RTO Insider
Your Eyes and Ears on the Organized Electric Markets
CAISO ■ ERCOT ■ ISO-NE ■ MISO ■ NYISO ■ PJM ■ SPP

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Trump Orders Coal, Nuke Bailout, Citing National Security

By Rich Heidorn Jr. and Michael Brooks

President Trump directed Energy Secretary Rick Perry Friday to force grid operators to provide a lifeline to struggling coal and nuclear plants, saying their retirements threaten national security.

The Department of Energy had not issued an order as of Friday afternoon. But a 40-page draft memo described as an "addendum" includes a reference to the order and describes the department's legal foundation, saying the closures threaten military bases and the nation's nuclear workforce. The memo was first reported by Bloomberg, which said it was prepared for a Friday meeting of the National Security Council.

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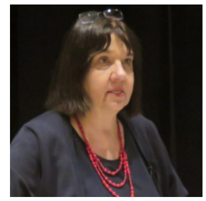
More Questions than Answers for FERC, RTOs

By Jason Fordney, Amanda Durish Cook and Rich Heidorn Jr.

WASHINGTON — FERC officials and RTO executives still had more questions than answers this week regarding the Department of Energy's plans for rescuing at-risk nuclear and coal plants.

Shortly before *RTO Insider* went to press Tuesday morning, FERC Chairman Kevin McIntyre told reporters at the Energy Information Administration conference in D.C. that he has not been briefed by DOE since President Trump ordered Energy Secretary Rick Perry to prevent further plant retirements.

He spoke minutes after DOE Undersecretary Mark Menezes told reporters at the conference that the department is still working out the details of the plan. He said the department would not necessarily be ordering RTOs and ISOs to purchase energy or capacity from at-risk plants — as was detailed in a DOE memo leaked last week — but that it was one of the options under review. He did not respond when asked why Trump had made the directive last week when the details were uncertain.



Cheryl LaFleur | © *RTO Insider*

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CPUC Approves Utility EV Infrastructure Programs

By Jason Fordney

California regulators last week authorized the state's investor-owned utilities to recover $738 million for electric vehicle charging infrastructure to help meet the state's greenhouse gas reduction goals.

The California Public Utilities Commission's Thursday order stemmed from its 2016 directive ordering the IOUs to propose projects that would advance the electrification of transportation. During the proceeding, the state's Office of Ratepayer Advocates and The Utility Reform Network negotiated aspects of the program, originally proposed at $1 billion by the utilities.

"The only way to get to a largely carbon-free California is by substantially electrifying the state's vast transportation system," Commissioner Carla Peterman said. "The decision made today aims to balance costs with benefits for all ratepayers, considers impacts on competition, and directs significant portions of the utility programs to disadvantaged communities often hit hardest by traffic and air pollution."

The Natural Resources Defense Council supported the CPUC's decision, saying it

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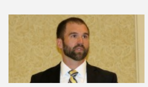

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CAISO NEWS

CAISO Hits Reset on Backstop Procurement Overhaul

By Jason Fordney

| © RTO Insider

FOLSOM, Calif. — CAISO is going back to the drawing board to overhaul its reliability-must-run program, switching to a "holistic" approach after a more narrowly crafted backstop procurement proposal was rejected by FERC last month.

The ISO said it will combine into one process what was previously two separate phases of RMR rule changes. It hopes to develop its new proposal and complete a stakeholder process in time for presentation to its Board of Governors in March 2019.

"We're not really talking about phases any more; this is really one big initiative," CAISO Infrastructure and Regulatory Policy Manager Keith Johnson said during a stakeholder meeting Wednesday. Many stakeholders had previously urged CAISO to combine the two phases and tackle what are perceived to be wider problems with the RMR construct, but the ISO had favored a more incremental approach.

As out-of-market payments, RMRs have stirred controversy among ISO participants and prompted a larger debate about resource adequacy in California and whether current policies are appropriately incentivizing needed generation. Most recently, CAISO issued a May 15 market notice saying it will seek RMR designations for NRG Energy's Ellwood and Ormond Beach units, which the company in March said it planned to retire. (See *NRG Set to Retire California Gas Plants* and *CAISO: New 2019 RMR Contracts Possible*.) Environmental groups had cheered the news of the retirements.

FERC last month rejected CAISO's proposal to make substantive changes to the separate but related Capacity Procurement Mechanism, which is similar to RMR in that it functions as a backstop to financially support needed generation. In its decision, the commission said the ISO needs to propose a more comprehensive package of reform for CPM. (See *FERC Rejects CAISO CPM Proposal*.)

The RMR program is used as a reliability tool when a generating unit wants to retire but is still needed for reliability. RMR participation is mandatory, and units receive payments based on their cost of service, while those units designated under the CPM participate on a voluntary basis and receive a capped market-based price.

Calpine's Mark Smith (left) discusses RMR issues with Southern California Edison's Eric Little. | © RTO Insider

The ISO said it is not currently planning to merge the two processes.

Among the items being considered in the newly crafted RMR reform package are:

- Modifying compensation for both RMR and CPM;
- Subjecting RMR units to a must-offer requirement in the wholesale market;
- Providing flexible RA credits from RMR units; and
- Modifying cost allocation of CPM to reflect load migration.

Other goals include lowering banking costs for RMR invoicing, streamlining and automating the RMR settlement process and making interim changes to the *pro forma* RMR agreement.

Whatever backstop procurement the ISO develops will have to conform to — and interact with — a package of RA reforms being developed by the California Public Utilities Commission. At the CPUC, the ISO is advocating enhancements to flexible RA capacity procurement requirements, establishing multiyear RA procurement and vetting appropriate load forecasting assumptions.

"The ISO does think the RA program could be refreshed," Johnson said.

CAISO has said it is likely the RMR reforms will need to go to settlement. During Wednesday's meeting, stakeholders discussed how to negotiate the terms of an agreement without having to go through a settlement process at FERC after the proposal is filed.

Mark Smith, vice president of government and regulatory affairs at Calpine, called for an increase in the scope of proceeding to

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CAISO News

Calif. Senate OKs Utility Wildfire Cost Recovery

By Jason Fordney

The California State Senate passed legislation Wednesday that would allow the state's investor-owned utilities to pass through the costs of wildfires to ratepayers if they conform with safety plans approved by the Public Utilities Commission.

SB 1088, introduced by Sen. Bill Dodd (D), would require electric and gas utilities beginning in 2019 to submit annual safety, reliability and resilience plans, which the commission could approve "with or without modification" within 18 months.

If a utility is in compliance with its plan, "the utility's performance, operations, management and investments addressed in the plan may be deemed reasonable and prudent for purposes of any subsequent CPUC proceeding and are prohibited from affecting any civil action and any previous events."

Dodd said that "by mandating that utilities meet new safety, reliability and resiliency requirements, we can avoid these catastrophic fires before they start." He introduced the legislation in April. (See *Calif. Legislation Shields Utilities from Wildfire Costs*.)

The bill passed the Senate on Wednesday on a 34-2 vote with three legislators not voting, including U.S. Senate candidate Kevin de Leon (D). Friday was the deadline for bills to pass out of their house of origin. The deadline for bills to be passed this year is Aug. 31, and the last day for the governor to sign or veto them is Sept. 30.

The measure comes amid a decade-long debate over utility liability for wildfires, which heightened last year as more than 170 fires swept across California. The Department of Forestry and Fire Protection recently found that Pacific Gas and Electric had caused four Northern California fires, and investigations continue into much larger fires that hit the state last year. (See related story, *CAL FIRE Says PG&E Caused 4 Wildfires Last Year*, p.5.)

Utilities argue that climate change and drought are compounding the effects of the fires. Some observers also blame forest management practices for exacerbating the problem. Last November, the CPUC rejected San Diego Gas & Electric's request to recover $379 million in wildfire-related costs for fires in 2007, drawing swift reaction from all three of the state's investor-owned utilities. (See *Besieged CPUC Denies SDG&E Wildfire Recovery*.) In addition to their concerns over recovering fire costs, utilities also face civil suits by property owners blaming the power companies for fire losses.

The bill would require the state Office of Emergency Services to adopt standards and model policies that utilities and local governments should employ for reducing fire risks, including defining "defensible space."

The Utility Reform Network had opposed the bill, saying that "rather than enhancing safety, SB 1088 would reduce current energy utility incentives to operate their systems safely and prudently and would effectively grant the utilities a blank check," according to a May 29 bill analysis.

The Consumer Federation of California said that the 18-month CPUC timeline "undermines the possibility for a review that is fully vetted by the regulator and the public" and that the legislation "leaves almost no room for the regulator to reject a utility plan."

Another Dodd bill passed by the Senate on Thursday, SB 901, requires utility wildfire mitigation plans to include a description of the factors the companies use to determine when they should de-energize distribution lines and procedures for notifying customers and first responders, who could encounter live lines.

Dodd's two proposals were part of a seven-bill package approved by the Senate last week, which also dealt with homeowner insurance coverage, controlled burns and landslides. President Pro Tempore Toni Atkins (D) said the Senate has also proposed a budget that includes $483 million for fire-prevention efforts and $551 million for wildfire mitigation.

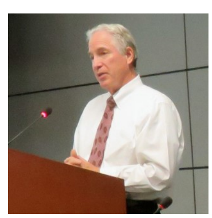
CAISO Hits Reset on Backstop Procurement Overhaul

Continued from page 3

include revising the RMR *pro forma* agreement, modifying transmission planning to prevent backstop procurement and other reforms.

"We have a difference of opinion from the ISO as what defines holistic," Smith said during a presentation.

Eric Little, manager of wholesale markets at Southern California Edison, said that RMR and CPM have become replacements for resources normally provided by RA. He also mentioned a must-offer requirement for RMR/CPM resources and said they should receive cost-based contracts plus a reasonable return.



Keith Johnson | © RTO Insider

"In addition, the compensation method that was once a trade-off of competitive market for capacity augmented by energy market rents will need to be made equivalent under a contract mechanism with the CAISO," Little said during a presentation.

The ISO is also working on increasing transparency around retirements, saying it will drop confidentiality provisions around notices of retirement or mothballing of units to ensure market participants are aware. That change, which will only require a revision to the ISO's generator management business practices manual rather than approval by the board, is due to be implemented by July 1.

CAISO plans to issue a new RMR straw proposal by June 26, with another stakeholder meeting July 11 to discuss the many complex issues around what will be a major change in its procurement policies.

CAISO NEWS

CAL FIRE Says PG&E Caused 4 Wildfires Last Year

Trees contacting Pacific Gas and Electric distribution lines caused four Northern California wildfires last year that burned about 9,400 acres, state investigators said.

After "extensive and thorough investigations," the California Department of Forestry and Fire Protection (CAL FIRE) determined PG&E lines sparked the LaPorte Fire in Butte County (which burned 8,400 acres), the McCourtney Fire in Nevada County (76 acres), the Lobo Fire in Nevada County (821 acres) and the Honey Fire in Butte County (76 acres).

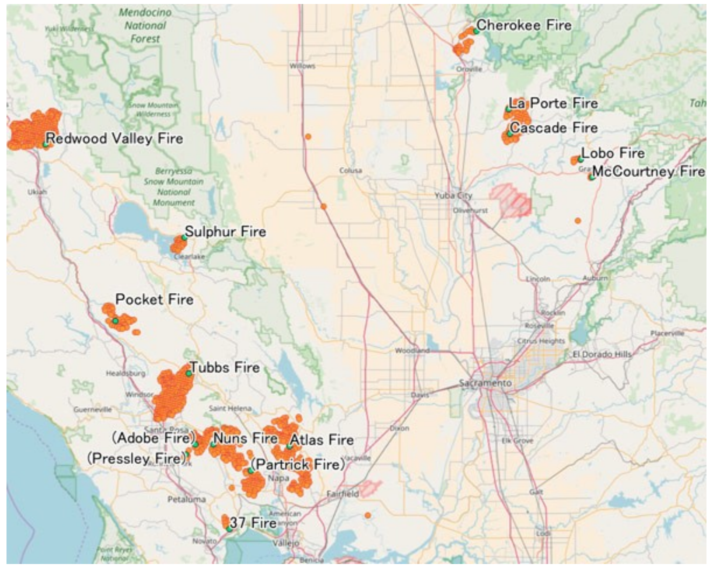
Tree limbs contacting lines caused the Lobo and Honey fires, and a tree falling onto power lines caused the McCourtney Fire, CAL FIRE said in statement. The La Porte Fire occurred after branches fell onto a PG&E power line.

While CAL FIRE found no violation of state law related to the La Porte Fire, the other three fires were allegedly because of the utility not adequately trimming vegetation near its lines.

"The McCourtney, Lobo [and] Honey investigations have been referred to the appropriate county district attorney's offices for review," CAL FIRE said.

The agency said the fires, which were among the smaller of the more than 170 fires that burned about 245,000 acres in Northern California last October, were the first to be investigated. The four fires caused structural damage but injured no civilians or firefighters.

On Wednesday, the California State Senate passed legislation that would allow PG&E and the state's other two investor-owned utilities to pass through the costs of wildfires to ratepayers if they conform with safety plans approved by the Public Utilities Commission. (See related story, *Calif. Senate OKs Utility Wildfire Cost Recovery*, p.4.)



The four fires alleged to be caused by PG&E lines were to the north of Sacramento.

— Jason Fordney

CPUC Approves Utility EV Infrastructure Programs

Continued from page 1

"marks the nation's single largest investment by the electric industry to eat away at Big Oil's longtime monopoly over transportation fuels."

Each IOU had its own package approved by the commission.

