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ISSN 2377-8016 : Volume 2017/Issue 42 October 24, 2017

FERC Flooded with Comments on DOE NOPR

Widespread Opposition Means Quick Approval Unlikely

By Rich Heidorn Jr.

FERC received more than 300 comments on Energy Secretary Rick Perry's proposed "resiliency" rulemaking by its Monday deadline, with coal and nuclear interests backing the idea and RTO officials and most other stakeholders roundly rejecting it (RM18-1).

The flood of comments was so heavy that it taxed FERC's filing system, causing the commission to announce late in the afternoon it would accept comments into today.

Perry's Notice of Proposed Rulemaking would require FERC-jurisdictional RTOs and ISOs with capacity markets and day-ahead and real-time energy markets to ensure "full cost recovery" for any generation that can provide "essential energy and ancillary services" and has 90 days of fuel supply on site. Units subject to cost-of-service rate regulation would be excluded.

In its request for comments on the NOPR, FERC asked stakeholders to weigh in on more than 30 questions. Few commenters bothered. But they were effusive in their support — and withering in their criticism.

FERC Commissioner Cheryl LaFleur and newcomers Neil Chatterjee and Robert Powelson will decide the fate of the rulemaking, which critics say could reverse 25 years of electric competition. | *© RTO Insider*

Those that depend on coal and nuclear generation, including labor unions, shippers and mining companies, heartily endorsed it.

Continued on page 52

RTOs Reject NOPR; Say Fuel Risks Exaggerated

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

RTO officials and their Market Monitors on Monday unilaterally rejected Energy Secretary Rick Perry's proposal to provide price supports to coal and nuclear plants, calling it expensive, inefficient and counterproductive.

The ISO/RTO Council (IRC) led the opposition, with CAISO, PJM, ISO-NE and NYISO also filing comments in opposition. Also filing statements opposing the proposal were PJM Market Monitor Joe Bowring; David Patton, Market Monitor for MISO, NYISO and ISO-NE; and Keith Collins, head of SPP's Market Monitoring Unit.

In a joint filing supporting the rule, the American Coalition for Clean Coal Electricity (ACCCE) and the National Mining Association criticized the RTOs for failing to address trends threatening coal and nuclear generators.

They said NERC's and RTOs' "confidence in the current state of electric reliability … are based, in large measure, on existing conditions and short-term forecasts, largely ignoring the trend toward premature retirements of baseload coal-fired generating capacity currently available to address reliability and resiliency needs."

Continued on page 23

EBA Mid-Year Forum

- **EBA Panelists Talk 'Wacky' NOPR, 'Modest' ZECs, 'Rent Seeking' (p.3)**
- **Momentum' Seen for U.S. Offshore Wind (p.5)**
- **Panelists Discuss Carbon Policy, Renewables Integration (p.6)**
- **Chatterjee Outlines Goals for FERC Tenure (p.7)**
- **'Good Markets, Bad Markets: CEOs Sound off (p.8)**

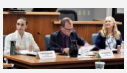
CAISO Stakeholders, Western Regulators Gather

- **Expanded Attendee Roster for CAISO Symposium (p.9)**
- **Symposium Panelists Talk Grid of the Future, Western RTO (p.11)**
- **Panel Talks Complexity of Storage Integration (p.13)**
- **Author of DOE Grid Study Disputes Recommendations (p.14)**

Also in this issue:

ERCOT IMM: 'Fat and Happy' Times Ending with Coal Closures (p.17)

MISO, PJM Reverse Support for Lone Interregional Tx Project (p.30)



Colorado Regulators Talk Governance with SPP (p.36)

New England, SoCal Gas Supplies Top FERC Winter Concerns (p.45)

FERC Sets 40-Year Term for Hydro Licenses (p.47)

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Subscription Rates:

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

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IN THIS WEEK'S ISSUE

- FERC Flooded with Comments on DOE NOPR (p.1)
- RTOs Reject NOPR; Say Fuel Risks Exaggerated (p.1)
- Storage Integration a Complex Process, Western Panel Says (p.13)
- Author of DOE Grid Study Disputes Recommendations (p.14)
- Connecticut Planning for Future with Changing Climate (p.24)

FERC
- New England, SoCal Gas Supplies Top FERC Winter Concerns (p.45)
- FERC OKs Cost Allocation on Va. Tx Undergrounding (p.46)
- FERC Sets 40-Year Term for Hydro Licenses (p.47)
- FERC Seeks Cyber Controls on Portable Devices; Sets GMD Plans (p.47)
- FERC Backs off Nonpublic Utility Refunds in MISO, SPP (p.48)

EBA
- EBA Panelists Talk 'Wacky' NOPR, 'Modest' ZECs, 'Rent Seeking' (p.3)
- 'Momentum' Seen for US Offshore Wind (p.5)
- EBA Panelists Discuss Future of Carbon Policy, Renewables Integration (p.6)
- Chatterjee Outlines Goals for FERC Tenure (p.7)
- Good Markets, Bad Markets: CEOs Sound off on State Policies (p.8)

CAISO
- CAISO Expands Attendee Roster for Stakeholder Symposium (p.9)
- CAISO Symposium Panelists Talk Grid of the Future, Western RTO (p.11)
- NRG Signals Pull-out on Proposed Puente Plant (p.12)

ERCOT
- Weeks Later, Utilities Still Awed by Scale of Hurricane Harvey (p.15)
- ERCOT IMM: 'Fat and Happy' Times Ending with Coal Closures (p.17)
- Board of Directors Meeting Briefs (p.18)
- ERCOT OKs Plant Retirement; TAC Meeting Canceled (p.19)

ISO-NE
- PAC Briefs (p.20)
- FERC Accepts Nondisclosure for ISO-NE Capacity Bids (p.22)

MISO
- $23 Million Owed to Ratepayers in Presque Isle SSR Case (p.26)
- FERC Rejects Inquiry on Manitoba Hydro Interconnection Fees (p.26)
- FERC Sees Discrepancies in MISO GIA Rules (p.27)
- Bigger Role Seen for Independent Forecast in MISO Tx Plan (p.28)
- MISO Sectors Mull Texas Project Delay for MTEP 17 (p.29)
- MISO, PJM Reverse Support for Lone Interregional Tx Project (p.30)
- Stakeholders Debate Limits of MISO Energy Storage Task Force (p.31)

NYISO
- FERC Approves NYISO Tx Cost Recovery Changes (p.32)
- New York PSC Adopts DER Rules, Sanctions ESCOs (p.32)

PJM
- PJM Board Approves $1 Billion in Tx Projects (p.34)
- MRC/MC Preview (p.35)

SPP
- Colorado Regulators Talk Governance with SPP, Mountain West (p.36)
- MOPC Briefs (p.38)
- SPP Tx Owners Take Zonal Placement Concerns to FERC (p.42)
- SPP to Consider Tx Planning Policy for Energy-Only Resources (p.43)
- FERC Again Rejects SPP Rules on ARRs, LTCRs (p.44)
- FERC Orders Section 206 Proceedings for 5 SPP TOs (p.44)

Briefs
- Company (p.49)
- Federal (p.50)
- State (p.51)

Energy Bar Association Mid-Year Forum

EBA Panelists Talk 'Wacky' NOPR, 'Modest' ZECs, 'Rent Seeking'

By Rich Heidorn Jr.

WASHINGTON — **Arnie Quinn**, director of FERC's Office of Energy Policy and Innovation, had modest hopes for reaching consensus when he moderated a panel on public policy and wholesale markets at the Energy Bar Association's Mid-Year Energy Forum last week.

From left to right: Market Monitor David Patton, Potomac Economics; Peter Fuller, NRG Energy; Kathleen Barron, Exelon; Rob Gramlich, Grid Strategies; and moderator Arnie Quinn, FERC Office of Energy Policy and Innovation. | *© RTO Insider*

The panel included Exelon's **Kathleen Barron**, a defender of zero-emission credits for nuclear plants, and NRG Energy's Peter Fuller, whose company is a harsh critic of the subsidies.

"While I think it might be hard to come up with a consensus about what ultimate landing spot we'd like to get to … at least agreeing on what we'd like to avoid would be helpful," Quinn said.

Quinn also invoked one unsafe word for the discussion: "MOPR" — minimum offer price rule. "Unfortunately, we've got a lot of pending dockets on minimum offer price rules," Quinn explained.

MOPR was not mentioned by the panelists. But consensus was indeed elusive in the discussion, which included FERC's May 1-2 technical conference on state policies and wholesale markers and Energy Secretary Rick Perry's call for price supports for nuclear and coal plants.

'Modest' Nuclear Supports

Barron, Exelon's senior vice president for competitive market policy, defended the ZECs approved in New York and Illinois, saying they had a "quite modest" impact on wholesale markets compared to state renewable energy credits and rate-based generation.

"I think we need to take a step back when we launch this conversation to just recognize that even the Eastern markets are not free of intervention," she said. "By 2025, about 30% of the generation in PJM will either be rate-based — through state cost-of-service regulation — public power or [renewable portfolio standard] programs," she said.

Even if all of PJM's nuclear generation — currently 19% of the RTO's capacity mix — were subsidized, she said, it would still have a smaller impact than state RPS goals. "How many renewable resources would they like to have: 25%, 30%, 50% by 2030?" she asked.

Moreover, while ZECs are worth $17.54/MWh in New York, that is less than the state's RECs, which run as high as $23.28, she said. Illinois' ZECs are $16.50/MWh, while their solar RECs are worth more than $200/MWh. And Maryland will pay $132/MWh for offshore wind RECs. "So we're talking about relatively small amounts compared to other clean generation programs," she said of ZECs.

'Four Product' Future

Despite his company's opposition to ZECs, **Fuller** did not contest Barron's claims. Instead he chose to discuss his company's "four product" vision of the future: renewables, energy storage, controllable demand and fast-ramping gas.

Fuller said that the Department of Energy's Notice of Proposed Rulemaking had sparked an "extremely important conversation" and that a role for fuel security is an "option to think about."

But he added, "The solution set, I think, is much broader than what was in the original notice from DOE."

In a future dominated by a zero- or low-marginal cost future, the LMP markets based on fuel costs "breaks down," he said. "Are we doing locational marginal pricing right? Are we calculating energy prices right? PJM has a proposal to really look at different eligibility for setting energy prices. That would be an important idea. Clearly we need scarcity pricing everywhere to capture the operational realities of the markets."

Fuller was the only member of the panel — which included **Rob Gramlich**, of Grid Strategies, and Potomac Economics' David Patton, whose firm performs market monitoring for MISO, NYISO, ERCOT and ISO-NE — who did not have FERC tenure on his resume.

'Wacky' Federal Initiatives and RTO 'Mission Creep'

Gramlich, a former senior vice president for

Continued on page 4

Energy Bar Association Mid-Year Forum

EBA Panelists Talk 'Wacky' NOPR, 'Modest' ZECs, 'Rent Seeking'

Continued from page 3

government and public affairs for the American Wind Energy Association who now consults for AWEA and other clean energy interests, said the DOE NOPR would "upend 25 years of progress toward competitive markets."

"We've had this conversation many times," said Gramlich, who served as senior economic adviser to FERC Chairman Pat Wood III in 2001-2005. "I think there's one major thing that's changed from the previous [discussions]. Usually the context is the wise, well intentioned federal authorities or the RTOs trying to clean up or fix what the wacky states are doing. [Now we're considering] not only wacky state policies but wacky federal policies and seeing whether we have a regulatory structure that can withstand that," he said, sparking laughter. "You might say whether it's resilient, whether it can withstand and bounce back rapidly from narrow political interventions."

Gramlich said market interventions have caused "mission creep" for RTOs beyond their traditional roles of running the transmission system and wholesale markets. "I'm frankly concerned that the RTO missions are getting extended well beyond those two core things and that a lot of states and utilities will look at these RTOs and say, 'I'm out.' Or, 'I'm in the West and I was thinking of joining. Now I'm not.'"

Gramlich was skeptical of Perry's call for compensating generation units for having on-site fuel supplies or providing "essential reliability services."

"We're seeing all sorts of interests saying their product or their generation type provides this, that or the other thing to the grid. I'm really relying on FERC here to decide: Is that actually needed? Is that actually a service? And if so, can others provide it as well? And let's create real competitive markets: define the service and then let any and all bidders bid to provide that service."

'Rent Seeking'

Patton said policymakers face an existential question. "You either believe in markets or not. And if you don't believe in markets then why are we doing this?" he asked.

"This just becomes a giant rent-seeking exercise. I know when I say that to a room full of lawyers, that doesn't sound terrible," he added to laughter.

Patton said FERC deserves blame because it has "never articulated any sort of standard on what a just and reasonable capacity market looks like. The closest they've ever come is in New York, saying it's got to produce a price signal that will be sufficient to get an adequate resource mix."

He noted that capacity markets incent

Continued on page 5

Energy Bar Association Mid-Year Forum

'Momentum' Seen for US Offshore Wind

By Rich Heidorn Jr.

WASHINGTON — Even as the Trump administration has rejected the Paris Agreement and works to boost coal-fired generation, optimism has been building on the East Coast for the offshore wind industry.

The U.S. market has gained momentum in the last two years, the head of DONG Energy Wind Power U.S. told the Energy Bar Association's Mid-Year Energy Forum during a panel discussion last week.

President **Thomas Brostrøm** credited state renewable portfolio standards and carbon reduction goals for creating demand. And he said the shallow waters off the East Coast provide attractive sites like those in Europe.

DONG, the No. 1 offshore wind generator in the world, clearly sees renewables as the future. On Oct. 30, it will ask shareholders to approve changing its name — originally an abbreviation for Danish Oil and Natural Gas — to reflect its commitment to renewable power. It completed the divestiture of its upstream oil and gas business in September. The new name, Ørsted, honors Danish scientist Hans Christian Ørsted, who is credited with discovering electromagnetism in 1820.

The company, which operates more than 1,000 offshore wind turbines in Europe, acquired the rights to develop more than 1,000 MW off New Jersey and is working on a pilot project with Dominion Energy off Virginia. (See *Dominion Plans 12-MW Offshore Wind Project, 2nd in US*.) It also has formed a joint venture with Eversource Energy to bid on Massachusetts' solicitation for 1,600 MW of offshore wind.

Brostrøm said the industry has matured over the last two decades as it has moved from "bespoke" projects to more standardization. At the same time, the technology has advanced from 3.6-MW turbines in 2009 to 8-MW turbines today, with next-generation models expected at 12 to 15 MW.

The panel discussion, moderated by Holland & Knight partner Mark C. Kalpin, also included **Walter Cruickshank**, acting director of the U.S. Bureau of Ocean Energy Management, and Curtis Fisher, executive director of the National Wildlife Federation's Northeast Region.

