigan Transmission; AEP Kentucky Transmission; AEP Ohio Transmission and AEP West Virginia Transmission.

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COMPANY BRIEFS

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The settlement resulted from a 2016 challenge by American Municipal Power, Blue Ridge Power Agency, Craig-Botetourt Electric Cooperative, Indiana Michigan Municipal Distributors Association, Indiana Municipal Power Agency, Old Dominion Electric Cooperative and Wabash Valley Power Association. FERC approved the settlement April 24.

FES Formally Notifies NRC of Plan to Close Three Nuclear Plants

FirstEnergy Solutions said April 26 it has filed a Certification Letter formally notifying the Nuclear Regulatory Commission of its decision to permanently deactivate its three nuclear power plants over the next three years due to "severe economic challenges."

FES said the letter affirms its March 28 notification to PJM of its intention to shut the plants, as well as its initial, informal notification to the NRC. The closures are subject to review by PJM, which will look into how they affect the reliability of its system. In the interim, FES said, it will continue normal operations at the plants.

"We are actively seeking policy solutions at the state and federal level as an alternative to retiring these plants, which we believe still have a crucial role to play in the reliability and resilience of our regional grid," said Don Moul, president of FES Generation Companies and chief nuclear officer.

FES plans to close the Davis-Besse Nuclear Power Station in Oak Harbor, Ohio, by May 31, 2020; Unit No. 1 of the Beaver Valley Power Station in Shippingport, Pa., and the Perry Nuclear Power Plant in Perry, Ohio, by May 31, 2021; and Unit No. 2 of the Beaver Valley Power Station by Oct. 31, 2021.

More: *FirstEnergy Solutions*

Duke Names Chief Distribution Officer, Florida President

Duke Energy said April 25 it has named **Harry Sideris**, 47, senior vice president and chief distribution officer. Sideris, who is president of Duke Energy Florida, will succeed Michael Lewis, who is retiring June 30 after a 30-year career in the utility industry.

Carolyn Stampien, 48, will succeed Sideris as president of Duke Energy Florida. She is senior vice president of corporate development.

More: *Duke Energy*

Transformer Fixed at Fermi 2 but Other Issue Keeps Plant Offline

DTE Energy said April 23 that it has addressed a transformer issue that prompted its Fermi 2 nuclear power plant in Newport, Mich., to shut down, but the plant remains offline.

A DTE spokesman said that while workers at the plant were performing inspections and tests during the shutdown, they identified a valve on the reactor recirculation system that needed to be repaired.

The plant had been online 359 days prior to the shutdown.

More: *Monroe News*

Northern Pass Asks for Reconsideration of Permit Denial

Northern Pass Transmission and Eversource Energy on April 27 filed a motion asking the New Hampshire Site Evaluation Committee (SEC) to reconsider its denial of a permit for the transmission project.

"We have presented to the SEC a solution that fully addresses the issues they pointed to in their order denying the permit," said Eversource New Hampshire President Bill Quinlan. "The solution is a comprehensive set of commitments and conditions, many of which were proposed by Counsel for the Public, that can be imposed to address the SEC's concerns."

Eversource, which operates utilities in New Hampshire, Massachusetts and Connecticut, is a partner in Northern Pass with Hydro-Québec. The transmission project is meant to bring hydropower from Hydro-Québec to New England. It originally was selected to provide renewable power to Massachusetts but after the SEC denied it a permit, Massachusetts chose another project.

The SEC has scheduled a hearing on Northern Pass for May 24.

More: *Eversource Energy*

Eversource to Spend $80M Trimming Connecticut Trees

Eversource Energy said April 25 it plans to spend $80 million to trim trees along 4,000 miles of power lines in 121 Connecticut towns.

The company plans to do the most extensive trimming in Woodstock, Haddam, Danbury and Greenwich — all of which were left without power for days in the nor'easters that struck Connecticut in the recently ended winter.

More: *Hartford Courant*

Proposed North Bergen, N.J. Plant's Developer Touts Its Benefits

North Bergen Liberty Generating held a news conference April 25 to tout the benefits of the $1.8 billion, 1,200 MW gas-fired power plant it wants to build in North Bergen, N.J.

The plant would send power to New York City via a 345-kV line under the Hudson River.

Critics of the plant cite the fact that its power won't go to New Jersey residents and concerns about its environmental impact.

More: *NJ Spotlight*

First Solar to Build 1.2 GW Solar Module Plant in Ohio

First Solar said April 26 it plans to spend $400 million to build a solar module factory near its flagship plant in Perrysburg, Ohio, if state and local incentive packages for the plant come through.