- San Diego Gas & Electric: A $137 million rebate program for 60,000 Level 2 home-based charging stations, and an EV-only variable hourly energy rate.
- Pacific Gas and Electric: $22 million for a "Direct Current Fast Charging Make-Ready Program" supporting 234 fast-charging stations at 52 sites. Also approved was make-ready infrastructure at a minimum of 700 sites to support the electrification of at least 6,500 medium- or heavy-duty vehicles.
- Southern California Edison: $343 million to install the make-ready infrastructure at a minimum of 870 sites to support the electrification of at least 8,490 medium- or heavy-duty vehicles, and three new time-of-use rates for commercial customers with electric vehicles.

Make-ready infrastructure includes service connection and supply infrastructure to support EV charging. It is composed of the electrical infrastructure from the distribution circuit to the stub of the EV charging station and can include equipment on the utility side, such as a transformer, or on the customer side, such as electrical paneling or wiring of the meter, the CPUC said.

The commission modified some of the budgets and terms of the program. For example, it rejected SDG&E's proposal to include existing EV customers in its program. TURN had argued that existing EV customers would be free riders, pointing to a survey that indicated 76% of California EV drivers have income of $100,000 or more. The commission included provisions for disadvantaged communities, setting rebates and adoption targets for EVs in those areas.

California's Clean Energy and Pollution Reduction Act of 2015 set new greenhouse gas reduction goals and directed the CPUC to work with other agencies to advance the electrification of transportation.

The CPUC began the proceeding in July 2017 and conducted 11 days of hearings last fall. Other parties included environmental groups, the California Transit Association, Union of Concerned Scientists, EV infrastructure companies and consumer groups.

The decision came just after the California Energy Commission issued a report saying the state will need between 229,000 and 279,000 EV chargers at locations other than single-family homes by 2025 to meet the state's goals for adoption of zero-emission vehicles. (See *California to Require Sharp EV Charger Growth by 2025*.)

ERCOT NEWS

Monitor Says Wholesale Market 'Performed Competitively' in 2017

Potomac Economics, ERCOT's Independent Market Monitor, released its annual State of the Market report last week, saying the wholesale market "performed competitively" in 2017.

The Monitor said higher natural gas prices led to higher energy prices last year, with ERCOT's load-weighted average real-time energy price rising 14.7% to $28.25/MWh. The average price for natural gas jumped 22%, from $2.45/MMBtu to $2.98/MMBtu.

Market conditions were rarely tight last year, the Monitor said, noting real-time prices did not exceed $3,000/MWh and broke $1,000/MWh for only three and a half hours.

However, total congestion costs in the real-time market almost doubled to $967 million. The Monitor attributed the increase to continued limitations on export capacity from the Panhandle, planned outages associated with the Houston Import Project's construction and "unusual operating conditions" after Hurricane Harvey.

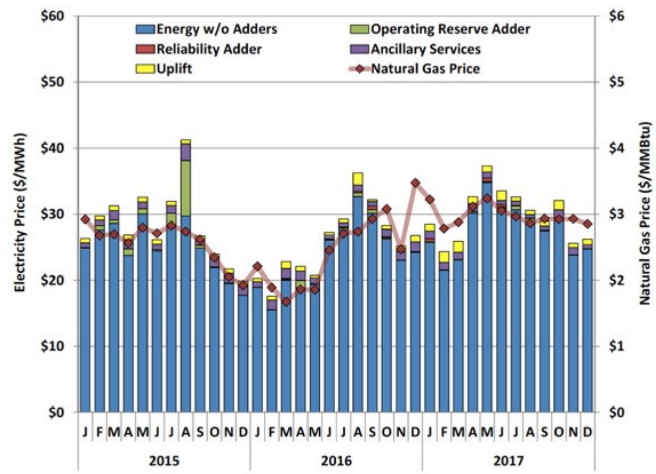
Although the market performed competitively, the Monitor made seven recommendations — all but one of them repeats from prior years — to improve the system's operation and resources and price formation in the energy and ancillary services markets.

The Monitor's new recommendation is to pay locational prices to all generators with output that affect a transmission constraint. Generators less than 10 MW and connected to the transmission system don't bear the same obligations as larger generators and are settled at the load zone price, not a location-specific nodal price.

"Small generators ... should settle in a manner consistent with the effect they have on the system," the Monitor said in its report. "The output of some small generators can significantly affect transmission congestion."

The Monitor suggests that when the smaller generators relieve a constraint, they be paid a much higher price than they are currently. When they aggravate a constraint, they would generally settle at a lower price.

"Settling with this generator [at] a zonal price fails to provide efficient incentive for it to operate in a manner consistent" with the system's reliability needs, the Monitor said.



Average all-in price for electricity in ERCOT | *Potomac Economics*

The report's repeat recommendations are:

- Implementing real-time co-optimization of energy and ancillary services.
- Evaluating policies and programs that create incentives for loads to reduce consumption for reasons unrelated to real-time energy prices.
- Modifying the real-time market software to better commit load and generation resources that can be online within 30 minutes.
- Consider including marginal losses in LMPs.
- Pricing future ancillary services based on the shadow price of procuring the service.
- Evaluating the need for a local reserve product.

The Monitor has called real-time co-optimization the "most vital" market improvement and "foundational" to efficient pricing. The Public Utility Commission of Texas in December approved ERCOT's proposed plan to further assess the benefits of implementing real-time co-optimization and marginal losses (Project No. 47199). As part of the project, the Monitor developed software to simulate co-optimization for 2017, and it intends to make the software, data and results available to all market participants.

The Monitor usually reviews the State of the Market report during the June Board of Directors meeting. Beth Garza, the Monitor's director and Potomac Economics vice president, is also scheduled to detail the market's performance during the Gulf Coast Power Association's June 21 luncheon in Houston.

System Sets New Demand Records for May, June

The ERCOT system began June the way it concluded May, registering a new monthly demand record in the face of sweltering Texas heat.

The grid operator, which manages the energy flow for about 90% of the state's electric load, recorded a new demand record for June on Friday with a load of 67.9 GW between 4 and 5 p.m. That broke the previous June record of 67.6 GW, set last year.

Real-time average prices peaked at $54.02/MWh in the interval ending at 2 p.m.

ERCOT established a new record for May for three consecutive hours on May 29, reaching 64.8 66.3 and then 67.3 GW during the intervals ending at 3, 4 and 5 p.m. The new mark is a 13.5% increase over the May record set last year.

Prices were as high as $92.95/MWh.

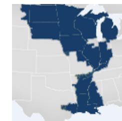
Texas has been beset with triple-digit temperatures. The National Weather Service issued a heat advisory for areas northwest of Fort Worth over the weekend, with predicted highs of 105 degrees Fahrenheit.

ERCOT said it had no plans to appeal for conservation, saying it has sufficient generation to meet demand.

The grid operator has now set monthly demand records for four months this year. It has projected a summer peak of 72.8 GW in August, which would break the 2016 record of 71.1 GW. It says it has 78.2 GW of capacity available, with a planning reserve margin of 11%. (See *ERCOT Gains Additional Capacity to Meet Summer Demand*.)

— Tom Kleckner

MISO News



MISO Mulls Additional Emergency Communication

By Amanda Durish Cook

MISO is asking stakeholders if they would like the RTO to provide generators an additional emergency notification declaring a maximum generation alert.

Manager of Unit Commitment and Dispatch Phil Van Schaack said MISO is considering creating a new capacity advisory or expanding its maximum generation criteria to include more conditions in order to provide market participants more advanced notice of possible emergency declarations for unit operators.

MISO was prompted to consider the move after forecasting possible emergency conditions for May 14 (a Monday) on May 11 (a Friday). The RTO ultimately declared an emergency alert just ahead of the weekend.

"Load, weather, very warm temperatures, outages made things very tight on May 14," Van Schaack said at a May 31 Reliability Subcommittee meeting.

However, MISO terminated the maximum generation event May 13 as conditions changed.

The RTO said stakeholders were mixed in their reactions to the advanced alert.

Some stakeholders attending the RSC meeting questioned MISO calling conservative operations on a Friday for tight operating conditions on Monday. They said weather forecasts beyond 36 hours become unreliable and predicting load patterns so far in advance is an uncertain business.

But Van Schaack said this May was likely the RTO's warmest on record, especially in MISO South. He predicted more emergency operating procedures over summer, in accord with the RTO's official spring predictions. (See *MISO: Summer Reserves Adequate, but Emergency Likely*.)

"The footprint capacity margin is tighter, and we anticipate more emergency procedures," Van Schaack said. He asked stakeholders if MISO should add a communication step "to improve awareness" prior to issuing a maximum generation alert.

Following emergency conditions during an extreme cold snap in January, multiple stakeholders asked MISO to distribute more real-time electronic communication to its members when it faces near-emergency or emergency conditions. (See *MISO Breaks down Recent Cold Snap*.)

But some stakeholders at the meeting pointed out that declaration of a maximum generation alert might already pre-empt any plan to create an additional emergency notice, as an alert is issued before a maximum generation warning, which is followed by declaration of a maximum generation event when conditions worsen.

"To go into an alert, you do have to go into conservative operations. ... We need to discuss the implications of more frequently going into conservation operations," Van Schaack said, asking stakeholders to provide written feedback on an intermediary communication before a maximum generation alert. He also noted stakeholders could suggest MISO adopt no change to its emergency notice system.

Stakeholders pointed out that the RSC doesn't hold another meeting until Aug. 2, which is likely to be well after the summer peak. Van Schaack responded that MISO would by then have more past alerts and emergency conditions to review and determine the best approach with stakeholders.

"Part of the reason we're here is that it's going to be hot in a few days. We'll have a few opportunities to try things out," Van Schaack said.

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MISO, PJM Seek Incremental ARR Coordination

By Amanda Durish Cook

MISO and PJM plan to unveil rule changes late this summer that will better synchronize how they manage incremental auction revenue rights (IARRs) along their seam.

Speaking during a May 30 Joint and Common Market meeting, PJM Senior Market Simulation Analyst Brian Chmielewski said the RTOs are working to clarify and improve their current IARR coordination process, particularly where it concerns PJM's customer-funded options.

Both RTOs offer IARRs, which represent additional auction revenue rights created by transmission upgrades that increase capability on their transmission facilities. IARR megawatts are awarded for the additional capability created for the life of the upgrade or 30 years, whichever is less, and valued each year based on annual financial transmission rights auction clearing prices.

However, PJM's process provides an additional option that allows a specified IARR to be awarded when a customer agrees to fund transmission upgrades necessary to support the new ARR request.

MISO and PJM coordinate studies of IARR requests when there is a potential impact on flowgates operated by either RTO, but they say there are gaps in the current process designed to coordinate IARRs between them.

Chmielewski said the RTOs need to ensure they are properly transferring firm flow entitlements on the impacted flowgates of an IARR to make sure FTR revenue remains adequate. Because PJM is also obligated to guarantee at least 80% of IARR megawatts, the RTO may have to require "some guarantee" from MISO on future firm flow entitlement allocations, Chmielewski said.

Chmielewski also said all of PJM's capabilities from upgrades might not be reflected in firm flow entitlement allocation between the two RTOs, and that current, non-active flowgates that could be activated in the future may impact the viability of IARRs.

The RTOs said they've met for several discussions on the issue since November and will present proposed revisions at the Aug. 29 JCM meeting.

Chmielewski said MISO and PJM could unveil joint operating agreement revisions by November, with a new process rolled out in the first quarter of 2019.

MISO NEWS

MISO Mulls Additional Emergency Communication

Continued from page 7

LMR Performance in January

MISO has concluded that it could improve its load-modifying resource performance after completing a detailed evaluation of the mid-January emergency, which identified issues with LMRs communicating their availability.

While the RTO requested 700 to 900 MW of LMRs throughout the emergency, it only received the requested amounts during five of the 10 hours of the emergency, with just 70% of LMRs that were called up by MISO meeting measurement and verification criteria. LMRs met scheduling instructions in 23 of 161 LMR interval hours, MISO said, while two LMRs missed instruction signals altogether. In total, MISO assessed $123,000 in penalties to six market participants for underperformance, MISO Manager of Resource Adequacy John Harmon said.

Harmon said market participants continue to provide inaccurate LMR availability reports to MISO operators.

"There continues to be a trend of the load reduction availability in the MISO communication system not matching up with actual load reduction capability," he said.

Vistra Energy's Mark Volpe asked Harmon to give overall LMR performance during the event a letter grade.

"I'll give it an elementary grade: 'needs improvement,'" Harmon replied.

But Customized Energy Solutions' Ted Kuhn asked MISO to grade LMRs in terms of "how many megawatts were requested and how many were received," not simply the "yes or no" of whether LMR volume was met in a specific hour.

MISO recently released a white paper documenting LMR characteristics in order to evaluate a growing reliance on LMRs in the footprint. The RTO concluded that it rarely sees the volume of LMRs that clear in the Planning Resource Auction made available in real time. The white paper recommended MISO take steps to:

- Increase awareness of when market participants voluntarily call on their LMRs;
- Ensure accurate reporting of LMR availability in the communication system;
- Consider price incentives for LMRs;
- Ensure MISO's notifications are in tune with actual LMR need, with special attention on LMRs that require a 12-hour notification before responding to emergencies; and
- Contemplate mandatory LMR access outside summer, the only season that LMRs are required to respond to emergencies.

MISO relies on LMRs' self-reported availability in the communication system in both summer and non-summer months.

Executive Director of Market Operations Jeff Bladen said the RTO will re-evaluate LMR rules and requirements as part of its larger effort to respond to changing resource availability. (See *MISO Looks to Address Changing Resource Availability*.) Bladen said "it may be true" that MISO could end up needing something more than LMR response to meet increasing regularity of emergency conditions.

MISO NEWS

DC Circuit Rejects Ark. PSC Review of FERC-Entergy Order

By Tom Kleckner

The D.C. Circuit Court of Appeals on Friday denied the Arkansas Public Service Commission's request that it review a 2016 FERC order directing Entergy Arkansas to continue sharing settlement proceeds under the Entergy System Agreement (16-1305).

