RTO Insider

Your Eyes and Ears on the Organized Electric Markets

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Coal, Nuclear Look to FERC, RTOs After DOE Grid Study

Coal Seeks 'Resiliency' Premium; FERC 'Fuel Wars' Coming?

By Rich Heidorn Jr.

The coal industry's hopes were boosted in April when Energy Secretary Rick Perry called for a report on what he said were risks to grid reliability caused by the retirement of "baseload" coal power plants. Both coal supporters and opponents saw Perry's April 14 memo as a means for President Trump to deliver on his promise to "save" the industry.

But the study released Wednesday didn't support several of the premises Perry laid out, nor did it provide the unambiguous case for coal that partisans on both sides expected.

The report came the day after the Associated Press reported that the Trump administration had rebuffed the industry's request to declare an emergency

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Nuclear Industry Seeks PPAs, 'Price Formation' Reforms

By Rich Heidorn Jr.

The nuclear industry hopes the grid study released by the U.S. Energy Department last week will accelerate RTO price formation efforts valuing baseload generation and that the federal government will begin purchasing nuclear power.

But states are still the first line of defense against premature plant closures, the Nuclear Energy Institute said at a press conference Thursday.

"We see the nearest-term opportunities for action to be at the state level while the RTOs and FERC [are] a little bit further out," said John Kotek, NEI's vice president for policy development and public affairs.

Kotek, a former DOE official, praised his former colleagues for what he called a "solid, fact-

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See related stories

ERCOT Reports 'Stable' System Conditions as Harvey Hovers

By Tom Kleckner

ERCOT said Monday that conditions remained stable on its system, despite the loss of two 345-kV transmission lines and other major high-voltage outages that cut power to more than 300,000 customers following Hurricane Harvey's landfall in Texas on Friday night.

The two 345-kV lines serve the Texas Gulf Coast near Corpus Christi and Victoria, at the center of the storm's landfall. More than 6,700 MW of generation capacity were offline for storm-related reasons, including a very small volume of renewables.

ERCOT said electricity demand has been about 20,000 MW below normal since Harvey came ashore, peaking at less than 44,000 MW because of structural damage along the coast and cooler temperatures. System restoration times will vary depending on the extent of damage, outage locations and weather conditions, the ISO said.

The ISO issued an emergency notice Friday and brought on extra engineering staff throughout the weekend to support efforts in its Taylor operations center for Harvey, the first Category 4 storm to hit Texas since 1971.

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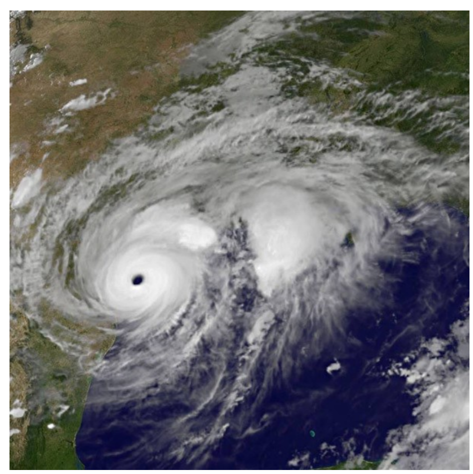

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CAISO NEWS

California CCAs Spur Worry of Regulatory Crisis

By Jason Fordney

SACRAMENTO, Calif. — Few parties in California are happy with the way the state's community choice aggregator (CCA) program is turning out, legislators learned during a Wednesday hearing at the state capitol.

In a discussion that at times grew tense, state senators heard how the evolution of California's CCA program has shifted hundreds of millions of dollars in costs to investor-owned utility customers because of long-term procurement contracts signed by IOUs decades ago in a radically different energy environment. The result is consternation among ratepayers and elected officials about increased costs — rather than the promised benefits of restructuring — and alarm about resource planning.

The situation "has become a very obvious conflict to people such as myself, and I am sure other legislators have been caught in the crossfire of this debate," State Sen. Ben Hueso, chairman of the Senate Committee on Energy, Utilities and Communication, said at the opening of the hearing.

CPUC President Michael Picker (right, foreground) and CPUC Energy Division Director Ed Randolph address the committee. | © RTO Insider

The State Legislature authorized the creation of CCAs with the passage AB 117 in 2002, after municipalities in the Los Angeles and San Francisco areas lobbied in response to a failed deregulation effort that in part caused the Western Energy Crisis of 2000/01. The law allows local governments to form CCAs by aggregating retail customers and securing electricity supply contracts to serve them. CCAs are growing rapidly in California and also exist in Ohio, New York, Massachusetts, New Jersey, Rhode Island and Illinois.

California Public Utilities Commission President Michael Picker told the committee that the state's retail electricity industry is being deregulated once again as it was in the mid-1990s, but this time by technology.

"We are being deregulated from the bottom up, and there is no real plan as to how it fits together," Picker said. Amid later questioning and discussion, he told the lawmakers, "I am looking to you for direction."

In an effort to spread the costs of legacy contracts, the IOUs in April proposed that the state adopt a new formula for allocating costs of departing CCA and other retail-

Continued on page 4

FERC Approves PG&E Transmission Cost Recovery

By Jason Fordney

FERC last week approved Pacific Gas and Electric's request to recover from its customers a portion of the costs of a $1.8 billion package of planned transmission improvements if the company is forced to abandon construction for reasons beyond its control.

The commission approved abandonment cost recovery for only some of the substation improvements and transmission lines that PG&E plans to construct (EL16-47). It also ruled that the utility is eligible for a 50-basis-point adder to its base return on equity as an incentive because the improvements are part of a regional transmission planning process.

The California Public Utilities Commission objected to PG&E's proposals, saying the company had not demonstrated the improvements would relieve congestion and had not provided enough information on the scope of the projects. PG&E was not transparent about cost control, projects costs had escalated since CAISO's approval and the utility had failed to quantify the possible abandoned plant cost to ratepayers, the PUC argued.

The PUC also contended that PG&E failed to disclose in CAISO's competitive solicitation process that it intended to seek from FERC incentive rate treatment for the projects.

The Sacramento Municipal Utility District, Transmission Agency of Northern California and the Six Cities group also protested the incentives.

FERC disagreed, saying "the CPUC does not point to any commission order or provision of the CAISO Tariff requiring project sponsors to disclose, in advance, that they intend to seek transmission rate incentives for their respective projects from the commission."

Public utilities can seek incentive-based rates for projects that preserve reliability or reduce delivered power costs by reducing congestion. To get the incentive and additional profit, PG&E must participate in a regional transmission planning process, which it does through CAISO.

The commission also held that PG&E was entitled to the rebuttable presumption that each of its projects would either increase reliability or reduce congestion because they were approved through CAISO's FERC-sanctioned transmission planning process.

The projects listed in PG&E's petition to FERC are the Wheeler Ridge substation; Northern Fresno 115-kV reinforcement; Midway-Andrew 230-kV project; Estrella 230/70-kV substation; Lockeford-Lodi Area 230-kV development; Martin Bus 2-kV bus extension; Oro Loma 70-kV reinforcement; and Spring 230-kV substation.

FERC approved PG&E's requests for abandoned cost recovery for the Wheeler Ridge, Northern Fresno and Midway-Andrew projects but denied them for the others. The approved projects met FERC's standard for a "nexus test" based on project scope and regulatory and construction risk because of land acquisition and other factors.

The commissioned also denied the company's request for recovery of costs incurred up to the point of its March 10, 2016, filing.

CAISO NEWS

California CCAs Spur Worry of Regulatory Crisis

Continued from page 3

choice customers, called the portfolio allocation methodology. (See *Utility Proposal Would Increase Legacy Costs for California CCAs*.) That approach would replace the current IOU exit fee levied on departing customers, called the power charge indifference adjustment (PCIA), which is meant to address the old contracts. The PUC is taking a look at its deregulation strategy. (See *California to Reconsider Retail Choice*.)

PG&E Calls for Quick Action

California's IOUs initially resisted the creation of CCAs by introducing a ballot proposition to make their creation more difficult, but that measure failed. The utilities said they are left holding the bag for long-term procurement decisions made years ago in an industry environment that has changed significantly in terms of rate structures, prices and technology. Those costs are being borne by a dwindling rate base — including low-income customers.

Malnight

PG&E Senior Vice President Steven Malnight told the committee that the legacy contracts, numbering more than 200 and signed in 2007 and 2008, enabled third-party resource developers to invest billions of dollars in California, create thousands of jobs and help the state to become an economic leader.

The IOUs "see a significant challenge that is in front of us — that needs to be addressed quickly — on cost allocation," Malnight said. When the contracts were procured, the IOUs were planning to service their customers for up to 20 years.

"The assumption was that those customers would stay in our service territory, and that we would need to serve them," he said. "Today, we know that reality is significantly different."

About 30% of PG&E's customers switched to third-party services, a number that is estimated to rise to 50% by 2020. PG&E procured energy on behalf of those customers and now must reallocate costs through the PCIA. Under that methodology, departing customers are assuming only about 65% of the costs that should be allocated to them. The remaining costs are being paid not by utility shareholders but by remaining IOU customers, many of them in areas without a CCA option, he said.

About $180 million has been shifted from CCA customers to IOU customers, he said, which will grow to $500 million by 2020. "I know in California that we do think big — but that is a lot of money," Malnight said. Long-term contracts are often needed to provide resources to deal with renewable integration and protect grid reliability, and IOUs are generally over-procured and have limited options for solving that problem.

"We can't arbitrarily walk away from that contract, [and] turn it over to a CCA or anybody else," he said.

California Coalition of Utility Employees counsel Marc Joseph told the committee that in 2007, IOUs were facing renewable mandates when their cost was much higher and the industry and its technologies were young. It was a seller's market, but CCAs now function in a "buyer's market."

IOUs could be paying back those contracts for decades, and the PCIA does not work to make IOU customers "indifferent" to the creation of CCAs. But CCAs are basing their current economic decisions on the current structure of the PCIA program, he said.

"It is easy to see the train wreck that will come," he said, telling the legislators CCAs "will come running to you to bail them out." He urged a slowdown in the CCA program while the PUC examines the PCIA issue, he said. Many new renewable developers are ready to build, but the result is no customers because IOUs are over-procured. As a result, in California "we have had a crash in the construction of new renewable projects" after healthy growth in 2016 at a time when large federal subsidies are available.

Contract Holders Expect to Get Paid

Independent Energy Producers Association CEO Jan Smutny-Jones told the committee that the group's members built a lot of the renewable projects in California and also do some business with CCAs, as well as holding the IOU contracts.

"We expect those contracts to be honored," he said, adding that "we are not really interested when someone else says something else should happen with those contracts." They are private contracts subject to contract law and out of the jurisdiction of the PUC, he noted.

"This is a big issue. This state has a very good history of honoring contracts with my member companies. … We need to keep that up," Smutny-Jones said. Not honoring the contracts would send a strong negative signal to companies considering investing in California.

Bradford Questions CCA Fairness

Bradford

Sen. Steven Bradford, who represents parts of Los Angeles County, said that CCAs can "pick and choose" which customers they serve. That assertion drew disagreement from Sonoma Clean Power CEO Geof Syphers, but Bradford insisted that "you can — that's why you are in Marin, that's why you are in Sonoma."

IOUs have an obligation to serve customers, and "you wanted to be everything a utility is, other than report to the PUC," Bradford said. As a State Assembly member in 2014, Bradford introduced legislation that was viewed as anti-CCA. It would have put default provider status back to the IOU rather than the CCA, but the bill was defeated after opposition from CCA supporters that argued that CCAs shouldn't be subjected to the same oversight as IOUs.

At its conclusion, Hueso said the hearing had been "enlightening" and that he was concerned about creating an ungovernable system. The committee plans to hold more discussions on the future of CCAs.

"Nobody talked about a collapse of our system, but there were a lot of comments that alluded to that," Hueso said.

CAISO NEWS

CAISO Finalizes Constraint Tool Proposal

By Jason Fordney

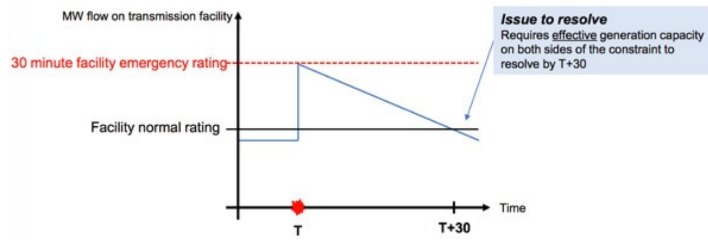
CAISO is close to finalizing a long-running effort to reduce exceptional dispatch of generation to resolve transmission constraints and comply with reliability standards, but market participants have raised last-minute questions about the proposal.

During an Aug. 21 call on the Contingency Modeling Enhancements (CME) draft final proposal, some stakeholders said they wanted more detail about where CAISO would apply a proposed "preventative-corrective constraint" tool. But the ISO, which is preparing to present a final plan to the Board of Governors next month, said it has provided enough transparency.

CAISO kicked off the CME initiative three years ago to address a Western Electricity Coordinating Council reliability provision requiring grid operators to return a critical transmission path to its system operating limit within 30 minutes of a destabilizing event, such as the loss of a generator or transmission line. The ISO's present approach to managing those contingencies relies on out-of-market interventions coupled with day-ahead market measures that procure a "bucket" of responsive capacity resources based on a flat megawatt rating of the line.

WECC has since retired that standard, but CAISO still needs to comply with NERC standards requiring a return to normal operations in 30-minute and four-hour time frames.

Under the proposal, resources contributing to restoring normal operations would receive both an energy payment and a payment for reserve "corrective capacity" set aside by the ISO, the cheapest way to provide needed generation if needed because of a contingency, CAISO says.



CAISO is trying to resolve temporal transmission system reliability constraints in its market. | *CAISO*

"The goal here is to reflect the real reliability constraint in the market," said Perry Servedio, CAISO senior market design policy developer. "We believe the proposal improves transparency related to these constraints by improving the pricing and dispatch." The latest version has "a hodgepodge of final tweaks to the policy."

Southern California Edison had previously raised concerns over the complexity of the proposal, while Calpine and NRG Energy were supportive but said that the mechanism should allow participants to bid for corrective capacity. The ISO said that the proposal "fully captures and compensates" for capacity needed to meet any restraints on the system.

During the call, some stakeholders questioned why CAISO had not specified on which transmission paths the constraint tool would be applied. SCE said there is not enough transparency around how the paths would be selected, making it difficult to analyze the benefits.

For SCE, "the benefits are very limited. We don't see any incremental benefit because you do have all the tools you have today," Senior Project Manager Wei Zhou said. He added it will increase complexity in the market.

CAISO Principal George Angelidis responded that "I think we are getting bogged down in implementation details and we are missing the big picture here." The fundamentals of the proposal have not changed, and it is "still a tool that will provide the ability to reduce constraints that are imposed by operators based on their judgement of system conditions," he said.

"I don't know why we are making a big issue on this trivial application change" of where the tool will be used, Angelidis said, adding that it would be used wherever it would provide a benefit.

Servedio said that "the selection criteria is: whatever we need to do to operate within our facility ratings."

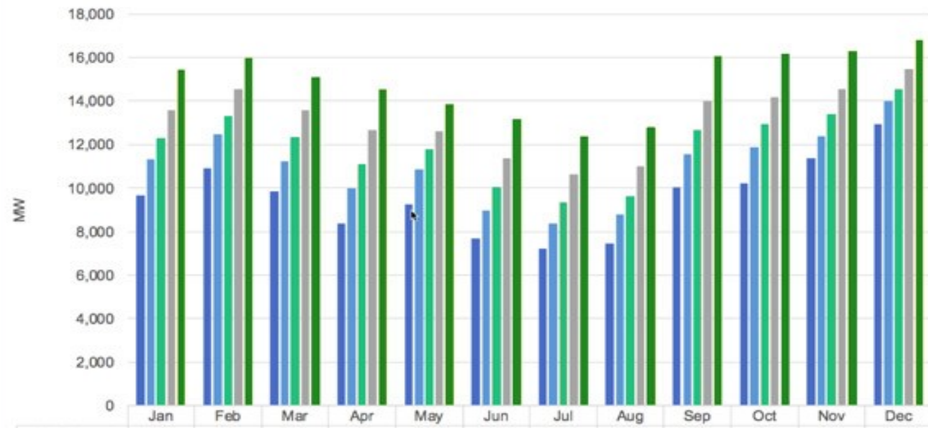
The grid operator is taking comment on the final draft proposal until Aug. 31.

CAISO has a separate and overlapping effort underway to resolve certain generator and transmission contingencies currently handled by out-of-market operations. (See *Stakeholders Wary of CAISO Contingency Modeling*.)

CAISO NEWS

Power Sellers Urge Action on CAISO Flex Capacity

By Jason Fordney



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016 (Actual)	9,687	10,891	9,828	8,397	9,263	7,669	7,214	7,463	10,030	10,228	11,375	12,960
2017	11,342	12,465	11,253	9,973	10,878	8,996	8,379	8,768	11,575	11,900	12,391	14,004
2018	12,282	13,313	12,352	11,111	11,803	10,039	9,326	9,617	12,660	12,954	13,376	14,567
2019	13,595	14,543	13,574	12,672	12,631	11,350	10,616	10,982	13,981	14,199	14,553	15,495
2020	15,439	15,984	15,089	14,572	13,859	13,181	12,391	12,821	16,061	16,169	16,293	16,817

Monthly three-hour generator ramp-ups are on the increase in CAISO. | *CAISO*

Power sellers and utilities in CAISO are urging the grid operator to develop a long-term plan to procure the flexible capacity resources increasingly needed to manage the integration of variable renewable generation.

Market participants commented on a recent stakeholder meeting regarding the ISO's Flexible Resource Adequacy Criteria and Must Offer Obligation Phase 2 (FRACMOO 2) proposal. The ISO is proposing to introduce new variations in its flexible resource adequacy (RA) capacity product, which is intended to increase the ramp rate of the flexible capacity fleet. (See *CAISO Flex Capacity Effort Targets Increased Variability*.) CAISO is needing quicker ramping speeds within shorter time cycles as more renewables are brought into the system.

The current proposal is a set of short-term solutions, and CAISO said it will later develop a "long-term RA roadmap" to integrate system, local and flexible capacity needs, and state renewable portfolio standards.

The bulk of the current proposal represents short-term modifications to the flexible capacity criteria to emphasize start-up and minimum run times. CAISO is exploring the use of intertie resources but does not yet have a specific proposal. It hopes to have a program in place in time for the 2020 RA year.

Southern California Edison (SCE) said it is not a function of the resource adequacy program to optimize resources, as stated in a Brattle Group proposal discussed in the stakeholder call. Brattle included "products to optimally utilize resources" as a goal of flexible capacity, but SCE said that optimal use is the role of the wholesale market. The RA program is meant to ensure that capacity is available via a must-offer obligation. "SCE does not believe that the CAISO has clearly demonstrated where the current three-hour product is failing," the company said.

Powerex, which markets BC Hydro output, commented that CAISO should examine why flexible capacity needs are causing challenges and how to make "cost-effective resource investments" to achieve environmental goals. Powerex said the ISO should develop additional tools to reduce the magnitude and steepness of net load ramps when they would otherwise exceed available flexible capacity in real time, allowing it to procure additional flexible capacity from existing resources.

The Western Power Trading Forum (WPTF) said that "this initiative does not have to be the end all, be all in incenting flexibility from the CAISO fleet. The CAISO can also enact energy market reforms and, if necessary, procure backstop capacity." The group urged the ISO to keep the proposal simple and target products that will incentivize load-serving entities to contract with the most flexible resources, and incent interties to economically offer in their capacity.

"This will provide proper market incentives resulting in economically efficient outcomes, including the potential of the retirement of less flexible, unneeded capacity," WPTF said.

The Alliance for Retail Energy Markets, a group representing competitive suppliers — including Constellation NewEnergy, Direct Energy and Noble Americas Energy Solutions — contended that CAISO should identify the root causes of the reliability needs and develop a market-based solution that properly assigns costs and provides price signals.

"In spite of many years of effort, the CAISO is still seeking to understand the flexible needs on the system," the group said in its comments. "In addition, the continued focus of the CAISO on specifying prescriptive capacity procurement requirements for load-serving entities (LSEs) is fundamentally misplaced and excessively burdensome." Meeting flexible capacity needs through ancillary services would provide transparency and investment signals for new resources, the suppliers said.

CAISO plans to have a draft final FRACMOO 2 proposal early next month and approval from the Board of Governors by the second quarter of 2018.

ERCOT NEWS

TAC Briefs

TAC Approves EEA Adder Compromise

AUSTIN, Texas — With Hurricane Harvey rapidly gaining strength in the Gulf of Mexico and threatening the Lone Star State, ERCOT's Technical Advisory Committee on Thursday focused on three tabled revision requests and appeals before quickly scattering to their homes and work.


Helton

"Be safe," urged TAC Co-Chair Bob Helton, of Dynegy, as he adjourned the meeting.

Committee members did approve one of the three tabled issues, passing a nodal protocol revision request (NPRR768) after staff filed comments most could agree to. The NPRR was the subject of vigorous debate during the July TAC meeting but was passed this time with only Shell Energy and Sharyland Utilities abstaining. (See "EEA Price Adder Change Tabled," *ERCOT Technical Advisory Committee Briefs: July 27, 2017*.)