The company said the plant would occupy 1 million square feet, employ 500 and be able

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Company Briefs

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to turn out 1.2 GW of its Series 6 thin film photovoltaic modules per year.

More: *First Solar*

Eversource Issuing $636M in Bonds for Divested Plants

Eversource's Public of New Hampshire subsidiary said April 26 it is preparing to issue $636 million in bonds to recover investments in power plants it had to divest as a result of changes in how New Hampshire regulates electric utilities.

"The costs remaining after the sale of our regulated power plants are being recovered now as part of the April 1st rate adjustment to a customer's stranded cost recovery charge," a spokesman said.

Residential electricity consumers buying 600 kWh of power a month directly from Eversource should see their monthly bills decline $9.12 to $114.52. Residential power consumers who buy 600 kWh of electricity a month elsewhere will see their monthly bills go up by $11, of which about $7 will go toward repaying the bonds.

More: *New Hampshire Union Leader*

Siemens Rehiring More than 100 at Iowa Wind Turbine Plant

Siemens Gamesa said April 25 that it plans to rehire more than 100 of the 195 workers it laid off in January from its plant in Fort Madison, Iowa, to make turbine blades for a proposed Kansas wind farm.

The announcement came about a week after the company said it was closing a factory in Burlington, Iowa, which will put about 125 people out of work.

More: *Associated Press*

Federal Briefs

Nevada Rep. Introduces Bill to Block DOE Action on Yucca Mountain

U.S. Rep. **Jacky Rosen** (D-Nev.) on April 26 introduced a bill seeking to stop Energy Secretary Rick Perry from taking further action on turning Yucca Mountain, Nev., into a repository from spent fuel from nuclear power plants until the Office of Management and Budget can come up with alternative uses for the site.

Yucca Mountain is in Nye County, Nev., about 90 miles northwest of Las Vegas. Darrell Lacy, who directs the Nye County Nuclear Waste Repository Project Office, said that the 5-mile, U-shaped tunnel at the site is remote and unsuited for commercial activity.

"Congress needs to provide funding and finish the licensing activities," Lacy said. "Until a final decision on the safety of Yucca Mountain is made, it is difficult to evaluate moving forward with a nuclear waste repository or any other options."

Rosen introduced her bill a day before the Nevada Legislature's Interim Legislative Committee on High-Level Radioactive Waste held a hearing on Yucca Mountain in Las Vegas and Carson City, which were connected by a video link.

At the hearing, critics of using Yucca Mountain as a nuclear waste repository cited its potential effects on health, tourism, culture and the spiritual well-being of Native Americans.

More: *Las Vegas Sun*, *Las Vegas Sun*

House OKs Bill Blocking Order to Spill More Water from Dams

The House of Representatives on April 25 approved a bill that would reverse a federal judge's order to spill more water from four Pacific Northwest dams to help migrating salmon reach the Pacific Ocean.

The bill, which would prevent any changes in dam operations until 2022, was sponsored by Republican Reps. Cathy McMorris Rodgers and Dan Newhouse, both of Washington state.

The bill now goes to the Senate, where Patty Murray (D-Wash.) has expressed concerns about it.

More: *Associated Press*, *Idaho Statesman*

Pruitt Proposes Limiting EPA to Studies with Publicly Available Data

EPA Administrator Scott Pruitt on April 24 proposed a rule that would allow the agency to only consider studies with underlying data that's publicly available.

Advocates say the rule would be a victory for transparency, but critics point out that the standard is not used by peer-reviewed journals and would limit the information the EPA can take into account.

"The best studies follow individuals over time, so that you can control all the factors except for the ones you're measuring," said former EPA administrator Gina McCarthy, who now directs the Center for Health and the Global Environment at Harvard's public health school. "But it means following people's personal history, their medical history. And nobody would want somebody to expose all of their private information."

The rule will be subject to a 30-day public comment period and could trigger legal challenges.

More: *The Washington Post*

Pruitt: Burning Biomass for Energy to Be Considered Carbon Neutral

EPA Administrator Scott Pruitt said April 23 that the agency will consider the burning of biomass, such as trees, for energy to be "carbon neutral" in many cases.

Those who consider burning wood to be carbon neutral say that although burning trees releases carbon dioxide, it will be pulled out of the air by trees planted to replace the ones that are burned, since trees absorb carbon dioxide as they grow. Scientists don't embrace the concept because they fear forests that are cleared so their wood can be used for energy may not

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FEDERAL BRIEFS

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grow back as planned, and because while burning wood releases carbon dioxide immediately, forests take decades or more to grow back.