FERC approved Entergy Arkansas' withdrawal from the agreement in 2009. In 2016, FERC held that the utility must continue to share the proceeds of its predeparture settlement with Union Pacific with the system's other member companies (ER13-432).

The PSC contended that the commission's order to share the settlement benefits and its method of allocating the benefits was unlawful and unsupported by substantial evidence.

The D.C. Circuit concluded that FERC had a lawful basis to order the sharing of the benefits and was "reasoned" in its allocation methodology.

The PSC pointed to Entergy Arkansas' withdrawal proceeding in arguing that FERC's order "essentially amounts to the imposition of an unlawful exit fee or post-withdrawal continuing obligation."

Writing for the three-judge panel, Senior Circuit Judge David Sentelle rejected the argument, saying FERC was right to conclude "that sharing the Union Pacific settlement benefits was necessary under the principles of equity and was not a penalty or recompense for the company's exit from the system."

The court also disagreed with the PSC's contention that FERC violated the filed rate doctrine by ordering Entergy Arkansas to share the settlement benefits. Under that doctrine, public utilities may only charge rates filed with FERC.

Sentelle said FERC had determined it was not overriding a filed rate, "but merely effectuating the purpose of a non-jurisdictional contract." He noted Entergy Services was a party to the settlement, and that "FERC found [Services] entered into the settlement on behalf of all the operating companies while they were under FERC's jurisdiction through the system agreement."

The court also agreed with FERC's use of its allocation method, noting the commission found it likely "Entergy Arkansas would have entered into a multiyear transportation contract in 2011 and not benefited from [a] price dip in 2012" without the Union Pacific settlement.

"There was no evidence that Entergy Arkansas could have anticipated the 2012 drop in coal transportation prices and made different contracting decisions," Sentelle said.

Entergy service area | *Entergy*

The proceeding stemmed from a 2008 settlement in Arkansas state court between Entergy Arkansas, Entergy Services and other parties against Union Pacific. The settlement locked in a below-market rate for rail delivery of coal by extending an Entergy Arkansas contract with Union Pacific to a three-year period ending June 30, 2015.

Under Entergy's system agreement, which expired in 2016, its operating companies purchased excess energy from their sister companies at cost, incorporating coal transportation as a component. Union Pacific failed to make coal deliveries at one point, leading to the settlement.

Entergy Arkansas passed a portion of the increased coal costs to the other operating companies under the agreement's service schedule, and also shared its beneficial coal transportation costs under the Union Pacific settlement.

However, the settlement did not address Entergy Arkansas' impending withdrawal from the agreement, which FERC approved in 2009.

The Louisiana Public Service Commission filed a Section 206 complaint with the commission, arguing that FERC should allocate the Union Pacific settlement benefits as part of the case. The D.C. Circuit eventually upheld the commission's decision, but it held FERC "must still review the post-withdrawal arrangements."

The Louisiana commission again raised the Union Pacific issue when Entergy Services filed a post-withdrawal successor plan with FERC. In response, the Arkansas commission and Entergy Services challenged FERC's authority to order Entergy Arkansas to share the settlement benefits, because the utility was no longer participating in the system agreement.

Following settlement discussions and a hearing, an administrative law judge determined that the settlement benefits should be allocated among the operating companies and adopted an allocation methodology. FERC affirmed the findings in 2016 and ordered Entergy Arkansas to make a compliance filing refunding the settlement benefits to its sister companies.

MISO NEWS

FERC Examining Cleco Plant SSR Compensation

By Amanda Durish Cook

FERC last week opened an investigation to determine whether the cost recovery for a Cleco Power gas-fired plant that serves as a MISO system support resource unit in southern Louisiana is justifiable.

Teche Power Station | *Google*

The commission accepted and suspended a Cleco rate schedule that allots a fixed monthly payment of $1.7 million for the continued operation of the 338-MW Teche Power Station Unit 3, and directed its chief administrative law judge to decide whether to initiate a hearing over the matter (ER18-1237).

MISO first won approval for the plant to operate under an SSR in mid-2017 after Cleco signaled that it intended to retire the unit. (See *MISO Wins OK for Cleco Plant SSR*.) At the time, the RTO said the Teche plant was needed to prevent severe thermal violations on its transmission system that could not be addressed until the Terrebonne-Bayou Vista 230-kV line could be put into service this year. Entergy now expects the line to be placed into service in early 2019.

In May, FERC granted MISO approval to renew the SSR agreement through March 31, 2019. The agreement provides for both hourly compensation of the plant and the fixed monthly charge, which Cleco says covers costs not included in hourly compensation and fully reimburses it for the costs of operating and maintaining the unit. Cleco had already included the associated $1.7 million in monthly payments in its rate schedule filed with FERC in March.

Entergy protested the rate schedule, saying Cleco failed "to provide enough information to establish that the proposed monthly payments are just and reasonable." Entergy contended that Cleco's filing failed to contain "many of the details" required by FERC regulations to allow the commission and interested parties to assess the validity of the costs associated with the agreement.

Cleco has contended that the compensation for its second SSR agreement "is just and reasonable and is no more than necessary to maintain the availability of Teche 3."

Entergy also contested Cleco's request for a waiver of the 60-day notice requirement, which would allow the proposed rate schedule to become effective April 1. In its May 29 ruling setting the Teche matter for hearing, the commission rejected Entergy's argument, saying its previous rulings have held that nothing in the SSR program would require a generator to shoulder uncompensated costs.

"Here, the record indicates that Teche 3 has been providing reliability service pursuant to the second SSR agreement since April 1, 2017," the commission said. "Thus, it is appropriate that Cleco be made whole for the costs that it incurs while providing SSR service."

FERC Rejects MISO Network Resource Process Streamlining

By Amanda Durish Cook

FERC last week rejected a MISO proposal to streamline the RTO's process to define and qualify its network resources, saying the changes would cause Tariff discrepancies.

"MISO's proposed revisions … lead to inconsistencies in its Tariff," FERC said in denying the filing without prejudice (ER18-502).

MISO filed the change in December to eliminate a requirement that network resource interconnection service (NRIS) generators must be qualified as a designated network resource in the RTO's Open Access Same-Time Information System (OASIS). MISO also proposed to remove a provision requiring network customers to "un-designate" extra capacity on OASIS before offering it into the RTO's markets and annual capacity auction.

The revisions would have reduced the information customers have to provide on network integration transmission service applications, including maintenance records and whether a unit will be an internal resource. MISO characterized the requirements as nothing more than "administrative steps."

MISO said NRIS resources already demonstrate their deliverability publicly, adding that it generally doesn't perform an additional study when network load designates a resource with NRIS. The RTO said the move would cut down on the amount of "duplicative information" it receives and increase efficiency for itself and market participants. MISO added it had "no downstream processes that rely on the designation information of NRIS resources."

But FERC said MISO's plan as worded could introduce confusion among its customers.

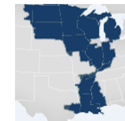
The commission noted MISO's proposed changes interchangeably use the terms "network load," "transmission provider's network load" and "network customer's network load." FERC had originally asked for clarification on the filing in February on similar use of the terms, and MISO responded by taking out some, but not all, of the language.

"These changes could lead to a misunderstanding of the ownership of network load," the commission said in the May 29 order.

The Missouri Joint Municipal Electric Utilities Commission and WPPI Energy protested MISO's filing, saying the proposed changes appeared to "erode" and "hollow out" the RTO's current obligation to plan and provide for the firm delivery of network resources to network load economically dispatched and regulated by network customers who pay MISO's load-ratio network service charge.

FERC said it would not address those concerns since MISO could not demonstrate its revisions were just and reasonable. MISO had contended that the two organizations misunderstood its revisions.

MISO News



MISO Makes Second Attempt at Pseudo-tie Contract

By Amanda Durish Cook

CARMEL, Ind. — MISO plans to file a reworked version of its *pro forma* pseudo-tie agreement this month after FERC rejected a previous proposal earlier this year.

The commission's February order rejecting the earlier agreement in part found fault with MISO's proposed suspension and termination provisions. (See FERC Rejects MISO Pseudo-Tie Pro Forma.)

This time MISO will file two separate *pro forma* agreements with FERC: one for generators pseudo-tying into the RTO and one for generation pseudo-tying out, Principal Engineer Kyle Abell said during a May 31 Reliability Subcommittee meeting. He said the two separate agreements will clarify the responsibilities of both MISO and the external balancing authority.

Additionally, MISO says it will coordinate the suspension and termination of pseudo-ties with external BAs and follow suspension processes outlined in joint operating agreements with those BAs, if they exist.

Identical provisions in both versions of the agreement would allow MISO to suspend a pseudo-tie if it poses a reliability risk, violates the Tariff or any applicable joint operating provisions, breaches the *pro forma*, or fails to provide required real-time data to the RTO. MISO may also terminate pseudo-ties when they are subject to two or more suspensions during a 30-day period.

Each of the agreements provides pseudo-tie owners up to 30 days to resume normal operation from suspended status when they provide "a remedy for the cause of the failure."

MISO could also terminate an agreement after a 60-day notice if it determines that the "existing market design does not accommodate the pseudo-tie." It also retained provisions to suspend or terminate pseudo-ties that do not maintain firm transmission service from source to sink for the life of the pseudo-tie or cannot maintain a generation-to-load distribution factor within 2% between MISO and an external balancing authority area.

During a May 30 MISO-PJM Joint and Common Market meeting, PJM's Tim Horger said there wasn't much left to report on the RTOs' overall pseudo-tie coordination plan, which he called a "good thing."

"A lot of the pseudo tie initiatives have come to a conclusion," Horger said.

MISO and PJM hope to implement the first phase of a previously announced fix to the double-counting of pseudo-tie congestion charges by Aug. 1, although FERC has not yet ruled on the RTOs' rebate solution filed in late October 2017. (See MISO, PJM Pursue Pseudo-Tie Double-Charge Relief.)

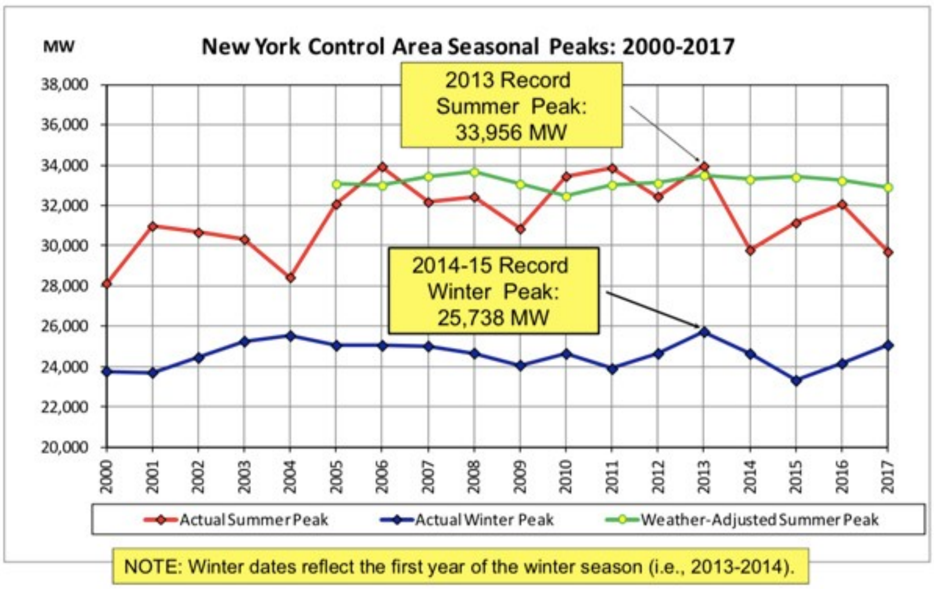
NYISO NEWS

NYISO Ready to Meet Summer Demand

NYISO said Wednesday it is prepared to meet peak demand this summer, with a total of 42,169 MW of power resources available to cover an expected peak of 32,904 MW — 2.9% above the long-term average.

Demand last summer peaked at 29,699 MW on July 19, coming in 7% below the 10-year average of 31,968 MW. New York set its record peak of 33,956 MW at the end of a weeklong heat wave in July 2013.

The ISO's summer capacity assessment used a "deterministic approach" to approximate capacity margins and operating reserves for baseline and extreme weather conditions, according to Wes Yeoman, NYISO vice president of operations. The assessment uses a set of projected derates based on five-year equivalent forced outage rate - demand averages.



| *NYISO*

At baseline peak weather conditions, the ISO forecasts 1,599 MW of capacity margin surplus, which is above the baseline peak load, plus 2,620 MW of required operating reserves. The baseline peak forecast is up 1,214 MW over last year's forecast.

For the 90th percentile forecast of extreme weather conditions, the ISO projects a capacity margin shortfall of 241 MW, an increase of 1,683 MW over last year's extreme weather forecast.

The ISO reported 39,325 MW of generating capacity available from power plants in New York and 1,219 MW of demand response resources plus another 1,625 MW available from neighboring regions.

"Based on historical performance, the net resources projected to be available to serve during the summer peak total 37,123 MW," said the report.

New York's 2018 operating reserve requirement of 2,620 MW is based on the potential loss of the system's largest single resource. Peak demand combined with operating reserves translate into a total capacity requirement of 35,524 MW.

— Michael Kuser

Stakeholders to Assess External MMU Performance

RENSSELAER, N.Y. — NYISO stakeholders are being asked to weigh in on how effectively the external Market Monitoring Unit is performing its duties before the ISO considers whether to renew its contract.

The ISO's Management Committee on Wednesday received the annual solicitation of market participant input on the MMU's performance. Shaun Johnson, NYISO director of market mitigation and analysis, said the three-year MMU contract with Potomac Economics runs through March 31, 2019. The ISO's Tariff calls for the Board of Directors to oversee and review the MMU's performance.