The revision request adds real-time DC tie imports and exports through registered block load transfers to the list of ERCOT-initiated actions that trigger a price adder to ensure that prices reflect scarcity conditions.

Staff revised the language to cap the total adjustment for DC tie imports at 1,250 MW, the current capacity of all DC ties.

That was enough to placate the Texas Industrial Energy Consumers group, which has opposed the measure throughout the stakeholder process.

"We have a philosophical disagreement about whether this is appropriate," said Katie Coleman, legal counsel for TIEC. "Rather than continue fighting about that, we got comfortable about moving this forward with a megawatt limit on it."

Shell's Greg Thurnher called the revised language a "nice compromise" and a "step in the right direction" to support scarcity pricing signals, but said he wasn't sure "every adder is a good adder."

"This one has a lot of fine print," Thurnher said. "We've had some growth in traditional [DC] ties that could be excluded for the circumstances it's trying to prevent. We've arrived at the solution, but I'm not sure it's a good one."

NPRR768 does not address the Southern Cross Project, a proposed HVDC transmission project that would transport more than 2 GW of electricity from Texas to Southeastern markets. Several stakeholders agreed that is a discussion for a later date.

"When we wrote this, we tried to recognize what exists today," said Kenan Ögelman, ERCOT's vice president of commercial operations. "We don't believe it's biased toward anything. Our process allows the accommodation of whatever the future is going to be. This was our effort to put something forward to get to a compromise and recognize some of the concerns."

Shell filed comments to ERCOT's revisions, suggesting modifying the NPRR to restrict price correction to imports ordered on DC ties classified as transmission facilities. Cratylus Advisors' Mark Bruce, speaking for Southern Cross, disagreed with the change.

"It seems pretty clear to us that once the Southern Cross project is interconnected to the ERCOT network, it will be a transmission element by definition, which means the definition of a transmission facility has to be amended to include it," Bruce said. "Shell's comments don't really change anything. It actually opens it up and includes Southern Cross when it goes live.

"The ERCOT approach, on its face, is sort of less discriminatory. It doesn't really start distinguishing between transmission facilities based on regulatory classification or ownership structure of the facility, which in our view isn't a permissible way to go about this. In our view, this is either a good policy, [and] you put the megawatts in the calculation, or it's not good policy, and you don't."

"Our intent was to impose a limit," Thurnher responded. "The protocols get tricky when they define things. I think of Southern Cross as a load sometimes and a generator sometimes, neither of which are transmission assets. If Southern Cross gets built, then this needs to be revisited."

Said Coleman, "We are intentionally leaving that for future discussion."

CRR Deration Remanded Back to Subcommittee

The TAC unanimously remanded back to the Protocol Revision Subcommittee NPRR821, which failed to pass the committee in July after substantial discussion, to reconcile "three very different" modifications proposed by stakeholders.

The revision request would eliminate the reduction of congestion revenue rights (CRR) payments, or deration, by reversing the day-ahead market's deration-settlement mechanism. The mechanism, which was introduced to deter market manipulation, has resulted in large financial losses to generators.

The deration price for a CRR path is determined at the constraint level and applied to the CRR payout. Payments can be derated if transmission elements are oversold, the target payment is a positive value, or the CRR source or sink is a resource node.

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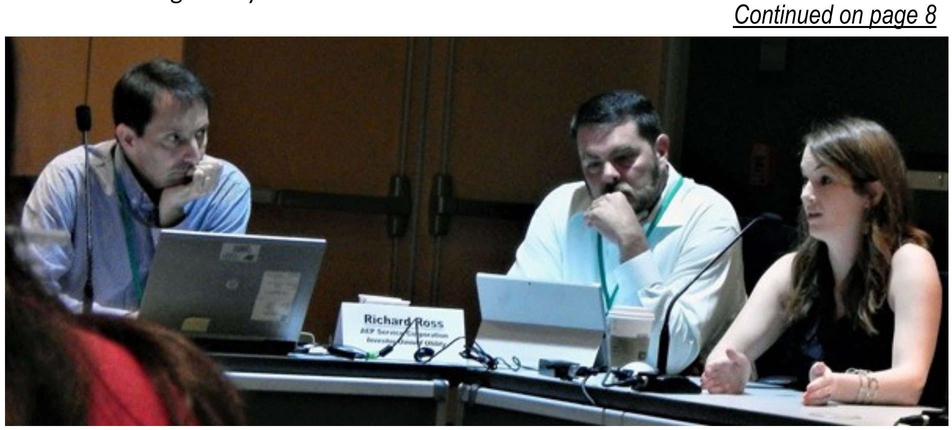

AEP's Richard Ross and Cratylus Advisors' Mark Bruce listen to TIEC's Katie Coleman make her case. | *© RTO Insider*

ERCOT NEWS

TAC Briefs

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The Lower Colorado River Authority filed two proposed adjustments to NPRR821 following a $1.9 million loss in 2016 that it called "unusual and unique." LCRA said it worked with ERCOT and others in attempting to find a balance between low impact and low implementation cost.

The company's preferred solution was linking the CRR's holder and the point-to-point (PTP) obligation of the qualified scheduling entity on the same path. It suggested linking the PTP price to the corresponding CRR value if a PTP obligation bid is awarded to a QSE with a CRR. If the CRR is derated, the PTP bid's settlement price is matched to the CRR's derated value.

The second option would cap the PTP's value at the derated CRR's value on the same path.

"It's clear a lot of folks still have a learning curve with how this process works and the way the money flows," said LCRA's Randa Stephenson. "If it's TAC's will to send this back, please be ready to vote on this. This is going to be an issue that comes back to us."

ERCOT staff agreed and volunteered to put together a presentation detailing all the proposed modifications.

"I just want to make sure everything's clear," Ögelman said, noting that LCRA's proposal considers PTPs, not CRRs. "People need to look at all of these things to understand all of the mechanisms."

DC Energy's suggestion to add a "circuit-breaker" lowering the capacity offered in the CRR monthly auctions when the balancing account reaches zero at the end of any month drew positive feedback from several stakeholders.

"It's a little bit more protection for our customers," said Austin Energy's Barksdale English.

Under DC Energy's proposal, the CRR balancing account would be allowed to rebuild its value before reverting to the 90% capacity offering status quo.

Morgan Stanley offered the third proposal, which it said would "level the playing field" for all CRR participants by making short pays equivalent, regardless of the source or sink of the owned CRRs. Eliminating the current process — which covers hub and load zone CRRs and provides hedge value for those instruments involving resource nodes (well over half of these shortfalls) — would eliminate the expense created for load, the company said.

"There was a request to try and narrow the NPRR, and this narrows the application as far as you can get it," said Morgan Stanley's Clayton Greer, whose first preference was either the original NPRR or DC Energy's proposal. "It actually eliminates all short-

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ERCOT Reports 'Stable' System Conditions as Harvey Hovers

Continued from page 1

ERCOT spokesperson Robbie Searcy said the day-ahead market cleared on time over the weekend.

Harvey was downgraded to a tropical storm Saturday afternoon, but it has spawned tornadoes and continues to drench much of the Texas Gulf Coast with torrential rains. The downpours are expected to continue well into the week.

The number of consumers without power peaked at just more than 300,000 early Saturday afternoon, based on reports from transmission providers in the affected areas. As many as 157 circuits were out of service at one point, with outages heaviest near Corpus Christi and Victoria.

ERCOT said extended outages are likely in most of those areas, and the outage numbers will fluctuate as transmission providers work to restore power.

The ISO has created a special page on its website to provide the latest updates on restoration efforts.

Houston's two major airports — William P. Hobby and George Bush Intercontinental — were both closed over the weekend. They may be reopened as soon as Wednesday.

ERCOT

The U.S. Coast Guard closed multiple ports along the Texas Gulf Coast, including those at Houston, Galveston, Texas City, Freeport and Corpus Christi.

ERCOT is responsible for about 90% of Texas' load, including Houston and much of the affected coastal region. MISO is responsible for Southeast Texas, which includes the cities of Beaumont, Port Arthur and The Woodlands.

MISO also manages parts of Arkansas, Louisiana and Mississippi, where the National Weather Service was forecasting as much as 4 inches of rain over the next five days.

MISO South Region Operations Director Tag Short said the RTO was activating its "established protocols" to maintain grid reliability and had additional operators and support staff in place and on call.

Spokesman Mark A. Brown said Sunday night that the MISO transmission grid remained stable, but that the RTO remained in a severe weather alert.

"Our region could still face significant amounts of rainfall and potential flooding," he said. "We will be carefully monitoring those conditions and will be prepared to take the appropriate steps to maintain the reliability of the transmission grid across the MISO footprint."

Entergy Texas reported more than 7,600 customers were without power as of 8:30 a.m. Sunday. "Crews are safely restoring power as quickly as possible, but the storm's continued wind, rain, flooding and falling trees could make it difficult to access Entergy's equipment and slow restoration," the company said. It serves more than 440,000 customers in 27 counties.

ERCOT NEWS

TAC Briefs

Continued from page 8

pay recoveries and hedge payments entirely. The retail segment argued that derate support was being done on the backs of load. If that's the case, then all derate coverage would be on the backs of load."

The Protocol Revision Subcommittee (PRS) plans to return with new language for NPRR821 in September.

Small Municipalities' Appeal Tabled Again

The committee once again tabled the Small Public Power Group of Texas' (SPPG) appeal of a rejected revision to the Nodal Operating Guide (NOGRR149) regarding the definition of transmission owners. In granting a six-month extension until February, the TAC agreed to take up the "substance of the appeal" at that time.

The revision would exempt distribution service providers without transmission or generation facilities from having to procure designated transmission operator services from a third-party provider if their annual peak load is less than 25 MW. The proposal was developed in 2015 to settle the non-compliant status of six municipally owned utilities with loads from 9 to 21 MW.

The SPPG has been filing monthly updates since the appeal was last tabled in January. In its most recent, the group said, "significant progress has been made" in reaching permanent market solutions for its members' designated TO service, but they have not yet been achieved.

"All of these have been proceeding as hard and as fast as they can," said Tom Anson, legal counsel for SPPG. "These things take more time than you think. We want another six months to keep working hard at it."

The appeal has now been tabled eight times since it was first brought to the TAC in March 2016, shortly after it failed to pass the Reliability and Operations Subcommittee.

PRS Adds Resource Definition Task Force

The PRS brought forward two unopposed NPRRs and announced the formation of the Resource Definition Task Force. The task force, chaired by Vistra Energy's David Ricketts and ERCOT's Jay Teixeira, will work to synch up the ISO and Public Utility Commission of Texas' definitions.

The TAC tabled NPRR829, one of two unopposed revision requests, to allow ERCOT time to refresh its initial impact statement. Staff said it believes the second impact statement, which should be complete for the next PRS meeting, will come in above the current $120,000 to $160,000 estimate to implement.

NPRR829 requires the use of telemetered data from non-modeled generation in the day-ahead market to more accurately calculate QSE collateral requirements. The change will increase day-ahead liquidity through the increased participation of non-modeled generation, and potentially allows ERCOT to gain near real-time transparency into the generation.

The committee unanimously approved NPRR836, which incorporates the following "other binding documents" into the protocols as a new Section 23 (Forms): Congestion Revenue Right Account Holder Application Form, Load Serving Entities Application Form, Managed Capacity Declaration Form, Market Participant Agency Agreement Form, Notice of Change of Information, QSE Agency Agreement Form, QSE Application Form, Qualified Scheduling Entity Acknowledgement, Resource Entity Registration Form, Transmission/Distribution Service Provider Registration Form and WAN Agreement.

Changes to these Section 23 forms will be made using the NPRR process.

— Tom Kleckner

ISO-NE NEWS

FERC Rejects Requests for Stay of Atlantic Bridge

By Michael Kuser

FERC last week denied requests by two Massachusetts municipalities for a stay of its January approval of the Atlantic Bridge Project, a $452 million expansion and upgrade of existing pipeline networks in New York and New England (CP16-9-001; CP16-9-004).

The two Boston-area communities — the town of Weymouth and city of Quincy — alleged that the prospect of construction was harming property values and making it "impossible for owners to sell their residences in the face of uncertainty."

The commission quoted its own environmental assessment that found the project's "pipeline segments primarily involve replacements of existing pipeline in the same location and would not require a new permanent pipeline easement. ... Existing property values in these areas account for the presence of the existing pipeline and/or compressor station infrastructure."

The Atlantic Bridge Project would expand Enbridge's Algonquin Gas Transmission and Maritimes & Northeast Pipeline systems by 132,700 dekatherms/day to serve the New England and Canadian natural gas markets. The project would replace existing pipelines and expand existing compressor stations or build new ones in New York, Connecticut and Massachusetts, including a 7,700-horsepower compressor station to be built in Weymouth. (See *Atlantic Bridge Project Approved by FERC*.)

While the Weymouth compressor station would be a new facility, it will be built "on a previously disturbed industrial property ... between an existing water treatment facility and electric power plant" and will not "result in other impacts that would significantly impact adjacent property values," the commission said.

Quincy also contended that FERC's order would cause harm by encouraging investors to back development of the separate Access Northeast pipeline project, which would run through the community. The commission found that contention "purely speculative" and said that the city did not allege what harm it would suffer from development of Access Northeast.

For Whom the Order Tolls

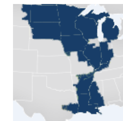
Weymouth additionally requested rehearing of a procedural tolling order issued by FERC Secretary Kimberly Bose in March.

The order stemmed from the commission's lack of a quorum, which Weymouth argued left the town no recourse, either through the commission or the courts, to halt construction of the project. But FERC rebuked that contention, explaining that the order was only meant to give the commission "additional time for consideration of the matters" raised on rehearing. Weymouth was "free to seek stays from the commission or other relief," it said.

Weymouth also called the tolling order unconstitutional, premising its argument upon a February 2017 D.C. Circuit Court of Appeals decision in *PHH Corp v. Consumer Financial Protection Bureau*, which held that "the consolidation of substantive decision-making authority into a single person eliminates ordinary constitutional checks and balances and is, therefore, unconstitutional."

FERC found Weymouth's argument inapplicable because the court "agreed to rehear the case *en banc* and vacated its earlier opinion. Moreover, the panel members differed on the appropriateness or necessity of the separation-of-powers ruling relied upon by Weymouth."

MISO NEWS



MISO Sets Target for Market Platform Upgrade Decision

By Amanda Durish Cook

CARMEL, Ind. — Now that it has completed a seven-month evaluation of its existing system, MISO says it will provide a detailed decision on how it would rebuild its computer-based market platform in 2019.

Porter

The RTO's near-term focus: to protect and extend the life of the existing market system while exploring and discussing upgrade options with vendors, according to MISO General Counsel Andre Porter.

MISO will present a business case for the making the upgrade at a Sept. 6 workshop on the status of the market platform. MISO's Board of Directors in June urged RTO officials to provide stakeholders with upgrade details — and a plan — in order to solicit comments. (See *MISO: $130M Needed for New Market Platform*.)

"Stakeholder participation is critical for the market system enhancement program," Porter said, urging stakeholders to bring questions to the workshop.

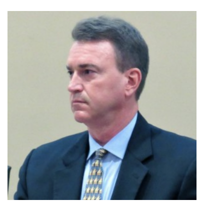
At an Aug. 24 meeting of the board's Technology Committee, Director Baljit Dail praised the RTO's stakeholder outreach, but stressed that it should make the upgrade information easier to understand.

MISO expects to select an upgrade option and confirm a vendor in 2019, with roll-out of the new platform targeted for no later than 2024. Officials plan to finalize a budget in October for the estimated $65 million needed to preserve the existing system for another five to seven years, while another $65 million would be allocated to build a new modular platform. The budget will also include a total contingency amount equating to up to 25% of the project cost.

Director Thomas Rainwater commended MISO for being able to finish the evaluation stage of the project on time. "We think that's a bellwether of what's to come," he said.

"The progress you all have made is phenomenal, and you guys should be very proud of this. As a committee, we want this project to be successful. It has the potential for a huge payout," Dail said, urging officials to provide frequent updates on the project.

As MISO completes the platform rebuild, officials will also explore the intellectual property rights of the software. A deeper discussion on possible copyrights was saved for a closed session of the Technology Committee.



Ramey

The existing market system, designed by General Electric, was built from scratch in 2005 for $245 million. To incorporate the ancillary services market in 2009, MISO spent $75 million. It spent an additional $30 million to expand the platform upon integration of MISO South in 2013. In any given year, MISO invests about $6 million to $9 million in maintenance and improvement costs, Vice President of System Operations Todd Ramey said.

"The system we use today, and have used since the start of our markets in 2005, is really based on infrastructure used in the late 1990s. This system has started to show signs of its age," Ramey said.

Several Market Roadmap design changes have been put on hold because of the aging infrastructure, Ramey said. MISO has growing concerns about security and, in some cases, market participants must use older versions of web browsers to view web pages.

ISO-NE and PJM also use GE-designed platforms. Both RTOs will undergo "common" upgrades using a staged approach in the next few years, said Jeff Bladen, MISO executive director of market design.

"In some respects, we're catching up [with other RTOs], but we have a plan to go beyond what's done today," Bladen said during an Aug. 23 Advisory Committee meeting.

Ramey noted that MISO would eventually be forced to change to its platform because GE plans to phase out IT support for the aging software.

The computer overhaul will mostly affect MISO's day-ahead market and Energy Management System programs. The RTO's settlement software system is being rebuilt in a different project launched in 2014. The RTO is currently completing system testing and expects to launch the new settlements platform sometime in the fourth quarter, in time for the early spring 2018 roll-out of five-minute settlements.

Routine July for MISO

CARMEL, Ind. — A mid-July heat wave failed to drastically alter MISO's monthly average load and energy price, stakeholders learned at an Aug. 22 Informational Forum.

July's temperatures averaged near normal overall, MISO Executive Director of System Operations Renuka Chatterjee said.

Load averaged 87 GW during the month, up from an average 80 GW in June and "consistent with the summer weather conditions," Chatterjee said. Load peaked for the year at 120.6 GW on July 20, close to last July's peak. Day-ahead and real-time energy prices averaged $30/MWh and $31/MWh, comparable to a year ago, owing to natural gas prices that held steady below $3/MMBtu.

"Overall, this July was a typical summer month," she said.

MISO experienced fewer forced outages this year but more planned outages when compared to last year. Forced generation outages decreased by about 3 GW from a year ago to about 11 GW, while planned outages were up 1 GW to about 6 GW. Real-time congestion stemming from forced outages led to "unanticipated higher prices" in MISO South on July 28, Chatterjee said.

July boasted 2,277 GWh of total wind generation, a 7% decrease compared with last July. Meanwhile, MISO's registered wind capacity increased from 15.9 GW to 16.8 GW year-to-year.

— Amanda Durish Cook

MISO News

Progress Builds for MISO Energy Storage Effort

By Amanda Durish Cook

MISO's Energy Storage Workshop underway. | © RTO Insider

CARMEL, Ind. — While a MISO workshop last week fell short of defining potential market rules for energy storage devices, it did provide stakeholders an opportunity to hash out their thoughts on a technology that straddles the boundaries between generation and transmission.

During the RTO's first energy storage workshop last month, stakeholders advised it to consider all the capabilities and types of battery storage before drafting market rules and creating definitions. (See MISO Rules Must Bend for Storage, Stakeholders Say.)

At the second — and likely final — workshop Aug. 24, MISO took a stab at providing structure for addressing the complex issue by suggesting which committees should field various storage proposals.

MISO assigned Chief Compliance Officer Joseph Gardner to serve as its liaison to the newly created Energy Storage Task Force, which will gather ideas that could eventually become proposals at the Resource Adequacy Subcommittee, Market Subcommittee, Reliability Subcommittee and Planning Advisory Committee.

The RTO suggested that the PAC could handle storage interconnection methods and possible transmission cost recovery, while the MSC would tackle compensation rules. Either the MSC or RSC could work on the creation of no-harm tests, operating traits and market participation models, while the RASC could undertake capacity accreditation rules, said MISO Executive Director of External Affairs Kari Bennett.

But discussion at the workshop focused on the beguiling and intriguing issues around storage — and how to accommodate the increased adoption of a resource that defies MISO's current market categories. The RTO currently has about 140 MW of battery storage requests in its interconnection queue.

'A Giant Lego Set'

Lin Franks stressed the future importance of storage resources in MISO, saying she's become a battery convert since volunteering to head the energy storage division at Indianapolis Power and Light.

Franks

"I feel like I learn something new about these things every day," Franks said. "Like I said, I'm a born-again Christian when it comes to batteries. They can solve problems, and solve them quickly."

IPL's Harding Street Station was MISO's first battery storage facility, commencing operation in May 2016. The facility can continuously deliver 5 MW for more than four hours, as well as move from a neutral state to full injection or withdrawal of energy in under one second. It serves only primary frequency response, reacting to unanticipated deviations.

"The faster you can solve the [frequency] degradation, the fewer megawatts you need," Franks said.

IPL last year mounted an unsuccessful campaign to have FERC order MISO to compensate resources for providing automatic frequency control. (See MISO Ordered to Change Storage Rules Following IPL Complaint.)

Like all grids, MISO's system was designed with control in mind, Franks said. Recent additions of rooftop solar and wind generation can erode that control, but autonomous storage resources can mitigate those risks and provide more resilience.