EPA's Science Advisory Board hadn't completed deliberating the matter and the policy memo that the agency released April 23 acknowledged that the board had determined in 2012 that "it is not scientifically valid to assume that all biogenic feedstocks are carbon neutral."

More: *The Washington Post*

Solar Tariffs Opposed by Nearly 60% of Registered Voters

Fifty-eight percent of 1,999 registered voters surveyed by the University of Maryland's Program for Public Consultation said they opposed the tariffs on imported solar generation products imposed by the Trump administration. Of Democrats, 76% opposed them. Only 51% of independents opposed the tariffs and 58% of Republicans favored them.

In very red districts, 54% opposed the tariffs. In very blue districts, 67% opposed them. Among Republicans who voted for President Trump, 63% favored the tariffs. Among those who did not vote for the president, only 27% supported the tariffs.

Respondents were given a short briefing explaining why the administration imposed the tariffs and why solar installers and environmental groups opposed them. They were then asked to evaluate arguments for and against the tariffs before giving their opinion. The briefing content was reviewed by experts in favor of the tariffs and experts against the tariffs, to ensure that it was accurate and balanced.

More: *Program for Public Consultation*

Wind and Solar Were 98% of New Capacity in Jan. and Feb.

Wind and solar comprised more than 98% of the electrical generation placed into service in the United States during the first two months of this year, according to a SUN DAY Campaign analysis of FERC's latest "Energy Infrastructure Update."

According to the update, 2,133 MW of wind and solar power came online in January and February, consisting of 14 new "units" of wind totaling 1,568 MW and 40 units of solar totaling 565 MW. The remaining 40 MW of capacity that came online in the first two months of the year was from two units of natural gas.

The additions pushed the total installed capacity of renewable energy sources to 20.39% of total U.S. generating capacity. Wind and solar capacity is now 10.18% of installed capacity, which is larger than nuclear power (9.11%), hydropower (8.49%) or oil (3.64%).

More: *Solar Power World*

Pruitt Gets Tough Questions from Democrats, Some Support from Republicans

EPA Secretary Scott Pruitt faced tough questions from Democrats and some criticism tempered with support from Republicans in two Congressional hearings Thursday.

In response to questions, Pruitt said he wasn't aware of the amount of the controversial raises given two EPA employees who had worked for him in Oklahoma, nor was he aware of the method used to give them the raises, which had been shot down by the White House.

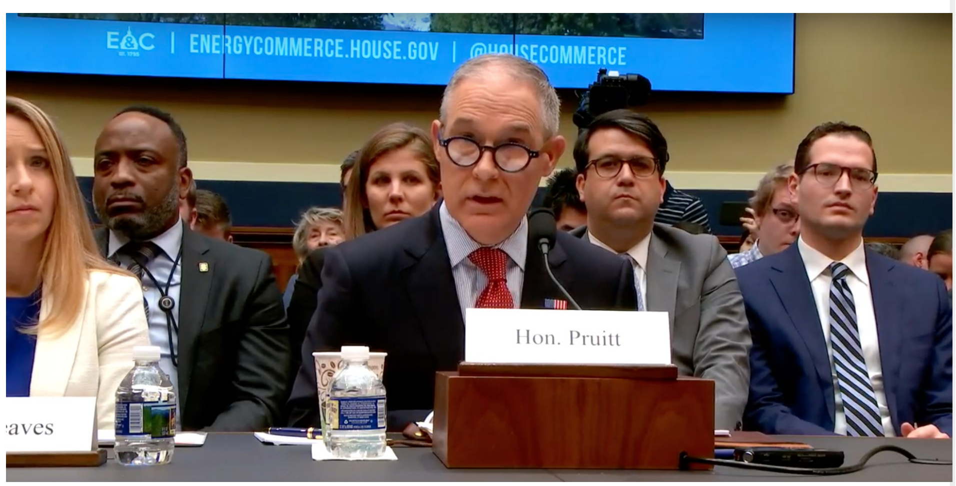
He also said he wasn't aware of the approval of $43,000 used to build his sound-proof phone booth.

As for his travel habits, Pruitt said he now flies coach, rather than first class. He also denied that any EPA employees had been fired for challenging his spending or other conduct, and defended his effort to repeal the Clean Power Plan, although he incorrectly said the plan had been struck down by the Supreme Court.

U.S. Rep. **David B. McKinley** (R-W. Va.) told Pruitt that the criticisms of him "have an echo of McCarthyism."