Since 2009, BOEM has issued 13 offshore commercial wind energy leases, giving leaseholders the right to seek approval for development plans. The U.S. currently has only one operating offshore wind project, Deepwater Wind's 30-MW Block Island Wind Farm in state waters off Rhode Island, which went into service last December.

"We have quite a bit to learn, still, about how things will operate — how developers will move forward with their projects," Cruickshank said.

On Aug. 31, Interior Secretary Ryan Zinke, Cruickshank's boss, signed an order setting a one-year target for completing environmental reviews under the National Energy Policy Act following the issuance of a Notice of Intent. "We haven't entirely figured out how we're going to do that yet, but we are working on trying to improve our processes," Cruickshank said.

Fisher said his organization supports offshore wind when it is sited "in the right places" and construction minimizes impacts on aquatic life. The group is especially concerned that foundations are not drilled during the migration of endangered North Atlantic right whales because the noise can disturb the marine mammals. Fewer than 500 are believed alive.

"This is our big chance" to address climate change, Fisher said. "I fundamentally believe that this is the challenge of our generation — to actually build [renewable] projects on scale to solve problems that many people think are just too big to solve."

EBA Panelists Talk 'Wacky' NOPR, 'Modest' ZECs, 'Rent Seeking'

Continued from page 4

generation investments that are evaluated over a lifespan of 30 or 40 years.

"If every year or two you have dramatic policy shifts that change fundamentally what people's expectations are about the market revenues they're going to get, then you get … the worst-case scenario.

"It's alarming how many times … new [FERC] commissioners have come in and said, 'I want to revisit whether capacity markets are a good idea. Let's have a technical conference and determine whether capacity markets are delivering on their objectives.' Basically, the subtext is we may do away with these things. And they're delivering roughly half the revenue that the generation needs to break even on a new investment. … It's like when Congress says, 'We may not raise the debt ceiling.' How do you even say that?"

Patton disputed arguments Perry and others have made in defense of price supports.

"When people tell me we're overly gas-dependent, we don't have markets that value fuel diversity, [I say] that's absolutely not true. When people say we don't have a market that motivates generators to be available and perform, that's absolutely not true," he said. "They're assertions that support doing something and changing the markets. But if you think about what we're talking about, if you have good shortage pricing and we're short somewhere because a gas pipeline blew up, then everybody who's got dual-fuel capability [or is] powered by something other than gas makes an enormous amount of money. Anyone who's gas-only and didn't make provisions to be able to run in that scenario loses a lot of money, especially under the New England [Pay-for-]Performance rules that overcompensate performance."

Patton said the NOPR's notion of "'resilience' is just reliability" for contingencies whose probabilities are so low that grid operators haven't planned for it.

"And if it happens, our shortage pricing is going to account for it," he said. "The overriding objective should be to maintain market signals, and there's only a few of them: There's energy, ancillary services and capacity. You don't need 10 products to do that."

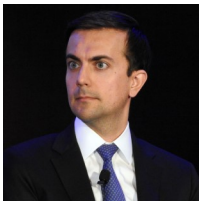
Energy Bar Association Mid-Year Forum

EBA Panelists Discuss Future of Carbon Policy, Renewables Integration

By Rory D. Sweeney

WASHINGTON — Two panels at the Energy Bar Association's Mid-Year Energy Forum last week offered starkly contrasting views of the future.

The opening morning panel focused on the future of carbon policy, with several panelists offering a potential future for coal. A later panel focused on the impact of increasing intermittent generation on the grid.



EPA Deputy General Counsel **David Fotouhi** said Administrator Scott Pruitt has targeted three coal-related environmental rules for reconsideration: the Clean Power Plan; 2015 steam-electric effluent limitations in the Clean Water Act; and the coal-combustion residuals rule in the Resource Conservation and Recovery Act.

"Those three efforts in common share the touchstones of rule of law, cooperative federalism and process, and making sure the process is regular," Fotouhi said.

Disagreement over Coal 'Bailout'

Paul Bailey, CEO of the American Coalition for Clean Coal Electricity, said he received no forewarning of the Department of Energy's Sept. 29 Notice of Proposed Rulemaking calling for price supports for coal and nuclear facilities.

"We didn't know this was going to happen until we saw it," he said. "We're also trying to understand this proposal like many others right now."

He said his organization, which represents coal-fired generators, doesn't view it as a bailout.

Marc Chupka of The Brattle Group said domestic coal production would be aided by the CPP repeal and improving mining techniques to reduce costs. However, he warned that inexpensive natural gas "will end up crushing coal."

"There is very little that [coal-fired] generators can do in the face of $3 gas," he said.

Benjamin Longstreth, an attorney with the Natural Resources Defense Council, disagreed with Bailey's description of the DOE NOPR and said there was "an absolute lack of analysis to support the proposal." He quoted Pruitt's complaint that EPA was "picking winners and losers" in the CPP.

"I don't agree with Pruitt's description of the Clean Power Plan, but I think it aptly describes DOE's proposal," Longstreth said. "We view it as a bailout."

The NOPR argues that retaining coal and nuclear facilities that have 90-day fuel supplies maintains grid reliability, but Longstreth said that only 0.007% of outages are due to fuel shortages.

Andrew McKeon, the executive director of the nine-state Regional Greenhouse Gas Initiative, said the past 200 years of economic prosperity has been "very closely tied" to fossil fuel use, but the two trends must "decouple" to address climate change.

"The fact is it's a global problem and needs a global answer," he said.

RGGI is providing one path, he said. The states involved — Delaware, Maryland, New York, Connecticut, Massachusetts, Rhode Island, Vermont, New Hampshire and Maine — have seen a 45% reduction in carbon dioxide emissions from electric generation since 2005.

"We're doing the job twice as fast as the rest of the country," he said.

Filling the Breach

All panelists acknowledged federalism and the importance of states making decisions on their own.

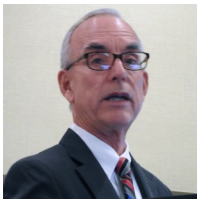
"We absolutely believe that states should step into the breach" left by Trump administration policies, Longstreth said.

New York is trying to be one of those states. In a later panel, NYISO's Robert Pike explained New York's analysis for implementing carbon pricing. The state is already providing renewable energy credits (RECs) and zero-emissions credits (ZECs) for nuclear facilities. The state commissioned a study by Brattle to determine if NYISO's market could achieve the same function as its existing administrative solutions.

"It's about a wash in costs," Pike said. "The bills stay about the same for consumers because the carbon price would then offset the need for RECs and ZECs."

Pike said there also are questions about how the DOE proposal would be applied. He noted a coal facility in New York that runs very infrequently.

"What does a 90-day coal pile look like at a unit that runs 1% of the time?" he asked.



Ralph Romero, of infrastructure developer Black & Veatch, said the cost of energy storage "has dropped dramatically" in recent years to between 40 and 50 cents/W depending on location. He said some analysts have predicted that $100/kWh for batteries by 2020 is "not beyond the realm of possibility."

ICF International's Kevin Petak joined with others in the natural gas pipeline industry who have said that securing firm pipeline capacity is complicated and not always feasible. He noted that while electricity can move at nearly the speed of light, gas moves about 30 mph, so suppliers require time and planning to ensure gas is physically available.

Pipeline companies have argued that gas-fired generators need to pay for uninterruptible pipeline deliveries if they want to ensure supplies, but Petak said generators aren't able to recover that cost from customers.

Marketers can bundle capacity with the gas when they make contracts, he said, but "since there is no mechanism to buy the capacity and pass that cost on to the consumer, there has been reservation on the part of generators to reserve capacity."

Chatterjee Outlines Goals for FERC Tenure

By Rory D. Sweeney

WASHINGTON — Neil Chatterjee, FERC's recently appointed interim chair, already has plans for shaking up the 40-year-old commission.

Speaking last Tuesday at the Energy Bar Association's midyear conference, the former energy adviser to Senate Majority Leader Mitch McConnell (R-Ky.) tallied off six objectives for revising FERC's regulatory posture.

They ranged from streamlining project review for natural-gas and hydropower projects, to determining a "just and reasonable" return on equity for transmission projects; from changing FERC's interpretation of *de novo* review and revising the Public Utility Regulatory Policies Act, to addressing cyber threats. Chatterjee said he also wants to ensure the industry doesn't outrun itself with technology advancements.

Reliability

But although it was buried deep in his speech, his timeliest goal appears to be maintaining grid reliability "during a time of rapid change," which comes in light of the Department of Energy's recent Notice of Proposed Rulemaking calling for price supports for coal and nuclear plants.

Chatterjee has already said he supports investigating the issue. (See *FERC Chair Praises Perry's 'Bold Leadership' on NOPR*.)

Last week, he suggested that those baseload resources may be needed to avoid changing the generation fleet too much, too quickly.

"Reliability is and will continue to be our foremost priority," he said, listing off several of FERC's responsibilities related to reliability. "In my view, the DOE NOPR fits comfortably within those efforts. … We must ensure we don't find ourselves coming to regret not having asked hard questions like these amongst all the changes in the energy industry."

He also said that news of attempts by Russia and North Korea to hack the grid highlight other reliability needs.

"It's clear that defending our nation from international cyber threats is one of the most serious challenges of our time," he said.

Streamlining Review

Chatterjee also voiced support for streamlining the review process for natural gas pipeline and hydropower projects.

"The FERC review process continues to get longer and longer, due in large part to increased participation in the process by stakeholders, including numerous legal challenges," he said. "FERC owes both sides an opportunity … to receive a timely up-or-down decision."

Chatterjee dismissed suggestions that FERC depart from its "longstanding" reliance on customer agreements to gauge the economic need for a project "in favor of weighing a broad range of economic, social and aesthetic values." Gas subscriptions on pipelines are "clear, unequivocal statements of economic need by the market itself." (See *FERC Chair: Court Ruling Won't Change Pipeline Reviews*.)

He blamed project delays on incomplete applications, negotiations with federal and state agencies and the "sheer number" of comments, saying "FERC is most definitely not the principle source of those delays." He urged applicants to use FERC's prefiling process and said he hopes to "pursue understandings that can be reached on an agency-to-agency basis" to improve response time. There is no way to speed up comments or responding to them thoughtfully, he said.

Additional Issues

With the generation fleet changing and transmission constraints raising prices, consumers stand to benefit from developing additional transmission infrastructure, Chatterjee said. The "most critical near-term piece" is finding the right financial incentives for enticing project investment, which will involve determining "what represents a just and reasonable return on equity for transmission projects."

Courts have rejected FERC's interpretation of its *de novo* review authority five times, he said, so the commission must develop a "proper scope" that is "fair and legally defensible." FERC has been chastised by Congress in the past for not properly handling enforcement cases. (See *FERC Enforcement Process Under Fire in House Hearing*.)

Finally, Chatterjee indicated he plans to address FERC's implementation of PURPA, specifically the "1-mile rule" for qualifying facilities. FERC has ruled that QFs located within 1 mile of each other are considered to be "located at the same site" and that wind farms of 20 MW or larger within ISO/RTO regions are presumed to have access to competitive markets and thus ineligible for PURPA's must-purchase obligation on incumbent utilities. However, stakeholders have complained that QF developers are circumventing the 20-MW cap by creating separate corporate entities for individual turbines or small groups of turbines, or disaggregating large projects by siting turbines more than 1 mile apart. (See *Witnesses Offer Alternate Realities on Need for PURPA Reform*.)

Neil Chatterjee | *© RTO Insider*

Energy Bar Association Mid-Year Forum

Good Markets, Bad Markets: CEOs Sound off on State Policies

By Rich Heidorn Jr.

From left to right: moderator Christopher R. Jones of Troutman Sanders, Dynegy CEO Robert Flexon, Large Public Power Council President John DiStasio and Pacific Power CEO Stefan Bird. | © *RTO Insider*

WASHINGTON — Panelists at the Energy Bar Association's Mid-Year Energy Forum last week heard two very different views of the health of wholesale markets.

Pacific Power CEO Stefan Bird was effusive in his praise of the Western Energy Imbalance Market (EIM), which saved parent company PacifiCorp almost $9 million in the second quarter of 2017. But Dynegy CEO Robert Flexon complained that CAISO and NYISO had become increasingly inhospitable to merchant generators because of state policies favoring renewables and nuclear generation, respectively.

"For us, the markets are [in an] incredibly fragile situation. California is a disaster. There isn't any competitive power company out there who wants to put a nickel into California," he said.

Flexon also bemoaned MISO Zone 4 in Southern Illinois, where he said competitive units face unfair competition from rate-based generation. The state also has approved zero-emission credits for nuclear plants, leading to fears in PJM — whose footprint includes Northern Illinois — that such subsidies will be contagious.

"PJM is doing everything they can to try to keep their market together. They're very proactive," Flexon said. "They're trying to fix price formation and the like. [Having] half our megawatts in PJM, I feel good about that."

Bird said his company's experience with the EIM has been an unquestioned success.

Moderator Christopher R. Jones, a partner with Troutman Sanders, had set off the discussion by asking Bird if the markets are "healthy."

"Are they enabling what our customers want? Are they enabling [a] low-cost, affordable, reliable future? I think the answer is resoundingly 'yes,'" said Bird, whose company has 740,000 customers in Oregon, Washington and California.

"We've really had unprecedented opportunities to move that dial on a very accelerated pace and lower costs as well as reduce emissions."

He said the EIM's economic dispatch and its ability to move renewable power to load centers enabled PacifiCorp to announce in June a $3.5 billion investment in renewables and transmission in Wyoming, Utah and Idaho "at very little to no costs for our customers and savings over the long term." (See *PacifiCorp IRP Sees More Renewables, Less Coal*.)

John DiStasio, president of the Large Public Power Council, said his members don't have a single view of the market. His organization, which represents the 26 largest members of American Public Power Association, has members in NYISO, SPP and ERCOT.

"Those members that view that there's economic benefits for them are participating in markets, and those who don't see that don't [participate]," DiStasio said.

He said RTOs have gone through "identity crises."

"When we started up with CAISO, it was really a traditional RTO. And at some point, state policy started to drive how they looked at supporting environmental policy as well. There's been hit and miss on how that's been priced. There's been hit and miss on how you get the right incentives for capacity in some of the markets." DiStasio said California's dominance of CAISO has been a barrier to greater market expansion in the West.

"Having said that … moving energy over wider regions I think is going to have a certain inevitability to it where we'll have more and more people operating in markets — even if it's just at the EIM level.

"From a Western perspective, I was appreciative that FERC didn't try to push the Energy Imbalance Market. Actually, it would have fallen apart had that happened given the history of the [2000-2001] energy crisis, the [1980 Pacific Northwest Electric Power Planning and Conservation Act], given what happened in the Northwest during the energy crisis.

"I think FERC trying to assert more control at that time actually would have had a negative effect. Now, the market dynamics seem to have emerged organically enough that you have people that are voluntarily creating critical mass.