"We like to talk about storage as one kind of animal, but it's not. It's a whole zoo of animals," Franks said. "When I talk about my lithium ion battery, that's not what all lithium ion batteries are like. They morph with the industry. They're like a giant Lego set."

Franks urged stakeholders to educate themselves on stored energy resources.

"Real-time operators don't like change. They know what works and they're comfortable with it. … Just like you, I see some arms crossed out there," Franks said, teasing the audience.

Franks noted that MISO and state and federal agencies are still working out policy details around storage, including capacity accreditation, facilities agreements, state-of-charge management, interconnection conditions, removal of Tariff barriers and clarification of state versus FERC jurisdiction. She also recommended that MISO lay out an "expedited path" in its annual Transmission Expansion Plan for storage resources.

Franks recounted the confusion Harding Street caused upon entering MISO's interconnection queue in 2014.

"None of us knew how to model these at the time," she said, adding that the RTO eventually settled on modeling the battery at its maximum injection and withdrawal.

MISO NEWS

Participant-funded Projects Get Second Shot at MISO Cost Recovery

By Amanda Durish Cook

MISO will resume discussion on possible cost recovery for participant-funded transmission projects under 345 kV after two wind industry organizations called on a stakeholder committee to revisit the issue.

The RTO's Advisory Committee will take up the subject at a Sept. 20 meeting during Board of Directors week in St. Paul, Minn., where stakeholder sectors can offer opinions on the matter.

Wind developer EDF Renewable Energy and nonprofit Wind on the Wires approached the Advisory Committee during an Aug. 23 conference call to once again appeal for cost recovery on customer-funded transmission upgrades under a proposed "non-[MISO Transmission Expansion Plan] upgrades" category. The RTO's Steering Committee last month declined to rehear the issue after determining it had been fully considered in the stakeholder process even if supporters of the change were disappointed with the outcome. Some stakeholders pointed out that customers accept the risks of funding their own upgrades performed outside the MTEP process, and an after-the-fact cost allocation would be too complex to introduce.

EDF and Wind on the Wires faced two options after the rejection: either approach the Advisory Committee or file a FERC complaint. (See *MISO Rejects Cost Recovery for Customer-Funded Projects*.)

"We don't think the discussion was robust enough," said Bruce Grabow, an attorney representing EDF.

Grabow said the discussion in MISO's Regional Expansion Criteria and Benefits Working Group (RECBWG) demonstrated a "fundamental misunderstanding of the need and request." The group had failed to discuss the current "gap" in congestion management or why participant-funded upgrades should be excluded from cost allocation, he said. There had also been no discussion of the possible unreasonableness of the status quo and no "exploration of how the proposal could work or be adjusted to address stakeholder concerns."

Grabow argued that there should be a "simple" one-time return of installed costs imposed on new interconnection requests. MISO's status quo of leaving the cost of customer-funded upgrades solely to the customer is "proving to be an insufficient means," as no such projects were brought forward in MTEPs 14, 15 or 16 despite the need for sub-345-kV projects that relieve congestion, he said.

"One of the biggest challenges facing wind generators today is congestion in various areas that cause curtailment," Wind on the Wires Executive Director Beth Soholt told Advisory Committee members. She said that customer-funded transmission upgrades meant to relieve congestion often become heavily trafficked with non-firm use themselves, diminishing the benefit that the project financier envisioned.

Grabow rebutted the RECBWG's opinion that allowing cost recovery on customer-funded upgrades would equate to buyer's remorse.

"If new customers are coming in and couldn't get transmission service but for the upgrade, it's not buyer's remorse. It was done for a particular reason: to relieve congestion," he said.

Grabow also argued that financial transmission rights are not adequate to ensure a fair payout.

"If new customers are relying on that transmission, they should pay their fair share," he said.

MISO Wins OK for Cleco Plant SSR

FERC last week approved MISO's proposed system support resource (SSR) agreement for Cleco Power's Teche 3 generating plant in Baldwin, La., effective April 1 (ER17-1227, ER17-1228).

MISO designated the 338-MW natural gas-fired plant as an SSR after Cleco notified the RTO it planned to retire the plant. The RTO said the plant will be needed to prevent severe thermal violations on its transmission system that are not addressed by available mitigation measures until the Terrebonne–Bayou Vista 230-kV line can be put into service in 2018.

The RTO said no feasible alternatives to SSR designation were identified in stakeholder meetings.

The commission rejected a protest by Entergy, which said the SSR agreement — which includes hourly compensation for the plant's production and operating reserve costs — should include a true-up mechanism for the recovery of fixed costs to prevent Cleco from being overpaid. The commission said that issue should be addressed in a separate docket opened by Cleco for obtaining additional compensation to ensure it recovers its full cost of service (ER17-1368).

Teche 3 was built in 1971. Unit 1, completed in 1954, retired last September. Unit 2, completed in 1956, retired in 2011, when Cleco completed Teche 4, a 35-MW gas-fired black start generating unit.

— Rich Heidorn Jr.

Teche Power Station | *Google*

MISO NEWS

MISO Revisits Eclipse Ops, Prepares for 2024

By Amanda Durish Cook

CARMEL, Ind. — While MISO officials were unsurprised that the Aug. 21 solar eclipse did not impact Midwestern grid operations, they do say an increase in solar capacity will complicate matters by the next total eclipse in 2024.

MISO Communications Director Jay Hermacinski last week said the RTO will study eclipse impacts over the next few weeks and request data from CAISO, a grid operator that was "truly" impacted by the eclipse. (See *Grid Operators Manage Solar Eclipse*.)

All of MISO's footprint fell within the 80 to 100% eclipse band, and Hermacinski said the footprint's solar generation reacted "as predicted." Grid-scale solar output dropped 100 MW during the eclipse, plunging to a nearly zero output during the peak and picking back up to about 40 MW around 3 p.m.

Hermacinski said that MISO operators had no problem meeting demand with stifled solar output.

"Our portfolio looked like it always does. We did not have to do anything special or bring on additional generation," he said during an Aug. 22 Informational Forum. "Quite frankly, our operators prepared for the solar eclipse as if it were any other day. … We did not expect the eclipse to have an impact on our grid operations, and it did not."

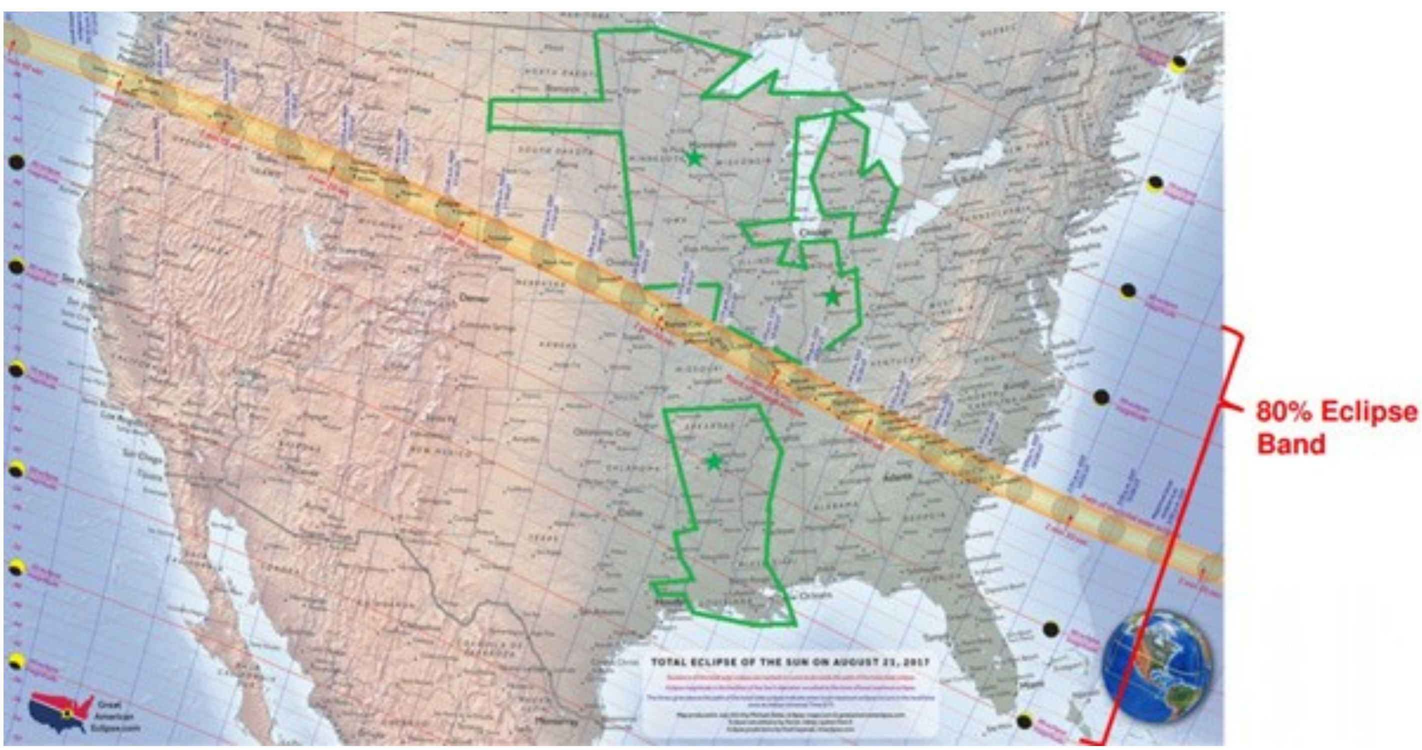
However, storms in the Upper Midwest and cooler-than-expected systemwide temperatures that day cut load, and MISO load dropped by 2 GW during the eclipse window.

"What we didn't expect was the number of pop-up storms in the MISO region that brought about a 5- to 8-degree drop in temperature," Hermacinski said.

MISO will use CAISO's data to complement its own to help prepare for the next solar eclipse in April 2024, which will cut a path of totality from southwest Mexico to the northeastern U.S., putting the RTO's Carmel, Ind., headquarters in the direct path. By that time, MISO is expected to have an additional 13.5 GW of grid-connected solar generation participating in its market, an amount exceeding that participating in the CAISO market today. MISO currently has about 180 MW of utility-scale solar and 350 MW of distributed solar in its footprint.

MISO Communications Director Jay Hermacinski jokingly performs a "how many fingers" test a day after the solar eclipse during the MISO Informational Forum. | *© RTO Insider*

"MISO will be in a much different position in 2024 in terms of solar capacity than it is today," Hermacinski said. A partial solar eclipse occurring in October 2023 will serve as a practice run before the 2024 event, he added.



The Aug. 21 solar eclipse's path of totality, with MISO's U.S. footprint outlined in green | *GreatAmericanEclipse.com*

MISO NEWS

MISO-PJM Markets Meeting Addresses Seams Issues

By Rory D. Sweeney

VALLEY FORGE, Pa. — PJM and MISO staff provided updates on their proposed *pro forma* pseudo-tie agreements, the "freeze date" on transmission rights and targeted transmission upgrades at their Joint and Common Market meeting Aug. 22.

Pseudo-Ties

MISO's Kevin Vannoy told stakeholders that FERC accepted the RTO's *pro forma* pseudo-tie agreement Aug. 9 with an effective date of March 15, though it was approved in a delegated order and could be subject to further review and refunds now that the commission has a quorum (ER17-1061). (See *FERC Conditionally OKs MISO's Pseudo-tie Pro Forma*.)

PJM's *pro forma* agreement, filed on Aug. 11, awaits FERC approval. The grid operators filed revisions to their joint operating agreement to address PJM's *pro forma* on Aug. 1.

PJM has until Sept. 17 to respond to a deficiency notice on its Tariff revisions for pseudo-tie requirements, which were filed March 9 (ER17-1138). (See *MISO, PJM to Try Again on FERC Pseudo-Tie Filings*.)

The grid operators next plan to address the "congestion overlap" that is causing some congestion to be charged twice and has led to complaints at FERC. The issue, which occurs when an associated market-to-market constraint binds in both markets, will require a two-phase solution.

"It's a complex solution" that can't be done in a single implementation, PJM's Tim Horger explained.

The first phase, which the grid operators hope to have implemented by Dec. 1, would include JOA changes to better model the impacts of firm-flow entitlements before the day-ahead dispatch is modeled. This will allow day-ahead LMPs for pseudo-tied resources to more accurately reflect expected real-time congestion. The balancing authority receiving the power will receive credit for the flow from the generation unit to the border, while the source balancing authority will model its impacts as loop flows.

"We think it's a major step and will remove most of the overlap," Horger said.

The second phase will allow for mitigating day-ahead charges either through refunds or virtual transactions to align transmission usage charges with available financial transmission rights hedges.

The RTOs plan to file JOA changes implementing market-to-market adjustments in September, with implementation of the phase one solution by the end of December. Dec. 1 is the target date for filing additional JOA and tariff changes. Phase two is scheduled for implementation by June 1, 2018.

Freeze Date Update

The grid operators have been using an April 1, 2004, "freeze date" to determine firm rights on flowgates, but issues with that date have "become prominent" over time, the RTOs said. They have developed a two-phase alternative that would be in place by June 1, 2019, MISO's Ron Arness explained.

The changes would affect designated network resources that came on after the freeze date, which currently are dispatched on a *pro rata* basis. The new rules would eliminate the *pro rata* allocation and have them dispatched in the order of their service date.

They also affect "freeze date" transmission service requests, which currently are treated as net imports or exports based on the local balancing authority. The new rules would provide "gross accounting" for imports and exports — generation-to-load LBA calculations would not include generation sourcing TSRs or load served by TSRs — with adjustments that will make the TSR sensitivity factors align with market flow sensitivity factors.

The RTOs plan to complete a whitepaper on the issue by next spring with implementation of phase one in the summer.

Targeted Market Efficiency Projects

PJM's Chuck Liebold said there has been no targeted market efficiency project (TMEP) study in 2017 because the RTOs are awaiting FERC approval of regional cost allocations for the new category. MISO filed for regional allocation Aug. 4 (ER17-2246), and PJM filed its allocation on April 11 (ER17-1406).

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

The TMEP proposals are designed to be quick, inexpensive fixes to address historical congestion. Five projects have been identified so far. At an estimated cost of $17.5 million, they are expected to create $99.6 million in benefits.

The RTOs are waiting on FERC approval before submitting the project recommendations to their boards. The benefit allocation for three of the five projects leans heavily toward PJM, with 88% of the $7 million Burnham-Munster project, 89% of the $1 million Bayshore-Monroe project and 90%

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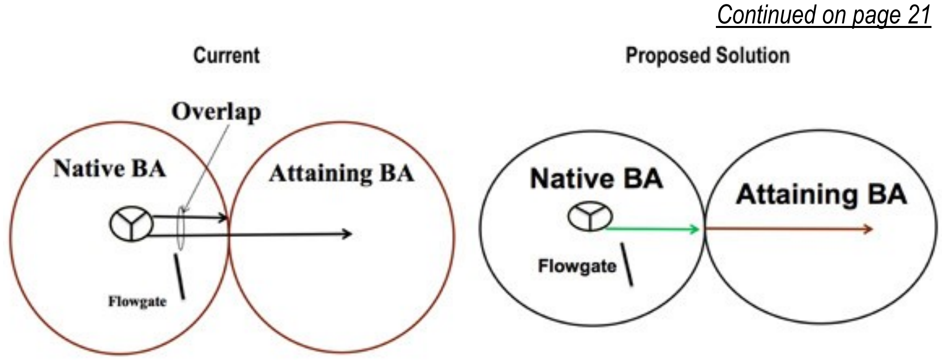
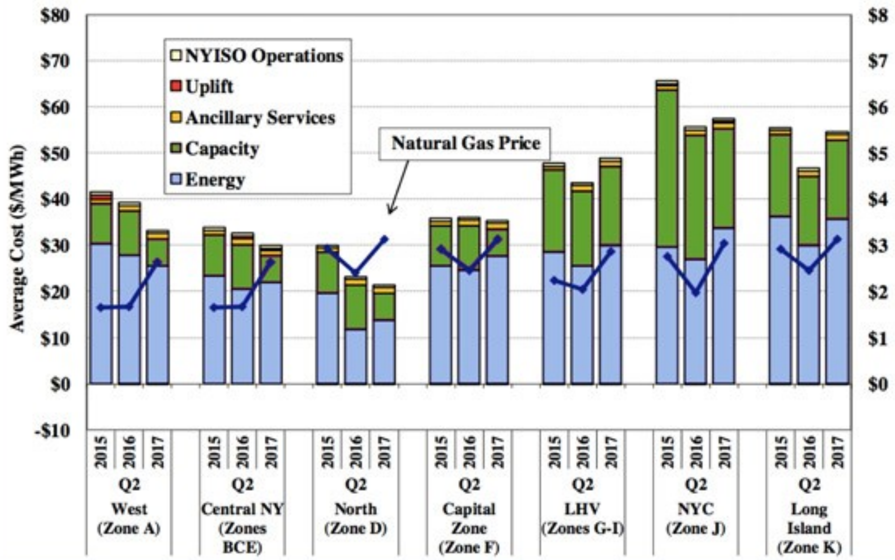


Congestion is charged twice when a market-to-market constraint binds in both PJM and MISO (left). The RTOs' proposed solution to the "congestion overlap" (right) would treat pseudo-tie transactions like dynamically scheduled interchange for M2M constraints. | *MISO, PJM*

NYISO NEWS

Nuclear, Hydro Help NY Offset Higher Gas Prices in Q2

By Michael Kuser



NYISO all-in prices by region | *Potomac Economics*

New York energy markets performed competitively during the second quarter, with changes in fuel prices, demand and supply availability driving variations in wholesale prices, according to the NYISO Market Monitoring Unit's second-quarter State of the Market report, released last week.

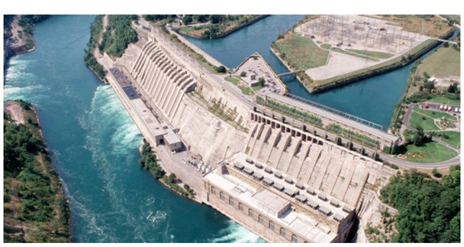
Gas prices rose 20 to 60% in eastern New York and 65% in the western part of the state. But much of the impact on locational-based marginal prices (LBMPs) was offset by higher output of approximately 950 MW from nuclear, internal hydro and imports from Quebec and Ontario.

All-in prices averaged from $21/MWh in the North Zone to $57/MWh in New York City. The range was primarily because of congestion on power flowing from the North Zone to central New York, Central East congestion, and capacity price differences. Zone-level LBMPs increased in most regions by 7 to 25%.

Capacity costs were impacted by changes in net cost of new entry from the recent demand curve adjustment process. (See "ICAP Manual Changes for Demand Curve Reset Updates," *NYISO Business Issues Committee Briefs: Aug. 9, 2017*.)

Congestion Management

Congestion costs from priced and unpriced constraints rose from 2016, with day-ahead congestion revenue up 24% from the same period a year ago to $117 million. Congestion increased into the city, across the Central East interface and along paths from western and northern New York, where priced congestion declined.



Sir Adam Beck Generating Complex in Niagara Falls, Ontario, the largest source of hydroelectric power in the province.

Unpriced congestion in the western and northern parts of the state became more prevalent because of improved hydro conditions within the state and low prices in the adjacent Canadian markets, as well as from transmission upgrades completed last year, which reduced priced congestion on 230-kV facilities in the west but shifted more flows onto parallel 115-kV circuits.

The Monitor found that "actions used to manage 115-kV congestion in western and northern New York led to import limitations from Ontario and Quebec as well as congestion on the 200-kV system in other parts of the state ... management [which] could be performed more efficiently through the [day-ahead] and [real-time] market systems."

PAR Operations with PJM

Real-time congestion costs for the Valley Stream load pocket on Long Island fell from a year ago because of improved modeling of lines between New York City and Long Island. Congestion increased through Millwood and into the city, but the ABC and JK lines were operated more efficiently.

The market-to-market phase angle regulator (PAR) coordination process with PJM expanded to include the ABC and JK lines in May after the 1,000-MW Con Ed-PSEG wheel expired. New coordinated flowgates were added mostly in New York City and the West Zone. For all PARs, actual flows typically exceeded their M2M targets toward New York, resulting in a small amount of M2M payments from PJM to NYISO in the second quarter.

The Monitor did find instances of efficient M2M coordination as PARs were moved in the correct direction to reduce overall congestion costs in a relatively timely manner. However, it cited "many instances" when PAR adjustments may have been available and would have reduced congestion but no adjustments were made.

"We observe that these PARs were often not utilized to help manage congestion, being adjusted only two to five times per day on average," the report said.

PAR adjustments were not taken in some cases because of difficulty in predicting the effects of PAR movements under uncertain conditions or when adjustment would have pushed actual or post-contingent flows close to a line limit — or because of the transient nature of congestion or mechanical failures, such as stuck PARs.

Continued on page 17

NYISO NEWS

Nuclear, Hydro Help NY Offset Higher Gas Prices in Q2

Continued from page 16

The Ramapo PARs have provided significant benefits to NYISO in managing congestion on coordinated flowgates. Balancing congestion surpluses have resulted from relief of transmission paths from central to east New York, indicating that they reduced production costs and congestion.

"Nonetheless, comparable benefits have not been observed from the operation of ABC and JK PARs in the second quarter of 2017," the report said. "We observed potential opportunities for increased utilization of M2M PARs."