The MMU's duties include attending meetings with stakeholders; ensuring wholesale markets function efficiently and appropriately; and identifying market violations, design flaws and power abuses. The unit also evaluates significant proposed revisions to NYISO's market rules.

The Monitor must additionally produce annual and quarterly state of the market reports assessing the performance of New York's electrical markets. (See "Potomac Economics 2017 State of the Market Report," *NYISO Business Issues Committee Briefs: May 16, 2018*.)

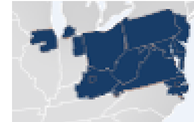
As presented at the Sept. 11, 2017, Budget and Priorities Working Group, the MMU budget for this year is $4.1 million, a $600,000 increase over the previous year to cover added cybersecurity costs and support capacity market enhancements.

Potomac Economics also monitors the ERCOT and MISO markets.

NYISO will accept stakeholder comments on the MMU's performance until June 21, 2018. They can be submitted to Johnson at sjohnson@nyiso.com and Leigh Bullock at lbullock@nyiso.com. All written comments will be treated as confidential to protect commercially sensitive matters.

— Michael Kuser

PJM News



FERC Postpones Tech Conference on PJM Regulation Market

Settlement Judge Appointed

By Rory D. Sweeney

FERC agreed last week to postpone a technical conference over PJM's frequency regulation market and appoint a settlement judge to help resolve a dispute over how the service is compensated (EL17-64, EL17-65, ER18-87).

The Energy Storage Association, Renewable Energy Systems Americas and Invenergy Storage Development, which had opposed PJM's October 2017 proposal to revise the service, joined with the RTO in asking FERC to postpone the technical conference. They said the delay would allow them "to focus their efforts on settlement proceedings and avoid potentially duplicative information gathering." They said appointing a settlement judge would "facilitate the expeditious resolution of the issues."

FERC ordered the technical conference March 30 while also granting in part a complaint by the ESA and rejecting PJM's proposed changes to improve its regulation market. (See *FERC Rejects PJM Regulation Plan, Calls Tech Conference*.)

In October 2017, PJM proposed a four-part plan that included redesigning its two regulation signals to work together to manage area control error. It included a new "regulation rate of technical substitution curve" to replace the "mileage ratio" calculation that the RTO says is problematic, and adjusted calculations for performance scoring, settlements and lost opportunity costs.

The opponents argued that related operational changes had significant negative impacts on battery storage and are "a symptom of the broader problem that the RTO misuses regulation resources to reduce generation on its system for sustained periods of time."

In rejecting PJM's proposal, the commission said the RTO hadn't addressed the issues for which the commission rejected previous proposals on the topic.

In their May 18 request to delay the technical conference, the parties said they've had "preliminary discussions" that "would be best addressed under the direction of a settlement judge and in a forum in which all interested intervenors could participate." They promised to file a joint update within 90 days of the judge being appointed.

PJM's Independent Market Monitor opposed the request, saying it's "premature" because FERC's most recent rejection remains subject to requests for rehearing.

FERC disagreed, saying its "policy favors settlement." It ordered the judge to file an update within 30 days of being appointed and every 60 days thereafter if the discussions continue.

PJM Experiences First Load Shed in the Capacity Performance Era

By Rory D. Sweeney

PJM ordered its first load-shed event since implementing Capacity Performance in 2015 after a transmission line in Indiana tripped offline on May 29.

It was also the RTO's first trigger for the significant performance-related bonuses and penalties introduced with CP.

The 30-minute event occurred at the Edison substation in American Electric Power's transmission zone, west of South Bend, Ind. PJM's Adam Keech explained that a transformer and a transmission line unexpectedly tripped out of service about 1:20 p.m., creating a load on the facility above its ratings.

As part of its response procedures, PJM simulated the effect on the system of losing that facility. The RTO's procedures call for continuing that analysis for facilities that subsequently would become overloaded and simulating their loss as well. If that continues for five steps without mitigation, or if it hits a larger issue and can't be resolved, PJM pre-emptively sheds load "before anything else tripped that would potentially create a cascading outage," Keech said during a special Markets Implementation Committee meeting Friday on updating the variable resource requirement curve.

For this situation, grid operators ordered a reduction of 71 MW of load, he said. However, the transformer kicked back into service, "so the total requested amount was never actually shed … because the equipment came back that quickly."

No demand response was called, Keech said. PJM later confirmed the actual load shed was 21 MW.

The situation triggered the first performance assessment interval (PAI) under the CP capacity construct, which analyzes the performance of generators that were paid for a capacity commitment to supply power in that region. Units that outperformed their commitments are eligible to receive bonus payments, while those that underperform receive stiff financial penalties. The analysis compares the supply needed to the units that have commitments and only includes units that were able to help by raising their output, Keech said.

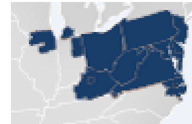
PJM is limited in how much information it can release, he said, because the event affected only a small number of generation owners. The RTO's confidentiality rules restrict what information staff can release if fewer than four generation owners were affected, he said.

Keech noted that some stakeholders expressed concerns with how the incident was communicated and said staff plan to revise procedures to address them.

"I think when we envisioned PAIs, the discrete, very localized load-shed event wasn't on everybody's mind. But now that we've got it, we should learn to handle it a little bit better," he said.

The event will have implications for several other markets and reliability calculations, including the balancing ratio and default market seller offer cap. (See "Balancing Ratio," *PJM Market Implementation Committee Briefs: May 2, 2018*.)

PJM NEWS



Gas Gens Ask FERC for 'Clean MOPR' in PJM

By Rory D. Sweeney

Three owners of gas-fired generation in PJM's territory have filed a complaint asking FERC to direct the RTO to adopt what they've termed a "clean MOPR" to be implemented in time for the May 2019 Base Residual Auction (EL18-169).

The minimum offer price rule sought by CPV Power Holdings, Calpine and Eastern Generation would be applicable to all subsidized resources and wouldn't include categorical exemptions like those in the Independent Market Monitor's MOPR-Ex proposal that PJM filed along with its own capacity repricing proposal as part of its "jump ball" proceeding.

While the clean MOPR would also include federal subsidies, it would retain an exemption for unit-specific justifications of offers below the rule's floor. MOPR-Ex includes exemptions for self supply, states' renewable portfolio standards, public power and competitive entry. (See *PJM Capacity Proposals Widely Panned*.)

The generators say they are offering "a vehicle for the commission to initiate a separate proceeding" from the other two proposals and a 2016 complaint, which Calpine and Eastern Generation joined, on how the existing MOPR handles subsidized resources (EL16-49). They say neither of the two previous dockets "allow the commission to take the sort of comprehensive action that is urgently needed at this time," but they also ask that the records from those two dockets be incorporated into their new complaint.

The complaint, which is more than 600 pages, includes an affidavit by Roy J. Shanker, a well-known industry consultant, who says that "the only realistic fix to subsidies is a clean MOPR" that is "straight-forward, easily understood and, with the elimination of the exceptions and exemptions, administratively simpler than MOPR-Ex." He goes on to list six attributes that the "clean MOPR" would provide, including facilitating "robust competition," not impeding or distorting price signals, ensuring least-cost resources are selected, price transparency, shifting risk from customers to private capital or the political entities creating the subsidies, and mitigating market power.

The companies also note that some subsidies "greatly exceed" BRA clearing prices, which Shanker says "should provide the commission great pause." The subsidies "crowd out" economic resources, causing them to retire early, and discourage new economic resources. Shanker says that the participation of 1,000 MW of subsidized resources in the auction could "depress overall market prices by $1 billion," and with states considering subsidies for perhaps 10,000 MW or more, "billions of dollars in price suppression is simply not sustainable."

The complainants make several arguments for why subsidies need to be eliminated from markets completely, lest they irrevocably break them. They mention the Monitor's warnings that "subsidies are contagious" and "an effort to reverse market outcomes with no commitment to a regulatory model and no attempt to mitigate negative impacts on competition."

The actions of one state "can have a significant impact on wholesale prices affecting loads in other states," they argue, urging FERC to "be cognizant of the fact that failure to protect the organized, multistate [Reliability Pricing Model] market from one state's policy choices inevitably impacts other states."

The generators say they've brought up the issues in PJM stakeholder meetings, but the results lead them to "believe that further discussions between the parties will [not] resolve the concerns."

PJM NEWS

PJM Urges FERC to Act on 'Jump Ball' Despite Criticism

By Rory D. Sweeney

Artificial Island | *BHI Energy*

PJM is pressing FERC to make a decision on the RTO's "jump ball" capacity filing, arguing that the commission is within its authority to do so and pointing out what it considers to be hypocrisy in opponents' criticism of the filing (ER18-1314).

The RTO's 38 pages of comments filed May 25 pushed back on widespread condemnation of PJM's proposal that FERC choose between two plans to isolate subsidized resources within its capacity auction in order to prevent them from suppressing prices. (See *PJM Capacity Proposals Widely Panned*.)

PJM reiterated its claim that the "status quo is not an option," arguing that either its own capacity repricing proposal or the MOPR-Ex developed largely by PJM's Independent Market Monitor would be reasonable. It also addressed concern about asking FERC to choose between the proposals, contending that it could have filed its repricing proposal first and — if rejected — then filed the MOPR-Ex.

But PJM neglected to address the question of how it would have prioritized which of the proposals would've been filed first. The RTO received significant criticism for filing its own proposal — which would give subsidized units a capacity obligation but remove their influence from the calculation of the clearing price — without stakeholder support. MOPR-Ex, which would extend PJM's existing minimum offer price rule to bar subsidized resources from receiving a capacity commitment, garnered more stakeholder support but ultimately failed in an endorsement vote.

PJM argued that the decision is within FERC's authority and represents an important issue for the commission, noting the commission's recent approval of "MOPR-style rules" in ISO-NE, a reference to its Competitive Auctions with Sponsored Policy Resources (CASPR).

"Ample precedent makes clear that PJM's wholesale capacity market rules fall squarely within the commission's exclusive jurisdiction, leaving no room for argument that changes to the offer price and clearing price rules somehow exceed the commission's authority or rob states of their authority," PJM wrote. "Restoring wholesale prices to just and reasonable levels — meaning a price higher than the price that would have resulted had the state program been ignored — is not an intrusion into state prerogatives."

The RTO's comments frequently cast the criticisms of its efforts as hypocritical.

"The commission should consider carefully each of these narratives, which in essence amounts to two sides of a single coin," PJM said. "A curious outcome of all the advocacy around price consequence is discovery that the same parties claiming PJM's prices are too low, in the next breath, argue for state and federal subsidy programs because such programs will prevent PJM's prices from rising."

PJM identified those parties as "several companies owning legacy coal and nuclear generation." The RTO also disparaged a Brattle Group report on the price impacts from closing nuclear plants in Ohio and Pennsylvania as "so astonishingly incomplete they leave no doubt as to the political calculation behind their preparation."

PJM noted that clearing prices were higher in its 2018 Base Residual Auction for delivery year 2021/22 and that roughly 7,000 MW of nuclear power failed to clear. The higher prices helped the resources that did clear.

"The nearly 20,000 MW of nuclear resources that did clear this year's auction, along with legacy coal, gas, and renewable resources, all had their future financial picture improve markedly based on weaker units failing to clear and clearing prices responding," PJM said.

PJM suggested that they could pay "subsidized resources a different price, recognizing their different circumstances … to alleviate the price objections some have leveled against capacity repricing."

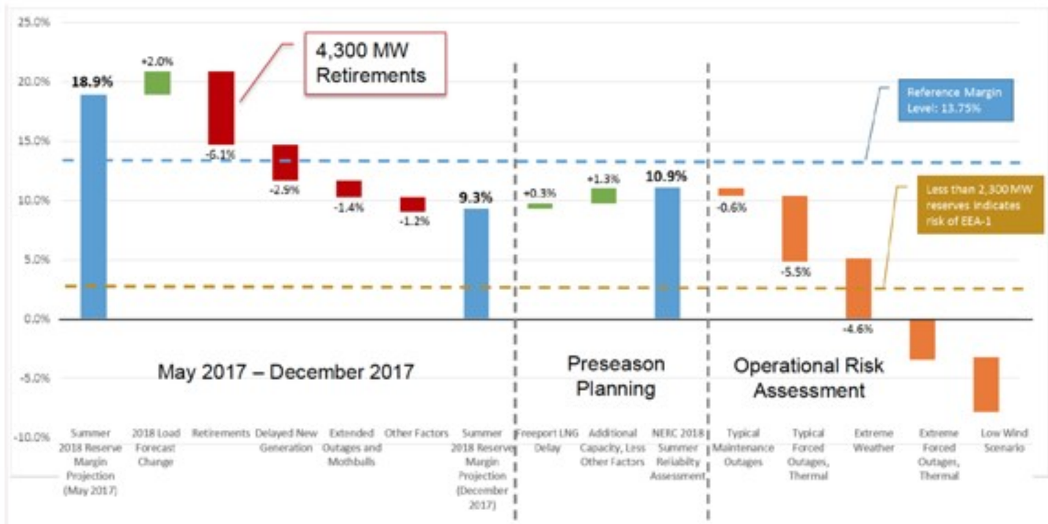
PJM also disputed an Exelon argument that FERC should factor in environmental externalities such as carbon, saying FERC "is not an environmental regulator."

"Let's be honest, or at least more direct. The PJM state programs in question are designed to retain particular nuclear resources," PJM fired back at critics. "If the more generic goal was to reward resources for their carbon free attributes, these programs would compensate all (not just financially challenged) nuclear plants, traditional renewable resources, demand response, and new investment, including new nuclear, that furthered the carbon free goal."