"I think this is really going to be a delicate balance going forward with how much does FERC push on state policy, and I think they may have to rethink the whole paradigm at some point. Because it is a clearly a hybrid and we're kind of stuck … in no man's land."

When the discussion turned to Energy Secretary Rick Perry's call for price supports for coal and nuclear plants, Flexon also called for FERC action.

"FERC has been missing while all the mischief has been happening," he said, referring to the agency's six months without a quorum. "They need to get back in the game and protect the markets they created."

CAISO News

Stakeholder Symposium 2017

CAISO Expands Attendee Roster for Stakeholder Symposium

By Jason Fordney

Symposium attendees watch as Catherine Reheis-Boyd, president of the Western States Petroleum Association, speaks. This year marked the first time CAISO invited representatives of other industries in California for a panel. About 1,000 people attended the convention. | *© RTO Insider*

SACRAMENTO, Calif. — The rapidly changing energy landscape in the Western U.S. was the recurring theme at CAISO's 2017 Stakeholder Symposium last week. About 1,000 attendees from the industry, its disruptors and other counterparts gathered at the Sacramento Convention Center.

This year, the ISO expanded the scope of the conference by inviting representatives from agriculture, Western oil and gas companies, and the commercial development industry to present fresh perspectives. The discussions revealed that policymakers, those responsible for grid reliability and large energy-using industries have accepted California's legislative, regulatory and public commitment to renewables.

But there are many questions about what lies on the road ahead. California's evolving mix of technologies and complex policymaking structure has placed much attention on a state that would boast the sixth largest economy in the world if it were an independent country.

A wide range of stakeholders, particularly those from neighboring states, are grappling with the questions of creating an RTO and a changing model for electricity delivery and consumption that is moving toward storage and distributed energy resources. Rising consumer costs and other impacts on the public were themes interwoven into the talks, and memories of the 2000-2001 Western Energy Crisis linger like ghosts among California policymakers.

Renewable Interests Discuss Storage

Participants on an Oct. 18 panel discussion of energy storage focused on the reliability and cost considerations of renewables and how energy storage can be used to better balance variable wind and solar output.

Left to right: panel moderator Colleen Regan, Bloomberg New Energy Finance; Kevin Smith, SolarReserve; and Paul Thomsen, Ormat Technologies. | *© RTO Insider*

Storage is seen as the next wave in California energy development because of the large amount of photovoltaic and thermal solar coming online, panelists said. Concerns center on replacing the ramping ability of traditional generation, a role that would be suitable for responsive energy storage devices.

High-volume, bulk storage allows solar thermal plants to act like a traditional generating station, SolarReserve CEO Kevin Smith said. The California market is headed toward 50% renewables and beyond, but there are problems related to the "duck curve" and negative energy prices due to overgeneration. To reach the goal of reaching even 50% zero-carbon sources, "you are going to have to have thousands of megawatts of energy storage," Smith said.

"Largely, renewable generation is going to have to go towards energy storage," he said. Solar PV plus batteries can provide short-term ramping capability of up to an hour, but longer ramping capability will be needed to meet system needs.

Continued on page 10

CAISO News

Stakeholder Symposium 2017

CAISO Expands Attendee Roster for Stakeholder Symposium

Continued from page 9

First Solar CEO Mark Widmar said "Solar 1.0" was about attaining as much solar energy as possible, while "Solar 2.0" will be "incorporating flexibility and controllability."

"Solar 3.0" will be about integration of storage. Other countries and states are looking to California to see how it is handling such a large influx of renewables, he said.

"Everyone is looking at California, particularly in the States," Widmar said. "Everyone wants to know how California is going to create a sustainable market."

The conversation about renewables often revolves around subsidies, but "maybe the market just needs to get the values right without overriding policies that skew that," Ormat Technologies Executive Director Paul Thomsen said.

California utilities have procured a great volume of low-cost renewable compliance solar, "and now they are struggling with the best fit, and that is where we are today," said Thomsen, a former member of the Nevada Public Utilities Commission. The market will provide the needed products, he said. "But we are not going to do it unless you give us a price signal."

Other Sectors Weigh in

To bring new voices into the conversation, CAISO invited representatives from the New Buildings Institute (NBI), California Farm Bureau Federation (CFBF) and Western States Petroleum Association (WSPA) to discuss how they are managing the changing electric grid.

WSPA President Catherine Reheis-Boyd said that big changes are also happening rapidly in the petroleum industry: "It is not just the electricity industry; it is ours as well."

Despite California's moves to electrify the transportation sector, there are still 26 million internal combustion engines in the state, compared with about 200,000 to 250,000 electric vehicles. California is the third largest consumer of transportation fuels in the world, she said, and the industry produces 3 million gallons of gasoline and diesel every hour.

"We are going to be with you in this conversation for a while, at least for the foreseeable future," Reheis-Boyd said, and "very much a part of this mix." The magnitude and timing of electrification is extremely important, she added.

NBI CEO Ralph DiNola said the group is committed to energy efficiency research in design and construction. "It is clear that California policy is driving toward electrification, and I think the building sector is front and center." Buildings serve as the nexus to the grid, he said, and can be designed and built as grid assets that can be managed and implemented.

A large percentage of energy is used by agricultural producers to pump water to irrigate crops and other after-harvest applications, CFBF attorney Karen Norene Mills said. Many have made investments to adjust to the existing time-of-use rate structure and the incentives matched their practices.

"Our members are struggling with what is happening with the changing landscape," she said, particularly changing rate structures. "We are finding as we talk to them that there are some real challenges with that." In the past they have been able to manage their systems and set up operations so they could pump off-peak, and if that is changing, their investments will not be as effective as they have been.

Left to right: Ralph DiNola, New Buildings Institute; Karen Norene Mills, California Farm Bureau Federation; Catherine Reheis-Boyd, Western States Petroleum Association; Jürgen Weiss, The Brattle Group. | *© RTO Insider*

CAISO News

Stakeholder Symposium 2017

CAISO Symposium Panelists Talk Grid of the Future, Western RTO

By Jason Fordney

John Danner (far left), a professor at the University of California Berkeley and Princeton University, moderates a panel of members of CAISO's Board Governors: (left to right) Chairman Richard Maullin, Angelina Galiteva, Mark Ferron and David Olsen. | *© RTO Insider*

SACRAMENTO, Calif. — CAISO's Board of Governors last week provided insight into a new 2030 energy "vision" for California and the region, one of many discussions at the ISO's 2017 Stakeholder Symposium.

Governor David Olsen said the "Electricity 2030" paper examines the "the sustained, orderly retirement of gas turbines." It also discusses the importance of states working together and collaboration among agencies and the public.

CAISO is taking comments on the document, which says a decarbonized, decentralized and more regional electric grid is driving the transition in California. The paper calls for a grid powered by two-thirds non-fossil fuel — and no nuclear — generation by 2030, and lists economic benefits from clean energy jobs and better public health.

But operational dispatch to meet locational capacity needs will be different on a decentralized grid, and "there are engineering challenges along the way" to incorporate the combined capabilities of new resources such as solar and distributed generation, Olsen said.

"It is very important for all of us to take these challenges seriously," he said, "because nothing will stop movement toward a modernized grid faster than a blackout."

Challenge and Opportunity

NRG Energy last week took steps to withdraw its application for a new natural gas plant in Ventura County to replace 2,000 MW of generation retiring because of the state's once-through cooling rules. (See *NRG Signals Pull-out on Proposed Puente Plant*.) The Ventura/Moorpark load pocket is one example of how locational needs require massive capital investment, as costs for the three distributed energy options to replace the capacity range from $309 million to $1.1 billion.

Governor Angelina Galiteva said the shift to a new type of grid is inevitable and discussed what she called the "financial justice" of the transition. Managing renewable integration "is a challenge, but it is also an opportunity," she said.

"We tend to agree that moving towards a much more decarbonized grid is where everybody is moving," Galiteva said. A diversity of resources is important to optimize the system, meaning that interstate cooperation to optimize resources "becomes increasingly important."

She added that climate change is a global issue, and developing countries will benefit from successful efforts in the U.S. "They can leapfrog technologies; they can build microgrids," she said.

Governor Mark Ferron called for an "optimistic" attitude toward the emerging technology and new communications and called for a "forward-looking approach."

"I kind of turn it around and say, 'What's the alternative?'" he said. "It is not a long-term winning strategy to try to restrict consumer choice or roll back new technology." He also mentioned the "sea change" of integrating electric vehicles, which must become a grid asset and not a liability.

Regulators Discuss Regionalization

Montana Public Service Commission Vice Chair Travis Kavulla moderated a panel of state regulators who discussed regional differences and the effort to regionalize the Western electricity grid, which is expected to be resumed by the California State Legislature next January.

"There are a variety of cultural issues these days," California Public Utilities Commission President Michael Picker said, adding that, aside from political differences in California, "we have a long-standing fear of FERC." He predicted there will be some flexibility in terms of governance of an RTO.

"We have this enormous advantage of having this great diversity of resources in the West," Picker said, which makes electricity planning easier than planning in other sectors, such as water rights.

Giving the inland West perspective, Laura Nelson, energy adviser to the Utah Public Service Commission, said: "Regionalization is inevitable, but it is a very, very slow-moving ship." There are political differences to contend with, she noted.

"In parts of the Rocky Mountain West, we really do have a different view of our resources," she said, but "Utah has been engaged in those conversations." Utah has traditionally used a lot of coal for generation but also has natural gas and is on track to increase its renewable penetration to 8%.

Most panelists agreed that the trend toward regionalization will increase with time, with the large and dynamic gathering in Sacramento perhaps representing a step toward that end, if all parties can be brought into sufficient alignment while keeping electricity affordable and reliable.

CAISO News

NRG Signals Pull-out on Proposed Puente Plant

By Robert Mullin

NRG Energy last week asked the California Energy Commission to suspend its review of a proposed 262-MW gas-fired plant in Oxnard, likely closing the book on a project that met with stiff resistance from community and environmental groups.

The company's request came after Commissioners Janea Scott and Karen Douglas earlier this month issued what they acknowledged was an "unusual" notice recommending denial of the Puente Power Project. They wrote that it would be "inconsistent with several laws, ordinances, regulations or standards and will create significant unmitigable environmental effects." (See *CEC Members Recommend No-Go for Puente Plant*.) The commission is responsible for issuing construction and operating permits for new generating plants.

Scott and Douglas, who together constituted the committee preparing the commission's decision on Puente, said they made their recommendation so early in the process because they saw a need to study alternatives to the plant after CAISO filed comments contending that the economic feasibility of preferred — or non-emitting — resources could only be established through a new request for offers. While Southern California Edison selected Puente through a standard procurement process, CAISO pointed out that costs for preferred resources have since declined enough to warrant a new RFO. The ISO also noted that cost should not be the only factor driving the decision.

The Puente plant would have been built on the site of the Mandalay Generating Station in Oxnard (shown), where NRG plans to shut down two existing steam turbine units to comply with California's once-through cooling restrictions. | *NRG*

"An economically feasible option need not be the least expensive option, especially given the environmental and performance issues that are unique to each portfolio," the ISO said.

The commission also received hundreds of comments opposing construction of the plant.

In its Oct. 16 filing with the commission, NRG said it is still considering whether to fully withdraw its application for certification (AFC) for Puente.

"Granting this motion [to suspend the proceedings] will ensure effective use of resources of the committee and the parties to these proceedings in the event that the applicant determines to withdraw the AFC," NRG said.

The company proposed to build the plant on the site of its Mandalay Generating Station, where it will shut down two existing gas-fired steam turbine units that don't comply with California's upcoming regulations restricting once-through cooling. About 2,000 MW of generation in the area is due to retire by 2020 because of the regulations.

The fast-ramping Puente plant would have been capable of reaching more than 95% of its capacity within 10 minutes, helping to integrate renewable resources and ensure reliability in the state's Ventura/Moorpark subarea, a load pocket that imports much of its electricity through a single substation, the company has said.

The California Public Utilities Commission has already authorized SCE to enter into a long-term resource adequacy contract with the plant, which was slated to begin operating in 2020.

Storage Integration a Complex Process, Western Panel Says

By Jason Fordney

| © RTO Insider

RENO, Nev. — Energy storage can provide many benefits to the Western electricity grid, but it will require complex and costly modeling to be integrated properly, a panel of regional energy experts said this week.

The power industry, and its regulators, will require a long-term effort to accurately analyze the benefits and costs of storage, the panel of utility representatives and others said during an Oct. 17 joint meeting of the Committee on Regional Electric Power Cooperation (CREPC) and the Western Interconnection Regional Advisory Body.

Sector participants must study what ancillary services and sub-hourly and locational benefits storage resources can offer along with the range of other uses being explored for the technology.

Fully modeling the impact of energy storage across the existing utility system "is going to be a very difficult nut to crack" and a big computational problem, said Elaine Hart, a Portland General Electric power analyst.

Oregon-based PGE has been using software tools to model storage, Hart said, utilizing a production cost model for its integrated resource plan (IRP) that simulates the electricity system and dispatch over 20 years and 30 different potential future scenarios based on gas prices, resource output, energy prices and other factors. The effort requires significant computing power and lengthy running of software programs to model possible outcomes.

"We are really lucky that we had this tool when we started evaluating energy storage," Hart said. To reduce computational time, timelines for modeling could be expanded to every few years instead of every year, for example, and other adjustments could be made, she noted.

Getting it Right

The Washington Utilities and Transportation Commission is working to help that state's investor-owned utilities integrate energy storage into their IRPs, commission energy adviser Jeremy Twitchell said. The regulator has directed utilities to improve their analysis of energy storage options, an initiative launched after it observed activities at FERC and in California, New York and around the country.

"The key takeaway as we looked around as there were niche storage applications at the time: There were cost-effective applications in a limited scope," he said. The commission knew utilities needed to be more flexible and that technology costs were dropping, but its modeling capabilities were inadequate.

The commission felt that if it got the modeling right, utilities would integrate the technology in a cost-effective way, Twitchell said. It held workshops to identify challenges, bringing in national laboratories to provide modeling advice and finding that storage can perform well as frequency support and fast response. He also said storage should also be studied for its impact on the transmission and distribution grid, and not just as an IRP resource.

The UTC earlier this month issued a policy statement saying that the absence of an organized market in the West is creating many of the challenges of integrating energy storage, but Twitchell said that perspective is changing because regulated utilities can still capture the benefits of storage without relying on wholesale market outcomes.

FERC in January issued its own storage policy statement "to provide guidance regarding electric storage resources seeking to receive cost-based rate recovery for certain services while also receiving market-based revenues for providing market-based rate services." According to FERC, the main issues around integrating storage relate to protecting cost-based ratepayers from the potential for double-recovery of costs, preventing adverse market impacts, and maintaining RTO and ISO independence from market participants.