The normal limit for each PAR-controlled line was more than 500 MW, but flows were generally well below that level. On average, each PAR was adjusted two to five times per day, well below the operational limits of 20 taps/day and 400 taps/month. This was also below the average five to six 30-minute blocks of time per day when the congestion differential between PJM and NYISO exceeded $10/MWh across these PAR-controlled lines.

Reserve Market Performance

Day-ahead 30-minute reserve prices have been substantially elevated since a market rule change in November 2015, driven primarily by the new limitation on scheduling reserves on Long Island (down 250 to 300 MW), an increased 30-minute reserve requirement (up 655 MW) and higher reserve offer prices from some units.

The Monitor found that many units that offer above the standard competitive benchmark — or the estimated marginal cost — in part because of the difficulty in accurately estimating the marginal cost of providing operating reserves.

According to the Monitor, day-ahead offer prices may fall as suppliers gain more experience, which was evident in the second quarter as a large amount of reserve capacity reduced its offer prices from previous years, helping reduce price averages.

The Monitor will consider potential rule changes, including whether to modify the existing $5/MWh "safe harbor" for reserve offers in the market power mitigation measures.

Uplift and Revenue Shortfalls

Guarantee payments were $11.2 million during the quarter, comparable to a year earlier. Those payments rose in New York City and fell in Western New York because of higher gas prices that increased the commitment costs of gas-fired units and supplemental commitment for reliability in the city, and decreased out-of-merit dispatch and commitment of the AES Cayuga coal-fired units in the west.

Congestion shortfalls were $21 million in the day-ahead market and $11 million in the real-time, higher and lower, respectively, than in the same period in 2016.

Transmission outages accounted for roughly 80% of day-ahead market shortfalls in the second quarter, and $17 million were allocated to the responsible transmission owner.

Nearly all the real-time market shortfalls were associated with the North Zone lines, the West Zone lines and the Capital to Hudson Valley lines, with North Zone shortfalls accruing almost entirely because of transmission outages on two days in early April, totaling $4.6 million.

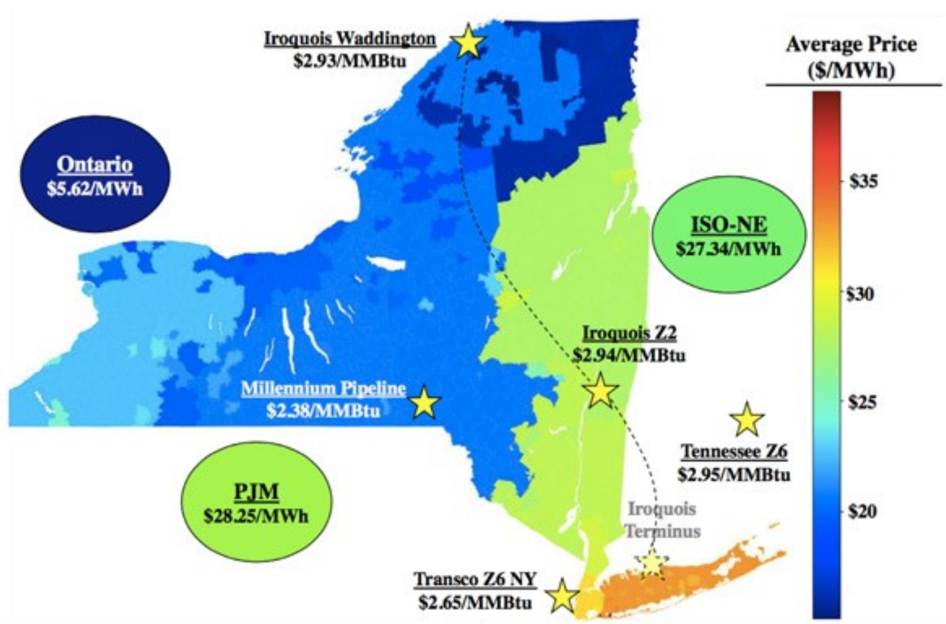
Capacity Market

Second-quarter capacity spot prices ranged from $1.99/kW-month in Rest-of-State to $8.02/kW-month in New York City. The average price includes one month of winter pricing (April) and two months of summer pricing (May and June).

Compared to the previous year, average spot prices fell 21 to 45% in New York City and the New York Control Area (NYCA) and rose 9% to 17% in the G-J Locality and Long Island.

Price changes in all regions were driven largely by changes to the installed reserve margin and net CONE of the proxy unit from the demand curve reset process. Net CONE values rose substantially in both the G-J Locality and on Long Island, while falling in the city and NYCA.

Additionally, import levels averaged 430 MW higher in the second quarter compared to 2016, with noticeably higher imports from PJM more than offsetting reduced imports from ISO-NE.



NYISO energy market outcomes | *Potomac Economics*

NYISO NEWS

FERC Again Rejects Emissions Controls for NY Demand Curve

By Rich Heidorn Jr.

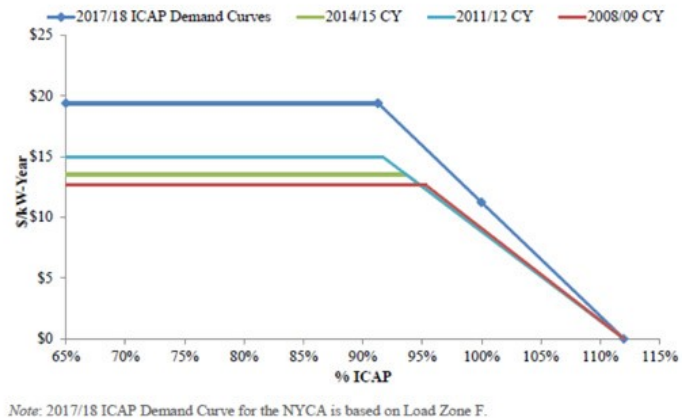
FERC on Wednesday again rejected a request that it include the cost of emissions controls in the peaking plant design for the New York Control Area (NYCA) capacity demand curve (ER17-386).

The commission rejected a rehearing request by the Independent Power Producers of New York (IPPNY), which contended that the state's Siting Board is likely to require selective catalytic reduction (SCR) emissions controls in the future because of concerns over fossil fuel generation.

FERC repeated its conclusion that SCR controls are not required for peaking plants in NYCA load zones C and F and that peakers can meet environmental rules by limiting their operating hours, dismissing as "speculative" IPPNY's prediction of tighter controls in the future.

IPPNY had asked the commission to reconsider its January ruling approving NYISO's revised demand curve for delivery years 2017/18 through 2020/21. (See FERC OKs NYISO Demand Curve Reset.)

The January order continued the use of F class frame peaking turbines as the proxy unit for setting the cost of new entry. It also continued the requirement that peaking plants include dual-fuel capability and SCR emissions controls for the New York City, Long Island and G-J Locality demand curves.



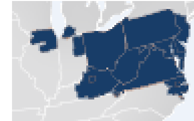
NYCA installed capacity demand curve 2017/18 vs. prior years | *Analysis Group*

But the commission rejected the ISO's proposal to extend the SCR requirement to the NYCA, where gas-only designs were permitted. Under current rules, FERC said, the NYCA peaking plant can operate under an annual operating hours limit in lieu of installing SCR emissions controls.

In its order this week, FERC also rejected IPPNY's request to shorten the amortization period or increase the rates of return for peakers in zones C and F. IPPNY said the changes would capture the risk that emissions rules on those plants will be tightened in the future.

The commission deemed as "speculative" the risk of having to retrofit an NYCA peaking plant with SCR controls, and also found NYISO's proposed amortization period and return on equity to be just and reasonable.

"The commission need not consider alternatives," FERC said. "Nevertheless, IPPNY provides no alternatives, but only a scant statement that the commission should impose either 'a significantly shorter amortization period than the NYISO's proposed 20-year period or an increased required return.' In contrast, NYISO's amortization period and return on equity were the subject of analysis by [the ISO's independent consultant] and extensive stakeholder discussions."



Stakeholders Seek to Trim PJM Capacity Construct Options

By Rory D. Sweeney

VALLEY FORGE, Pa. — With nine proposals to compare and four months left in the year, stakeholders appear to be eyeing the finish line of PJM's yearlong effort to consider reforming its capacity construct.

Last August, a coalition of public power organizations, concerned that conversations about potential modifications to the RTO's Reliability Pricing Model regarding the impact of state policies were taking place out of the PJM stakeholder process, began a campaign to win stakeholder approval to reexamine the RPM.

The Capacity Construct/Public Policy Senior Task Force (CCPPSTF) started meeting in March with a goal of filing with FERC by the end of the year any changes to the capacity market stakeholders agree to make.

That ambitious timeline has led the CCPPSTF to meet about twice a month and schedule six meetings in August alone. At the group's fifth meeting for the month, stakeholders began to show signs of restlessness.

The Skinny Model

PJM's Murty Bhavaraju explained additions to a model developed by RTO staff to compare nine capacity revision proposals using fictional and simplified numbers. PJM's Dave Anders called it a "skinny model" because it's designed to be shaved down to just the essential pieces to understand the mechanics of the proposals.

Adrien Ford of Old Dominion Electric Cooperative pressed RTO staff to make the model more representative of real-world conditions so that stakeholders can determine whether any of the nine proposals would work better than the existing process.

"I'm just hopeful that this skinny model is Step 1 in the analysis," she said. "This doesn't get me to the point where I understand whether we have an issue. … People are going to look at the numbers and the numbers aren't realistic."

PJM has resisted using historical numbers in the models because they will require incorporating a lot of assumptions that could drastically skew results, which stakeholders might incorrectly view as price forecasts. (See *PJM Stakeholders Begin Defining Capacity Design Needs*.)

Poulos

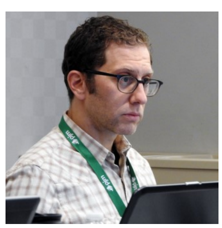
Greg Poulos, executive director of the Consumer Advocates of the PJM States, asked staff to develop some way to whittle down the options to compare.

"There's still so many on the table, it makes it hard to think about where we'd go," he said.

Panoply of Proposals

Another round of proposals received updates from their initial presentations based on feedback.

American Municipal Power filled in some blanks in its proposal, which would emphasize long-term bilateral contracts and reduce the significance of the forward-looking annual capacity auction to fill in whatever capacity obligations remain outstanding beyond the contracts.



Lieberman

AMP's Steve Lieberman said the auction would be held between 12 and 18 months prior to the start of the delivery year, with a single Incremental Auction held 30 to 60 days ahead of the delivery year. Under the current construct, PJM holds Base Residual Auctions three years ahead of the delivery year, with IAs occurring annually after that until the delivery year.

AMP is also developing the idea of a secondary capacity exchange.

John Hyatt with Monitoring Analytics expanded on the Independent Market Monitor's proposal to extend the existing minimum offer price rule (MOPR). Monitor Joe Bowring has long argued that competitive, pure markets are unable to accommodate subsidized bids; therefore such bids must not be allowed to influence auction results.

Chen

Jennifer Chen with the Natural Resource Defense Council provided additional context to the Sustainable FERC Project's proposal, which would reduce the capacity requirement to the needs of the off-peak season and allow seasonal resources to account for the additional demand during the peak season.

Chen said her plan would use the BRA construct to procure always-ready Capacity Performance resources up to the needs of the off-peak season (i.e., winter needs for summer-peaking zones and vice versa), then allow the peak season to be addressed using what she termed a "seasonal CP product." The plan would shift the variable resource requirement demand curve left, reducing the annual procurement to account for the reduced amount of CP resources procured.

The plan has no repricing mechanism to eliminate the influence of subsidized offers. Subsidies that only compensate for a desired attribute, such as carbon-free generation, would leave the generation unit free to offer into the BRA to be compensated for its contribution to resource adequacy. Units that receive a subsidy sufficient for full compensation would be treated like a contracted resource, and the load-serving entities contracting that source could opt out of a corresponding amount of its capacity obligation.

The proposal left stakeholders perplexed.

"I don't get how it addresses [subsidized units'] impacts on the market," said Carl Johnson, who represents the PJM Public Power Coalition. "I'm really confused about how mechanically this would do that."

Chen said her reading of the task force's charter was that the goal is to accommodate state actions to promote certain fuel types and that her proposal does that.

Johnson asked for Chen's proposal to outline what it definitively commits to, but Lieberman defended the ability of the proposals to be flexible.

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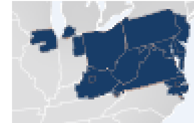
PJM NEWS



MRC Briefs

Division Remains on Oversight of Intraday Offers

WILMINGTON, Del. — PJM and its Independent Market Monitor remain at odds over whether price-based offer updates should be connected to cost-based offers and specified in each unit's fuel-cost policy.

Morelli

At last week's Markets and Reliability Committee meeting, PJM's Lisa Morelli outlined the RTO's planned Manual 11 revisions for implementing intraday offers. The presentation was the culmination of a long debate at August's Market Implementation Committee meeting, where stakeholders pressed PJM and the Monitor to find as much common ground on the issue as possible. (See "Stakeholders Push PJM and IMM for Consensus on Intraday Offers Rules," *PJM Market Implementation Committee Briefs: Aug. 9, 2017*.)

Morelli's presentation outlined where PJM and the Monitor continue to differ on linking a unit's price-based offer to its fuel-cost policy. The RTO believes there's no need for them to be linked, but the Monitor says updating price-based offers should be limited to simultaneously updating cost-based offers, which must be specified in the unit's fuel-cost policy.

"We think it's the only way to ensure that the timing of price-based offers and cost-based offers don't permit the exercise of market power," Monitor Joe Bowring said. "What we're concerned about is this will result in one-way optionality for the generators to raise prices during the day but not be required to reduce costs when gas costs go down."

Bowring

Baker

The two sides will continue to seek compromise until the September MRC meeting, but they will have to pursue separate Tariff revision proposals if they haven't reached agreement by then, Morelli explained. It could come as a new problem statement for stakeholders to consider, she said.

On energy-offer verification, PJM and the Monitor also remain divided over whether self-certification by the curtailment service provider is sufficient validation for demand response. The Monitor says it is not.

"The main arbiter in this is really FERC," PJM's Rami Dirani said. "So FERC has to really decide whether this approach is actually the proper approach going forward."

There is also some difference of opinion on the exception process for verifying offers that are not consistent with a unit's fuel-cost policy, verifying offers over $1,000/MWh and verifying operating reserve credits for verified offers over $1,000/MWh, but PJM believes the two sides are moving toward a compromise.

Summer-only DR to be Studied

Stakeholders approved by acclamation a problem statement and issue charge regarding summer-only DR, but not before state and consumer representatives pushed for additional revisions.

The proposal came out of the Seasonal Capacity Resources Senior Task Force, which culminated in a seasonal resource aggregation filing and approval at FERC late last year, PJM's Scott Baker explained. However, RTO staff pared the problem statement's scope down to eliminate other seasonal resources, such as wind, hydro or energy efficiency.

John Farber with the Delaware Public Service Commission asked for a friendly amendment that specifically noted analyzing the load forecast would be in the scope of the group.

"One of the values of DR is to manage the peak. A managed peak costs less than one that's not managed," he said.

Greg Carmean, executive director of the Organization of PJM States Inc., noted the Energy Policy Act of 2005 stipulated that unnecessary barriers to DR participation in the markets be removed. "I haven't seen where PJM has gone back and evaluated whether or not their annual product actually is a barrier to demand response," he said.

Stu Bresler, PJM's senior vice president of operations and markets, said that the RTO's strategy paper on DR indicates how it intends to move forward on the issue. The problem statement identifies several items that are already considered out of scope, including loss-of-load expectation analysis; seasonal capacity procurement or developing a seasonal market; re-establishing non-Capacity Performance products such as base capacity; or limited DR.

The initiative is following through on the

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Stakeholders Seek to Trim PJM Capacity Construct Options

Continued from page 19

"To me that's actually a positive that some of these proposals don't seem so stuck to where they're at" and are open to feedback and revisions, he said.

The task force is turning its focus to identifying appropriate polling questions and potential repricing triggers, but both efforts received stakeholder criticism.

ODEC's Ford asked why staff wanted to develop polling questions rather than just determine the popularity of the nine proposals. PJM's Anders, who is facilitating the group, said he learned the relative popularity from the group's final vote.

"I hear your point that it may not be ready to poll on the packages," Ford said. A poll on various capacity construct components is "better than nothing," she said, "but it would be better to poll the packages."

Exelon's Jason Barker asked why the task force was waiting to address the repricing triggers, as most proposals reference a trigger but fail to identify a specific mechanism. Anders said that since almost all of them are to be determined, the actual trigger can be determined later once the group has agreed on a plan.

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MRC Briefs

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strategy paper's list of goals. PJM's Pete Langbein said the Demand Response Subcommittee will be working on those in sequential order.

"I think this problem statement is a continuation on working on valuing DR," Baker said.

Greg Poulos, executive director of the Consumer Advocates of the PJM States, said recent PJM rule changes have "hit hardest" on residential DR viability, "so this is great to see PJM taking these efforts."

"The current construct is a barrier for residents to participate," he said. He asked that PJM reconsider DR's potential as a capacity product, but Baker declined to include the amendment.

Eclipse Hot Takes

PJM's Ken Seiler provided some initial observations on PJM's response to the Aug. 21 solar eclipse, saying the analysis will be used to better prepare for the 2024 eclipse, whose path of totality is expected to cross over PJM's western edge.

Operationally, he said the RTO performed without incident. "We had enough regulation; we had enough reserves."

About 2,200 MW of solar generation was lost, he said, but that remains largely an estimate as about three-quarters of it is behind-the-meter generation. Only about 500 MW was grid-connected and directly observable.

"The real surprise" came when operators saw CAISO and MISO curtailing units in expectation of lower demand, he said.

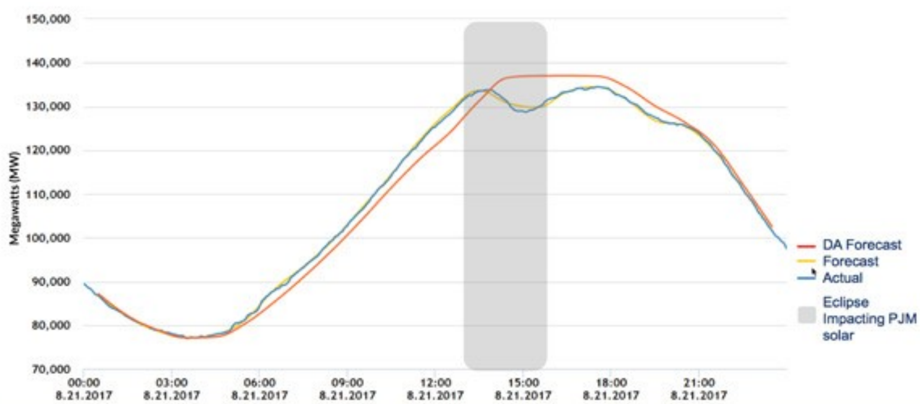
"We thought the load would be pretty much flat," but PJM also saw a load drop similar to other grid operators, Seiler said. PJM had a load of about 133,600 MW about 1:45 p.m., which dropped to 129,500 MW an hour later.

Weather likely accounted for some of the decline. Certain regions saw temperatures drop by up to 10 degrees Fahrenheit, which "does seem to correspond fairly significantly with the load drop," he said. The weather forecast predicted temperatures in the 90s, but the average was around 85, he said. Additionally, unpredictable "pop-up" storms materialized in the footprint, which have a dampening effect on temperature.

"Certainly, wind and weather and cloud cover provided some level of impact," he said.

However, human activity seemed to also play a major role. PJM found through discussions with the Nest home thermostat supplier that the company had advised customers that they could cut back on air conditioning during the eclipse to compensate for the reduction in solar output, resulting in a 750-MW drop in load.

Additionally, people departing from their normal business day to view the eclipse caused a reduction. PJM received reports that some manufacturing facilities delayed lunch and instead shut down during the eclipse.



PJM load curve: Aug. 21, 2017 | *PJM*

Stakeholders Approve Misc. Actions

Stakeholders endorsed by acclamation several manual revisions and other operational changes:

- Manual 11: Energy & Ancillary Services. Revisions, along with others associated with the Regional Transmission and Energy Scheduling Practices document, were developed as part of the implementation of Coordinated Transaction Scheduling, a new real-time energy scheduling product across the PJM-MISO interface.
- Tariff and Operating Agreement revisions that clarify the two-year limit on requests for billing adjustments.
- Joint operating agreement and Tariff revisions to develop a *pro forma* agreement for dynamic scheduling. (See "OC Discusses Pro Forma Agreements for Pseudo-Ties, Dynamic Schedules," *PJM OC Briefs: July 11, 2017*.)

— Rory D. Sweeney

MISO-PJM Markets Meeting Addresses Seams Issues

Continued from page 15

of the $4.6 million Michigan City-Bosserman project. MISO shoulders most of the allocation on the other two, with 59% of the $150,000 Reynolds-Magnetation project and 76% of the $4.5 million Roxana-Praxair line.

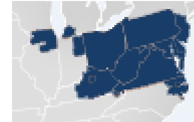
Two-Year System Plan Study

The RTOs have completed regional benefits analysis for the eight interregional projects that were proposed for the solicitation that ended Feb. 28. Only one project — Northern Indiana Public Service Co.'s proposed new line between its Thayer and Morrison 138-kV substations in northwestern Indiana — is expected to provide more benefits than costs. (See *1 of 8 MISO-PJM Proposals Pass Initial Test*.)