FERC & FEDERAL NEWS

NERC: ERCOT, CAISO Face Summer Reliability Concerns

By Tom Kleckner



Contributing factors to ERCOT's reserve margin changes since May 2017 and operational risk for summer 2018 | *NERC*

NERC said Wednesday that ERCOT and CAISO will face operational challenges and potential reliability concerns this summer because of the Texas grid's loss of baseload generation and California's lack of fuel assurance.

According to the organization's summer reliability assessment, ERCOT faces a generation shortfall "due in part" to the retirement of about 4.5 GW in coal-fired generation last fall and delays in the construction of about 2.1 GW in new resources. California is facing a limit on natural gas output because of Aliso Canyon storage facility constraints, NERC said.

"It's very important to focus on the operational aspect," said Thomas Coleman, NERC's director of reliability assessments, during a conference call with reporters Wednesday. "We can't do much at this point [about resource adequacy]. We want to draw attention to how we are prepared … from an operational standpoint."

FERC earlier this month said it would be closely monitoring ERCOT and Southern California for reliability issues this summer. Both regions lie in a portion of the West expected to be warmer than usual. (See *FERC Keeps Eye on ERCOT, CAISO as Hot Summer Approaches*.)

Coleman said the majority of NERC's assessment areas "maintain sufficient resources" to meet their reference planning reserve margins this summer. The exception is ERCOT, which saw its reserve margins drop from 18% last year to a projected 10.9% this year. Given the ISO's 13.75% planning reserve margin, ERCOT faces a capacity shortfall of 2 GW, NERC said.

No Cause for Alarm?

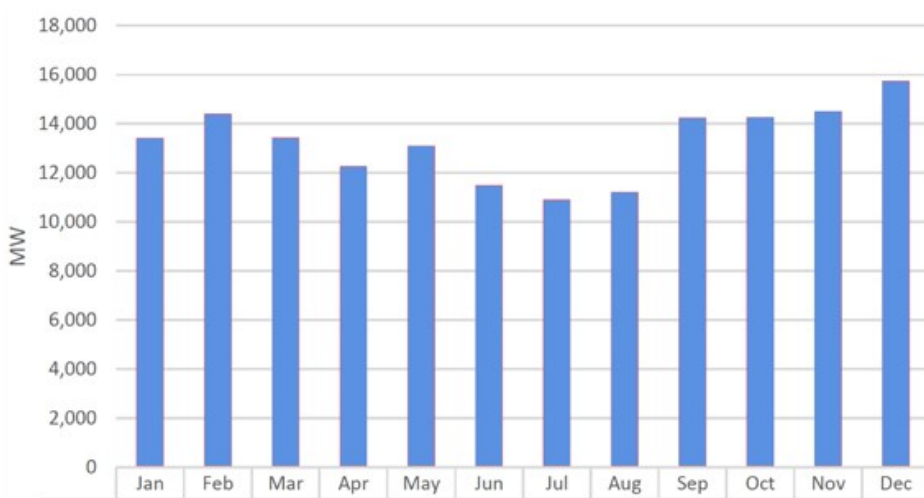
A Texas Reliability Entity assessment expects the ISO will be required to deploy ancillary services and contracted load control programs during peak demand periods. NERC's study cautions that "typical generator outages expected under normal conditions" could limit ERCOT's ability to maintain operating reserves.

Coleman said NERC took it one step further and ran an operational risk analysis that looked at typical maintenance or forced outages, extreme forced outages, extreme weather and a low-wind scenario.

"Any one of those events would drop [ERCOT] below its operating reserve margin" (of 2.3 GW) and lead to energy emergency alerts," Coleman said, noting that operational challenges occur during times of peak demand, low wind output and generator outages.

"When we don't have the wind available, those are the types of scenarios we want to pay attention to," he said.

NERC's study finds the risk of load shedding caused by insufficient reserves in ERCOT's footprint would increase under extreme summer conditions, such as



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2018	13,415	14,409	13,435	12,272	13,095	11,497	10,908	11,219	14,248	14,271	14,505	15,743

CAISO forecasted flexible capacity need for 2018 | *CAISO*

Continued on page 17

FERC & FEDERAL NEWS

Analyst: FERC Asserts Role in Handling Nuke Subsidies

By Rory D. Sweeney

FERC and the U.S. Department of Justice struck a blow against opponents of state subsidies for nuclear plants last week when they jointly filed a brief urging the 7th U.S. Circuit Court of Appeals to reject the argument that Illinois' zero-emission credit program is pre-empted by the Federal Power Act.

But an analyst for an industry law firm believes the brief, which was quickly cross-filed by Exelon in a similar case in New York before the 2nd Circuit, has a deeper meaning: Leave this to us.

"FERC made clear that 'we have jurisdiction under the Federal Power Act to deal with what we view as states subsidizing these generation facilities,'" Jennifer Mersing of Stoel Rives told *RTO Insider*. "I think FERC was saying essentially, 'We are handling this. … Let us be the forum where this gets worked out.' They didn't tip their hand about how they would rule … but I think that FERC is trying to keep within its court how it's going to deal with states subsidizing certain nuclear facilities."

The Electric Power Supply Association and retail ratepayers asked the courts to overturn district court rulings last year that dismissed challenges to the states' ZEC programs. They argued that the state laws were stripping FERC of its authority over the sale of wholesale energy. (See *Ill. ZECs Defenders Face Harsh Questioning on Appeal*.)

"The Illinois program is not pre-empted," FERC and the Justice Department said. "It does not require participation in FERC-jurisdictional wholesale auctions as a precondition to receive ZECs. Rather, the Illinois ZEC is 'targeted' at an attribute of generation resources over which Illinois has regulatory authority. … The object of the subsidy is the 'participant,' not the 'actual wholesale transaction.' The district court thus properly concluded that the ZEC program 'falls within Illinois' reserved authority over generation facilities.'"

Exelon, which owns five nuclear facilities that stand to benefit from the laws, joined the states in their defense and lauded the brief's filing.

"The U.S. Department of Justice and Federal Energy Regulatory Commission told the courts that states are free to favor clean nuclear energy over pollution-emitting energy from coal, oil and natural gas power plants," the company said in a statement. "We remain confident that the courts will uphold the view of policymakers and regulators who support the continued operation of Illinois' nuclear plants and the environmental benefits they provide for consumers."

Mersing agreed the brief would likely tip the court's decision in favor of the states and leave FERC to address the issue. Judges in the Illinois case had previously questioned why EPSA was bringing the issue to them when they were simultaneously pleading their case with FERC, which noted in its brief that it will address complaints pending on the issue.

"It's hard to quantify … but I think that if you have the agency in charge of regulating wholesale power sales [saying it] doesn't view this law as being pre-empted by the statute it's in charge of enforcing, I think that's going to weigh heavily," Mersing said. "I think the court was probably waiting for FERC to weigh in, so I would expect a decision would come sooner, but we can't predict when the court will act."

She predicted the courts will likely uphold the laws, making it unlikely the Supreme Court would take up the case if EPSA were to continue its appeal. The decisions will likely signal other states to pursue similar nuclear subsidies but keep them funneled through FERC, she said.

"You'll see more states following the path because it removes some legal challenges, but it also depends on how FERC decides to handle the programs," she said. "I think you're going to see more complaints at the FERC level versus the federal court level."

EPSA has requested permission to respond to the brief by June 9, which Exelon has opposed.

NERC: ERCOT, CAISO Face Summer Reliability Concerns

Continued from page 16

above-normal temperatures and higher-than-expected generation outages.

However, the Texas grid operator has assured stakeholders there is no reason for alarm and said it plans to address the projected generation shortfall by seeking voluntary load reductions from utilities, if needed. (See *ERCOT Gains Additional Capacity to Meet Summer Demand*.)

Asked about a repeat of severe weather, as ERCOT experienced last August with Hurricane Harvey, Coleman said NERC was "encouraged by the level of resilience in the system last year."

"We've gotten better about handling those types of events," he said, noting most outages occur at the distribution level and don't affect the bulk electric system. "During hurricanes, when we have distribution outages, there's less load, so that doesn't necessarily pose challenges."

California Challenges

Coleman said NERC feels "very comfortable" about CAISO's reserve margins but also noted the Aliso Canyon operational constraint continues to affect the availability of natural gas in Southern California, increasing ramping requirements. Below-normal hydro generation is also projected to exacerbate the potential reliability concern, according to the NERC assessment.

"If we don't have [the] ability to get the fuel there, we could have operational challenges," Coleman said.

NERC said the need for fast-ramping gas generation and other flexible resources across California also presents a reliability challenge for the bulk power system this

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FERC & FEDERAL NEWS

NERC: ERCOT, CAISO Face Summer Reliability Concerns

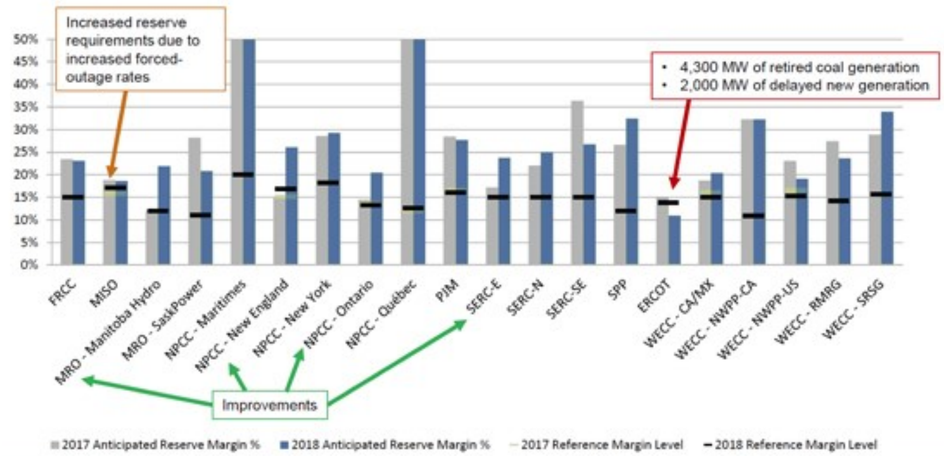
Continued from page 17

summer because of the state's high penetration of renewables. CAISO in March set an all-time record when 49.95% of demand was served by transmission-connected solar.

The California grid declared its first Stage 1 emergency in 10 years in May 2017. In October, it activated demand response measures but did not require any load shed.

NERC's study says MISO has a summer reserve margin of 19.1%, above its target reserve margin of 17.1%. It is expected to rely increasingly on emergency operating procedures to access resources needed to meet load and operating reserves.

MISO's actions are anticipated to provide sufficient energy or load relief to cover the normal forecasted system conditions, the agency said. Coleman said the RTO acknowledges a 79% chance it will experience at least one Level 1 emergency this summer.



Summer 2017-2018 anticipated reserve margins year-to-year change | *NERC*

NERC conducts its reliability assessments to "provide a high-level view of resource adequacy and to identify issues that have the potential to impact bulk power system planning, development and system analysis over the summer months." The summer assessment covers June through September.

AEP Wind Catcher Project Notches Regulatory Wins

By Tom Kleckner

The Wind Catcher site | *Invenergy*

American Electric Power's massive Wind Catcher Energy Connection project in the Oklahoma Panhandle continues to rack up regulatory wins.

On Wednesday, independent transmission company GridLiance and Tri-County Electric Cooperative announced they have joined a settlement agreement with AEP related to the company's proposed 2-GW, $4.5 billion project.

Meanwhile, a Texas administrative law judge has issued a proposed decision approving AEP's application before the state's Public Utility Commission. The PUC will take up the proceeding at its July 12 open meeting (Docket No. 47461).

Under the settlement's terms, GridLiance subsidiary South Central MCN will have the option to construct, own and operate any additional Wind Catcher interconnections in Tri-County's panhandle service territory of Cimarron, Texas and Beaver counties. The agreement will also provide protections guaranteeing that AEP subsidiary Public Service Company of Oklahoma (PSO) will not provide retail service in Tri-County's certified service territory for 25 years after the project begins commercial operation.

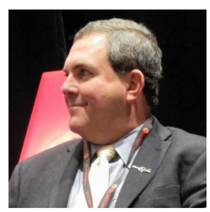
South Central and Tri-County, along with the Oklahoma Municipal Power Authority and Oneta Power, have now joined with Oklahoma Industrial Energy Consumers and Walmart in reaching settlement agreements with PSO on Wind Catcher.

The parties are requesting that the Oklahoma Corporation Commission approve the terms of the agreements. PSO said the terms "collectively result in significant customer savings guarantees and increased use of natural gas power" generated in Oklahoma. (The recent agreements include a new power purchase agreement with Oneta for 300 MW of gas-fired energy and capacity beginning in 2022.)

Dallas-based GridLiance said agreeing to the settlement will allow it to "adequately plan and operate its existing transmission system and future interconnections for the benefit of its utility partners." Those partners included Tri-County, which will also retain the right to serve retail electric load in its service area.

The co-op's CEO, Zac Perkins, said the right to serve retail load will last for the life of the Wind Catcher project.

"By partnering with GridLiance on this settlement, we were able to secure the rights to defend the service territory of our retail customers," Perkins said.



Calvin Crowder | *© RTO Insider*

GridLiance CEO Calvin Crowder said the company was pleased with the settlement.

"The panhandle's economic development depends on a reliable local transmission system that serves multiple needs, and GridLiance remains committed to serving those needs now and in the future," he said.

GridLiance, which focuses on collaborating with public power entities, entered into an agreement with Tri-County in 2015 to plan, construct and operate transmission infrastructure projects in the panhandle. (See *GridLiance Makes First Acquisitions*.)

PSO CEO Stuart Solomon said in a release that the agreements further demonstrate that Wind Catcher is good for customers.

"The agreements guarantee customers will save money and allow us to move forward with our plan to increase use of Oklahoma-based renewable energy and natural gas generation to provide affordable, reliable service to our customers," he said.