Commissioner Cheryl LaFleur dissented against the policy statement, which was approved by former Chairman Norman Bay and former Commissioner Colette Honorable, saying she disagreed that the issue should be split off from a Notice of Proposed Rulemaking that FERC issued in November 2016.

Price Discovery

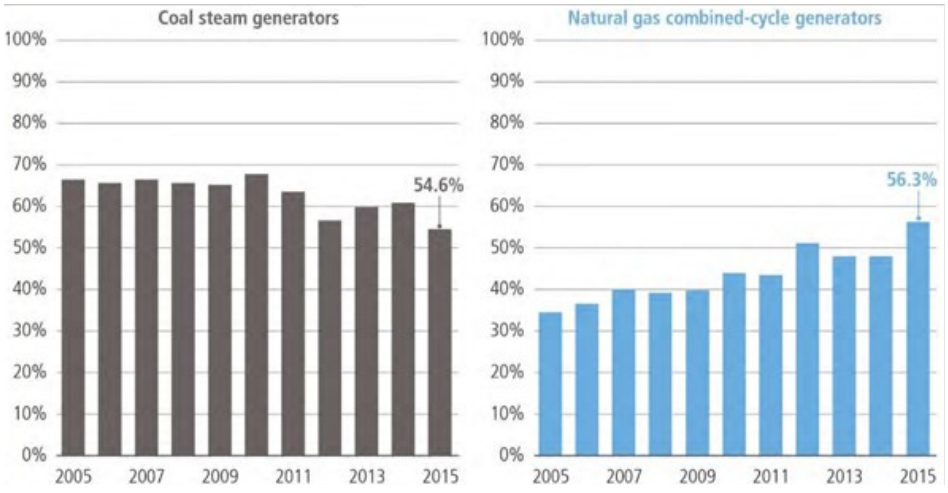
Travis Kavulla, CREPC co-chair and Montana Public Utilities Commissioner, asked the panel how more "price discovery" could be incorporated into the modeling process. He said that storage has generally been implemented in two ways: as a "mandate backed up with technocratic guess-work shoved into the rate base," or with ISOs designing products that let batteries compete in markets.

Tucson Electric Power's Lee Alter said that IRPs covering all resources could discover pricing and compare different technologies, and that studying storage "jibes really well with the IRP process." He said his utility is beginning to model energy storage, including sub-hour modeling that serves to study not just integration of batteries, but other impacts from the Western Energy Imbalance Market, pumped storage and other resources.

The discussion made clear that modeling the impacts of energy storage, identifying the benefits and turning energy storage services into a consistent revenue stream will be an ongoing challenge for utilities, regulators and other stakeholders.

Author of DOE Grid Study Disputes Recommendations

By Jason Fordney



Annual average capacity factors | *Department of Energy*

RENO, Nev. — If she had her way, the principal author of the Department of Energy's August grid study would have written its recommendations a bit differently. And she wouldn't have attempted to use it as a pretext for price supports for struggling coal and nuclear plants, she said last week.

Alison Silverstein, an independent consultant and former adviser to FERC Chairman Pat Wood III, gave a presentation last week at a joint meeting of the Committee on Regional Electric Power Cooperation and the Western Interconnection Regional Advisory Board, recommending the protection of wholesale markets and not particular technologies.

She argued that coal units are not good for grid "resilience" and contested their inclusion among so-called "baseload" plants.

"Coal plants that retired recently did not operate as baseload," she said. "Retired plants were smaller, older, had higher heat rates, and therefore were dispatched less often and ran at lower capacity factors."

The department's Notice of Proposed Rulemaking to FERC would require RTOs with both energy and capacity markets to compensate generators their full operating costs if they maintain a 90-day supply of on-site fuel.

Silverstein said that most coal plants have on-site inventories of 45 to 70 days, not 90 days as sometimes cited by coal interests.

She recommended that grid planners "identify, define, productize and compensate essential reliability and resilience services to meet multi-hazard threats and scenarios." She said that "every essential service should be compensated," but not all should receive market-based compensation, and "some should be conditions of interconnections with value-based compensation."

She also recommended that renewables and demand response be used for frequency response because they are better at providing those services than conventional generation, if they receive proper incentives.

While the department's study recommended that FERC consider action similar to the NOPR, the technical portions, of which Silverstein wrote the initial draft, contained little new information or data, citing trends familiar to observers of the markets. Many stakeholders, particularly those in renewable energy, feared that the department would attempt to manipulate the data to support its recommendations. (See *Perry Grid Study Seeks to Aid Coal, Nuclear Generation*.)

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.

DOE's 'Deregulatory Push'

Fisher was also at the conference. He said DOE will soon issue a report on its "deregulatory push" following President Trump's executive order on reducing regulations. The department is focused on technology and cybersecurity, the latter of which is "a huge issue and a top priority" for Secretary Rick Perry, he said.

He said that the industry needs to work more closely with government, and noted that discussions at the conference had focused on better computer modeling. DOE is doing a lot of work in that area, and "we actually are here to help," he said.

'Exciting Things'

The meeting also featured a panel on contracting led by Harry Singh, a vice president at Goldman Sachs and chairman of Western Systems Power Pool. What is driving many financial players in the West is "sustainability and renewables" through renewable policies in states such as California, he said.

"Two very exciting things in the West" are the Western Energy Imbalance Market (EIM) and SPP's move to integrate Mountain West Transmission Group, Singh said. (See *SPP, Mountain West Integration Work Goes Public*.) Renewable power purchase agreements have expanded in SPP and Texas because of the wind resources there, he said. Singh discussed the impacts of contracting on reliability and other issues surrounding procurement in the West.

California Public Utilities President Michael Picker discussed issues in the state's electricity planning, and said that by 2022, up to 83% of California load could be served by third-party providers as customers depart for competitive suppliers, community choice aggregators and other programs.

"Essentially, we are seeing deregulation from the bottom up," Picker said, adding that customer disaggregation is occurring in a number of different forums, "with not necessarily a strategy in mind." He added that he that "we will have a variety of challenges and "these are things that everybody is going to have to deal with as they see their load disaggregate."

The commission established a team to follow up on comments gathered from its "Consumer and Retail Choice, the Role of the Utility, and an Evolving Regulatory Framework" report issued in May.

ERCOT News

Weeks Later, Utilities Still Awed by Scale of Hurricane Harvey

Recovery Aided by Drones, Helicopters, Airboats — and Facebook

By Rich Heidorn Jr.

| *CenterPoint Energy*

How big was Hurricane Harvey?

So big that, even before it made landfall in Texas on Aug. 25, the National Weather Service was warning via Twitter that it was "unprecedented."

"All impacts are unknown and beyond anything experienced," NWS said. "Follow orders from officials to ensure safety."

"If you follow the National Weather Service ... on Twitter, there's not usually a lot of hyperbole," ERCOT CEO Bill Magness observed. "This one, you could tell, was like nothing they'd ever seen."

There was no shortage of superlatives last week as AEP Texas and CenterPoint Energy executives briefed ERCOT board members on the impact of the massive storm and their recovery from it.

The largest rain event in U.S. history dumped an estimated 40 to 60 inches of water in southeast Texas and southwest Louisiana — so much that the NWS had to add more colors to their maps to display the totals, Magness said.

Harvey made landfall at Rockport, Texas, as a Category 4 hurricane with winds of 130 mph on the evening of Aug. 25. The following day, it stalled over the state, picking up more moisture from the Gulf of Mexico before making a final landfall in Louisiana on Aug. 30.

While that meant unprecedented flooding, "from a transmission system perspective, the fact that it stopped was a good thing because … it was pretty much tearing up the transmission system that it passed through," said Dan Woodfin, ERCOT's senior director of system operations.

"When the storm was first coming onshore in the late hours of the 25th, we were having upwards of 20 … transmission elements tripping off each hour," Woodfin continued.

"Our folks were running … N-1-1 studies — so, not just what it takes to be secure, but what it takes to be secure if the next line goes out. … Almost as soon as they finished the study, that line would trip and then we'd have to redo it for the next N-1-1."

The ISO lost 12,000 MW of generation as gas-fired plants were evacuated or flooded and coal plants were derated as they switched to gas, their coal piles too sodden to burn. Wind turbines were shut down until the winds fell below their maximum operating speed. Other generators that could have run were unable to because they had no transmission.

Luckily, cooler weather meant that loads were as much as 25,000 MW lower than the week before.

The wind was the biggest problem for AEP Texas' territory along the Gulf Coast, company President Judy Talavera told the ERCOT board. The utility, which had 220,000 customer meter outages at its peak, had to replace or repair 766 transmission structures and more than 5,700 distribution poles. Four million feet, or about 757 miles, of transmission and distribution conductor was replaced.

| *CenterPoint Energy*

About 5,600 people, many from other utilities, helped the company restore 96% of outages within two weeks. "We drill for these types of events but those don't quite prepare you for the actual event," Talavera said.

For CenterPoint, which serves the Houston area, rain and lightning was the bigger challenge than wind, said Kenny Mercado, the company's senior vice president of electric operations. The company recorded 42,000 lightning strikes. There were 150 tornado warnings in Houston, with more than 30 twisters touching down. The warnings created "a tremendous amount of anxiety" for residents, he said.

Seventeen substations were impacted; half of them knocked out of service, the other half inaccessible because of the flooding of the San Jacinto River, the Buffalo Bayou and other waterways.

The unrelenting rain limited the utility's ability to restore service. In 2008, by contrast, "[Hurricane] Ike moved through the city and then we could go to work," Mercado said.

Only 200,000 metered customers were out of service at any time. "But the problem was every day we'd get another 200,000. And

Continued on page 16

ERCOT News

Weeks Later, Utilities Still Awed by Scale of Hurricane Harvey

Continued from page 15

the next day we'd get another 200,000, and the next day. So, it never ended until eventually we saw blue skies," Mercado recalled.

Helped by Hardening, Technology

The good news, utility officials said, was that flood protections and technology added in recent years limited damage or increased the speed of the recovery.

A flood wall built after 2001's Tropical Storm Allison protected the Grant substation, which serves the Texas Medical Center in Houston, the world's largest medical complex.

A 50-MVA mobile substation installed on a church's grounds allowed the company to restore power for 10,000 customers after 10 days. "They would have been out for probably another five days without it," Mercado said. "So, the mobile substation technology that we have today is very, very valuable in terms of resiliency of the grid."

| AEP Texas

| AEP Texas

Hundreds of intelligent grid devices saved 140,000 customer outages and provided critical situational awareness for restoration. Smart meters allowed the company to bill 700,000 accounts with actual readings and execute 45,000 orders remotely during the storm.

The companies resorted to drones to survey damage, airboats and amphibious vehicles to reach flooded substations and helicopters to move new transmission poles.

When standing water became a health hazard to workers, AEP outfitted their workers with mosquito nets to wear over their hardhats.

One technology that was not so successful for CenterPoint was its Tiger Dam, water-filled balloons that can function like sandbags but are quicker to deploy.

"Didn't have so much luck with it in Round 1," Mercado said. "But it's a skill set. We're going to have to learn a little bit better how to do something in real time in terms of planning and preparation to look at those kinds of solutions."

The company also plans to raise substation equipment to make it less susceptible to flooding.

Automated Calls, Facebook

The utilities also made use of newer means of communicating with their customers, including Twitter and Facebook.

Although 1.2 million CenterPoint customers lost service, "we only had 175,000 customers call … letting us know the power was out. … Only 67,000 customers used a live agent," Mercado said. "So, the world's changing. We're seeing more and more automation take care of customers' needs. Our power alert service technology pushed [text messages] out to 350,000 customers."

CenterPoint's website saw six times as much traffic as normal.

AEP Texas saw its Facebook followers more than double as the company made about 100 informational postings.

Public Support

Talavera said she was touched by the customers' expressions of thanks to the restoration workers.

Residents offered workers meals, water and Gatorade, "wanting to show how much they appreciated them," she said. "It's really humbling. We know we provide an essential service and we're proud of the efforts that were undertaken to restore service to our communities. But it's certainly a partnership in working together with them."

| AEP Texas

ERCOT News

ERCOT IMM: 'Fat and Happy' Times Ending with Coal Closures

By Rich Heidorn Jr.

ERCOT will face higher prices and lower capacity margins following Vistra Energy's retirement of 4,100 MW of coal-fired generation, Independent Market Monitor Beth Garza told the ISO's Board of Directors last week.

Assuming ERCOT's analysis of the pending retirements doesn't identify local reliability concerns that would result in reliability-must-run contracts for any of the units, Garza said, "We're looking at a much different situation going into the summer of 2018 than the fat and happy times … of the last couple of years.

"We've had really two years of clearly unsustainably low prices with high reserve margins," she continued. "I think I've been saying it in those terms for the last couple of years, and I think we're now seeing evidence of that unsustainability."

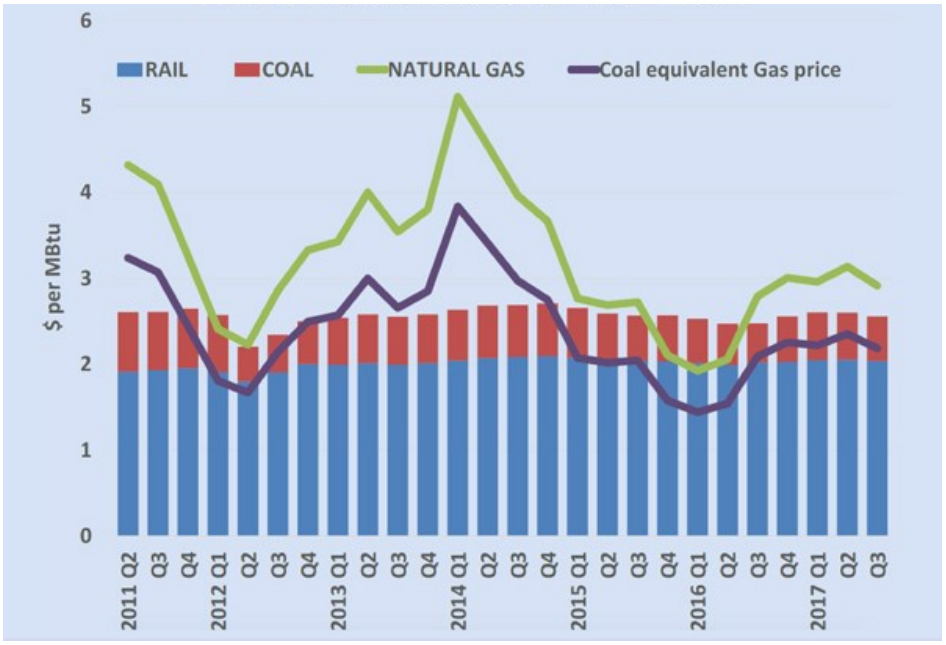
Since Oct. 6, Vistra Energy's Luminant unit has announced retirements of the two-unit Big Brown generator north of Houston (1,150 MW); the two-unit Sandow, northeast of Austin (1,137 MW); and its three-unit Monticello plant in East Texas (1,800 MW). The retirements will leave the company with just two coal plants totaling 3,850 MW. (See *Vistra Energy to Close 2 More Coal Plants*.)