More: *The New York Times*

McKinley | *U.S. House*



EPA Administrator Scott Pruitt testifies at House Environment Subcommittee Thursday. | *U.S. House*

STATE BRIEFS

ARIZONA

Ducey Signs Bill Meant to Help Navajo Power Plant

Gov. Doug Ducey on April 25 signed a bill that will exempt coal from sales tax.

The bill's supporters hope it will help attract a buyer for the Navajo Generating Station, which is scheduled to close next year.

The plant gets its coal from Peabody Energy's Kayenta Mine, which would close if the plant closes.

More: *azcentral*

CALIFORNIA

FERC Approves CAISO Funds Distribution

FERC on April 25 approved CAISO's request to distribute money collected for violations of its rules of conduct in 2016, as well as interconnection study funds (ER18-565).

At the end of each calendar year, CAISO allocates the proceeds of penalties plus interest to scheduling coordinators of market participants in accordance with its Tariff. CAISO's petition sought approval to distribute the proceeds of penalties assessed during the 2016 calendar year.

CAISO will distribute $365,000 in penalty proceeds and $847,286 in interconnection study funds, plus interest. FERC said neither of the requests were unjust or unreasonable under the CAISO Tariff.

CAISO Granted Delay of Tariff Changes

CAISO will delay the effective date of certain resource adequacy Tariff revisions by one month, to May 1, after FERC on April 25 approved the grid operator's April 3 request.

The ISO originally requested the April 1 effective date of its Resource Adequacy Availability Incentive Mechanism to align with certain resource adequacy rules in a separate initiative. CAISO said the software code to implement both initiatives was developed as a single project and the waiver allows it to avoid implementing potentially flawed systems, according to FERC.

FERC said it granted the request because it met requirements of being in good faith, is limited because it involves a one-month delay and it addressed the concrete problem without undesirable consequences (ER18-728).

MARYLAND

People's Counsel, Pepco, Delmarva Power Settle Over Defective Notices

People's Counsel Paula Carmody said April 24 the Public Service Commission has approved a settlement agreement between her office, Potomac Electric Power Co. (Pepco) and Delmarva Power and Light concerning problems with the notices the companies are supposed to send to residential utility customers facing service terminations.

Carmody said the companies either failed to send the notices or sent defective ones, depriving customers of information they needed to help them address past-due bills, submit disputes to the PSC and avoid significant threats to their health and safety.

Under the agreement, Pepco has certified it has refunded the reconnection fees it charged 39,000 customers whose service it cut off from May 2015 through October 2016. Pepco had sent the customers termination notices that left out essential information about energy assistance and dispute procedures they could have used to avoid having their service terminated.

Among other things, both companies also agreed to provide funds to local assistance organizations.

MASSACHUSETTS

Deadline for Offshore Wind Procurement Pushed Back to May 23

The utilities helping the state with its offshore wind procurement sent the Department of Public Utilities a letter on April 23 saying they needed to move back the deadline for selecting projects from April 23 to May 23.

The companies said they still expect to submit a negotiated contract for the procurement to the state for its approval by July 31.

As reasons for the delay, the companies cited the three nor'easters that struck New England in March, which they had to respond to, leaving them less time to work on the procurement, and delays in the state's hydropower procurement, which involves some of the people also working on the offshore wind procurement.

More: *State House News Service*

NEW JERSEY

BPU Issues RFQ for Offshore Wind Development Strategic Plan

The Board of Public Utilities said April 25 it has approved the issuance of a request for quotation that will facilitate the creation of a strategic plan to enable it to implement Gov. Phil Murphy's executive order to develop wind generation off the state's coast.

The board said it wants bidders to help define the standards for development the state needs to achieve its initial goal of 1,110 MW of offshore wind capacity and the subsequent buildout to the proposed 3,500 MW of capacity.

The board is accepting quotations until 2 p.m. May 23 and wants all questions about the RFQ to be submitted by 2 p.m. May 9.

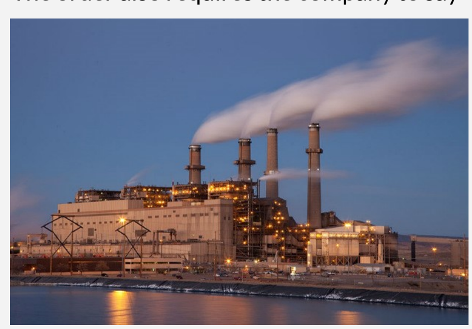
More: *New Jersey Board of Public Utilities*

NEW MEXICO

PRC Gives PNM 13 Days to Explain Silo Collapse, Fire at Power Plant

The Public Regulation Commission (PRC) on April 25 issued an order giving Public Service Company of New Mexico 13 days to explain the cause of the March coal silo collapse and resulting fire at its San Juan Generating Station.