PSO is seeking regulatory preapproval to recover $1.36 billion in project costs. It has proposed to the OCC that it cap project costs at 103%, and it has guaranteed the project would qualify for 100% of federal production tax credits available when Invenergy began construction in 2016.

Wind Catcher would consist of an Invenergy-developed wind farm containing 800 2.5-MW turbines. A 360-mile, 765-kV line from the panhandle to Tulsa will connect the wind farm to PSO's grid and that of sister company Southwestern Electric Power Co., which owns 70% of the project.

AEP says Wind Catcher will result in $7 billion in energy savings for its utility customers in Arkansas, Louisiana, Oklahoma and Texas. The Arkansas Public Service Commission has already approved the project, but it still awaits regulatory OKs in the other three states.

SWEPCO has filed an application before the Texas PUC to amend its certificate of convenience and necessity and authorize its interest in Wind Catcher, and for preapproval of various ratemaking treatments to recover the project costs. The utility estimates its share of the costs at approximately $3.2 billion, with $1.1 billion within Texas retail jurisdiction.

In recommending the project's approval, Texas ALJ Henry Card relied on the precedent set by the commission's recent approval of Southwestern Public Service's wind farm in West Texas. In that proceeding, the commissioners overcame their concerns that SPS was requesting 478 MW of energy when it already had sufficient capacity on its system to meet demand. (See *Texas PUC Issues Final Order for SPS Wind Farm*.)

"Utilities may obtain a CCN for general economic purposes not just when there is an increase in demand necessitating additional generation," Card said in his decision.

COMPANY BRIEFS

Entergy Louisiana Agrees to Buy 50 MW of Solar for 20 Years

Entergy Louisiana said May 31 it has agreed to a 20-year deal to purchase all the power from a 50-MW solar plant proposed for West Baton Rouge Parish.

The agreement is with Eagle Solar Group, which is developing the plant, and must be approved by the Louisiana Public Service Commission.

The plant is scheduled to be up and running by March 2020.

More: *The Advocate*

Toshiba Abandons Expansion Plan at NRG Nuclear Plant

Toshiba said May 31 it has abandoned a plan to add two nuclear reactors to NRG Energy's South Texas Project, which already has two 1,280-MW reactors.

Toshiba and NRG agreed to expand the plant in March 2008. NRG abandoned and wrote off its share of the expansion project in 2011 after the Fukushima nuclear accident.

Toshiba continued searching for other companies willing to invest in the expansion project but couldn't find any.

More: *Reuters*

Southern Power Buys 10th Wind Project

Southern Company's Southern Power subsidiary said May 29 it has acquired its 10th wind project, the 100-MW Wildhorse Mountain Wind Facility in Pushmataha County, Okla.

The project was developed by Roaring Fork Wind, a partnership between Renewable Energy Systems Americas, which will handle much of the construction, and Vestas, which will provide and maintain the wind turbines.

Once the wind farm is operational, its electricity, capacity and other attributes will be sold to Arkansas Electric Cooperative Corp. under a 20-year power purchase agreement.

More: *Southern Power*

Exelon Announces Layoffs Related to Oyster Creek Closing

Exelon Generation on May 30 filed a Worker Adjustment and Retraining Notification with the state of New Jersey, saying 84 workers at the Oyster Creek nuclear power plant in Lacey Township will begin leaving the company effective June 22.

A spokeswoman for the Exelon subsidiary said the workers were not laid off; instead, their positions were eliminated and they chose not to take other jobs with Exelon.

Exelon has filed with the Nuclear Regulatory Commission a 60-year, $1.4 billion plan for making the plant site usable for anything else. The plan calls for Exelon to start shutting down and defueling the plant on Sept. 17 and finish it on Sept. 30.

More: *The Press of Atlantic City*; *The Press of Atlantic City*

FERC OKs Duke Tx Filing; Rejects ROE Challenge

FERC last week approved Duke Energy Ohio's and Duke Energy Kentucky's proposed revisions to their formula rate templates, rejecting American Municipal Power's challenge to the companies' 10.88% base return on equity.

AMP said although it did not object to the template revisions, the commission should also reconsider Duke's 10.88% base ROE and the 50-basis-point ROE incentive for the company's participation in PJM. AMP said the 10.88% base resulted from a settlement in 2014, when capital costs were higher, and that current settlements are as much as 100 basis points lower. It also contends that because Duke is required to participate in an RTO under Ohio law, it should not be eligible for the incentive adder.

FERC accepted the filings effective June 1, 2018, saying the changes will make the companies' formula rates more accurate reduce the amount of over- or undercharges. The commission ruled that AMP's challenges were beyond the scope of the proceeding.

More: *ER18-1274*

MidAmerican Seeks Approval of Iowa Wind Farm

MidAmerican Energy said May 30 it was going to ask the Iowa Utilities Board to approve a $922 million, 591-MW wind farm that would enable it to generate renewable power in an amount equal to all the electricity its customers consume.

The company said it expects to complete Wind XII in late 2020, assuming the board approves the project.

MidAmerican said it won't need to ask for a rate increase to fund the project.

More: *MidAmerican Energy*

Group Sues to Force Dynegy to Clean up Coal Ash Ponds

Prairie Rivers Network on May 30 filed a lawsuit in the U.S. District Court for the Central District of Illinois to force Dynegy to clean up coal ash ponds that it says are leaching pollution into the Middle Fork of the Vermilion River.

The environmental organization says the pollution is coming from unlined coal ash ponds that run a half-mile along the river near the site of Dynegy's now retired coal-fired Vermilion Power Station.

The group said it will ask the court to order Dynegy to "take all actions necessary" to stop the illegal pollution and to pay penalties to the U.S. Treasury of up to $53,484 per day for each day over the last five years that Dynegy has violated the Clean Water Act.

More: *Prairie Rivers Network*

Continued on page 21

COMPANY BRIEFS

Continued from page 20

Cobra Lands $900M Puerto Rico Contract

Mammoth Energy's Cobra Acquisitions subsidiary has signed a one-year, $900 million contract with the Puerto Rico Electric Power Authority to help finish reconstructing Puerto Rico's transmission and distribution system, executives of the Oklahoma City-based company said May 29.

The new contract means Cobra will send another 350 employees to Puerto Rico, joining the 900 already there.

Cobra received a 120-day, $200 million contract in October 2017 to begin emergency work to help restore power in Puerto Rico following Hurricane Maria. The contract was increased to $445 million in January 2018 and boosted again to $950 million in March.

More: *The Oklahoman*

Rocky Mountain Power Issues RFP for Renewables

Rocky Mountain Power said May 29 it is seeking cost-competitive bids for solar, wind and geothermal energy projects in Utah to interconnect to the system of its parent, PacifiCorp.

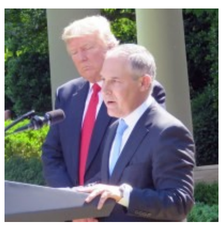
The company said it has issued a request for proposals for 308,000 MWh of power generation, which equates to roughly 40 MW of geothermal capacity or approximately 100 to 126 MW of wind or solar capacity.

Rocky Mountain Power customers sponsoring the request for proposals include Park City, Salt Lake City, Summit County, Park City Mountain Resort, Deer Valley Resort and Utah Valley University.

More: *Rocky Mountain Power*

FEDERAL BRIEFS

US Emissions Trend Unchanged Despite Paris Withdrawal



EPA Administrator Scott Pruitt, beside President Trump, announces the withdrawal from Paris a year ago. | © *RTO Insider*

A year after President Trump announced the U.S. would withdraw from the Paris Agreement on climate change, and despite his administration's efforts to reverse environmental rules, the trajectory of the nation's greenhouse gas emissions is largely unchanged, researchers say. (See *Trump Pulling U.S. Out of Paris Climate Accord*.)

The Climate Action Tracker said the U.S.' projected 2030 greenhouse gases emissions has improved in the last year because of reduced coal-fired electric generation and increased renewables, trends driven mainly by market forces. And although Trump has pledged to cancel the Obama administration's Clean Power Plan, the country is on track to meet the CPP's goals, said the Rhodium Group's Kate Larsen. "All of that is driven by cheap renewables and cheap natural gas," she said.

Even achieving the Obama administration's Paris pledge of a 26 to 28% emissions cut below 2005 levels would be too little to help achieve the agreement's goal of limiting global warming to 2 or 1.5 degrees Celsius (3.6 or 2.7 degrees Fahrenheit), however. The world's commitments thus far would lead to a warming of 3.3 C (5.94 F).

More: *The Washington Post*

EPA Plans to Deny Emissions Reduction Petitions from Md., Del.

EPA said Friday it plans to deny petitions by Maryland and Delaware seeking emissions reductions from power plants in five upwind states.

Maryland and Delaware had sought to reduce emissions of ozone-forming nitrogen dioxide from power plants in Indiana, Kentucky, Ohio, Pennsylvania and West Virginia.

EPA said it will accept comment on its proposed action for 45 days and hold a public hearing in D.C.

More: *The Associated Press*

FERC Conference to Focus on Reliability, NERC Priorities

FERC will conduct a commissioner-led technical conference July 31 on policy issues related to grid reliability. According to an agenda posted Friday, the daylong session will include discussions on NERC's priorities, resilience metrics, cybersecurity threats and changing demands caused by the growth of distributed energy resources and storage.

More: *AD18-11*

DOE/DHS Report: More Work Needed on Grid Cybersecurity

A report released May 30 by the departments of Energy and Homeland Security says the U.S. is generally "well prepared" to manage major disruptions to the electricity grid.

But it details a number of gaps preventing utilities, government entities and other stakeholders from effectively to a major cyberattack. These include underemployment in the cybersecurity field and a lack of clarity over different government agencies' role during an attack.

More: *The Hill*

2017 Power Sector Fossil Fuel Consumption Lowest Since 1994

Fossil fuel consumption in the electric power sector declined to 22.5 quadrillion Btu in 2017, its lowest level since 1994, the Energy Information Administration said May 29.

EIA said the decline has been driven by decreases in the use of coal and petroleum for generation, which have been slightly offset by an increase in natural gas to produce power. Improvements in generation technology also have played a part.

In 2017, the electric power sector's coal consumption reached its lowest level since 1982, EIA said. The sector's petroleum consumption was the lowest since recordkeeping began in 1949.

More: *Energy Information Administration*

STATE BRIEFS

CONNECTICUT

Gov. Proposes $15M in Upgrades To Pier for Offshore Industry

Gov. Dannel P. Malloy said May 29 the state will provide $15 million toward revitalizing the Connecticut State Pier in New London for potential use in the deployment of equipment and workers for offshore wind projects.

The money will be used to demolish selected structures, make site improvements, improve storm water treatment and drainage, increase the pier's laydown capabilities, construct a heavy lift pad, improve the pier's load-bearing capacity and replace mooring dolphins.

The funding is subject to approval by the Bond Commission on June 1.

More: *Office of Gov. Dannel P. Malloy*

INDIANA

IURC Grants Indiana Michigan Power 7.26% Rate Increase

The Utility Regulatory Commission on May 30 approved a 7.26% rate increase for Indiana Michigan Power, much less than the 19.7% the utility originally requested.

The increase will boost I&M's annual revenue by $96.8 million. The utility originally asked for a $263.2 million increase, then reduced that to $191.5 million after the Tax Cuts and Jobs Act was passed. The increase will take effect in phases starting in July.

More: *The Journal Gazette*

MASSACHUSETTS

Baker Adviser Helped Companies Win Renewable Contracts

Conroy

Gov. Charlie Baker's top political adviser also worked as a paid consultant for Vineyard Wind and Central Maine Power in their bids to win bids for the state's renewable energy procurements, according to the *Boston Globe*.

Jim Conroy, who managed Baker's 2014 campaign and is advising him in his re-election bid this year, confirmed his work with the *Globe*. The Baker administration said Conroy did not influence its selection of the projects. Jay Gonzalez, one of two Democrats challenging Baker in the election, is calling for the release of all public records related to the procurements.

Vineyard was recently awarded the offshore wind procurement. (See *Mass., R.I. Pick 1,200 MW in Offshore Wind Bids*.) The New England Clean Energy Connect project, a joint venture between Central Maine Power and Hydro-Quebec, was selected as the alternative to the Northern Pass transmission project in a clean energy solicitation in February and was awarded the solicitation in late March after Northern Pass was unable to obtain necessary permits in New Hampshire. (See *Massachusetts Bids Adieu to Northern Pass*.)

More: *Boston Globe*; *Boston Globe*

MICHIGAN

PSC Approves Settlements Passing Tax Savings on to Customers

The Public Service Commission on May 30 approved settlement agreements with seven utilities to pass their savings from the Tax Cuts and Jobs Act on to their custom-

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STATE BRIEFS

Continued from page 22

ers, starting in July. Three other utilities had no impact from the changes.

The agreements will enable Alpena Power, Northern States Power, Upper Michigan Energy Resources Corp. and four gas utilities to pass on to their customers nearly $50.3 million in savings from the law.

The commission said the law didn't affect the rates of Presque Isle Electric & Gas Co-op and Wisconsin Electric Power Co.

More: Public Service Commission

Groups Appeal PSC Approval Of $1B DTE Gas Plant

Several clean energy organizations have asked the Court of Appeals to reverse the Public Service Commission's April 27 decision to approve DTE Energy's certificates of necessity to build a $1 billion combined cycle natural gas-fired power plant in East China Township.

A coalition that includes the Environmental Law and Policy Center, the Union of Concerned Scientists, the Ecology Center, the Solar Energy Industries Association and Vote Solar said May 29 that DTE didn't show the plant was the most "prudent" means of supplying power to its customers as required by state law.