In addition, the Texas Municipal Power Agency announced in July that it will put its 470-MW Gibbons Creek unit in seasonal mothball status, operating only from June through September.

Garza said the announcements were no surprise given that coal units' fuel costs have been consistently above combined cycle gas units since the beginning of 2015 and coal units were likely unprofitable in 2016.

Beth Garza | *© RTO Insider*

Although the trends have been clear for some time, Garza said the timing of the Luminant announcements forced her to revise her presentation to the board.



Gas (7 MBtu/MWh) vs. coal (10 MBtu/MWh) | *Potomac Economics*

Her presentation showed a 15% reserve margin for 2018. But that could fall to 12% because of the new retirements, she said. She cautioned that her data did not reflect changes in the interconnection queue since ERCOT's last Capacity, Demand and Reserves report in May.

"It seems to me like the market's working and folks are responding to appropriate market incentives," said Director Peter Cramton. "And now it's time for us to let the market work."

"I would echo that," Garza responded. "Generators have a fairly low barrier to entry to the market. Along with that, I think it's important to have an easy exit as well."

"You've been rubbing the dark side of your crystal ball here pretty good," Director Karl Pfirrmann pressed Garza. "Now let's start rubbing the other side a little bit. Tell me, what is it in our marketplace that's going to correct this problem?"

Garza said the retirements are likely to push forward prices higher, creating pressure for load-serving entities. "If I were a load-serving entity, I would be a little more anxious about the surety of supply going into the forward years than I am right now," she said. "So, you might see contracting opportunities for new generators that haven't been there in the past.

"I'm hopeful … that we won't try to keep units in the market longer than they would like to be there," she continued. "We just have to be comfortable with what that means — likely higher, more volatile prices going forward than what we've experienced in the last couple of years."

Cramton, an economist at the University of Maryland, agreed. "If we let the market work, it will be a higher forward price — and especially the forward prices many years out. There'll be pressure on the demand side."

But he said he feared the transition could be interrupted by "regulatory uncertainty around large subsidies for keeping guys in the market that shouldn't be there." It was an apparent reference to Energy Secretary Rick Perry's call for price supports for coal and nuclear units, although his proposal is limited to FERC-jurisdictional RTOs and ISOs.

"That's what's going to damage the market," Cramton added. "So, I would urge everyone to tell their congressmen to stop that."

ERCOT News

Board of Directors Meeting Briefs

'Affiliate' to be Redefined

ERCOT plans to revise its bylaws after discovering that dozens of members could be construed as affiliates under current rules because of stakes owned by investment funds such as Vanguard Group and Fidelity Management and Research.

The ISO learned of the issue from Vistra Energy, which informed ERCOT in September that Vanguard owns more than 5% of its voting securities — the current threshold for presuming that a shareholder exercises "substantial influence or control."


Seely

ERCOT General Counsel Chad V. Seely told the board last week that further investigation into Vistra's letter identified 30 members who could be considered affiliates of each other based on common equity investors and that the number could go as high as one-third of the ISO's 309 members.

Already, more than a dozen companies, including Calpine, Dynegy, Exelon and NRG Energy, have informed ERCOT they are in a situation like Vistra.

In addition to Vanguard and Fidelity, ERCOT said it has determined that at least five other investment firms may own more than 5% of two or more members: BlackRock, Capital Research Global Investors, Hotchkis & Wiley Capital Management, Oaktree Capital Management and State Street Global Advisors.

"In brief, ERCOT legal believes that this is just the beginning of identifying a longer list of potential members who may be affiliates through common equity ownership by a broader list of institutional investors," Seely wrote board members in a memo.

Seely said companies deemed to be affiliates could be forced to change their industry segment or lose their voting rights.

His office issued membership applications on Oct. 2 for the year 2018. Corporate members must be registered by Nov. 10 to vote on board members at ERCOT's Dec. 12 elections.

To address the issue, Seely recommended that the ISO revise the affiliate definition in the bylaws. In the interim, he said ERCOT should issue a "blanket" resolution saying that investment companies that own less than 20% of a member are assumed *not* to have control of the member.

The higher threshold would apply only to shareholders meeting one of the exclusions from the definition of "affiliate" under Texas' Public Utility Regulatory Act (PURA) or has been determined to hold ownership interests in the member for investment purposes only. Not eligible for the 20% trigger would be members sharing a common parent or board member or under common influence or control of another entity.

Board Nominees

Corporate members will vote during the annual meeting Dec. 12 on a second term for unaffiliated board member Peter Cramton, a University of Maryland economics professor. They also will consider a newcomer, Terry J. Bulger, a banking executive specializing in risk management.

Unaffiliated directors, who serve staggered three-year terms, are also subject to approval by the Public Utility Commission of Texas. (Last Tuesday was the first ERCOT board meeting attended by new PUCT Chair DeAnn Walker.)

Consent Items

The board approved three nodal protocol revision requests (NPRRs) and one system change request (SCR) on the Technical Advisory Committee consent list.

- NPRR768 — Revises the categories of ERCOT-initiated actions that trigger the real-time online reliability deployment price adder pricing run to ensure prices reflect current system conditions.
- NPRR821 — Eliminates the congestion revenue right (CRR) deration process for resource node to hub or load zone CRRs, an effort to improve CRR funding.
- NPRR840 — Synchronizes the implementation of NPRR782 (settlement of infeasible ancillary services due to transmission constraints) by removing the two-hour advance notice period inadvertently left in protocol language when NPRR782 was approved.
- SCR791 — Populates unused megawatt and price values in security-constrained economic dispatch (SCED) generation resource data (GRD) energy offer curves with null values rather than zeroes, to improve the usability of the 60-day SCED GRD disclosure report.

Consent, Non-Consent Items OK'd

The board also approved three additional NPRRs on individual voice votes:

- Director Carolyn Shellman, of the Municipal Market segment, voted against two NPRRs, citing budgetary concerns. NPRR817 created the Panhandle 345-kV trading hub that would be excluded from the ERCOT-wide hub average and bus average calculations at an estimated cost of $150,000 to $200,000. "This would reduce the cost of future hubs," TAC Vice Chair Bob Helton said.
- Shellman also opposed NPRR829, which will allow a qualified scheduling entity to provide data on its net generation to the ERCOT transmission grid from their non-modeled generators so that the output can be considered in the estimate of real-time liability (RTL). The change is expected to cost between $200,000 and $300,000. The members of the Municipal segment opposed the proposal, but ERCOT supported it, saying it will improve the calculation of collateral requirements and transparency into non-modeled generation.
- The board unanimously approved NPRR836, which incorporates 11 binding document forms into the protocols as a new Section 23, and allows changes to the forms to be made using the administrative NPRR process. Morgan Stanley, a member of the Independent Power Marketer segment, opposed the proposal at the Protocol Revisions Subcommittee.

Line of Credit

After an executive session, the board briefly reopened the meeting to renew its revolving line of credit with JPMorgan Chase.

— Rich Heidorn Jr.

ERCOT NEWS

ERCOT OKs Plant Retirement; TAC Meeting Canceled

TAC Cancels October Meeting; Web Session Monday

ERCOT's Technical Advisory Committee has canceled its Oct. 26 meeting because of a limited number of items for consideration. The TAC instead held a one-hour web information session Monday in preparation for an email vote on the load distribution factor (LDF) library.

Staff will discuss the methodology behind generating and maintaining LDFs used in the congestion revenue rights (CRRs) and day-ahead market clearing activities. LDFs are developed using historical state estimator or supervisory control and data acquisition (SCADA).

ERCOT protocols require the ISO to maintain the appropriate LDF libraries for use in the day-ahead and CRR auctions. Staff updates the libraries by maintaining the existing LDF sets and generating new LDF sets when required, based on significant changes in systemwide load patterns.

TAC Vice Chair Bob Helton has yet to set a date for the email vote.

ERCOT Approves Barney Davis Gas Unit's Retirement

ERCOT on Thursday approved the retirement of a 330-MW gas unit at the Barney Davis plant near Corpus Christi, saying it is not needed to support system reliability and can now be decommissioned.

Talen Energy announced on Sept. 27 its intention to retire the unit, triggering ERCOT's reliability review. The unit went into service in 1974.

— Tom Kleckner

Barney Davis power plant | *Terry Ross/Flickr*

ISO-NE News

PAC Briefs

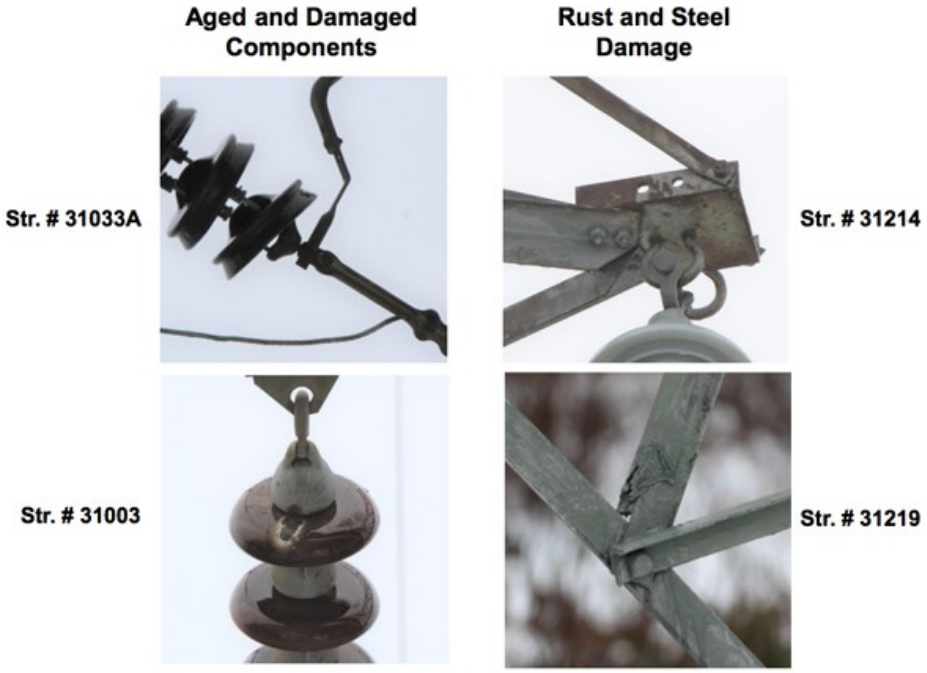
Tx Planners Rethink 2027 Needs Assessment

ISO-NE will revise the scope of its 2027 transmission needs assessments for Eastern Connecticut, Southwest Connecticut and New Hampshire after stakeholders raised questions about the study's dispatch modeling, Director of Transmission Planning Brent Oberlin said Wednesday.

"It seems to be as you dial in more and more on the bus basis, the dispatches seem to be very severe in some of the cases," Oberlin said.

During the September Planning Advisory Committee meeting, ISO-NE presented the assumptions and study methodology behind the 2027 Needs Assessment Scope of Work, a study produced biannually to provide insights into the system 10 years into the future. (See "2027 Needs Assessment Scope of Work," *ISO-NE Planning Advisory Committee Briefs: Sept. 28, 2017*.)

"If you look at the difference between the 90/10 cases and the 50/50 load level cases, you can see things becoming even more severe beyond what was anticipated using this new method, so we are going back and kind of hit the pause button for a second here trying to understand exactly what's happening, what's causing it," Oberlin said. "We plan to come back to the November PAC to go into more detail on the issues that we're seeing."



| *Eversource Energy*

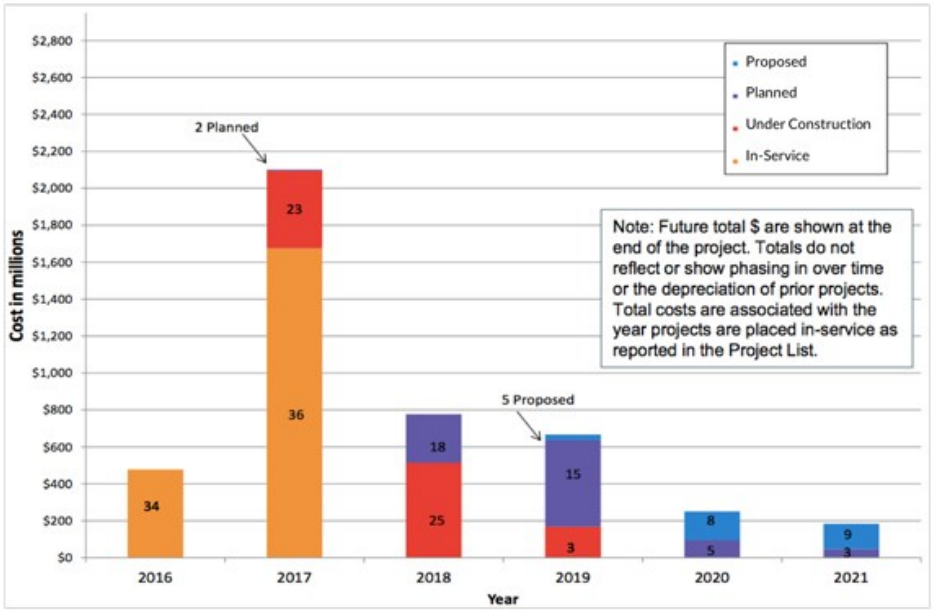
Regional System Plan Tx Projects Update

Cost estimates have changed significantly for two transmission projects since the last Regional System Plan update in June 2017: the Connecticut River Valley project in Vermont (down $9.8 million) and the Maine Power Reliability Program project (up $7 million).

Fabio Dallorto, an ISO-NE transmission planning engineer, spoke about the projects and asset conditions during an update to the PAC.

The Vermont project (No. 1614) entails rebuilding a 115-kV line from Coolidge to Ascutney to resolve thermal overload. The decreased costs reflect competitive bids throughout the project and a reduction in the amount of contingency — from 50% to 10% — included in the estimates now that the projects are better defined, Dallorto said.

The RTO reported no new projects but said 16 upgrades on the project list have been placed in service since June, including four in the greater Boston area.



New England transmission reliability projects by status through 2021 | *ISO-NE*

Western Massachusetts Structure Replacement

John Case of Eversource Energy reported that 19 of 263 structures on the 1231/1242 lines in Western Massachusetts need to be

Continued on page 21

ISO-NE News

Planning Advisory Committee Briefs

Continued from page 20

replaced to maintain reliability. Some of the structures are more than 90 years old, and one crossing the Deerfield River lacks shield wire, which was inexplicably not replaced following a helicopter crash that damaged the wire several years ago.