The order also requires the company to say



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STATE BRIEFS

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what repairs it plans to make and when it will make them to get unit No. 1 at the plant back in service.

New Energy Economy and seven other advocacy groups petitioned the PRC on April 12 to investigate the collapse and fire and require PNM to perform a cost-benefit analysis to justify the unit's continued operation.

More: *Santa Fe New Mexican*

NEW YORK

Second Large-Scale Renewable Solicitation Launched

Gov. Andrew Cuomo on April 25 announced the second solicitation for large-scale renewable energy projects under the state's Clean Energy Standard.

The state said the solicitation for up to 20 projects is expected to spur up to $1.5 billion in private investment and support 1.5 million MWh of renewable electricity per year, advancing the state's commitment to secure 50% of its power from renewable sources by 2030.

The state said the solicitation includes new standards and requirements for effective community outreach and planning and ensures that good-paying jobs will be created by requiring the prevailing wage for applicable positions.

More: *Gov. Andrew Cuomo*

NORTH CAROLINA

AG Appeals Decision on Coal Ash Costs to Supreme Court

Attorney General Josh Stein on April 26 said in a filing with the Utilities Commission that he is appealing to the Supreme Court the commission's February decision allowing Duke Energy Progress to charge consumers $232 million over five years to recoup money it has spent on coal ash cleanup.

Stein said he considers the decision "unlawful, unjust, unreasonable or unwarranted."

A Duke Energy spokeswoman said the company thinks the decision was fair to Duke and its customers.

Marshall ash basin | *Duke Energy*

More: *Associated Press*

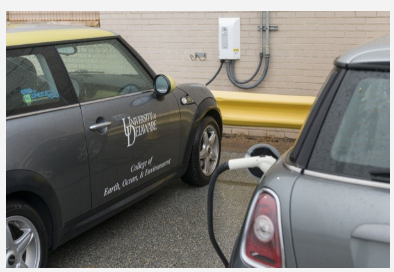
OHIO

AEP Gets Permission to Spend up to $10 Million on EV Charging Stations

The Public Utilities Commission on April 25 gave American Electric Power (AEP) Ohio approval to spend up to $10 million on rebates and incentives meant to encourage the development of as many as 375 charging stations for electric vehicles (EVs).

AEP's customers will reimburse the company for the money it spends through a charge on their bills.

The incentives will go to apartment owners, businesses and others. About a third of the stations will be in public areas, while others will be at workplaces, condominiums, apartment complexes and other places that may not be open to the public.



More: *The Columbus Dispatch*

PUC Rules Utilities Must Continue Setting Aside Tax Savings

The Public Utilities Commission (PUC) ruled April 25 that American Electric Power, Dayton Power & Light, Duke Energy and FirstEnergy must continue to set aside their savings from the Tax Cut and Jobs Act until details about how the money will be used to lower rates are worked out.

The commission rejected the utilities' legal arguments for not passing the savings from the act, which reduced the federal corporate tax rate to 21% from 35%, on to their customers.

The utilities can appeal the decision to the Supreme Court.

More: *Associated Press*

OKLAHOMA

Court Rules Regulators Wrongly OKd OG&E Coal Scrubbers

The Supreme Court on April 24 issued a ruling requiring the Corporation Commission to vacate a 2016 decision determining it was reasonable for Oklahoma Gas and Electric Co. (OG&E) to spend $500 million to install coal scrubbers at the Sooner generation station to meet federal environmental regulations.

The court said the commission relied upon the authority to regulate utilities it gets from the state constitution to make the 2016 decision, when it should have relied on a statute requiring it to consider whether the costs of proposed projects are fair and reasonable to utilities' ratepayers.

An OG&E spokesman said the company will continue installing the coal scrubbers and file to recover their cost under a traditional rate case.

More: *The Oklahoman*

WISCONSIN

PSC Determines Tax Savings Use for We Energies, WPS

The Public Service Commission (PSC) on April 26 ruled that We Energies and Wisconsin Public Service (WPS) must return 20% of their savings from the Tax Cut and Jobs Act to their customers and use the remaining 80% to pay down deferred costs that aren't included in their current rates.

The act cut the federal corporate tax rate from 35% to 21%. PSC staff estimated the lower rate will save We Energies electric customers $61.9 million a year and WPS electric customers $27.8 million a year. We Energies and WPS are owned by WEC Energy Group.

More: *Milwaukee Journal Sentinel*