Sierra Club, Natural Resources Defense Council and the Michigan Environmental Council said May 30 they had filed an appeal with the Court of Appeals based on the same arguments. The three groups also said they have filed a petition for a rehearing with the PSC.

More: Vote Solar; Sierra Club

NEVADA

NV Energy Projects Depend on Voters' 'No' on Question 3

NV Energy said May 31 it would ask the Public Utilities Commission to approve the construction of six solar projects with 1,001 MW of capacity and three related battery resources with 100 MW of capacity, but noted that it retained the option not to build them if voters decide to open the state's power market to competition.

The company said details of the projects would be contained in its integrated resource plan, filed June 1. If it proceeds with the projects, it expects them to be finished by the end of 2021.

NV Energy is hedging its bets on the projects because Question 3, which, if approved by voters in November, would end the company's monopoly on the generation and retail sale of energy in the state and require lawmakers to set up a competitive power market by 2023.

More: NV Energy; The Nevada Independent

NEW MEXICO

2 PRC Members Call for Nonprofit Head's Resignation

Nanasi

Public Regulation Commissioners Sandy Jones and Lynda Lovejoy are calling for Mariel Nanasi to resign as executive director of New Energy Economy, a clean energy nonprofit, saying she is violating federal law by also heading a public action committee that supports their opponents in the Democratic primary next month.

Nanasi said she has contributed to the committee, Responsible Leadership NM, but isn't a founder or director of it. She said Jones and Lovejoy are calling for her resignation to deflect attention from NEE's May 23 motion asking them to recuse themselves from considering an application involving an Albuquerque solar energy company because of "an obvious appearance of impropriety."

Jones and Lovejoy received campaign

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STATE BRIEFS

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contributions from individuals associated with the company, Affordable Solar Installation, according to a May 2 report by the *Santa Fe New Mexican*.

More: *Santa Fe New Mexican*

NEW YORK

NYPA To Spend up to $250 Million On Initiative to Expand EV Use

Gov. Andrew Cuomo on May 31 announced a New York Power Authority initiative to expand the use of electric vehicles that could receive as much as $250 million from the state.

The initial phase of EVolve NY, which was approved May 22 by NYPA trustees, directs $40 million to three primary new programs by the end of 2019. Two of the programs will use public/private partnerships to install up to 200 DC fast chargers along key interstate corridors and install DC fast chargers at or near John F. Kennedy and LaGuardia airports. The third will involve a partnership with a NYPA municipal or co-operative distribution utility to support an EV friendly model community that will test and scale new EV infrastructure and service business models meant to encourage more residents to transition to driving EVs.

More: *Gov. Andrew Cuomo*

Group Says Cuomo Admin Misallocated RGGI Funds

Environmental Advocates of New York on May 29 released a report saying the administration of Gov. Andrew Cuomo hasn't properly allocated some of the funds the state receives from the Regional Greenhouse Gas Initiative.

The group said the New York State Energy Research and Development Authority has used $208 million, or more than one out of five dollars the state has received from RGGI, to support Long Island Power Authority's renewable and energy efficiency programs. As LIPA has cut its spending on those programs, NYSERDA is effectively subsidizing LIPA rates and putting Long Island ratepayers ahead of other New York ratepayers, the group said.

Additionally, the group said, the state, through its budgeting process, has stripped $170 million in RGGI dollars from NYSERDA to pay for existing projects. RGGI proceeds are meant to supplement already existing clean energy programs, the group said.

More: *Environmental Advocates of New York*

RHODE ISLAND

Deepwater to Spend $250M, Hire 800+ for Offshore Wind Farm

Deepwater Wind will invest $250 million in the state and use more than 800 local workers to build the 400-MW Revolution Wind offshore wind farm, Deepwater CEO Jeffrey Grybowski and Gov. Gina Raimondo (D) said May 30.

The company will spend $40 million to improve the Port of Providence, the port facilities in the Quonset Business Park in North Kingstown and possibly other ports in the state that would be used as construction-staging sites for the wind farm.

The company finished the country's first offshore wind farm, a five-turbine test project off the coast of Block Island, nearly two years ago.

More: *Providence Journal*

TEXAS

ERCOT Pulls Plug on Breeze After Default on Agreement

ERCOT on May 30 revoked Breeze Energy's permission to sell electricity in the state after the company defaulted on its market participant agreement with the ISO.

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STATE BRIEFS

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As a result of the default, ERCOT has shifted Breeze's 9,800 customers to other electric providers, which likely have different rates than Breeze did. The customers can try to negotiate different rates than the ones they were initially given by their new providers or search for other power providers.

More: Click2Houston

Regulators Roll out Incentives for Reduced-emission Vehicles

The Commission on Environmental Quality on May 30 introduced rules for the state's Emissions Reduction Plan, which provides incentives of $2,500 to buyers of electric and hybrid vehicles and up to $5,000 to buyers of eligible compressed natural gas and liquified petroleum gas vehicles.

More: Houston Chronicle

LP&L Gets Approval to Install 105,000 Smart Meters

The Lubbock Electric Utility Board on May 29 gave Lubbock Power & Light its approval to buy and install roughly 105,000 smart meters.

The board unanimously approved a set of contracts worth about $35 million for purchasing advanced metering infrastructure and related customer information and billing systems. Some of the contracts must be approved by the Lubbock City Council, which will consider them at its next meeting.

LP&L hopes to have the AMI and related systems in place and operating in mid-2020.

More: Lubbock Avalanche-Journal

WISCONSIN

Judge Upholds PSC Decision that Badger Coulee Line Fills Need

An appeals court on May 30 upheld La Crosse County Circuit Judge Todd Bjerke's 2017 ruling that the Public Service Commission followed state law in determining there was a public need for the $580 million Badger Coulee transmission line.

The court also upheld the PSC's decision to route a 7-mile segment of the line on separate towers from an existing high-voltage line in La Crosse County.

The 180-mile line between La Crosse and Madison is being developed by American Transmission Co. and Xcel Energy. Dairyland Power Cooperative, Southern Minnesota Municipal Power Agency-Wisconsin and WPPI Energy also own a portion of it.

More: La Crosse Tribune

Trump Orders Coal, Nuke Bailout, Citing National Security

Continued from page 1

The memo said DOE would be directing RTOs and ISOs "to purchase or arrange the purchase of electric energy or electric generation capacity from a designated list of Subject Generation Facilities (SGFs) sufficient to forestall any further actions toward retirement, decommissioning or deactivation" for 24 months — the time it said the department and its and National Laboratories will need to identify "Critical Defense Facilities" served by "Defense Critical Electric Infrastructure (DCEI)."

"To identity DCEI facilities, additional analysis will be required to gain a more detailed understanding of location-specific security vulnerabilities in our energy delivery systems, including the interdependencies associated with electric generation and transmission, and natural gas and petroleum pipelines, as well as their supply chains," the memo said. "In the meantime, DOE's order provides a temporary stop-gap measure to prevent the further permanent loss of the fuel-secure electric generation capacity for the grid upon which our national security depends."

DOE said it also is directing SGFs outside RTO/ISO territories "to continue generation and delivery of electric energy according to their existing or recent contractual arrangements with load-serving entities." The draft did not identify the generators that would benefit from the order.

The president's long-awaited and highly controversial action was announced by Press Secretary Sarah Huckabee Sanders. "Unfortunately, impending retirements of fuel-secure power facilities are leading to a rapid depletion of a critical part of our nation's energy mix and impacting the resilience of our power grid," Sanders said in a statement. "President Trump has directed Secretary of Energy Rick Perry to prepare immediate steps to stop the loss of these resources and looks forward to his recommendations."

It is the administration's second bid for a coal and nuclear bailout. In January, FERC rejected Perry's Notice of Proposed Rulemaking to subsidize coal and nuclear plants with onsite fuel. The commission instead initiated a rulemaking on grid resilience (AD18-7). (See Don't Rush on Resilience, Commenters Urge.)

'Tipping Point'

DOE warns of a "tipping point" in the loss of "fuel-secure" generation, citing the retirements of 59 GW of coal capacity between 2002 and 2016, the loss of 15 nuclear plants since 1990 and announced retirements of 12 nuclear units representing 11 GW.

It cites a 2008 Defense Science Board report that concluded Defense Department installations are "99% dependent on the commercial power grid."

In addition to the purported risk to DOD facilities, the memo also cited the need for a "robust civilian nuclear industry" to support the "entire U.S. nuclear enterprise — weapons, naval propulsion, nonproliferation, enrichment, fuel services and negotiations with international partners."

"Without a strong domestic nuclear power industry, the U.S. will not only lose the energy security and grid resilience benefits but will also lose its workforce technical expertise, supply chain and position of clean energy leadership," it said.

DOE said it supports FERC's actions, including its opening of the resilience docket in January, but that "too little progress has been made, while the risk of high-impact events, especially those caused by intentional attacks, continues to grow."

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Trump Orders Coal, Nuke Bailout, Citing National Security

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"Given the need to safeguard the existence of fuel-secure generation facilities to promote our national defense and to maximize domestic energy supplies, DOE is compelled to exercise its authorities to avert a serious supply disruption in the wake of a natural disaster, an adversarial attack or some combination of the foregoing."

It quotes from a 2017 NERC report that said increased "reliance on natural gas exposes electric generation to fuel supply and delivery vulnerabilities" and that "premature retirements of fuel-secure baseload generating stations reduces resilience to fuel supply disruptions."

It also cites NERC's November 2017 report on potential disruptions to the natural gas system, which noted that some regions rely on gas for more than 60% of their peak electric demand.

DOE also cites the threat of cyberattacks on the grid, saying, "To avoid and recover from blackouts, it is essential that the system have adequate generation and transmission capacity broadly dispersed." It notes that only nuclear generators maintain "the kinds of 'guns, guards and gates' and other physical and cyber-hardening measures that would be needed in the event of a major attack."

Legal Challenges Likely

Observers Friday differed over whether the administration's action will survive almost certain legal challenges.

In rebuffing Perry's NOPR in January, FERC said DOE had failed to show that existing RTO tariffs were unjust and unreasonable under Section 206 of the Federal Power Act.

The DOE memo claims different legal authority, citing the Defense Production Act of 1950 (DPA) and Section 202c of the FPA, which allows the energy secretary to issue emergency orders during shortages of electric energy, facilities or fuel.

The memo cited DPA Section 101c, which gives the secretary authority to issue orders based on findings that energy supplies "are scarce, critical and essential" and needed for "maintenance of energy facilities [and] cannot reasonably be accomplished without exercising [this] authority."

DOE said the legislative history of Section

President Trump and Energy Secretary Rick Perry in June 2017

202c shows that "Congress contemplated the use of the provision not merely to react to actual disasters, but to act in a preventive manner. A variety of man-made and natural threat conditions require … a federal agency ready to do all that can be done in order to prevent a breakdown in electric supply."

The department says it has deployed FPA Section 202c on eight occasions. However, those were in response to regional energy challenges; it has not previously been applied nationwide.

During the Western Energy Crisis in late 2000, DOE issued an order to ensure gas supplies to Pacific Gas and Electric, then on the verge of bankruptcy. In several instances, the department has ordered temporary interconnections to provide supplies to regions following blackouts or natural disasters, including hurricanes Katrina and Rita.

The law was invoked on three prior occasions to require operation of generation facilities to prevent energy or reactive power shortages.

In 2005, DOE granted the D.C. Public Service Commission's request to order Mirant Corp. to continue running its Potomac River Generating Station despite its inability to meet EPA's National Ambient Air Quality Standards, finding that the region otherwise faces a "reasonable possibility" of extended blackouts.

Most recently, DOE granted PJM's request to order Dominion Energy Virginia to continue running its Yorktown Power Station despite its violation of EPA's Mercury and Air Toxics Standards, finding reliability could be at risk during summer peaks.

To minimize conflicts with environmental regulations, DOE noted, it limited its orders to having the generators serve only as backup power if other sources were unavailable.

ClearView Energy Partners analyst Christine Tezak noted in a bulletin to clients Friday that the DPA gives DOE "significant authority to determine and respond to national security impairments, even in peacetime, and thus far the courts have been reluctant to intervene."

"Unless and until critics marshal counterarguments to the concerns DOE has presented in [its] memo, we will continue to assign low probabilities to successful judicial intervention or reversal," she added.

Rabeha Kamaluddin, a partner at Dorsey & Whitney, predicted in an interview that the courts will reject DOE's claim that the subsidies are justified by 202c. But, she said, "you can expect anything in today's political landscape." DOE "may have a leg to stand on" using the DPA in combination with the FPA, she added.

"Combining [202c with] the DPA provides more room for DOE to make creative legal arguments," said Ari Peskoe, director of the Electricity Law Initiative at Harvard. "It's still far from clear that the proposal would be upheld by a court."

"There is no grid emergency that justifies this," tweeted Joel B. Eisen, law professor at the Richmond School of Law. "Nor does the combo of two laws, neither of which is appropriate in its own right, add any further support."

"202c gives pricing authority to FERC," said Avi Zevin of the New York University School of Law's Institute for Policy Integrity. "FERC has already said market rates are sufficient to meet reliability and resilience. So, I'm still not clear how we get around that even when you add DPA into the mix."

FERC's role in implementing the order is unclear. While 1977 amendments to the FPA transferred the emergency declaration authority under 202c to the energy secretary from the Federal Power Commission — FERC's predecessor — the commission still has dominion over rates under FPA Sections 205 and 206, Kamaluddin said.

FERC declined to comment.