The majority of structures on the circuits are double-circuit steel lattice towers. Replacing them reduces the potential for structural failures, Case said.

The project's scope includes installation of 15 115-kV double-circuit and four single-circuit light-duty weathering steel structures to replace lattice towers.

Eversource estimated the project will cost $8.1 million.

Environmental Update Cites Uncertainty at Federal Level

Emphasizing the "uncertainty and the changes that are afoot at the federal policy level," ISO-NE senior analyst Patricio Silva spent half an hour updating the PAC on all relevant environmental policy and regulatory matters affecting larger generation and linear transmission projects.

"We're seeing significant changes with the Clean Air Act, Clean Water Act, Resource Conservation Recovery Act and the National Environmental Policy Act, [which] is actually having a dramatic impact in a variety of different regulatory forms," Silva said during his presentation.

Silva pointed out that the Trump administration has advanced with its proposed withdrawal from EPA's Clean Power Plan, which would affect carbon dioxide emissions from existing electric generating units. (See *EPA to Announce Clean Power Plan Repeal*.) The agency's New Source Performance Standards for carbon emissions are also in limbo pending a review, and related litigation has been stayed. The agency's pause, now reversed, in implementing new ozone standards also triggered litigation, he said.

"Lastly, more technical, but of particular interest to generators, there are changes afoot in the regulations under the Clean Air Act covering start-up, shutdown and malfunction events at generators," Silva said. "That is a rule that's under reconsideration and that's also subject to litigation."

Silva noted that his presentation only covered the Clean Air Act. "I hope you're taking away from this that there's a lot going on and we do not know what the outcome may be on some of these actions," he said. "In fact, we do have in the oil and gas sector under the Clean Air Act an example of a misstep, where EPA paused and stopped to reconsider a rule only to have the litigation that was being used by the industry to stop the rule swept away."

With the Trump administration rejecting EPA's previous approach and the D.C. Circuit Court of Appeals essentially putting rules into effect mid-step, "there's a risk of regulatory snap-back, where depending on where the EPA is procedurally with a reconsideration or a policy or implementation change, an affected industry sector may suddenly discover that they're facing a fully implementable standard with a compliance deadline that has passed," Silva said.

ISO-NE is closely watching upstream oil and gas policy because it could have a variety of implications under the Clean Air Act, especially for the operations of existing and new generators, he said.

— Michael Kuser

ISO-NE News

FERC Accepts Nondisclosure for ISO-NE Capacity Bids

By Michael Kuser

FERC on Thursday approved ISO-NE's request not to disclose — even to non-market participants — any proprietary information from certain de-list bids for the RTO's upcoming 12th Forward Capacity Auction.

The commission's Oct. 19 order (ER17-2110) accepted the filing of de-list bids and granted the RTO's request to waive a requirement that parties seeking privileged treatment for certain filings provide intervenors who execute a nondisclosure agreement access to that material.

ISO-NE in July submitted both privileged and public versions of a filing describing the permanent de-list bids and retirement de-list bids submitted for the upcoming FCA 12, to be held in February 2018 for the 2021-22 Capacity Commitment Period.

The RTO reported that it received one permanent delist bid and 23 retirement delist bids from six power suppliers for the upcoming FCA, covering resources located throughout all eight New England zones.

FERC staff in August issued a deficiency letter in response to ISO-NE's filing of de-list bids, asking that the RTO also submit a form of NDA. The RTO responded two days later with an NDA as well as its waiver request.

The RTO's auction qualification process requires owners of existing capacity resources that wish to exit their capacity supply obligation to submit de-list bids specifying a price below which they do not wish to provide capacity. Such bids submitted ahead of an FCA may be "static" for a one-year exit from the capacity market; "permanent" for a permanent exit from the capacity market; or a "retirement" de-list bid for permanent exit from all ISO-NE markets, including that for energy.

Public Citizen Protest

Public Citizen filed the only protest to the request, contending that lack of access to the privileged components of the filing made it "impossible to determine" whether the permanent de-list bids and retirement de-list bids were just and reasonable.

ISO-NE countered that the privileged information includes "the [de-list] bidders' expected cash flows, expectations regarding capacity market payments and information regarding opportunity costs … [and] critical aspects of suppliers' likely bidding strategies ... [which], in conjunction with the other confidential information, reveals the prices at which supply would be withdrawn in the auction."

The grid operator asserted that the privileged portions of its filing contain "highly confidential, market sensitive information" that could "provide market participants who obtain it with an unfair competitive advantage" in future capacity auctions, thus negatively affecting the competitiveness of those auctions. The RTO referred to an earlier FERC order on FCA 8 in which the commission agreed that revealing resource-specific bid data would result in such significant harm to the Forward Capacity Market that it could not be provided to parties even if they signed an NDA.

Public Citizen argued that the FCA 8 order did not apply to its own request because the organization is not a market participant.

"We disagree," the commission said in its ruling. Although the FCA 8 order referred to market participants, the commission reiterated its finding that harm could not result solely from disclosure to market participants. Rather, "the potential for harm to the FCM and to New England customers from any disclosure of this protected information could be significant."

In the FCA 8 order, the commission noted that parties had access to a significant amount of publicly available information regarding the auction and therefore did not require ISO-NE to disclose the privileged information.

"We find that the same rationale applies here," FERC ruled Thursday.

ISO-NE News

RTOs Reject NOPR; Say Fuel Risks Exaggerated

Continued from page 1

The coal groups acknowledged that some RTOs "have tried to explore measures intended to maintain traditional baseload capacity in the market, and have even taken some halting and less-than-full steps in that direction, a tacit recognition that existing market rules and structures are not properly valuing the reliability, resiliency and long-term price stability benefits that traditional baseload capacity provides."

But it said "the few revisions to existing RTO/ISO tariffs and related market structures and rules have so far been much too little and far too late. Without action by the commission to remedy these tariffs and market structures, the electric system will devolve to lose the value of fuel diversity and end up overwhelmingly dependent on intermittent renewable and natural gas generation."

Rebuttal

Patton recommended FERC define the contingencies the Department of Energy seeks to address. "Without first identifying in detail the contingencies and associated reliability risks to the system, there is no way to quantify a resilience requirement," he said.

He said MISO and ISO-NE have already conducted fuel-security studies.

"MISO's evaluations of the adequacy of the gas pipeline infrastructure found the MISO North and Central regions to be 'favorably located at the crossroads of pipeline corridors extending from many supply basins … with more than 20 interstate pipelines and significant gas storage resources.' Hence, MISO's potential exposure to natural gas supply contingencies is relatively low, and the need for the payments called for under the [Notice of Proposed Rulemaking] is similarly low."

Patton acknowledged New York and New England are more vulnerable to natural gas system contingencies than MISO. But, he said, "it is highly unlikely that the proposal in the NOPR is a feasible or reasonable means to address these vulnerabilities," saying dual-fuel capability "has been the most effective and cost-effective means" to address them.

"This illustrates the problems that arise when one starts with a very specific answer, rather than starting with a clearly defined issue or objective and allowing the markets to provide the most efficient answer," he said.

ISO-NE

ISO-NE found fault with what it called the NOPR's "one-size-fits-all" approach to the region's risks and said its stakeholder processes were preferable to the NOPR to "develop market-based solutions, if any are needed."

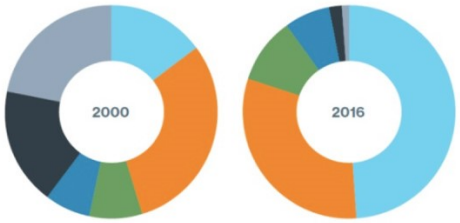
"The NOPR does not address these risks, and ISO-NE proposes to instead use the time the region has in 2018 and beyond to quantify its fuel-security risks," the RTO said.

The grid operator said the NOPR would "significantly undermine the efficient and effective wholesale electricity markets," and that moreover, "New England has no urgent need to rush to a solution, given that the three-year Forward Capacity Market has ensured resource adequacy until at least 2021, and the region has already taken steps to improve operating procedures and generator incentives to secure firm fuel supplies."

Commenting on the proposed rule's estimated burden of $291,042 per respondent RTO/ISO to develop and implement new market rules as proposed, including potential software upgrades, ISO-NE said such efforts would "be in the millions of dollars for each RTO."

The NOPR would undermine New England's wholesale electricity markets in two ways, the RTO said: "First, these resources may have no incentive to bid their appropriate fuel and operating costs in the energy market ... [and] could profitably bid zero. While there are admittedly few coal resources remaining in the region, if these costly units bid zero, it will undermine price formation in the day-ahead and real-time energy market and increase emissions."

Second, the RTO said, its FCM enables resources to offer to retire if the market does not clear at or above a specific price:



	2000	2016
Natural Gas	15%	49%
Nuclear	31%	31%
Renewables	8%	10%
Hydro	7%	7%
Coal	18%	2%
Oil	22%	1%

ISO-NE annual fuel mix | *ISO-NE*

"Normally, as units age and their costs rise, new resources will be more economic than retaining aging units that require a higher price. With full cost recovery guaranteed, however, these aging resources will remain, deterring the development of newer, more efficient and more cost-effective generating units."

ISO-NE also said it has developed new operating procedures to improve information on generator availability during cold weather conditions, such as requiring generators to report their anticipated availability to the grid, including details on their ability to procure fuel.

The RTO said it also has increased market-side efficiency and improved gas-electric coordination to mitigate the supply problems arising from natural gas pipeline constraints.

"For example, the ISO has shifted the day-ahead energy market timeline to better align the electricity and natural gas markets to give generators more time to procure the gas they need to run," it said.

NYISO

NYISO asked FERC not to adopt the proposal but said if it deemed action necessary, it should give the RTOs at least

Continued on page 34

Connecticut Planning for Future with Changing Climate

By Michael Kuser

CROMWELL, Conn. — In Connecticut, "50 by 50" does not refer to the state's renewable energy goals by the half-century mark, but to the projected rise in sea level: 50 centimeters by 2050.

Speaking last week at the Connecticut Power & Energy Society's Future of Energy Conference, Robert Klee, commissioner of the state's Department of Energy and Environmental Protection (DEEP), pointed out that the Connecticut Institute for Resilience and Climate Adaptation had just briefed his staff the previous day on estimates for localized sea level rise.

"That's a fundamental change in the way we need to plan for infrastructure along the coast," Klee said.

But Klee touted the state's grid-scale clean energy procurements and low- and zero-emission renewable energy credit programs — as well as the work of the Connecticut Green Bank — in helping develop a sustainable energy framework.

"You can't drive around Connecticut anymore without seeing rooftop solar somewhere, on homes, on businesses — and that's a real achievement," Klee said. "And microgrids were kind of a sleeper hit. I go to microgrid conferences, and folks in other states are always amazed that we have six that are operational. Most other states are still [at the stage of] drawing boards or concept."

Penni McLean-Conner, Eversource Energy (left); and Anthony Marone III, UIL | *© RTO Insider*

Utilities Focus on Customers

Penni McLean-Conner, chief customer officer at Eversource Energy, serves on the Boston Green Ribbon Commission, which gathers business, institutional and civic leaders to seek ways to fight climate change.

She explained that her company built its newest substation in Boston's Seaport neighborhood 23 feet above sea level, designed to handle 150 mph winds and with 80 pilings that sink into the bedrock below.

"Why? Because we're right on the water," she said. "We know the flooding is going to occur as we look at the climate models going out to 2050, so if we're going to put in an asset that's going to last another 50 years, we need to be thinking about resiliency."

But whether adapting to climate change or using new technologies to provide a reliable energy platform, the utility of the future will be dramatically different from today in that it will be grounded in the voice of customers, McLean-Conner said.

UIL Holdings CEO Anthony Marone III agreed, saying utilities need to match offerings to customer wants.

"You can have all the technology in the world, but not every customer wants to pay for it," Marone said. "We can't just keep putting more gadgets on the system if there's not a value proposition that makes sense."

Mike Calviou | *© RTO Insider*

Mike Calviou, senior vice president for regulation and pricing at National Grid USA, said the utility of the future has to be more agile to meet varied needs, driven by three primary forces: decarbonization, decentralization and digitization.

"On regulatory innovation, we're absolutely convinced that the traditional, backwards-looking, rate-based regulated utility just really doesn't make sense in the environment we're moving into," Calviou said. He cited electrification of transportation as the most exciting opportunity for utilities.

Need for Market Evolution

On Energy Secretary Rick Perry's call earlier this month for price supports for coal and nuclear plants, Dean Ellis, Dynegy senior vice president for regulatory affairs, said "I would argue there's a big difference between a sales tax break upstream or a property tax agreement, and paying someone to produce electricity when it's not economic to do so." (See *FERC Chair Praises Perry's 'Bold Leadership' on NOPR*.)

Subsidies lead to more subsidies, and while production incentives incent a build-out of a particular resource type, they also affect other resources competing in the market, Ellis said.

"We definitely agreed with the [Department of Energy's] issue that there needs to be some evolution here with the markets, but the way they went about it was absolutely wrong. It's a solution looking for a problem," he said. "If the DOE is going to pay us to keep 90 days of coal on-site, we'll put coal in the cafeteria if we have to, but that's not the

| *© RTO Insider*

Continued on page 25

Connecticut Power & Energy Society Future of Energy Conference

Connecticut Planning for Future with Changing Climate

Continued from page 24

best way to go about incenting the outcomes. If one of the outcomes is to increase grid reliability, then let's have a really honest conversation about what a reliable grid looks like in the future."

Stephen Molodetz | © RTO Insider

Carbon pricing looks better than subsidies to Stephen Molodetz, vice president for business development at Hydro-Québec US.

"We're one of the few suppliers who thinks the real solution is to price carbon into the market," Molodetz said. Getting participants in a multistate RTO like ISO-NE to agree on a pricing mechanism "seems to be the Holy Grail," he added.

"We're currently working hard [on carbon pricing] in New York, again a one-state ISO ... and to be honest there, I still think it's a longshot," Molodetz said.

The X Factor

Katie Dykes | © RTO Insider

Katie Dykes, chair of Connecticut Public Utilities Regulatory Authority (PURA), asked industry executives what "X factors" they've considered in the their company planning.

"If you look at some of the recent history of the emergence of the New England markets, there's a lot of unexpected surprise factors that have created the landscape, the shale gas revolution being one," Dykes said. "Who would have guessed that we were going to have people fretting about how to deal with very low wholesale prices?"

Molodetz said that, in Hydro-Québec's six partnered bids for Massachusetts' recent clean energy procurement, he was surprised by the high level of public engagement in the siting processes. And that's not a negative point, he added. (See *Hydro-Québec Dominates Mass. Clean Energy Bids*.)

"Increased environmental stakeholder involvement will lengthen the siting process, but we'll have better projects for it," he said. "The demand for clean energy is large and it's growing. Québec peaks in winter, while New England peaks in summer, so matching those peaks in connected transmission is great for consumers and for grid operators."