Liebold said the cost-benefit was not the only factor in recommending projects, but "for a project to be promising, you would expect to see benefits above costs."

The RTOs will make recommendations to their respective boards on the proposals around November or December.

PJM News



PJM Stakeholders Debate Weight of Transmission Cost Caps

By Rory D. Sweeney

VALLEY FORGE, Pa. — As PJM begins to define its overarching principles for assessing cost-containment guarantees in competitive bids for developing transmission projects, one is destined to remain contentious.

"A cost-cap commitment is only one factor considered by PJM in its overall review and evaluation of project proposals for selection in the [Regional Transmission Expansion Plan]," the RTO has said.

Some merchant transmission developers, such as LS Power, are pushing to have those commitments become a defining factor, while PJM transmission owners, such as ITC Holdings and Public Service Electric and Gas, have argued that other aspects should be given just as much weight. State and consumer representatives have also expressed support for giving increased weight to cost caps. (See *Containment Policy: PJM Takes Up Cost Caps*.)


Glazer

Beyond being one of many factors considered in a project proposal, cost-cap provisions would be voluntary and limited to project construction costs. PJM's Craig Glazer outlined the RTO's other proposed principles last week at a special session of the Planning Committee on the topic. They include:

- Clearly articulating the cost-cap commitment in the proposal submission, along with what is covered and any exclusions;
- Providing proposed contractual language on covered and excluded items;
- Ensuring that all cost-cap terms and conditions will be made public, while any information and part of the proposal inappropriately labeled as confidential will not be considered;
- Supporting the rationale for any exclusions, with PJM evaluating the risk and potential cost impact of excluded events;
- Providing quarterly progress updates, with cost-cap enforcement through FERC's ratemaking process; and
- Reserving for PJM's Board of Managers the right to reconsider projects that aren't making required progress and reassign completion to another developer.

"If the cost cap gets exceeded, I don't want [PJM] to be the only entity that sues to enforce the DEA [designated entity agreement]," Glazer said. "The cost cap portion of the DEA … is really an agreement with FERC, an agreement with the ratepayers: Here's what the project is going to cost."

He explained that the legal process would likely require action from the developer to address the overages.

"The shoe would be on the developer's foot to try to recover those costs," he said. "PJM would provide an opinion on that subject, but we're not central to that case. You're not suing PJM for having violated the DEA."


Segner

LS Power's Sharon Segner said PJM was missing as an overarching principle that meaningful cost caps are preferable to cost estimates. When RTO staff hesitated to agree to that, she argued that additional clarity is needed in how proposals are being evaluated.

"If you go back to the original language in Order 1000 … there was specific instruction to the regions to disclose how proposals will be evaluated," Segner said. "I think it's reasonable to the development community for PJM to give general guidance on how it uses cost estimates versus cost caps in the evaluation process, and I think that is consistent with the mandate of Order 1000."

"To simply make a bland statement that we value cost caps — and we do — it has no value," PJM's Steve Herling said. "The problem is the cost cap has 100 different parts, and depending upon how you structure those parts, you have a cost cap that's valuable or a cost cap that's completely meaningless. So for us to make a general statement that we value cost caps, it's motherhood and apple pie, but it doesn't actually tell you anything."

"All I've heard so far was 'meaningful cost caps' or 'valuable.' … Propose [legal] language because we're kind of at a loss as to what would be good here," Glazer said.


Prokop

"We're comfortable with the fact that you're considering cost caps," ITC's Brenda Prokop said. "We're not comfortable with it being always the most important factor. We don't think that's appropriate."

PSE&G's Alex Stern agreed with that.

John Farber of the Delaware Public Service Commission urged patience in making any definitive decisions on the issue.

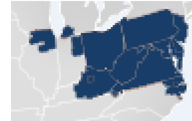
"Cost caps are a recent phenomenon, and it's way too early in my opinion for PJM to be forced to make definitive statement as to the role cost-cap proposals would have in its evaluation," Farber said. "I tend to agree with Sharon that legally binding cost caps could be superior to just cost estimates or desktop worksheets — but that doesn't mean that they would be. I think PJM needs to gain experience with cost-cap proposals to understand how different terms have different effects."

Glazer explained that part of PJM's hesitation is how a proposal with a cost cap should be considered if it is substantially higher than a credible proposal with just a cost estimate. He described the cost cap in that situation as a "fig leaf" designed to attract positive consideration.

But Greg Poulos, the executive director of the Consumer Advocates of the PJM States, argued that giving caps deference doesn't mean they have to be determinative in every situation. "I think there's a big difference between the two," he said.

The group has its next meeting scheduled for Sept. 8.

PJM NEWS



Trader Agrees to Pay $2.7M in Win for FERC Enforcement

By Rich Heidorn Jr.

Fort Lauderdale-based trader K. Stephen Tsingas agreed to pay $2.7 million in penalties and restitution in a deal with FERC's Office of Enforcement that will also bar him from trading in commission-jurisdictional markets for three years. The commission approved a consent agreement setting the terms on Aug. 22 (IN5-5).

Tsingas and his former company, City Power Marketing, agreed to the settlement without admitting to the commission's allegation that they violated the Federal Power Act and commission regulations by engaging in market manipulation and later lying to FERC investigators.

City Power also agreed to pay a $9 million civil penalty, but the company is defunct and FERC agreed not to pursue Tsingas for the additional amount. In a filing in 2015, Tsingas said that FERC's investigation forced him to lay off all his employees and "destroyed" the company. (See *UTC Trader: Firm was Ruined by 'Unfair' FERC Prosecution*.)

Although the $11.7 million in penalties were reduced from the $16.3 million the commission had sought, the case represents a victory for FERC in its crackdown on traders who profited from what the commission called risk-free up-to-congestion (UTC) trades. FERC said the trades were intended to cash in on line-loss rebates in PJM — the same type of trading that gave rise to the commission's high-profile battle with brothers Kevin and Rich Gates and their Powhatan Energy Fund.

Three Types of Trades

The commission said City Power collected the rebates — or marginal loss surplus allocations (MLSA) — through three types of UTC transactions: "round-trip" trades that canceled each other out; trades between import and export pricing points of the same PJM interface with equivalent prices (SOUTHIMP-SOUTHEXP); and trades between two PJM nodes that historically had a very small price spreads (NCMPAIMP-NCMPAEXP).

The commission concluded that City Power created the false impression that it was trading to arbitrage price differences "when, in fact, it was engaging in trades solely to collect MLSA payments to the detriment of other market participants."

Tsingas

The commission also accused Tsingas of attempting to mislead investigators by denying the existence of incriminating instant messages between him and a trading colleague.

The commission sued Tsingas after he failed to respond to a July 2015 order demanding the $16.3 million. The two sides reached a settlement in March, after a U.S. district court last August rejected Tsingas' motion to dismiss and in January denied FERC's motion for summary judgment. Approval of the settlement was delayed by FERC's loss of a quorum in February.

Under the consent agreement, Tsingas will pay $1.3 million in disgorged profits to PJM and a $1.42 million penalty to the U.S. Treasury Department. Tsingas must pay $825,000 to PJM within 60 days, paying the balance over 10 years.

Barred from Trading

Tsingas also agreed that neither he, nor any person acting on his behalf, "will engage or participate (whether through consulting, advising, directing or strategizing), directly or indirectly, in any trading transaction (whether physical or financial or virtual) within the commission's jurisdiction for three years."

However, the bar "does not apply to any business entity in which Tsingas has an ownership interest, or its employees, so long as Tsingas does not personally engage or participate in, directly or indirectly, or otherwise operate or consult about, any trading transaction within the commission's jurisdiction."

"FERC would not have been able to pursue this remedy had the court decided the case on the merits," observed Matthew Connolly, a senior associate in the litigation department of Nutter McClennen & Fish.

Like Tsingas, the Gates brothers and Coaltrain Energy — a third set of defendants accused of profiting from riskless UTC trades — have sought *de novo* reviews of FERC's allegations, in which a federal district court would decide all issues of fact and law. (See *Traders Deny FERC Charges; Seek Independent Review*.)

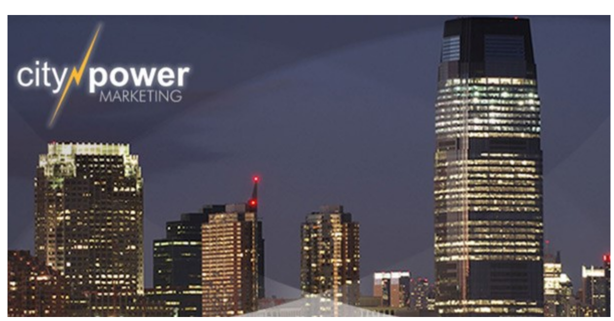
The Powhatan case has been stalled in the Eastern District of Virginia, awaiting a judge's ruling on how the review should proceed. FERC has asked for a short, appellate-style review (3:15-cv-452).

Coaltrain is awaiting a ruling from a judge in the District Court for Southern Ohio on its motion to dismiss (2:16-cv-00732).

PJM Seeks Advice

In April 2015, PJM asked FERC for advice on who should receive the disgorged profits and how they should be calculated. It also sought direction on how refunds should be made to parties who are no longer PJM members and noted that there were six entities alleged to have engaged in sham trades who would also be considered victims of the City Power trades. (See *PJM Asks FERC for Direction on Refunds from Illegal Trades*.)

In an order in July 2015, the commission told PJM to establish a method to distribute the resettled MLSA payments to market participants that would have received higher rebates if not for the money collected by City Power. The RTO must seek approval of its methodology from the director of the Office of Enforcement within 45 days after receiving the disgorged funds.



SPP NEWS

Great Plains, Westar File Revised Merger Plan

By Amanda Durish Cook

Westar electric service territory | *Westar*

Great Plains Energy has pulled back from its attempted acquisition of Westar Energy, recasting the move as a "merger of equals" after the two companies last week asked Kansas regulators for permission to merge under a tax-free share exchange.

The Kansas Corporation Commission blocked an earlier version of the deal in April, criticizing the $60/share purchase price as too high. (See *Westar Shares Fall as Kansas Regulators Block Great Plains Deal*.) Shareholders are poised to gain less in the new, stock-for-stock proposal.

Under the new proposal, Great Plains would no longer become Westar's parent company. Instead, the two companies would combine under a $14 billion holding company operating in Kansas and Missouri. Westar shareholders would own about 52.5% of the company with Great Plains shareholders holding the rest, according to the amended merger application (18-KCPE-095-MER).

The new deal would entail no cash exchange or transaction debt, and retail customers would receive $50 million in upfront bill credits across all rate jurisdictions. The combined company would serve about 1 million customers in Kansas and almost 600,000 customers in Missouri.

The two companies are expected to retain their original names after the merger, and Westar will continue to maintain an operating headquarters in Topeka, Kan., staffed by 500 employees. The companies have pledged not to lay off any employees. Corporate headquarters for the merged company would be located in Great Plains' Kansas City, Mo., location.

The plan requires approval from both the KCC and the Missouri Public Service Commission. The companies will also file applications before FERC and the Nuclear Regulatory Commission as early as this week and will seek respective shareholder approval during the fourth quarter. If approved, the deal is expected to close in the first half of 2018.

The CEOs of both companies say the revised agreement represents savings for customers and an opportunity for long-term growth for shareholders, while better positioning the companies to invest in infrastructure.

"We carefully listened to the KCC's concerns with our original transaction and crafted a new merger agreement using the KCC's earlier order for guidance to bring better value to customers and shareholders of both utilities compared with remaining standalone," said Great Plains CEO Terry Bassham.

Westar CEO Mark Ruelle called the merger "a long and unpredictable path" during a second-quarter earnings call in early August: "We spent a lot of time in May and June confirming that there wasn't just a stop sign in the order, but also road map to approval. … It wasn't the course on which we first set out, but I'm pleased where it's taken us and encouraged by the value it creates for our customers and our shareholders. The KCC order was clear that a big premium deal was going to be problematic."

Fewer Future Rate Cases

In testimony to support the filing, Ruelle said that without a merger, Westar's "flat sales and rising costs" will translate into higher prices. Bassham testified along similar lines, saying that "costs to serve … customers will continue to rise unchecked" and absent a merger, Great Plains "would need to seek higher prices and more frequent price increases as the remedy for any unmitigated higher costs."

Both CEOs claim the merger will lessen the need for future rate cases.

"With the merger savings, we'll no longer be as dependent on rate cases to produce earnings," Ruelle said during the earnings call.

In early August, Great Plains posted a second-quarter loss of $22.1 million ($0.10/share), while Westar announced earnings of $72 million ($0.50/share), in line with last year's second-quarter results.

SPP NEWS

Westar to Pay $180,000 for Inaccurate Energy Offers

By Tom Kleckner

Westar Energy will pay a civil penalty of $180,000 for submitting inaccurate mitigated energy offer curves (EOCs) under a settlement with FERC's Office of Enforcement.

Westar also agreed to be subject to Enforcement monitoring under the settlement, which was approved by FERC on Thursday (IN15-8). The Kansas utility will submit annual compliance monitoring reports for two years, with a third year possible at the office's discretion.

The violations occurred between October 2014 and February 2015, when Westar submitted cost inputs three times for its State Line plant that FERC said were "inconsistent" with the cost parameters on file with SPP's Market Monitoring Unit. The incorrect data resulted in Westar receiving make-whole payments of about $60,000.

The MMU requested in March that Westar produce data validating its mitigated EOCs. It found the data insufficient and referred the company to Enforcement.

Mitigated EOCs in the RTO's Integrated Marketplace must be based on an individual resource's costs and unit characteristics.

State Line power plant | *Westar Energy*

They are generated according to a formula that contains several inputs, including a fuel cost adder for variable operations and maintenance (VOM) costs.

Enforcement's investigation determined a Westar employee inadvertently increased the fuel VOM charge from 5 cents to 50 cents for the company's share of the two State Line units. Staff also found the utility submitted incorrect heat rate coefficients for one of the units.

Westar voluntarily refunded the $60,000 to SPP in June 2015 and took "effective measures to identify mitigated EOCs that [it] failed to properly update," FERC said.

The commission noted Westar cooperated throughout the investigation and promptly responded to requests for data and testimony. The utility filed a detailed report in June 2015 explaining the origin of the errors, the steps taken to correct them and the plans implemented to prevent them in the future.

Westar is the largest electric company in Kansas, serving 690,000 residential, commercial and industrial customers in the eastern third of the state.

SPP NEWS

FERC OKs Missouri River ROE Settlement over Staff Objections

FERC last week approved a settlement agreement granting five municipalities belonging to Missouri River Energy Services a 9.6% base return on equity, with a 50-basis-point adder for SPP membership (ER15-2324).

The settlement revises SPP's Tariff, adding formula rates that allow Moorhead, Minn.; Orange City and Sioux Center, Iowa; and Pierre and Watertown, S.D., to recover annual transmission revenue requirements for facilities that moved under the RTO's functional control.

FERC trial staff opposed the settlement, saying its discounted cash flow (DCF) analysis indicated the municipalities should have an 8.42% base ROE. Staff also said the capital structures of four of the five MRES members have abnormally high equity ratios and that hypothetical capital structures should be used for them instead.

Nebraska Public Power District filed comments expressing concern over the ROE but did not oppose certification of the settlement.

FERC approved the settlement despite staff's concerns because, the commission said, it "reaches compromises on issues other than the ROE and capital structure issues raised by trial staff, and rejecting the settlement because of these components would upset the negotiated agreement reached by the settling parties on many other issues."

The commission said the base ROE of 9.6% is a rate reduction from what MRES originally proposed and "is consistent" with FERC-approved ROEs in other recent uncontested settlements in the SPP transmission zone.

"Trial staff's DCF analysis would not go unchallenged by the parties during litigation," the commission added. "A contested hearing might not produce an ROE appreciably lower than the settlement's base ROE and could produce one that is even higher. Moreover, the settlement includes a rate moratorium providing customers with rate certainty for the future."

The RTO was given 30 days to file revised Tariff records.

— Tom Kleckner

SPP Registered Entities Face Oct. 31 Deadline for New RE Choice

NERC staff told SPP's registered entities Friday they have until Oct. 31 to submit their transfer requests to another Regional Entity, following the dissolution last month of the RTO's RE. (See *SPP to Dissolve Regional Entity*.)

Requests may be submitted by an individual entity or as part of a group, staff said. NERC is working with the 120 registered entities within SPP's footprint to smooth their transfer to new compliance enforcement authorities, with ReliabilityFirst, Midwest Reliability Organization and SERC Reliability seen as the most likely landing spots.

Registered entities should provide in their requests the location of their bulk power facilities, their relationship to their desired RE and their views on the proposed destinations for other entities in their regions. NERC will provide a weekly list of questions and answers to SPP's registered entities, along with other materials.

"An entity does have the ability to request the NERC Board [of Trustees] reconsider a move if they don't agree with it," NERC General Counsel Charlie Berardesco said during a webinar for the SPP RE's members.

Berardesco said registered entities must meet all obligations during the transition period, including compliance with reliability standards. Pending approval by NERC's board and FERC, the SPP RE will cease to exist by the end of 2018.

— Tom Kleckner

Sempra Begins 'Listening Tour' of Key Stakeholders

By Tom Kleckner

Metric	Sempra's U.S. Utilities	Oncor
Rate Base	$ 12.8 B	$ 11.0 B
Utility Meters	8.2 M	3.4 M
Consumers	25.3 M	10.0 M
Authorized Capital Structure (Equity / Debt)	SDG&E: 52% / 45.25% SoCalGas: 52% / 45.60%	42.5% / 57.5%
Return on Equity	SDG&E: 10.2% SoCalGas: 10.05%	9.8%

Sempra Energy

Sempra Energy has wasted little time getting to know Texas stakeholders, embarking on a "listening tour" just days after its surprise announcement it was seeking to acquire the state's largest utility, Oncor.

"We're approaching North Texas with a fair amount of humility," Sempra CFO Jeff Martin told financial analysts Friday during a conference call.

Martin and Sempra CEO Debbie Reed conducted the call from a hotel room in Austin, Texas, taking a break from meeting with Texas regulators, intervenors and other key Sempra and Oncor stakeholders.

The San Diego-based company last week announced an agreement to acquire Energy Future Holdings, Oncor's bankrupt parent and indirect 80% owner, for $9.45 billion, besting Berkshire Hathaway Energy's $9 billion offer. (See Sempra Outmuscles Berkshire for Oncor.)

Sempra had been eyeing Oncor for several years, but "this deal came together very quickly," Reed said. Company staff have been reviewing the history and transcripts of previous proceedings before the Public Utility Commission of Texas, which denied previous attempts by Hunt Consolidated and NextEra Energy to acquire the utility. The PUC rejected both suitors because of their inability to meet strict ring-fencing measures put in place after EFH declared bankruptcy in 2007.

"We tried to listen and learn from prior transactions, and we're working to understand the issues that are important to the regulators and intervenors," Reed said. "We intend to be a long-term owner of Oncor and want to ensure the company continues to do an exceptional job meeting the needs of its customers."

Reed pointed to Oncor's "incredible history of success," its ability to pay dividends and recent completion of a rate case as reasons for Sempra "to get comfortable with the requirements that the regulators had put on in prior transactions."

Those requirements have included an independent board of directors, a continued Texas presence and reinvestment of capital expenditures.

"If Oncor needs those funds to invest in their business, we are very supportive of that because we see the utility investment is positive," Reed said, referring to Oncor's plans to spend about $7.5 billion in capital over the next five years.

"We're all about partnerships and making sure that from a stakeholder analysis standpoint, we're doing all the right things to address those concerns," Martin said. "We're just starting that process, and we're confident about telling our own story. I think we're comfortable with a lot of the issues that have been raised with us."

However, some intervenors in Oncor's prior proceedings are skeptical of Sempra's offer, a source told *RTO Insider*. BHE had reached a settlement agreement with key intervenors based on its ability to wipe out the utility's debt overhang with an all-cash deal, but those parties now complain that Sempra is providing very little information in what has been called a "half-baked" proposal.

Sempra executives said Friday that they intend to fund the $9.45 billion purchase with $3 billion of investment-grade non-course debt, with the company providing about 60% of the remaining $6.45 billion and third-party investors covering the rest.

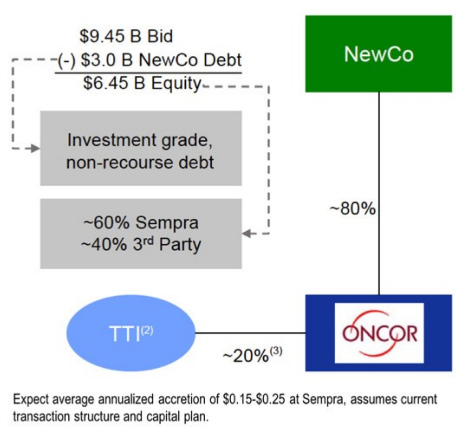
Martin said Sempra is not considering EFH's current creditors or hedge funds; instead, it is looking to partner with investors that are "aligned with our long-term interest in reinvesting and growing Oncor," such as pension or infrastructure funds. He said the company plans to issue a combination of debt and equity to fund its 60% portion, with equity representing at least half that.

Sempra agreed to a $190 million termination fee, compared with BHE's $270 million fee.