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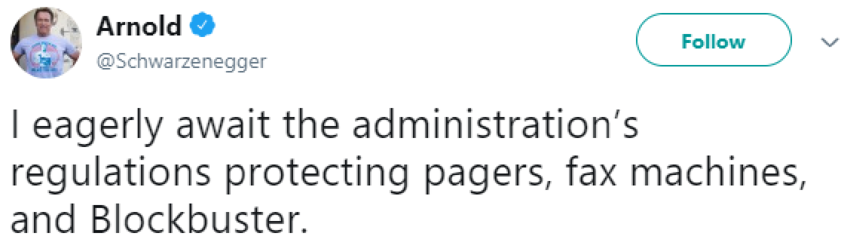
Trump Orders Coal, Nuke Bailout, Citing National Security

Continued from page 26



Bailout Costs

The bailouts could cost from $311 million to $900 million in PJM, ISO-NE, NYISO and MISO alone, according to Energy Innovation Policy & Technology, which supports policies reducing greenhouse gas emissions. The low estimate represents the out-of-market payments needed to bring units with negative net cash flows up to zero. The upper limit adds capital recovery and a rate of return on undepreciated capital and future capital expenditures.

The group compiled the estimates based on the rejected DOE resilience NOPR. "There are, of course, important differences between the resilience NOPR and the 202c actions being discussed by the Trump administration, but our study is a good rough estimate of the cost to keep the same group of uneconomic plants online," said Robbie Orvis, director of energy policy design for the group.

More than 80% of the coal subsidies coal would go to five companies (NRG Energy, Dynegy, FirstEnergy, American Electric Power and Talen Energy), while 90% of the nuclear price supports would go to five companies (Exelon, Entergy, Public Service Enterprise Group, NextEra Energy and FirstEnergy), the group said.

Industry Reaction

The renewable energy and natural gas industries united with consumer groups to condemn the bailout. Representatives of 10 trade groups — Advanced Energy Economy, the American Council on Renewable Energy, American Petroleum Institute, American Wind Energy Association, Business Council for Sustainable Energy, Electricity Consumers Resources Council, Electric Power Supply Association, Energy Storage Association, Natural Gas Supply Association and Solar Energy Industries Association — released a joint statement calling the move an unprecedented overreach that would distort competitive markets.

"There was no emergency when coal and nuclear interests sought federal relief, and there is none today that justifies such unprecedented executive branch intervention in the economic life of the country," EPSA CEO John Shelk said.

"The administration's plan to federalize the electric power system is an exercise in crony capitalism," said Malcolm Woolf, AEE senior vice president of policy.

John P. Hughes, CEO of the Electricity Consumers Resource Council, which represents industrial consumers, said the threats cited are "phony" and that the costs could cripple U.S. manufacturers. "The federal government should not use the pretext of 'national security' to pick winners and losers in the energy markets, and it must certainly not treat U.S. manufacturing jobs as inferior to the jobs at uneconomic power plants," he said.

The American Coalition for Clean Coal Electricity praised the action, noting that "almost 40% of the nation's coal fleet has shut down or is expected to close."

PJM said Friday that the grid is "more reliable than ever," and that its recently announced fuel security initiative will ensure grid resilience without upsetting its markets. (See *PJM Seeks to Have Market Value Fuel Security*.)

"Any federal intervention in the market to order customers to buy electricity from specific power plants would be damaging to the markets and therefore costly to consumers. There is no need for any such drastic action."

In response to an inquiry, ISO-NE spokeswoman Marcia Blomberg said "it's too early to comment on a draft proposal that has just been revealed."

"MISO is monitoring the reports of the potential Department of Energy action along with our ISO/RTO counterparts," spokesman Mark Brown said. "At this time, we have seen no official communication from DOE."

Other grid operators did not respond to requests for comment. DOE and NERC also did not respond to inquiries.

Requests from Murray Energy, FirstEnergy

Although Trump promised during his campaign to end the "war on coal" and put miners back to work, the Sierra Club says retirements have continued unabated since he took office. "In the first two months of 2018, we've already retired more coal that we did in three of the Obama years, and we're on track for our second biggest year of coal retirements ever," the group said in March.

Coal mining chief executive Robert Murray and FirstEnergy, his company's biggest customer, have lobbied relentlessly for subsidies. (See *Photos Show Murray's Role in Perry Coal NOPR*.) FirstEnergy asked Perry to invoke 202c in a letter in March. (See *FES Seeks Bankruptcy, DOE Emergency Order*.) FirstEnergy lobbyist Jeff Miller, who ran Perry's unsuccessful 2016 presidential campaign, reportedly made the case to Trump over dinner in April.

Exelon, the nation's largest nuclear generator, has largely focused its lobbying efforts on winning state subsidies for endangered reactors.

Despite news of the administration's action, Exelon saw shares drop 1% Friday, while FirstEnergy was down 0.6% on the day.

Shares of mining company Peabody Energy rose 4.6%, while Arch Coal was up 2%.

"Any federal intervention in the market to order customers to buy electricity from specific power plants would be damaging to the markets and therefore costly to consumers. There is no need for any such drastic action."

PJM

More Questions than Answers for FERC, RTOs on Bailout

Perry Praises Trump Order but Offers no Details

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[Editor's Note: *RTO Insider* will have a full report on McIntyre's and Menezes' comments later at www.rtoinsider.com.]

"It's certainly something I am watching very closely, because depending on what direction they go, there could be various implications for FERC and the organizations we oversee," FERC Commissioner Cheryl LaFleur said in an interview at the Western Conference of Public Service Commissioners in Boise, Idaho, on Monday. "But the devil is in the details in these things — what actually issues.

"I will say when I got here [at the conference], everyone was talking about it, and we're fairly far from the scene of the action. It's a big energy story, so we'll see what this week brings," LaFleur continued.

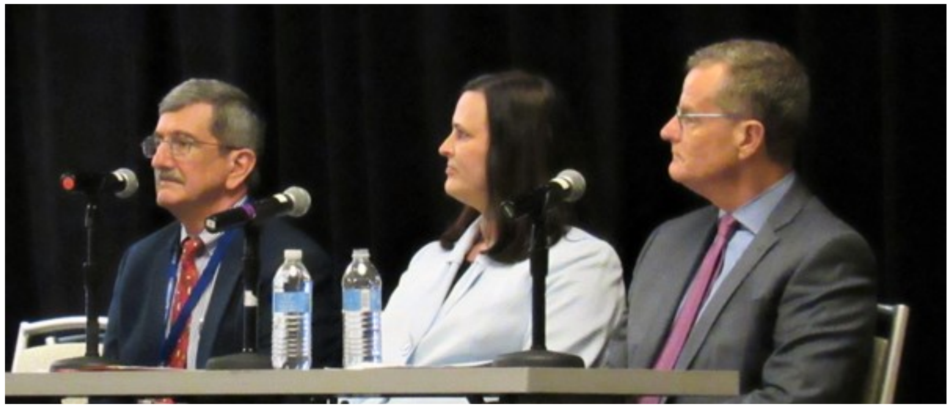
Asked about the prospect of legal challenges to the administration's action, LaFleur observed: "It is pretty easy to file a complaint at FERC if you're unhappy with something."

No Details from Perry

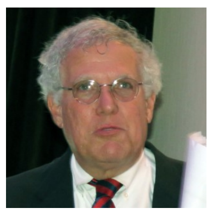
Perry commented favorably on Trump's directive in a speech at a DOE cybersecurity conference in Austin, Texas, Monday but did not elaborate. "Fuel-secure units are retiring at an alarming rate that — if unchecked — will threaten our ability to recover from intentional attacks or from natural disasters," Perry said. "The president is right to view grid resilience as a serious national security issue, and he's directed me to prepare immediate steps to stop the loss of these critical resources."

PJM and MISO officials said Monday they were caught off guard by President Trump's directive Friday and said they had received no information since then.

"At this time, we have seen no official communication from DOE," said Shawna Lake, MISO's senior director of communications and stakeholder affairs.



Left to right at MARC's 2018 Annual Conference: Carl Monroe, SPP; Suzanne Daugherty, PJM; and Bill Magness, ERCOT. | © *RTO Insider*



Craig Glazer | © *RTO Insider*

"I saw it when it flew in my inbox Friday," Craig Glazer, PJM's vice president of federal government policy, said before speaking at the EIA conference Monday.

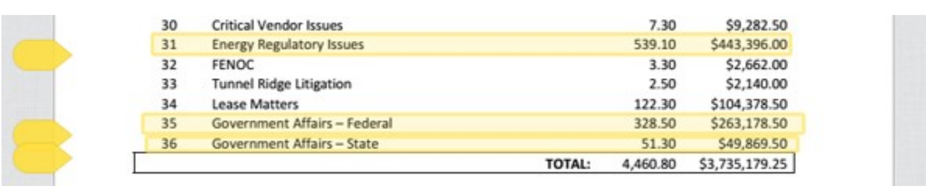
FirstEnergy's Lobbying Bill Revealed

Perhaps the most interesting development in the story Monday came from the Energy and Policy Institute, which published a blog post on a new filing in the bankruptcy case for FirstEnergy Solutions. The 174-page report shows Akin Gump billing FES $3.8 million in fees and expenses during April, including more than $753,000 in fees for "Energy Regulatory Issues" and federal and state "Government Affairs" work.

Including the $230,000 Akin Gump disclosed in a federal lobbying report for January-March, it has billed FES almost $1 million in lobbying expenses since January.

On April 13, for example, lobbyist James Romney Tucker, a former aide to Newt Gingrich, reported a "call to DOE re potential 202c determination" and a "call with White House staff re 202 status." Tucker alone billed FES $54,312 at $930/hour for his "Public Law & Policy" work during April.

The institute is a self-described watchdog "exposing the attacks on renewable energy and countering misinformation by fossil fuel interests." Akin Gump is D.C.'s top-earning lobbying firm.



30	Critical Vendor Issues	7.30	$9,282.50
31	Energy Regulatory Issues	539.10	$443,396.00
32	FENOC	3.30	$2,662.00
33	Tunnel Ridge Litigation	2.50	$2,140.00
34	Lease Matters	122.30	$104,378.50
35	Government Affairs – Federal	328.50	$263,178.50
36	Government Affairs – State	51.30	$49,869.50
	TOTAL:	4,460.80	$3,735,179.25

Akin Gump billed FirstEnergy Solutions $3.8 million in fees and expenses during April, including more than $753,000 in fees for work on "Energy Regulatory Issues" and federal and state "Government Affairs" work. | *Energy Policy Institute*

Lifeboat Revived?

One RTO official who asked not to be identified suggested the administration's plan may be like the "lifeboat" then-acting FERC Chairman Neil Chatterjee suggested last November in response to DOE's Notice of Proposed Rulemaking, which the commission rejected in January. Chatterjee had contemplated a "show cause" order requiring grid operators to compensate at-risk resources that provide resilience benefits as an interim measure while the commission conducted a longer-term rulemaking. (See *Chatterjee to Push Interim 'Lifeboat' for Coal, Nukes*.)

Chatterjee had said his plan would not alter RTO dispatch practices or distort markets, though he acknowledged a lot of details remained undetermined. The idea was apparently forgotten after Kevin McIntyre joined the commission in December, replacing Chatterjee as chairman.

RTOs Caught in the Dark

RTO/ISO executives speaking at the Mid-

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More Questions than Answers for FERC, RTOs on Bailout

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America Regulatory Conference in Kansas City, Mo., Monday had similar reactions to the memo, with all offering assurances that reliability is well under control in their footprints.

Panel moderator and Missouri Public Service Commission Chairman Daniel Hall characterized the memo as a "possible intrusion into the markets" and asked executives for their reactions.

MISO President and Chief Operating Officer Clair Moeller said he thinks an order is unnecessary but added that the RTO keeps out of retirement decisions. He said the decision whether to close a plant in MISO is between the plant owner and the state in the mostly vertically integrated footprint. "We like to say we're policy takers, not policymakers," Moeller said.

However, he offered that the proposed 90 days of on-site fuel supply is not a historical standard. "We've never had 90 days of coal on site in the 40 years I've been in the industry," Moeller said. He offered that resilience is "how you take the stuff you have and make it work to keep people safe."

SPP Executive Vice President and Chief Operating Officer Carl Monroe also said his mostly vertically integrated RTO likely won't see plants directly impacted, though an order could cause energy prices to rise in its footprint.

"I don't think I get to say that it won't affect us," laughed Suzanne Daugherty, PJM's chief financial officer and treasurer, noting that most states in the RTO's territory have adopted retail choice.

But she said PJM will exceed its current resource adequacy standards in the foreseeable future. "We've done the planning studies, and we're going to hit targets well above what we were trying to reach."

The move is a "drastic step" that could become a financial burden for ratepayers, Daugherty said. "Each type of resource, whether it's intermittent, hydro, coal, nuclear, all have [fuel supply] issues."

She also said it would be a "challenge" for independent power producers to make queue investment decisions if generators expected to retire instead begin receiving revenue streams. She pointed out that PJM has already initiated a fuel security study to examine how efficiently fuel is delivered to all plant types during times of peak demand.

ERCOT CEO Bill Magness said he is waiting on the full order to understand the possible impacts. "We're not sure if this is applicable to ERCOT," Magness said. "The Defense Production Act is not something I'm that familiar with, but I'm learning about it now," he added, smiling.

"We're trained to run security-constrained economic dispatch," Magness said. "And if this [order] fits into security-constrained economic dispatch, well, we can do that." But he cautioned that fuel security issues — like ensuring rail cars arrive on time — is outside of ISO/RTO control.

PJM's Glazer told the EIA conference Trump's directive will "probably complicate" his RTO's struggle to deal with state nuclear subsidies.

He said he fears a "half slave/half free" industry in which generators dependent on market revenues increasingly compete with those receiving cost-of-service payments or subsidies.

"I'm not sure that's sustainable, to be honest," he said. "I worry as we move down this path that we're ignoring the lessons of the past" — the 1970s, before electric restructuring.

Jason Fordney reported from Boise, Amanda Durish Cook reported from Kansas City and Rich Heidorn Jr. reported from D.C.