Molodetz said Hydro-Québec foresaw growing demand for renewables and began expanding its hydro capabilities a decade ago to enable the company to increase its cross-border transmission. The company's largest customer is still the province of Québec, with New England a distant second and New York behind that.

Elisabeth Treseder, senior regulatory adviser at DONG Energy North America, pointed to the technological leap in capability for renewable resources. She said renewable energy providers often look to the states for leadership on procurement, but that everyone benefits from evolving technology.

"We recently decommissioned our first offshore wind project, built in 1991, which produced as much in 25 years as one of our new projects can generate in 16 days," Treseder said.

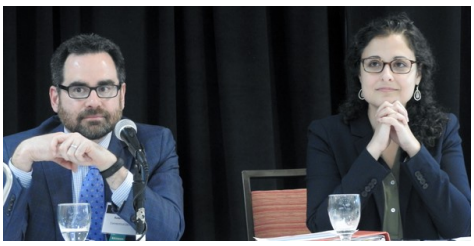
Millstone Issue

During the conference, Commissioner Klee also addressed a question about state support for Dominion Energy's Millstone nuclear plant.

In June, Connecticut's General Assembly failed to pass a bill that would have allowed the 2,111-MW facility to bid into the state's procurement process (S.B. 106). The following month, Gov. Dannel Malloy issued an executive order requiring state officials to assess the plant's economic viability and determine whether the state should support it financially.

The governor also directed DEEP and PURA to assess the viability of all forms of renewable energy and to report their findings by Feb. 1. (See *CT Gov Orders Financial Analysis of Millstone Plant*; *Commenters Seek Broader Response on Millstone*.)

"Millstone is the largest single power plant in New England and is essential in terms of being a carbon-free resource and to the grid's reliability," Klee said. "The flip side is, because it is so large, our normal set of tools that we traditionally use don't always seem to fit or may start to cause intersections with the regional grid and its market rules and components that are new and different, uncharted territory."



DEEP Commissioner Robert Klee (left) and Deputy Commissioner Mary Sotos | © RTO Insider

The plant is also essential for the region's winter peak problems, which are exacerbated by gas pipeline constraints, he said. The state is currently getting those gas-free and carbon-free reliability attributes for "free" in paying wholesale with no adder, Klee said.

"That valuation process is complicated and that starts getting into things that are more in the crucible of a legislative session," Klee said. "The answer is still unknown and it gets more complicated by the week as DOE is inserting itself into this space with their [Notice of Proposed Rulemaking] on reliable or 90-day sources of baseload energy."

Mary Sotos, deputy commissioner for energy at DEEP, encouraged participants to comment on the docket her agency has opened on Millstone. "We're accepting comments throughout the proceeding and are required to deliver the results of that study to the legislature in the beginning of February," she said.

Dynegy's Ellis said the DOE proposal talked about preserving baseload energy because it is more resilient.

"Again I would argue that all resource types offer different reliability attributes," Ellis said. "Natural gas-fired plants complement the intermittency of renewable energy better than baseload energy does. ... If we're going to pick and choose which reliability attributes we want to value, we need to take a look at all of them."

MISO News

$23 Million Owed to Ratepayers in Presque Isle SSR Case

By Amanda Durish Cook

FERC ruled Thursday that Wisconsin Electric Power Co. overcharged ratepayers on Michigan's Upper Peninsula by almost $23 million under MISO-ordered system support resource agreements.

The commission largely agreed with an administrative law judge's initial decision on refunds under two SSR agreements that kept the 344-MW Presque Isle coal plant in Marquette, Mich., running in 2014 and early 2015 for reliability (ER14-1242-006, *et al.*).

Judge Michael Haubner issued an initial decision in July, saying WEPCo had overcharged ratepayers over the SSR agreements. (See *Upper Peninsula Ratepayers to Seek FERC Probe of Billing Fraud*.)

WEPCo had argued that the commission should accept its simple three-year average of historical costs from 2011 to 2013 as basis for compensation in the SSR agreements, but FERC took the judge's view, agreeing that SSR compensation should be limited to actual costs. FERC said the plant's compensation "must be limited to Wisconsin Electric's going-forward costs, and the record shows that the negotiated amount was not shown to be a reasonable estimate of Wisconsin Electric's going-forward costs. In fact, the negotiated amount greatly exceeded Wisconsin Electric's actual going-forward costs." The commission also rejected the company's portrayal of the order as "retroactively implementing a new standard for SSR compensation without providing fair notice."

Presque Isle | *WEPCo*

Under MISO's first SSR agreement (Feb. 1 through Oct. 14, 2014), WEPCo collected almost $37 million in fixed-cost compensation, but FERC said the utility should have only gotten about $23 million, resulting in a refund of about $14 million.

FERC said ratepayers were due an $8.6 million refund from MISO's second SSR agreement (Oct. 15, 2014, through Jan. 31, 2015) because the agreement contained an excessive cost of capital and ineligible capital expenditures. FERC agreed with Haubner's view that MISO didn't adequately support its proposed 11.5% long-term cost of capital during the second SSR, saying 9.68% was more appropriate.

The refunds include a $2.4 million charge collected under the first SSR agreement to overhaul a generator turbine. FERC ruled the charge must be refunded to avoid WEPCo taking advantage of upgrade costs and then planning a return to service.

FERC gave MISO 45 days to make a refund report, brushing aside the RTO's complaints that Haubner's initial order did not provide clear guidance on how to calculate refunds.

The commission also agreed with the judge that WEPCo must refund a $1.4 million consulting services invoice relating to upgrades to bring the 61-year-old coal plant into compliance with EPA's Mercury and Air Toxics Standards. But it stopped short of determining whether changed dates on the invoices constituted fraud.

Last year, Cloverland Electric Cooperative accused WEPCo of backdating the consulting contract after the plant operator learned that the second version of its SSR agreement would cover costs incurred from MATS upgrades under a revised fixed-cost component. MATS upgrades were ineligible for recovery under the previous SSR agreement.

"We make no findings at this time regarding whether Wisconsin Electric committed fraud or engaged in manipulation when a date was changed on an invoice for MATS compliance related costs, but we have referred the matter to the commission's Office of Enforcement for further examination and inquiry as may be appropriate," FERC said.

FERC Rejects Inquiry on Manitoba Hydro Interconnection Fees

By Amanda Durish Cook

FERC last week rejected a request to rehear its October 2016 ruling requiring MISO to revise its interconnection fees, saying the treatment of external generator Manitoba Hydro was beyond the scope of the order (EL16-12-002, *et al.*).

The commission had ordered MISO to apply milestone payments equally across all classes of customers, prompting the American Wind Energy Association (AWEA) and Wind on the Wires (WOW) to question how the RTO is processing 3,500 MW of external generation from Manitoba Hydro. The wind advocates claimed sales of Manitoba Hydro's generation were allowed onto the system under a firm transmission service right, thus circumventing milestone payments.

The arrangement equated to preferential treatment, the two said, and asked FERC to determine under what Tariff provision MISO allows Manitoba Hydro sales. They said Exelon's 3,500 MW of external generation is processed under interconnection service and external network resource interconnection service (E-NRIS), which now requires milestone payments.

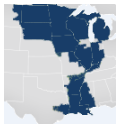
In rejecting the rehearing request Thursday, FERC said AWEA and WOW could raise their concerns in MISO's stakeholder process or submit a fresh complaint to the commission.

The commission said last year's order centered on which classes of interconnection customers must make milestone payments and is not focused on an "overbroad interpretation" of the "terms and conditions of transmission service in specific transactions involving MISO and Manitoba Hydro, which are outside the scope of this proceeding."

The October 2016 order stemmed from a complaint by a group of internal MISO generators who contested the RTO's

Continued on page 27

MISO News



FERC Sees Discrepancies in MISO GIA Rules

By Amanda Durish Cook

FERC last week opened a Section 206 investigation into inconsistencies in MISO's Tariff after re-examining the 2016 termination of a North Dakota wind farm's generator interconnection agreement (GIA).

The commission on Thursday said MISO's rules may not be just and reasonable because of discrepancies between the generator interconnection procedures outlined in the RTO's Tariff and its *pro forma* GIA. It required MISO and interested parties to file briefs for a paper hearing (EL17-18). FERC expects to render a final decision in June and issued an Oct. 19 refund date.

The commission's concern centers on a pre-2012 provision in the generator interconnection procedures that allowed an interconnection customer to extend its commercial operation date by up to three years without losing its position in the interconnection queue if MISO found that the extension would not adversely impact lower-queued customers. The provision was narrowed in 2012 so that once entering the definitive planning phase, MISO only allowed the three-year extension if it was caused by a change in milestones by another party to the GIA or a change in a higher-queued interconnection request.

MISO added a third provision for study delays in 2016. At the time, FERC said, "MISO's proposal to limit the types of changes permissible in the definitive planning phase is consistent with the need to ensure that a project that enters the definitive planning phase is 'definitive.'"

However, MISO's GIA was never edited to add the three conditions for a three-year extension and "effectively provides interconnection customers an ability to extend their [commercial operation date] by three years before MISO can seek to terminate a GIA," according to the commission.

FERC pointed out that MISO has cited the three-year limit in its generator interconnection procedures when terminating GIAs and said the RTO's latitude to terminate GIAs is "permissive in nature." The commission also said MISO's outright termination of GIAs based on the three-year condition ignores its material modification analysis process, which is triggered when an interconnection project experiences changes that affect cost or in-service timing.

FERC said MISO's interconnection procedures should be revised to reference its GIA and "allow that once a GIA is executed or filed unexecuted, a three-year period from the [commercial operation date] should lapse before MISO seeks to terminate the GIA."

The issue was initially raised by EDF Renewables subsidiary and wind developer Merricourt Power Partners, which contested FERC's acceptance of a MISO notice of termination of a GIA entered into by enXco Development and subsequently assigned to Merricourt. (See *FERC Upholds MISO Cancellation of GIA*.) At that point, the 75-turbine, 150-MW Merricourt wind project in North Dakota had missed its Dec. 1, 2012, commercial operation date by more than three years.

In seeking rehearing of the decision, Merricourt had argued that the commission erred by relying on MISO's generator interconnection procedures alone and not considering language in the GIA.

FERC ultimately denied Merricourt's request for rehearing of the termination, saying that MISO's generator interconnection procedures don't allow the three-year-plus commercial operation date extension the company sought, even considering "factors beyond the plain language" (ER16-471-001). The commission also said that it could not consider MISO's study delay provision for Merricourt because it wasn't yet active at the time the company missed its operating date.

FERC Commissioner Cheryl LaFleur issued a concurring statement, saying the investigation would provide "needed clarity to MISO and interconnection customers regarding their respective obligations going forward." LaFleur was the sole dissent in FERC's first decision to cancel the GIA, saying it could create barriers for other wind projects.

"I concur in the decision to deny Merricourt's requested relief at this time. While I would have granted that relief in March 2016, it is now over a year and a half later, past even the Sept. 30, 2017, [commercial operation date] extension date sought by Merricourt. I do not see a basis to grant rehearing at this point," LaFleur said.

EDF is still working to secure permitting from the North Dakota Public Service Commission for the project.

FERC Rejects Inquiry on Manitoba Hydro Interconnection Fees

Continued from page 26

practice of exempting external generating resources from paying a significant fee levied on any new internal resources seeking to enter the final stage of the interconnection process. (See *FERC Orders MISO to Levy Interconnection Fees Equally*.) At the outset of the definitive planning phase, new MISO interconnection customers within the footprint must make an M2 milestone payment to fund impact studies and cost analysis. MISO had waived the fee for both new and existing generators outside its footprint under the assumption that those resources have already established interconnection agreements within their own balancing areas.

MISO applied the new rules required by last year's order to two service agreements: 30 MW of E-NRIS from Exelon's Fairless Hills Power Plant in Pennsylvania and 2,300 MW of E-NRIS from Exelon's Byron Nuclear Facility in Illinois (ER17-1000, ER17-1013). FERC accepted both on Thursday.

AWEA and WOW had protested acceptance of the service agreements, arguing that Manitoba's large external service agreement earned a 147-page reliability study result from MISO, and an analysis of Exelon's external generation only yielded an 18-page result. The two said the reports contained "insufficient data to confirm MISO's conclusion that there are no reliability and deliverability violations and that no network upgrades are needed to accommodate the new 2,330 MW." FERC said the claims were unsubstantiated.

MISO NEWS

Bigger Role Seen for Independent Forecast in MISO Tx Plan

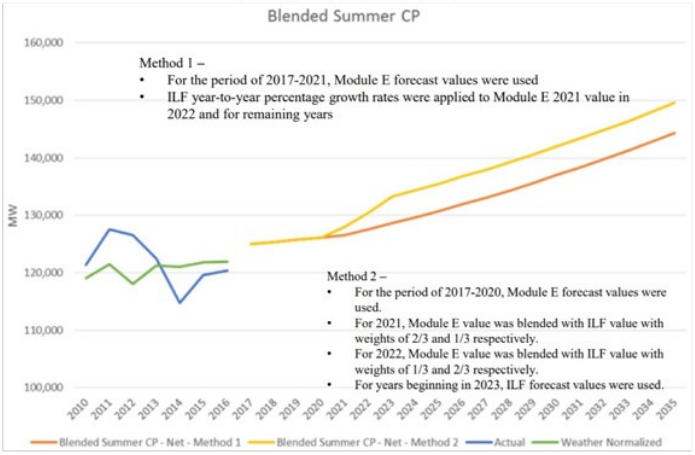
By Amanda Durish Cook

MISO on Wednesday revealed plans to rely more heavily on its own load forecasting to support long-term transmission planning, instead of primarily drawing on a combination of forecasts provided by load-serving entities.

Stakeholders were unenthusiastic about the idea, which would elevate the role of an independent long-term forecast provided by Purdue University's State Utility Forecasting Group. MISO says stakeholder input will influence a second version of the proposal presented in December.

Under its existing planning process, MISO draws on an aggregate of about 150 LSE resource adequacy forecasts submitted under Tariff Module E to inform economic studies for its annual Transmission Expansion Plan. The LSEs currently provide 24 months of load forecasts and produce additional predictions for eight seasonal peaks to create a 10-year forecast. The RTO uses the data to extrapolate another 10 years into the future to fit its 20-year planning horizon.

MISO also consults the Purdue forecast — which relies on 20-year forecasts produced by states — but only to draw comparisons with the LSEs' predicted growth rates. The RTO earlier this year said it was investigating ways to improve that independent forecast. (See *Dynegy: MISO LSE Load Forecasts Require Tune-up*.)



MISO planning horizon | *MISO*

Blending Forecasts

MISO is now proposing to blend the LSE and Purdue forecasts, adviser Rao Konidena said during an Oct. 18 Planning Advisory Committee meeting. Under the new approach, it would no longer extrapolate the LSEs' predictions, instead relying on Purdue's forecasts to predict growth rates for the second half of the planning horizon.