The California company now faces two important regulatory hurdles. The U.S. Bankruptcy Court for Delaware will consider the merger agreement Sept. 6, followed by a hearing to confirm EFH's reorganization plan. That second hearing would take place about 30 days should the PUC approve Sempra's offer. Reed said Sempra plans to file with the commission shortly after the merger agreement is approved.

The PUC meanwhile last week sent Oncor CEO Bob Shapard a letter asking him and board Chair Jim Adams to appear at Thursday's open meeting in Austin.

The commission told Shapard it wants to discuss Oncor's views "as to the likely structure and timing" of Sempra's proposal, and the utility's current financial condition and liquidity as it relates to the PUC's "legal obligation to protect" the company's financial integrity. The commission said it also wants to delve into accrued expenses over the last two years as a result of the Hunt and NextEra acquisition attempts.



Sempra Energy-Oncor acquisition expected financing and structure | *Sempra*

FERC NEWS

FERC Must Consider GHG Impact of Pipelines, DC Circuit Rules

By Rich Heidorn Jr.

FERC must consider the impact of greenhouse gas emissions when licensing natural gas pipelines, a split D.C. Circuit Court of Appeals panel ruled Wednesday (16-1329).

The panel's 2-1 ruling in favor of a petition by the Sierra Club parted with previous D.C. Circuit rulings that found FERC did not have to consider the climate-change effects of exporting natural gas in its licensing of LNG terminals.

The majority — Judges Thomas Griffith, a George W. Bush appointee, and Judith Rogers, a Bill Clinton appointee — remanded FERC's environmental impact statement (EIS) on the Southeast Market Pipelines Project, ordering the agency to estimate the project's impact on GHG emissions or explain more fully why it could not do so.

Judge Janice Rogers Brown, also appointed by Bush, dissented, saying the court should have ruled as it did in the LNG cases.

The Southeast Market Pipelines Project involve three pipelines, including the nearly 500-mile Sabal Trail, which will connect the other two pipelines between Tallapoosa County, Ala., and Osceola County, Fla., south of Orlando. Scheduled for completion in 2021, the project has a capacity of more than 1 Bcfd.

Existing Pipelines near Capacity

With both of its two major natural gas pipelines near capacity, Florida is at risk of having demand outstrip supply, according to Florida Power & Light and Duke Energy Florida, which have committed to buying nearly all the gas the project can transport.

The project's developers — Duke Energy, FP&L parent NextEra Energy, Spectra Energy Partners and the Williams Companies — said increased gas supplies will allow utilities to retire old coal-fired power plants, thus providing a net reduction in GHG emissions.

FERC has jurisdiction over licensing interstate gas pipelines under Section 7 of the Natural Gas Act, which requires a finding that the project will serve the public interest before issuance of a certificate of public convenience and necessity. The commission began the EIS on the project in fall 2013 and issued its final report in December 2015, before approving the project in February 2016 (CP14-554, *et al.*). It rejected rehearing requests on the order in September 2016.

Because some of the pipeline's gas would be burned by new or existing electric generators, resulting in CO_2 emissions, "at a minimum, FERC should have estimated the amount of power-plant carbon emissions that the pipelines will make possible," Griffith and Rogers ruled.

Prior Rulings

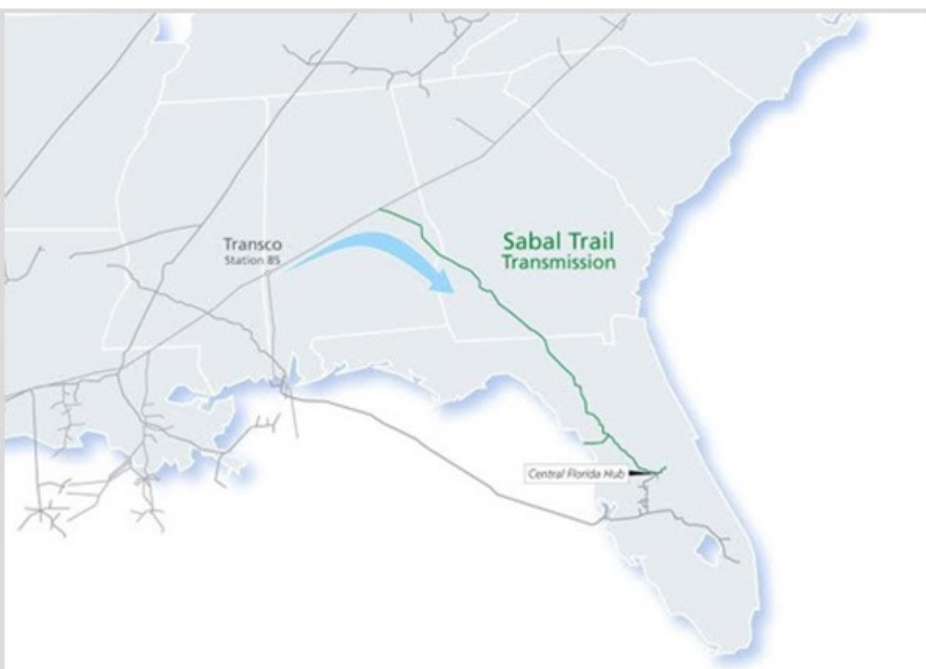
The pipeline developers contended FERC was not obliged to consider emissions, based on the Supreme Court's 2004 ruling in *Department of Transportation v. Public Citizen* (541 U.S. 752), in which it said that because the Transportation Department could not exclude Mexican trucks from the U.S., it was not required to gather data about the environmental harms of admitting them.

The D.C. Circuit applied the *Public Citizen* rule in three challenges to FERC approvals of LNG terminals, siding with the commission in all of them because it is the Energy Department — not the commission — that ultimately decides whether the terminals can export gas (*Sierra Club v. FERC*, 827 F.3d 36 (D.C. Cir. 2016); *Sierra Club v. FERC*, 827 F.3d 59 (D.C. Cir. 2016); *EarthReports, Inc. v. FERC*, 828 F.3d 949 (D.C. Cir. 2016)). FERC's jurisdiction over LNG, delegated by DOE, is limited to approving the construction of the terminals.

In reviewing pipelines, "FERC is not so limited," the court said in this week's order. "Congress broadly instructed the agency to consider 'the public convenience and necessity' when evaluating applications to construct and operate interstate pipelines." Thus, FERC could deny a pipeline certificate by concluding that the environmental harm posed by the project outweighed its public benefits, making the commission a "legally relevant cause" of environmental effects of pipelines it approves, the judges said.

FERC: Impact Unknown

FERC contended that the impact of the



FERC's ruling affects the Southeast Market Pipelines Project, including the nearly 500-mile Sabal Trail pipeline between Alabama and Florida. | *Sabal Trail Transmission*

Continued on page 29

FERC NEWS

FERC Must Consider GHG Impact of Pipelines, DC Circuit Rules

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pipelines on GHG emissions was unknowable, dependent on variables including the operating decisions of individual plants and regional power demand. But the court said the National Environmental Policy Act — which mandates an EIS for each "major federal action significantly affecting the quality of the human environment" — requires some "reasonable forecasting."

"The EIS gave no reason why [the pipeline's capacity] could not be used to estimate greenhouse gas emissions from the power plants, and even cited a Department of Energy report that gives emissions estimates per unit of energy generated for various types of plant," the court said. It said FERC "should have either given a quantitative estimate of the downstream greenhouse emissions that will result from burning the natural gas that the pipelines will transport or explained more specifically why it could not have done so."

Without comparing the emissions from this project to other projects or to total emissions from the state or the region, "it is difficult to see how FERC could engage in 'informed decision making,'" the judges said.

The court said FERC also must explain in the revised EIS its position on whether it should use the Social Cost of Carbon in its evaluations. The commission has argued previously against using the measure, saying that some of its components are subject to dispute and that not every harm it accounts for is "significant" under NEPA.

Dissent, Reaction

In her dissent, Brown said the pipeline case presented "virtually identical circumstances" to the LNG cases that the court said did not require GHG impact analyses. Because the Florida power plant Siting Board has the sole power to approve or deny new power plants in the state, "this breaks the chain of causation," Brown said.

FERC declined to comment on the ruling.

The American Petroleum Institute, which absorbed America's Natural Gas Alliance in 2015, said it believes FERC acted properly and is evaluating the ruling. "Regulatory certainty is critical to ensuring that infrastructure is constructed efficiently. Further delays due to needless regulatory hurdles will slow consumer access to reliable, affordable natural gas and opportunities for job creation," it said.

The Natural Gas Supply Association, which represents 14 large gas producers and marketers, said it was "disappointed" by the order but had no other immediate comment.

RGGI States Agree to Increased Emission Reductions

By Michael Brooks

The nine states comprising the Regional Greenhouse Gas Initiative have agreed to accelerate reductions in power sector carbon dioxide emissions by lowering the cap-and-trade program's annual allowances by 30% over 10 years.

The changes to the program, announced Wednesday, also include the addition of an Emissions Containment Reserve (ECR), in which the participating states — Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island and Vermont — can withhold emission allowances from the quarterly auctions if prices fall below a certain threshold.

"The RGGI states are demonstrating our commitment to a strengthened RGGI program that will utilize innovative new mechanisms to secure significant carbon reductions at a reasonable price on into the next decade, working in concert with our competitive energy markets and reliability goals," Connecticut Public Utilities Regulatory Authority Chair Katie Dykes, who serves as chair of the RGGI board of directors, said in a statement.

RGGI currently reduces the emissions cap by 2.5% annually, targeting 78.2 million tons in 2020. The changes set the 2021 cap at about 75.1 million tons and reduces it by 2.275 million tons (3%) annually after.

Environmentalists and Massachusetts officials last year called for doubling the current rate of reduction, but Maryland Environment Secretary Ben Grumbles balked at the proposal, arguing that the state would be at a disadvantage because its coal-fired power plants must compete in PJM, while most states in the program are in the ISO-NE footprint. (See Md. Balks at Proposed Emission Cuts as RGGI States Ponder Future.)

Grumbles said such an aggressive rate could cause Gov. Larry Hogan to withdraw the state from the program, as New Jersey Gov. Chris Christie did in 2011.

"Maryland is proud of the teamwork among states to achieve consensus for a stronger and broader, balanced and sustainable RGGI," Grumbles, who serves as the RGGI board secretary and treasurer, said about the agreement.

"Maryland is committed to finding real bipartisan, common sense solutions to protect our environment, combat climate change and improve our air quality," Hogan said in a statement. "By working together, we are showing that it is possible to find consensus to protect our natural resources, promote clean energy, and grow our economy for current and future generations."

With the implementation of ECRs starting in 2021, states would be able to withhold up to 10% of their allowances if auction prices fall below \$6/ton, with the price trigger rising 7% each year after. The withheld allowances would not be bankable, meaning they could not be resold in a future auction.

Low prices in previous auctions spurred the initial calls for reforms last year, and prices have only continued to fall since. The latest auction, on June 7, saw a \$2.53/ton clearing price, a 15% drop from the previous quarter and 44% from a year ago.

RGGI will hold a meeting at the Maryland Public Service Commission in Baltimore on Sept. 25 to solicit public and stakeholder feedback on the changes.

Company Briefs

ATC Development Invests in oneGrid

Canadian independent transmission developer oneGrid announced Thursday that ATC Development has invested development capital in it and has joined its board of directors.

With projects in North and South America, oneGrid is presently developing a portfolio of utility-scale HVDC transmission projects using underwater submarine cables.

oneGRID hopes to leverage ATC's regulatory and operational expertise to help identify HVDC transmission projects that will solve transmission congestion, improve system reliability and help connect renewable generation, CEO John Douglas said.

More: *oneGrid*

Sunrun Stock Surges Following Comcast Solar Deal

COMCAST

Sunrun's shares surged as much as 12.1% in trading Thursday following an announcement that it will be the exclusive solar installer for Comcast.

Under a 40-month partnership, Comcast will include the solar offering in its Xfinity Home product, which provides security and home automation. The deal comes after the two companies completed a one-year pilot program.

It is Sunrun's third partnership with a brand-name company this year, following deals with National Grid and ENGIE.

More: *Bloomberg Technology*; *The Motley Fool*

Energy Transfer Sues Greenpeace For Interference with Pipeline

Energy Transfer Partners filed a lawsuit last week against Greenpeace and other groups for damages that could approach $1 billion relating to the groups' efforts to stop construction of the Dakota Access pipeline.

The suit alleges the groups interfered with ETP's business, facilitated crimes and acts of terrorism, incited violence, targeted financial institutions that backed the project, and violated racketeering and defamation laws.

Greenpeace attorney Tom Wetterer said the lawsuit is "meritless" and part of "a pattern of harassment by corporate bullies."

More: *The Associated Press*

Lawsuit Says Duke Failed to Supply Coal Ash Byproduct

Duke Energy Progress is on the receiving end of a lawsuit claiming it reneged on an agreement to sell a byproduct of its coal operations that is used to make drywall.

CertainTeed filed suit in North Carolina Business Court seeking a declaration that Duke isn't complying with a deal to sell and deliver 50,000 tons of synthetic gypsum per month through 2029 from its coal plants in Roxboro and Mayo, N.C.

The construction materials manufacturer alleges in the suit that, relying on the supply agreement, it invested more than $160 million to build a manufacturing facility adjacent to Duke's Roxboro plant, with rail access to the Mayo plant.

More: *Charlotte Business Journal*

Nissan Offering $10K Rebate to JCP&L Customers

Nissan North America is offering a $10,000 rebate to Jersey Central Power & Light customers who purchase its all-electric 2017 Nissan Leaf.

The rebate, which is being offered through Sept. 30 or while supplies last, could take one-third off the price of the Leaf depending upon the model.

More: *Asbury Park Press*

S&P Lowers Ratings for FirstEnergy Solutions; Views Parent as Stable

Standard & Poor's has downgraded the bond rating of FirstEnergy Solutions but has revised its outlook for parent company FirstEnergy from negative to stable.

S&P lowered its ratings for Solutions under the belief that the company's negotiations with creditors are a first step toward it seeking bankruptcy protection before 2018. S&P believes the parent company will be able to cover the bankruptcy costs as it sells off Solutions or alternatively moves it under the protection of a regulated company.

FirstEnergy CEO Chuck Jones told analysts on July 28 that he would participate in negotiations that Solutions had quietly begun with its creditors.

More: *The Plain Dealer*

Federal Briefs

Study: Batteries Can Lower Power Bills for 5M Businesses

Nearly 5 million U.S. businesses with demand charges of at least $15/kW could lower their monthly power bills by installing battery systems, according to a study released Thursday by the National Renewable Energy Laboratory and Clean Energy Group.

The study of more than 10,000 utility rate plans found that falling battery costs and rising utility fees have made it possible for savings in high-cost states, such as California and New York.

It additionally found that storing energy would be profitable for at least 1 million commercial consumers in Georgia, Colorado, Michigan, Texas, Florida and New England.

More: *Bloomberg*

TVA Approves $10.4B Budget; 1.5% Rate Increase

The Tennessee Valley Authority on Wednesday approved a $10.4 billion budget, which includes a 1.5% rate increase that takes effect in October.

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FEDERAL BRIEFS

Continued from page 31

The increase will amount to $1.50 more per month for the average ratepayer using 1,000 kWh/month. The budget keeps operations and maintenance spending flat.

More: *The Associated Press*

Interior Investigating Whether Zinke Threatened Murkowski

The Interior Department has launched a preliminary investigation into reports that Interior Secretary Ryan Zinke attempted to pressure an Alaska senator into voting to repeal and replace the Affordable Care Act by threatening the state's energy projects.

Murkowski

Sen. Lisa Murkowski (R-Alaska) was one of three Republican senators to break party lines during the GOP's failed effort to dismantle the health care act.

More: *The Huffington Post*

Anthony Pugliese Named FERC Chief of Staff

FERC Chairman Neil Chatterjee announced last week that he had appointed Anthony Pugliese chief of staff at the commission.

Pugliese

Since January, Pugliese has served as senior White House adviser at the Transportation Department, where his responsibilities included overseeing pipeline safety and regulatory issues.

He previously was a consultant on energy issues involving solar, oil and natural gas at Pugliese Associates.

More: *FERC*

Interior Halts Study of Health Risks near Coal Mining Sites

The Interior Department on Friday halted a study of health risks for residents near surface coal mining sites in the Appalachian Mountains as part of its review of projects costing more than $100,000.

The study was being conducted by an 11-member committee of the National Academies of Sciences, Engineering and Medicine. The academy said it did not know when the government's review would start or end.

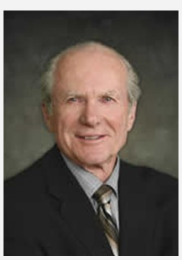
More: *The Washington Post*

STATE BRIEFS

ARIZONA

Regulator Sues to Void Rate Increase for APS

A utility regulator is asking the state Supreme Court to void a vote last week giving Arizona Public Service permission to immediately charge its customers an additional $7/month, claiming he was denied the opportunity to determine whether the utility's campaign contributions tainted the ruling.



Burns

Corporation Commissioner Bob Burns, who was the lone dissenter in the 4-1 vote, claims the process did not comply with statutory and constitutional requirements for a full airing of all the relevant issues.

The company has admitted it spent $4.2 million last year to elect a commission of its liking. Burns has also raised issues relating to how much of $3.2 million spent by "dark money" organizations during the 2014 campaign came from the utility.

More: *Arizona Capitol Times*

CALIFORNIA

Republicans Oust Assembly Leader over Cap-and-Trade

The Assembly Republican Caucus voted in a closed-door meeting Thursday to replace Assembly Republican Leader Chad Mayes, in a shakeup linked to his support last month for extending the state's cap-and-trade program.

Mayes

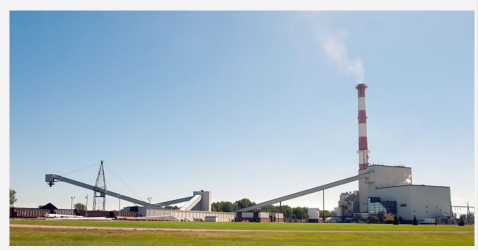
Mayes, who will remain leader through Sept. 15 when the legislative session ends, spent weeks negotiating with Gov. Jerry Brown and Democratic colleagues for changes that would make the cap-and-trade system more amenable to industries most directly affected and to potentially give Republicans greater say in how revenues are spent. He, along with six members of his caucus, pushed the cap-and-trade bill over the two-thirds threshold.

Mayes had withstood a vote last week to oust him from his leadership post.

More: *The Mercury News*

MICHIGAN

Coal-Burning Erickson Power Plant Set to Retire by 2025



The Lansing Board of Water & Light plans to retire its coal-burning Erickson Power Plant by 2025 under an agreement reached with the Sierra Club.

By 2025, the plant would be more than 50 years old, which is 13 years older than its original design life, said Stephen Serkaian, a spokesman for the city-owned utility. He said in an email last week that the city plans to replace its coal-based power generation with a mix of renewable energy, energy efficiency and natural gas.

The Sierra Club intended to sue the utility over reported environmental violations at

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STATE BRIEFS

Continued from page 32

Erickson as well as its Eckert Power Plant before an agreement was made, said Regina Strong, the organization's director of its Beyond Clean Coal Campaign in the state. The utility plans to retire the Eckert plant by 2020.

More: Lansing State Journal

NEW YORK

EPSA Appeals Dismissal Of ZEC Challenge

The Electric Power Supply Association on Thursday asked the 2nd U.S. Circuit Court of Appeals to overturn a July 25 district court ruling dismissing a challenge to the state's zero-emissions credit program (16-CV-8164).

Roseton Generating and Selkirk Cogen Partners joined EPSA and members Dynegy, Eastern Generation and NRG Energy in seeking a review of the order by U.S. District Court Judge Valerie Caproni. The judge dismissed the case at the request of the Public Service Commission and Exelon, the owner of the three nuclear plants in the state that would receive ZEC payments. (See New York ZEC Suit Dismissed.)

Cuomo Announces Clean Energy Competition for Students

Gov. Andrew Cuomo last week announced a $3 million competition for students at two- or four-year public or private colleges and universities in the state to develop clean-energy solutions for their campuses and surrounding communities.

Energy to Lead 2017 will award $250,000 to $1 million per project. It is the second round of the Energy to Lead competition, which in May 2016 awarded $1 million each to Bard College, SUNY University at Buffalo and SUNY Broome Community College.

Bard's project will show how novel microhydropower generators can dramatically reduce greenhouse gas emissions. The Buffalo project will demonstrate how a college or university can partner with its community to transform the local energy ecosystem and has a goal of installing 100 MW of solar power throughout the city's college and university campuses. Broome will show how a geothermal system can harness the energy stored in the earth to heat and cool a campus.

More: Gov. Andrew Cuomo

OHIO

Pipeline Approval on 'Hold' over Superfund Site

The approval process for Duke Energy's proposed 13-mile natural gas pipeline through the middle of Hamilton County was put on hold by the state Thursday at the company's request because of "potential concerns" about construction near a Superfund site.

The site in question is Pristine Inc. in Reading, which is a former liquid waste disposal facility where cleanup has been ongoing for decades. The city of Reading brought the site to Duke's attention toward the end of July, Reading Safety-Service Director Patrick Ross said.

Duke was expected to make its case for constructing the Central Corridor Pipeline Extension Project at the state's final hearing on Sept. 11.

More: Cincinnati Enquirer

New Albany Could be 1st To Get Metal Tx Line Poles

New Albany could be the first community in the state to get a new type of high-capacity power line that is supported by metal structures instead of wooden poles.

American Electric Power plans to submit a proposal to the Power Siting Board this fall for a $30 million project to install 6.5 miles of line using supports, resembling upside-down anchors, that consist of a single metal pole. The pole, which would be about 100-feet tall, is lower and narrower than a wooden structure with similar capacity.

More: The Columbus Dispatch

Kasich Doesn't Support Bailout For State's Nuclear Plants

Gov. John Kasich last week said that he can't see supporting an electricity rate increase to save FirstEnergy's Davis-Besse and Perry nuclear plants.


Kasich

A proposal that could result in $300 million a year in new charges to FirstEnergy customers to keep the two aging plants alive has been stalled in the state legislature since late spring.

More: The Associated Press

Coal Seeks 'Resiliency' Premium; FERC 'Fuel Wars' Coming?

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that would have allowed Perry to keep threatened coal plants running.

In a blog post Monday, National Mining Association spokesman Luke Popovich praised the report's recommendations on valuing on-site fuel supplies and pressed for what he called a "more forceful, vigilant role for FERC in overseeing and managing the grid" as "constructive and necessary." He acknowledged, however, that the recommendations "weren't revolutionary or bold."

Popovich also praised the call for changing EPA's New Source Review rule on coal plants, which the report said "discourages rather than encourages installation of CO_2 emission control equipment and investments in efficiency."

But because implementing such a change would likely require amending the Clean Air Act — no small task — it is unlikely to provide relief any time soon.

"Hurricane Harvey will likely have a bigger impact on the energy grid than this vanilla report," Popovich concluded.

Much is at stake. The Department of Energy said a net 36 GW of coal capacity retired between 2002 and 2016, about 12% of total coal capacity. Coal mining company Murray Energy says 24 coal fired plants are scheduled to close over the next year.

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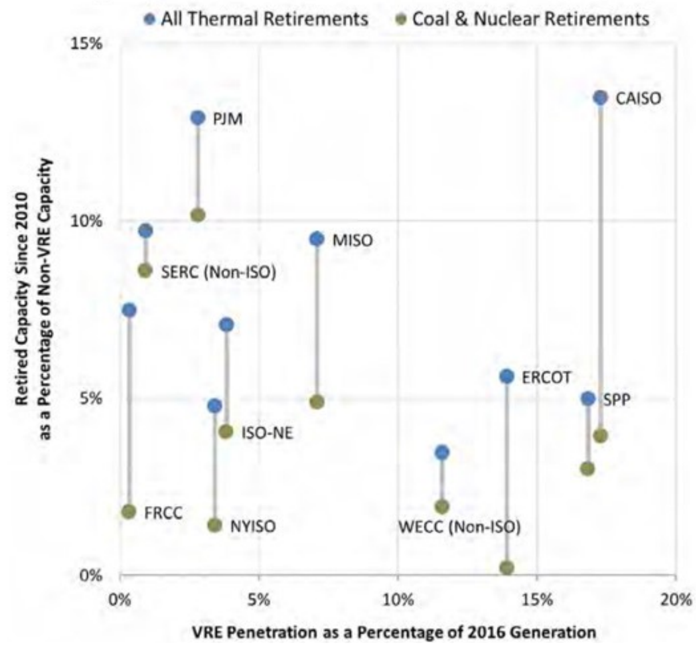
Perry Grid Study Seeks to Aid Coal, Nuclear Generation

By Rich Heidorn Jr.

Energy Secretary Rick Perry's much-awaited grid study calls on the federal government to rescue traditional "baseload" power — coal and nuclear — by addressing renewables' negative pricing and ending EPA's New Source Review rule on coal generators.

The 187-page study, which was released late Wednesday night, contains little if any new data or analysis. Virtually all the trends it cites and the issues it raises have been under discussion for months or years at FERC, in state legislatures and at RTO/ISO stakeholder meetings. What is new are some of the policy recommendations, which reflect the Trump administration's support of the coal industry and its rejection of the Obama administration's Clean Power Plan.

The report cites Executive Order 13783, saying that while the Energy Department is not specifically named in the order, the department "should continue to prioritize energy dominance" and that it and other federal agencies "should accelerate and reduce costs" for licensing "nuclear, hydro, coal, advanced generation technologies and transmission. DOE should review regulatory burdens for siting and permitting for generation and gas and electricity transmission infrastructure and should take actions to accelerate the process and reduce costs."



VRE penetration as a percentage of 2016 generation vs. retired capacity since 2010 as a percentage of non-VRE capacity | *DOE*

'Unnecessary Burden'

As one example, it suggests ending the New Source Review rule, administered by EPA under the Clean Air Act, saying coal-fired generators should be allowed "to improve efficiency and reliability without triggering new regulatory approvals and associated costs."

"The uncertainty stemming from [New Source Review] creates an unnecessary burden that discourages rather than encourages installation of CO_2 emission control equipment and investments in efficiency because of the additional expenditures and delays associated with the permitting process," it said.

It also says FERC should require valuation of "Essential Reliability Services," in which it includes reliability-must-run generators and ancillary services (frequency and voltage support, and ramping capability).

Perry, who requested the study in an April 14 memo, said it was "long overdue."

"The industry has experienced massive change in recent years, and government has failed to keep pace," he said in his cover letter to the report. "This report examines the evolution of markets that has occurred over the last 15 years. Policymakers and regulators should be making decisions based on what the markets look like today, not what they looked like years ago."

Perry's memo, which set a 60-day deadline, called for the department to "explore critical issues central to protecting the long-term reliability of the electric grid," and to analyze "market-distorting effects of federal subsidies that boost one form of energy at the expense of others." The report arrived two months late.

Vehicle for Trump Policy?

The memo sparked concern among renewable energy advocates that the study would be a vehicle for President Trump to deliver on his campaign promises to "save" the coal industry.

Their fears were heightened by the involvement in the study of Travis Fisher, a former FERC economist hired by DOE in January who had written a 2015 report for the conservative Institute for Energy Research that alleged the "single greatest threat to reliable electricity in the U.S. does not come from natural disturbances or human attacks" but federal and state government policies such as renewable subsidies and mandates.

But the politicization appeared to have been tempered by the involvement of career DOE staffers and contractor Alison Silverstein, once senior adviser to former FERC Chair Pat Wood, a Republican appointee of President George W. Bush. Silverstein is board secretary for the American Council for an Energy-Efficient Economy.

Another factor was the leak of a draft of the report in June, which contradicted Perry's memo by concluding that low natural gas prices rather than renewable-friendly policies were the main cause of coal and nuclear plant retirements.

Changes from Leaked Draft

Joe Romm, a writer for the progressive website ThinkProgress, compared the final version with the draft and concluded that "while Trump officials clearly tried to rewrite the previously leaked staff draft to give the impression that renewable energy sources are a threat to baseload power and grid resilience, they mostly botched the job."

The draft report found that environmental regulations and renewable energy subsidies "played minor roles compared to the long-standing drop in electricity demand relative to previous expecta-

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tion and years of low electric prices driven by high natural gas availability."

The draft also concluded that "the power system is more reliable today due to better planning, market discipline, and better operating rules and standards."

Both of those conclusions were eliminated from the final report, Romm said.

Instead, the final report concedes that "the biggest contributor … has been the advantaged economics of natural gas-fired generation," and that "another factor … is low growth in electricity demand."

The report also substituted the finding that renewable subsidies had a minor impact on baseload plant retirements with the conclusion that "dispatch of VRE [variable renewable energy] has negatively impacted the economics of baseload plants" — a statement that is undermined elsewhere in the report citing data that "do not show a widespread relationship between VRE penetration and baseload retirements."

While the final report notes that "recent severe weather events" have "demonstrated the need to improve system resilience," it removes the words "climate change," which many scientists believe is a contributor to the phenomenon.

"Perry and his staff took a perfectly solid report on the grid and added a (surprisingly light, to my eye) coating of political propaganda," wrote columnist David Roberts on Vox. "The result is a muddy report, with findings in it to please (or enrage) every onlooker."

Coal, Nuclear Groups Praise Report

In early reaction to the report, many groups seemed to be able to find something they liked — with the coal and nuclear lobbies most effusive. Environmentalists were dismissive, if relieved.

"We commend Secretary Perry and the Department of Energy for studying the challenges facing the electricity grid," said Paul Bailey, CEO of the American Coalition for Clean Coal Electricity. "One of the biggest challenges is how to preserve the nation's coal fleet so it can continue supporting a reliable and resilient electricity grid."

"We commend Secretary Perry for his leadership in beginning this important but long overdue conversation about the future reliability and resilience of our electric power system," said National Mining Association President Hal Quinn. "Among other findings, the report notes that 'regulations and mandates,' in addition to market forces, have accelerated the closure of a substantial number of baseload power plants. … As the report notes, many states and regions bear an increased risk from the destruction of traditional baseload power and the resulting diminution of grid resilience."

Nuclear Energy Institute CEO Maria Korsnick said the study "reaffirms our view that nuclear energy is a key and necessary contributor to a clean, reliable and resilient electric grid."

"In the 10 years since the last comprehensive grid study by our government, electricity markets have changed radically," she continued. "Today electricity markets do not properly credit nuclear energy for the numerous benefits it delivers, forcing plants to close years before the end of their useful lives and compromising grid reliability and resiliency in the process."

Kelly Speakes-Backman, CEO of the Energy Storage Association, said the group was "encouraged" by its initial review of the report.

"The report plainly states that advanced energy storage systems are critical to ensuring that electricity is reliable, affordable and secure," she said. "We also agree with the key findings that better strategies are needed by markets and in resource planning to properly reward the values that energy storage systems provide to the grid, especially increased reliability and resiliency."

Tom Kiernan, CEO of the American Wind Energy Association, said the group agrees with the department "that it makes sense to determine how a portfolio of domestic energy resources can ensure grid reliability and resilience."

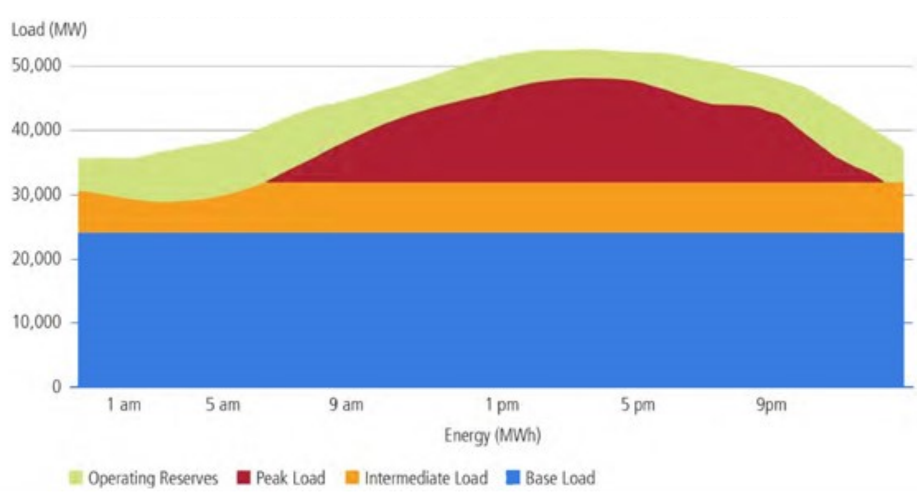
Kiernan — who noted that the U.S. wind industry is expected to "support" 147,000 jobs by 2020 — said the report "provides a number of valuable policy recommendations."

"In particular, DOE's recommendations to value essential reliability services, which wind provides; to minimize regulatory barriers to energy production; and to accelerate infrastructure and transmission development are prudent and will help continue America's wind power success story," he said.

Dissenting Voices

The Alliance to Save Energy said the discussion about the report overlooked the role of energy efficiency. "As we look at the portfolio of solutions we can't just look at supply," said President Kateri Callahan. "We have to remember that increasing efficiency and productivity is the fastest and cheapest way to reach our goals — and it's also a tremendous economic opportunity. Already efficiency is the leading job creator in the clean energy sector with some 2.2 million jobs in construction, manufacturing and other fields."

Graham Richard, CEO of Advanced Energy Economy, a group of clean-energy and



Schematic of typical daily load curve showing base load | *DOE*

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FERC, RTOs to DOE: We Got This

By Rich Heidorn Jr. and Tom Kleckner

The U.S. Energy Department grid study released Wednesday added no new information to debates that have been going on for months at FERC technical conferences and RTO/ISO stakeholder meetings.

The report also acknowledged that the department has virtually no authority over generation or wholesale markets, leaving it to FERC and RTOs to act on its recommendations. (See *Perry Grid Study Seeks to Aid Coal, Nuclear Generation*.)

On Thursday, FERC and several RTOs responded. Their message: We're already working on it.

Acting FERC Chairman Neil Chatterjee issued a statement saying the report "highlights many activities that the commission is carefully considering, including examining ways to enhance wholesale electric capacity markets and improve price formation in those markets, to increase electric and gas coordination, and to assure bulk power system reliability and resilience. The commission will remain focused on these and other issues that are critical to maintain the nation's competitive wholesale electric markets and keep the lights on."

PJM, ISO-NE, MISO, CAISO and SPP also issued statements assuring DOE that they are addressing the issues and that — despite the ominous warning Secretary Rick Perry used in his April 14 memo ordering the study — that there are no imminent risks to grid reliability.

Price Formation

Among the report's recommendations were a call for FERC to "expedite its efforts with states, RTO/ISOs and other stakeholders to improve energy price formation in centrally organized wholesale electricity markets."

"After several years of fact finding and technical conferences, the record now supports energy price formation reform, such as the proposals laid out by PJM and others," it said, citing PJM's June report, "Energy Price Formation and Valuing Flexibility," and MISO's extended LMP initiative. (See *PJM Making Moves to Preserve Market Integrity*.)

The report says that although all RTOs/ISOs have some type of shortage pricing, the designs differ, a "variance [that] could present challenges to market participants who require a threshold level of certainty to make an investment decision." Although it acknowledged that FERC Order 831 doubled energy offer caps in the organized markets to $2,000/MWh, it cited concerns expressed by Market Monitors Joe Bowring and David Patton over the volatility of shortage pricing revenue. (See *Lawyers Take an Economics Class: Capacity Markets vs. Scarcity Pricing*.)

It also called for mitigating negative prices "to the broadest extent possible," quoting from the department's January Quadrennial Energy Review report that "price suppression is occurring in RTO/ISO wholesale markets with noticeable amounts of wind and solar generation (and low-cost gas generation)."

	CAISO	ERCOT	ISO-NE	MISO	NYISO	PJM	SPP
Product name – ramp reserve	Flexible Ramping Product			Ramp capability			
Ramp reserve – when procured	FMM and RTM (not DAM)			DAM and RTM			
Voltage control – payment mechanism provision and capability	Provision payment based on lost opportunity cost or contract	Lost opportunity cost for provision	Lost opportunity cost and American Electric Power (AEP) method	Lost opportunity cost and AEP method	Lost opportunity cost and fixed tariff rate	Lost opportunity cost and AEP method	Compensation rate for provision
Black start service payments	Contracted through reliability contracts	Procured through bi-annual competitive process	Paid standard black start rate or station-specific rate	Receive cost-based rate after committing to 3-year period	Paid cost-based rates	Paid cost-based rates	Not procured through SPP

Ancillary service products by grid operator | *DOE*

Essential Reliability Services

The department also urged FERC to require valuation of "essential reliability services" through fuel- and technology-neutral markets or regulatory mechanisms. The report includes in that description ancillary services such as frequency and voltage support, and ramping capability.

A table in the report (left) shows that only MISO and CAISO have any product in the

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Perry Grid Study Seeks to Aid Coal, Nuclear Generation

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technology companies, said he was pleased that the department "recognizes that changes in the grid are primarily the result of low-cost natural gas, not policies supporting renewable energy."

But he said the report "seriously overstates the challenges associated with new energy resources. It also implies that certain power plants now losing out in the marketplace make an irreplaceable contribution to reliability and resilience, which is not the case."

"Our nation's grid operators themselves have said they are facing no difficulty in managing an increasingly diverse set of resources, and that they will have no difficulty maintaining reliability as uncompetitive power plants inevitably retire," he added. "What is happening in our power grid is a natural process of technology progress and market competition. That process should be allowed to continue, not be distorted by this administration's preference for 'baseload' resources over the flexible resources that are modernizing the electric power system."

Also critical was environmental group Earthjustice, which said the report "shows that science is not safe from manipulation under this administration."

"Sound findings in the earlier draft of the report have been mysteriously excised, replaced by trumped up claims about the costs of environmental regulations," said Earthjustice attorney Kim Smaczniak. "And this report says nothing about climate change. By willfully burying its head in the sand on climate change, the administration will make the grid more vulnerable to the next Superstorm Sandy, which left millions without electricity."

FERC, RTOs to DOE: We Got This

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"ramp reserve" category. SPP's David Kelley said the RTO is evaluating the benefits of a ramping product for the Integrated Marketplace and is exploring designs deployed in other markets. It has no current timeline for implementation.

Resilience

The report also called for further study on mandatory capacity markets, which it noted have "been the subject of near-constant debate" and the development of metrics and tools for evaluating "resilience."

The department said NERC "should consider adding resilience components to its mission statement and develop a program to work with its member utilities to broaden their use of emerging ways to better incorporate resilience."

"RTOs and ISOs should further define criteria for resilience, identify how to include resilience in business practices and examine resilience-related impacts of their resource mix," it continued.

The report acknowledged that while wholesale markets "do not explicitly recognize or compensate system resilience," PJM and ISO-NE have changed their capacity market rules to incentivize generator performance during scarcity conditions. It notes that only some RTOs — naming PJM, ISO-NE and NYISO — value onsite fuel storage, a characteristic of coal and nuclear plants that natural gas plants without oil-fired back-up lack.

Quoting PJM, the report notes that "criteria for resilience are not explicitly defined or quantified today."

"Each RTO/ISO should strive to explicitly define resilience on its system and conduct resource diversity assessments to more fully understand the resilience of different resource portfolios," the department said. "Federal, state and local work to define and support systemwide resilience is also needed."

NERC issued a statement saying that reliability and resiliency "are key priorities for NERC and we appreciate the recognition of our work on these matters."

ISO-NE

ISO-NE spokeswoman Marcia Blomberg said the RTO is reviewing the study. "However, in the two decades since their creation, competitive wholesale electricity markets in New England have achieved what they were designed to accomplish, including power system reliability supported by an adequate resource base, competitive wholesale power prices that accurately reflect the cost of reliable power production and a shift in resource investment risk from ratepayers to investors.

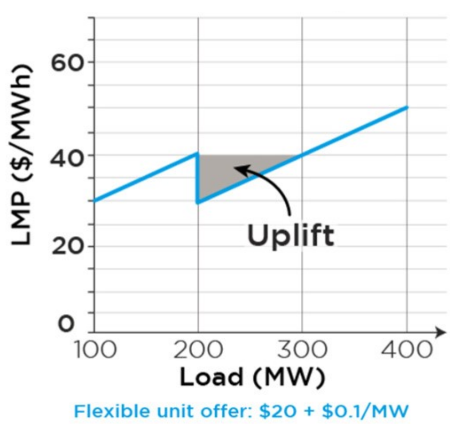
"As the energy landscape evolves, ISO New England will continue working with industry stakeholders and state policymakers to ensure that the markets can adapt to changing industry dynamics, such as state environmental policies and fuel security challenges, while continuing to produce competitive prices that support the resources needed to reliably meet consumer demand for power."

PJM

PJM called the report "thoughtful" and "comprehensive."

"The report acknowledges that wholesale power markets are working and providing reliability at the lowest possible cost and that power supply resources are more diverse than they have ever been. It also highlights the importance of expediently addressing needed reforms in energy price formation followed by a focus on grid resilience. These issues are a top priority."

The RTO noted that it has posted discussion papers on price formation and capacity market reform to accommodate state policies. "Earlier this year, we published a paper, 'PJM's Evolving Resource Mix and System Reliability,' which demonstrated that the PJM region has remained reliable throughout the rapid changes in the resource mix. PJM's analysis also indicated a need to focus on fuel assurance and resilience to take into account the changing operational risks that the industry faces." (See PJM: Increased Gas Won't Hurt Reliability, Too Much Solar Will.)



Current LMP-setting logic: only flexible units allowed to set price | PJM

CAISO

CAISO said it has "experienced success in integrating large amounts of renewable resources without threatening grid reliability. There's no doubt that energy markets are evolving as the fundamental resource mix changes. The ISO will continue to operate a reliable grid that can capture the benefits of this transformation."

MISO

MISO said it "has been preparing for the challenges of the evolving resource mix, and we will continue to ensure that planning constructs, market designs and operational practices are in place to support the reliability of the electric grid across our footprint. We look forward to continuing our work with DOE, regulators, policymakers and stakeholders as that effort continues."

SPP

SPP spokesman Derek Wingfield said the RTO "is pleased the report acknowledges the value of transmission investments in enabling 'an array of benefits' including reliability, congestion relief, market competition, diversity of fuel sources and more, and that our own Value of Transmission study had some influence on the Department of Energy's analysis. The report's recommendation to further study market structures and the impacts of renewable integration is also welcome, and we pledge to assist the DOE and FERC with such analyses should the opportunity arise." (See SPP Begins Promotional Campaign to Tout Transmission Value.)

Last month, SPP stakeholders approved recommendations from a study on how much wind energy the RTO's system can safely and reliably absorb. The RTO has routinely broken the 50% penetration level for wind energy, and has said it can go even higher. The recommendations include the installation of online transient-stability and voltage-stability analysis tools. (See "Wind Integration Study's Recommendations Move On," SPP Markets and Operations Policy Committee Briefs: July 11-12, 2017.)

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Coal Seeks 'Resiliency' Premium; FERC 'Fuel Wars' Coming?

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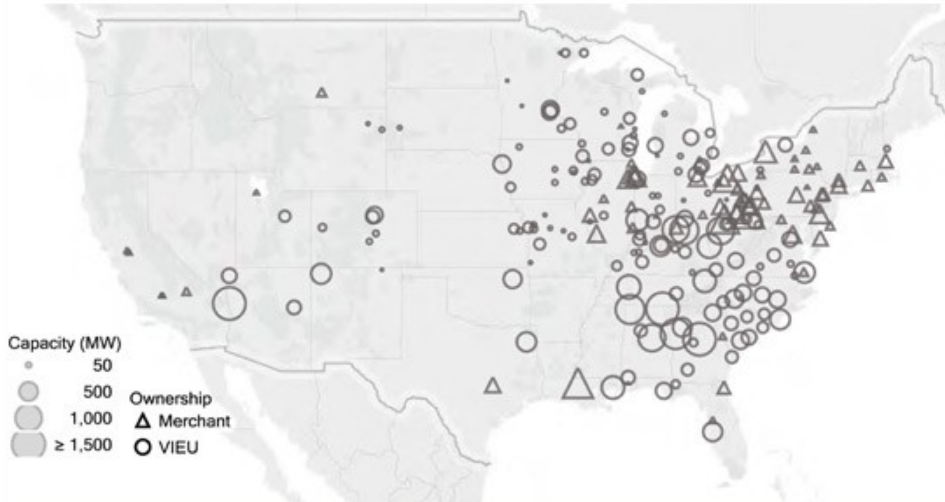

Location of coal retirements, 2002-2016 | *DOE*

Ensuring a Place for Coal?

The best hope for the coal industry may be that FERC could adopt the report's recommendation that it lean on RTOs to begin valuing on-site fuel storage as a measure of "resiliency." At least one FERC commissioner, acting Chair Neil Chatterjee, has indicated he is receptive.

In a podcast interview posted Aug. 14, Chatterjee said one of his primary goals is supporting coal, the favored fuel in his home state of Kentucky — also the home of his former boss, Senate Majority Leader Mitch McConnell.

"Baseload power … including our existing coal and nuclear fleet, need to be properly compensated to recognize the value they provide to the system," Chatterjee said, citing their value to "resilience and reliability."

"I'm a Kentucky native," he continued. "I've seen firsthand throughout my life how important a contribution coal makes to an affordable and reliable electric system. Last year, coal provided over 80% … of the electricity in Kentucky. As a nation, we need to ensure that coal, along with gas and renewables, continue to be part of our diverse fuel mix."

Chatterjee, the acting chairman pending the confirmation of fellow Republican Kevin McIntyre, did not elaborate on how he intended to accomplish his goal in the interview. His comments suggest the commission could be entering a new, more contentious environment. FERC policy until now has been — in the words of former Commissioner Philip Moeller — "fuel neutral but not reliability neutral."

"Chatterjee comes out for coal and nukes specifically. [Fellow Republican Commissioner Robert] Powelson has been a great friend and promoter of gas. [Democratic nominee Richard] Glick could be called a renewables advocate," observed one former senior FERC official who asked not to be named. "For the first time we could have FERC fuel wars."

FERC did not immediately return a request for comment on Chatterjee's remarks.

"All the fingers seem to be pointing, rightfully, at FERC," Paul Bailey, CEO of the American Coalition for Clean Coal Electricity (ACCCE), told the *Washington Examiner* last week. "I think most people understand the need for speed; the question is whether this whole system with FERC and the grid operators, and technical conferences, are set up to move these things quickly." Bailey declined an interview request from *RTO Insider*.

"I think it's all going to come from what time frame FERC gives these grid operators," Michelle Bloodworth, ACCE's chief operating officer, told the *Examiner*. "If they kind of say, 'well, OK, we'll let you talk to your stakeholders,' then I'd say they would take years."

Bloodworth said the group hopes FERC will act as it did following the 2014 polar vortex, when it ordered grid operators to report within 90 days on their efforts to ensure generators have adequate fuel. (See NERC Optimistic on Winter Prep as FERC Seeks Assurances on Fuel.)

Facts Don't Support Perry Thesis

The department's 187-page report failed to support the claim in Perry's memo that generation diversity has declined (it is actually more diverse than ever, the report said) or that renewable power was largely to blame for coal and nuclear plants' financial problems (renewables were identified as a secondary factor, far less important than competition from cheap natural gas).

Nor did the report provide evidence that coal plant retirements have caused threats to grid reliability. It noted that NERC's most recent State of Reliability report concluded "bulk power system reliability remained … adequate" in 2016, repeating the group's findings from 2013–2015.

Perry's contention that "baseload power is necessary to a well-functioning electric grid" was also undermined by the study, which quoted NERC CEO Gerry Cauley as saying "resource flexibility is needed to supplement and offset the variable characteristics of solar and wind generation."

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FERC, RTOs to DOE: We Got This

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ERCOT

ERCOT, which is not subject to FERC jurisdiction, held a discussion with the Texas Public Utility Commission on Aug. 11 on price-formation issues including scarcity pricing and marginal losses. (See ERCOT, Regulators Discuss Need for Pricing Rule Changes.)

ERCOT has also successfully integrated renewables at 50% penetration levels.

NYISO officials had no immediate comment, saying they were digesting the report.

Coal Seeks 'Resiliency' Premium; FERC 'Fuel Wars' Coming?

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However, Cauley also noted the need for replacing "essential reliability services, such as frequency and voltage support, [and] ramping capability," lost with the retirement of conventional generation.

In a blog post, John Moore, director of the Natural Resources Defenses Council's Sustainable FERC Project, and NRDC attorney Miles Farmer said the study "grasps for any possible rationale to support outdated, expensive and highly polluting coal plants, but fundamentally fails to come up with concrete reasons to do so."

"The report is disjointed, making misguided recommendations to relax environmental rules and saddle customers with extra costs that are largely unconnected to and unsupported by the report's findings," they said. "In short, while we believe customers should pay less and get cleaner energy, Trump and the coal industry want customers to pay more and get dirtier energy."

Defining 'Resilience'

The report continues attempts by coal and nuclear supporters to identify a new attribute — resilience — in addition to traditional measures of reliability. Where reliability is reflected in loss-of-load events — commonly seeking no more than one outage day every 10 years — resiliency refers to the ability to respond to supply disruptions caused by catastrophic weather or cyberattacks.

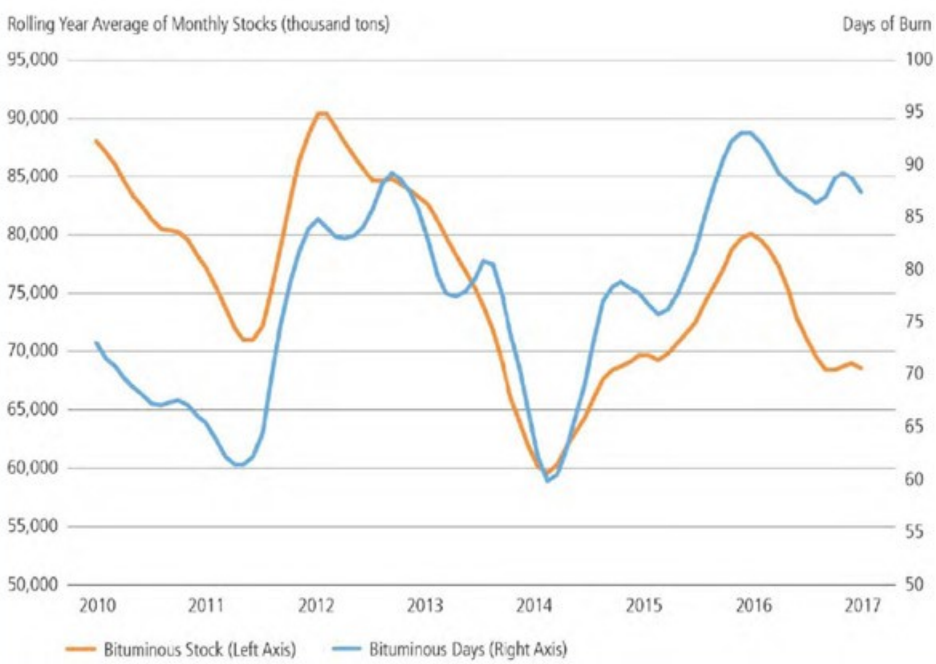
ACCCE said before the report that it hoped the department would "explain the distinction between reliability and resilience; call for resilience analysis and the establishment of uniform resilience criteria."

"The DOE study should identify attributes that strengthen grid resilience (e.g., on-site fuel supplies, firm fuel contracts, and black start capability) and attributes that can diminish grid resilience (e.g., just-in-time fuel delivery, fuel storage disruptions, pipeline outages, interruptible fuel contracts and over-reliance on any one fuel type.)"

Supporters say coal should receive compensation for having 60 to 90 days of fuel at plant sites; operators of nuclear plants, which refuel every 18 to 24 months, have made similar claims. (See related story, *Nuclear Industry Seeks PPAs, 'Price Formation' Reforms*, p.1.)

Most natural gas generators, in contrast, have little storage on site and rely on just-in-time pipeline deliveries.

ACCCE said one-quarter of the natural gas burned by generators in the nation's largest power pools in 2016 was delivered under interruptible contracts, which allow pipelines to cancel them with little or no notice. Interruptible gas use was highest in NYISO (61%) and ISO-NE (57%), the group said.



Coal stocks and days of burn, January 2010-May 2017 | *DOE*

The American Gas Association, which represents distribution utilities, insists the gas transmission and distribution system is "inherently resilient" compared to other energy delivery systems.

"Natural gas systems are far more resilient in the face of extreme weather events because natural gas pipelines are predominantly underground and more protected from the elements," AGA President Dave McCurdy said in response to the report last week. "Our natural gas infrastructure also has the advantage of built-in redundancy of interconnections for receipt and delivery of natural gas."

The study noted that during the 2014 polar vortex, many natural gas-fired generators with non-firm gas contracts had their fuel supplies curtailed while others were unable to operate because the cold caused fuel to gel and some pipelines to freeze. But it also notes that "many coal plants could not operate due to conveyor belts and coal piles freezing." Nuclear generators, it said, fared best during the cold spell, recording an average capacity factor of 95%.

Fuel Diversity not a Panacea

The American Petroleum Institute released a report in June that argued it is not fuel diversity, but the presence of "reliability attributes," that policymakers should seek for the good of the grid. The study, done for API by The Brattle Group, concluded that gas-fired generation is "relatively advantaged" in all but one of the 12 attributes it identified, failing only on storage capability. (See *NG Lobby Goes on Offensive vs Coal, Nukes*.)

API said the report was not intended to preempt the DOE study but "to push back against" state policies that seek to maintain coal and nuclear plants "at any cost."

In March, PJM issued a study concluding it could maintain adequate reliability with a generation fleet almost entirely composed of natural gas units, but that a capacity mix of more than 20% of solar would unacceptably increase the LOLE risk. (See *PJM: Increased Gas Won't Hurt Reliability, Too Much Solar Will*.)

Nevertheless, in June, it issued a report proposing to allow nuclear and coal plants needed for reliability to set clearing prices based on their marginal costs. (See *PJM Making Moves to Preserve Market Integrity*.)

Despite Promise to Save Coal, Trump Rebuffs Emergency Call

By Rich Heidorn Jr,

On Aug. 4, coal magnate Robert Murray wrote an impassioned letter to a White House aide. Merchant generator FirstEnergy Solutions is "on the verge" of a bankruptcy filing that would force the company to immediately close its coal-fired generators, he wrote. "Their bankruptcy will force Murray Energy Corp. into immediate bankruptcy, promptly terminating our 6,500 coal mining jobs" and leaving the company unable to make $140 million in debt payments due between September and December.

In a later message, Murray said, "these bankruptcies would have a cascading effect which would decimate the states of Ohio, West Virginia and Pennsylvania, all of which voted overwhelmingly for President Trump."

During the presidential campaign, Trump famously donned a miner's helmet and promised to save the industry.

Nevertheless, the Associated Press reported Aug. 22, the Department of Energy rejected Murray's plea that it use its emergency powers under the Federal Power Act to order a two-year moratorium on the closing of coal-fired generators.

The AP obtained letters in which Murray claimed Trump had promised to take the emergency action. The letters said Trump made his commitment in private conversations with executives from Murray and FES, one of the coal mining company's biggest customers. The CEOs of mining companies Peabody Energy and Alliance Resource Partners also had called for an emergency declaration.

The White House declined to say whether Trump had promised to act, but a spokeswoman told the AP that the White House was helping the industry in other ways. "Whether through repealing the Clean Power Plan and the 'Waters of the U.S. Rule,' removing the U.S. from the Paris Climate Agreement, or signing legislation to overturn rules and policies designed to stop coal mining, President Trump continues to fight for miners every day," she said. Trump also signed legislation in February reversing an Obama administration rule to protect streams from coal mining waste.

Section 202(c) of the Federal Power Act allows the energy secretary to order power plants to operate for reliability reasons during emergencies.

The section has been used infrequently, notably during the Western Energy Crisis in 2000 and after Hurricane Katrina in 2005.

But attorneys for Latham & Watkins observed that the Energy Department "has interpreted its potential application broadly," defining as an emergency "an unexpected inadequate supply of electric energy" and "regulatory action which prohibits the use of certain electric power supply facilities."

In April, the department invoked 202(c) as a so-called "reliability safety valve" to keep the Grand River Dam Authority's Grand River Energy Center Unit 1 running despite its failure to meet the requirements of EPA's Mercury and Air Toxics Standards (MATS). GRDA had planned to replace Unit 1 with power from MATS-compliant Units 2 and 3, but Unit 2 was idled by a lightning strike and construction on Unit 3 was delayed by flooding. The order authorized GRDA to operate Unit 1 as needed to provide reactive power support until replacement generation capacity is available around the Grand River.

In June, the department used 202(c) again to authorize Dominion Energy Virginia to operate Yorktown Units 1 and 2 when PJM determines they are needed for reliability. The order stems from Dominion's difficulty in gaining approval for a 500-kV transmission line across the James River. (See *DOE Approves Emergency Dispatch of Yorktown Units*.)

FirstEnergy: No Bankruptcy Decision Until Mid-2018

Last November, FirstEnergy announced its plan to exit competitive generation. (See *FirstEnergy Wants out of Competitive Generation*.)

But the company on Monday denied Murray's claim that a bankruptcy filing for FES is imminent.

"Bankruptcy of FirstEnergy Solutions, the company's competitive subsidiary that owns the power plants, is one of the possibilities under consideration, but no decisions have been made at this time," said FirstEnergy spokeswoman Jennifer Young. "We have previously indicated we expect to complete the strategic review by mid-2018."

She said the company's "strategic review" is exploring options, including "the possible sale of some competitive gas and hydro assets; legislative efforts to move some competitive assets to regulated or regulated-like constructs; seeking a solution for nuclear units that recognizes their environmental benefits; the sale of other generating assets; or additional deactivations."

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based, dispassionate analysis of the issues facing today's electric grid."

"We know that states are more nimble in their ability to respond to the challenges immediately in front of them," agreed Matt Crozat, NEI senior director of policy development and another ex-DOE staffer.

He also urged Congress to exercise its oversight authority to ensure prompt action by FERC and RTOs on price formation rules.

"I think FERC can create the requirement to demonstrate how the [RTO] tariffs reflect these attributes that are important to the system," he said, adding, "I'll be watching closely to see how FERC begins to frame the question for itself."

"Based on what we've heard out of FERC leadership, it does sound like they're poised — it sounds like the system operators are poised — to actually move out fairly smartly on these things," Kotek said.

In a podcast interview with FERC's chief spokeswoman earlier this month, acting FERC Chair Neil Chatterjee said, "Baseload power … including our existing coal and nuclear fleet, need to be properly compensated to recognize the value they provide to the system." He cited their value to "resilience and reliability."

NEI also noted the DOE report's reference to the "important nonproliferation" implications of allowing the industry to decline.

DOE quoted Michael Webber, deputy director of the University of Texas' Energy Institute, who cited the risk to "our most important anti-proliferation asset: a bunch of

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Location of nuclear power plant retirements: closed, announced and averted | *DOE*

smart nuclear scientists and engineers. … The loss of expertise from a declining domestic nuclear workforce makes it hard for Americans to conduct the inspections that help keep the world safe from nuclear weapons."

NEI officials said they hope federal officials will consider making power purchase agreements from nuclear plants like the ones military bases signed with renewable power developers during the Obama administration.

"Those types of arrangements were clearly struck both to meet electric demand but also to promote, in this case, the growth of renewable energy deployment across the United States," Kotek said. "If we as a nation determine that the national security benefit of a strong domestic nuclear industry, along with the clean air benefits and the resiliency and reliability of nuclear plants are worth keeping around, then that's one avenue you could pursue in the effort to ensure we retain the plants that we've got.

"And it's a potential means for building new [plants]," Kotek continued. "You may know [that] the sustainability order that was put in place by the last administration included small modular reactors, for example, as a technology that would qualify as meeting clean energy demand going forward. It's one … potential tool in the tool box."

The officials cautioned against attempting to precisely price resiliency attributes into wholesale power markets.

"I think there are more expansive ways to go at this question without having to necessarily settle on 'Reliability is worth $4/MWh' or something like that," Crozat said. "That's going to be a difficult calculation to derive."

Crozat said he was encouraged by PJM's June report proposing to allow nuclear and coal plants needed for reliability to set clearing prices based on their marginal costs. This would be particularly helpful in addressing negative clearing prices in off-peak hours, he said. (See *PJM Making Moves to Preserve Market Integrity*.)

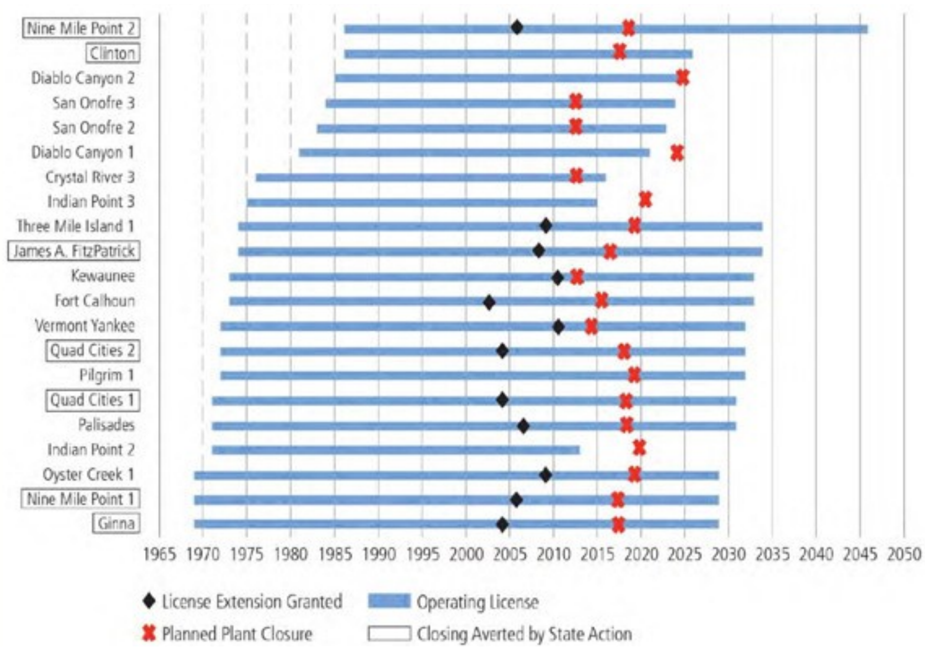
"If I know I have units that are going to be needed for reliability, I'll ensure that the prices are being set in a way that recognized the cost of those units," he explained. "It just changes slightly the economic logic of who's allowed to set prices and who isn't."

Exelon, the nation's largest nuclear operator, said it was encouraged by the Energy Department's recommendation that FERC "expedite" its efforts to improve energy price formation in organized wholesale markets. The company is defending zero-emission credits for its plants in New York and Illinois.

"These reforms will help preserve clean energy sources and ensure critical American assets remain part of the mix, including baseload nuclear plants that provide more than 60% of our nation's emissions-free energy," the company said in a statement. "We applaud the Department of Energy for their work, and urge FERC and the RTOs to swiftly enact common-sense reforms that will help safeguard the reliability, resilience, diversity and affordability of our supply of electricity."

NRG Energy, one of the independent power producers that have fought ZECs, also urged FERC to act on price formation and provide fuel- and technology-neutral ways to value reliability services.

"These efforts — and not expensive and market-destroying state subsidy programs to benefit particular generating facilities — would do more than anything else to ensure resiliency and reliability in an environmentally responsible and consumer-friendly way," the company said in a statement.



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