The RTO said it planned to use the independent forecast in part because it does not know what economic drivers underpin the LSEs' forecasts or whether the LSEs include state renewable or efficiency mandates and emissions goals. Use of both forecasting methods will lead to "better evaluation of impacts of variations in assumed penetration levels of demand response resources, energy efficiency, and distributed energy resources," it said.

Adam McKinnie, an economist with the Missouri Public Service Commission, asked whether MISO had faith that utilities were making thoroughly researched predictions of future load growth with their state-submitted resource adequacy plans.

"Do you ask utilities for the drivers of economic growth behind their load forecasts?" McKinnie asked. "You seem to be taking shots at the Module E forecasting," he added.

"All I'm saying is that I don't know what goes into the economic drivers," Konidena responded.

Minnesota Public Utilities Commission staff member Hwikwon Ham wondered if MISO thinks it's overbuilding or underbuilding transmission based on the use of its existing Module E process. "You have to show that there is a better process," he said.

Konidena stressed that MISO only wants to use a forecast that's designed with the next 20 years in mind, rather than simply extrapolating a 10-year forecast. Use of two separate forecasts for the same planning studies will lower the risk of load forecast miscalculations being compounded into "poor year-out projections," he said. MISO has also noted that Applied Energy Group predicts that demand-side management programs will hit a saturation point in a decade, something the RTO will fail to include in its growth rate if it simply extrapolates aggregated utility forecasts.

Real Projects, Real Money

Indianapolis Power and Light's Lin Franks said that the sample coincident peak produced by the blend is too aggressively high: It results in a 150-GW summer coincident peak by 2035, about 5 GW higher than if MISO relied on a Module E extrapolation alone.

"I'm worried about this. This is real money. These are real projects that people are going to want to build, and when we get there, those transmission lines are going to be empty," Franks said.

WPPI Energy's Steve Leovy says his company already forecasts 20 years in advance and said he'd be happy to share the longer forecasts with MISO.

Konidena asked stakeholders to submit suggestions on the blended approach by Nov. 17. He said MISO would continue discussing possible expanded used of the independent load forecast at the December PAC meeting.

"You've asked if stakeholders have ideas on how to blend the forecasts, to provide them. If we have ideas about not blending them, are you open to that too?" asked Entergy's Yarrow Etheredge, eliciting laughter.

Konidena said he was open to such suggestions if stakeholders could make a business case for keeping the forecasts separate.

MISO NEWS

MISO Sectors Mull Texas Project Delay for MTEP 17

By Amanda Durish Cook

MISO is confronting a pair of conflicting motions as some stakeholders push back on including a Texas project in the RTO's 2017 transmission plan.

One motion — backed by MISO itself — asks the RTO's Planning Advisory Committee to recommend that the Board of Directors approve the current draft of the 2017 Transmission Expansion Plan, which includes a new $129.7 million, 500-kV line and substation in southeastern Texas. The motion requires PAC sectors to acknowledge that they "have provided written comments and suggestions for improvement of MISO's planning activities to be included in future planning processes" and be willing to present their stances at a future PAC or board meeting.

But MISO's Transmission Owners sector submitted an alternative motion calling into question the decision process and cost estimate behind the Texas project, MTEP 17's only market efficiency project, which is meant to alleviate constraints in the West of the Atchafalaya Basin area straddling Texas and Louisiana. (See *Late Changes to Texas Project Frustrate MISO Participants*.) The motion recommends the plan's project list but delays the Texas project "until the time that MISO can adequately address the cost estimation and other concerns that have been raised."

A number of TOs declined to sign on to the sector motion, including Ameren, East Texas Electric Cooperative, Indianapolis Power and Light, ITC Holdings, MidAmerican Energy, Northern Indiana Public Service Co., Prairie Power, Wabash Valley Power Association and City Water Light & Power.

Vote Looming

PAC sectors will vote on the measures in an email ballot after having to temporarily suspend Robert's Rules of Order during an Oct. 18 conference in order to simultaneously consider the conflicting motions. Chair Cynthia Crane said that a tie vote would likely prompt the committee to hold an emergency meeting to further discuss its MTEP recommendation.

The System Planning Committee of the Board of Directors will review MISO's final MTEP 17 draft report in November regardless of whether the PAC recommends the plan in full. The RTO has added 10 projects valued at an additional $1 million since a first draft of the project list was released last month. (See *MTEP 17 Proposal: 343 New Transmission Projects at $2.6B*.) MTEP 17 now contains 353 recommended transmission projects at $2.7 billion. Of those, 70% are projects driven by local needs and not subject to cost allocation, and 22% are projects needed to maintain baseline reliability.

Back and Forth

At Wednesday's PAC meeting, MISO project manager David Lucian said the RTO stands by its recommendation of the Texas project, which currently shows a 1.35:1 benefit-cost ratio. He also noted the RTO does not think Hurricane Harvey reconstruction efforts will hamper construction as Xcel Energy has suggested.

In written comments to MISO, Xcel said it had "concerns that have not been, or haven't had adequate time to be addressed before recommendation," including a company cost estimate that aligns with MISO's estimate under minimum project requirements. Xcel concluded that it made sense to delay project approval until the June board meeting in order to give the RTO time to double-check its estimate.

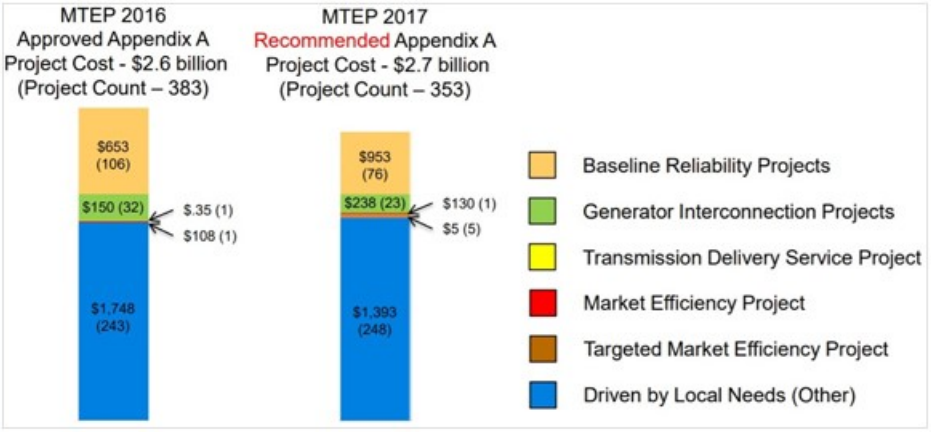
The company said that while it didn't doubt the Texas project's economic benefits, it had lingering concerns that MISO had changed the original project scope and MTEP futures weighting midway through the 2017 process, moves that could be perceived as "favoritism." MISO adjusted the futures weighting for a MISO South study after region's transmission owners and state regulators asked for less emphasis on a carbon-regulated future. (See *MISO Changes MTEP Futures Weighting for South*.)

NRG Energy's Tia Elliott asked why concerns with the projects weren't brought up sooner. "To delay this project would set very dangerous precedent," she said.

Texas Public Utility Commissioner Ken Anderson warned against holding up transmission construction when the state clearly needs the project.

"I will say this now: Texas has been waiting five years for any tangible benefit out of the MISO planning process," Anderson said. "A delay won't be viewed favorably by the stakeholders here. It will call into question the value proposition. This is a very important project for the state and southeastern Texas."

Some stakeholders argued that endorsing MTEP 17 in its current form would allow MISO to recommend a flawed project to the board. Other stakeholders said the possible market efficiency project, whether competitively bid or not, would be subject to cost reporting to MISO, another safety mecha-



| *MISO*

Continued on page 30

MISO News

MISO, PJM Reverse Support for Lone Interregional Tx Project

By Amanda Durish Cook

MISO and PJM have withdrawn their support for developing the lone interregional market efficiency project to emerge from the RTOs' two-year coordinated system plan, stakeholders learned Friday.

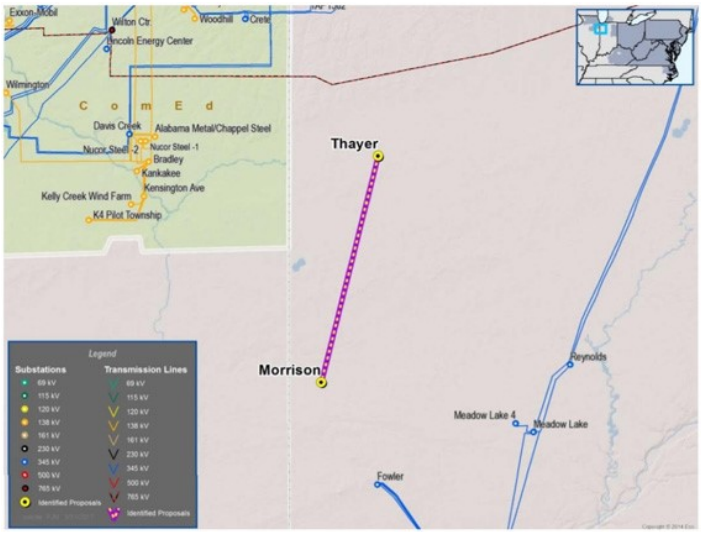
The proposed 30-mile, 138-kV line between Northern Indiana Public Service Co.'s Thayer and Morrison substations near the Indiana-Illinois border was expected to cost $61.8 million and be in service by December 2022. NIPSCO's early estimates pegged the cost at $42.5 million. (See "MISO-PJM Coordinated System Plan Produces One Project," *FERC Conditionally OKs MISO-PJM Targeted Project Plan*.)

The project was the only one of nearly 100 stakeholder-originated suggestions to initially pass the RTOs' benefit-cost criteria, but it ultimately failed a joint 5% generation-to-load-distribution factor (GLDF) test, which requires each RTO to show that one of its generators has at least a 5% impact on the affected flowgate. PJM did not meet the threshold.

During an Oct. 20 Interregional Planning Stakeholder Advisory Committee conference call, NIPSCO's Matt Holtz said the addition of the GLDF test essentially equates to a joint benefit test that FERC ordered the RTOs to eliminate from their "triple hurdle," which included their separate regional benefit tests. He expressed disappointment that both RTOs would withdraw support from the project when "just using the regional processes showed a lot of economic benefit to MISO and PJM."

"I'm not sure that we would agree with that analysis," PJM engineer Alex Worcester responded. "I'm not sure that each RTO's impact on the model ties to a triple hurdle."

"The 5% criteria has long been in the [joint operating agreement]," said Chuck Liebold, PJM manager of interregional planning.



Thayer-Morrison project | *MISO, PJM*

Another PJM stakeholder said the GLDF test amounted to a "technicality." Worcester said PJM is open to examining its test requirement.

To address congestion in the area, local transmission owner Ameren upgraded its transmission ratings, resulting in congestion being shifted away from a nearby 138-kV line to another line in the PJM footprint, Worcester said. The updated ratings cleared up congestion on the PJM side of the seam, compelling the RTO to withdraw its recommendation for the project based on its regional

Continued on page 35

MISO Sectors Mull Texas Project Delay for MTEP 17

Continued from page 29

nism in the cost estimate process.

"Notably, I think the cost estimate has changed with each presentation," Entergy's Yarrow Etheredge said. She added that the PAC has not been able to provide feedback on the final project estimate.

Counting the Cost Estimates

MISO staff have said the $129.7 million estimate has not changed since early August. In July, the RTO provided a $137.6 million estimate, which included an expansion of two existing substations instead of construction of a new substation. But the project and cost estimate changed after local TO Entergy increased a flowgate rating in March, putting the project below the required 1.25:1 benefit-cost ratio, a detail MISO revealed to stakeholders in July when it was forced to alter the project. At the time, MISO presented stakeholders with possible project alternatives and collected stakeholder opinion before settling on the most recent iteration of the project. (See *Late Changes to Texas Project Frustrate MISO Participants*.)

GridLiance's Paul Jett said MISO "clearly followed the process." He pointed out the altered project's cost benefit has been consistently above the required 1.25:1 ratio, and that differences between scoping-level and final cost estimates are natural.

"It isn't new to use scoping-level cost estimates," he said. "If this really is an issue, MISO's board will decide in their approval," he said.

Jett also said it isn't within MISO's purview to delay projects based on the possibility of states enacting right of first refusal (ROFR) laws, another argument raised by Xcel. "Ultimately, if there's a ROFR in Texas, then the project won't be completely bid," he said.

Brian Pederson, MISO senior manager of competitive transmission administration, said that next year the RTO will continue to host discussions on how to improve planning-level and scoping-level cost estimates.

MISO News

Stakeholders Debate Limits of MISO Energy Storage Task Force

By Amanda Durish Cook

While stakeholders are still deciding what topics MISO's Energy Storage Task Force must take on to prepare the RTO for integrating a revolutionary technology, they must also recognize which are off-limits in order to avoid intruding on state jurisdiction.

The new task force has been charged with creating a list of detailed storage issues to be assigned to other MISO stakeholder groups. The RTO in August already floated its suggestions on how to dole out the work. (See *Progress Builds for MISO Energy Storage Effort*.)

Invenergy's John Fernandes, the task force's chair, doesn't want his group to simply provide MISO's Steering Committee "a laundry list of issues and wish them luck." That committee is responsible for assigning specific storage-related issues to other stakeholder committees.

"I don't want to leave things open-ended," Fernandes said during the group's first conference call Oct. 16.

He said the task force should identify in what ways existing market rules might impede participation by storage resources, while also providing the committee with a recommended course of action. That would include helping to determine how to assign issues across committees and identifying which parts of the Tariff require revision.

Clarity from Complexity

The task force's draft charter stipulates that the group consult storage experts to sort out issues that arise from market integration "that may introduce complexity to the footprint."

MISO liaison Joe Gardner said the RTO's goal for the task force is to identify possible near- and long-term changes and additions to market rules.

"Getting as much clarity and consensus now will behoove us in the long run … for planning, reliability and markets," Gardner said. MISO has set aside funding to conduct storage-specific planning studies, he added.

However, stakeholders attending the task force meetings were at odds over the specifics of discussions.

Minnesota Public Utilities Commission staff member Hwikwon Ham cautioned that the task force should not interfere with state jurisdiction, saying stakeholders can explore whether MISO should create potential market products if states decide to allow aggregators to offer storage, but they should steer clear of deciding rules for interconnection. "We have to have a discussion about what we can do within the law," Ham said.

"I have no interest in treading on state jurisdiction," Fernandes said, adding that the group will also steer clear of retail tariffs and distribution rules. "But the industry is going to force our hand," he warned, predicting a future influx of storage participation that will require market rules.

Generation or Transmission?

Indianapolis Power and Light's Lin Franks said the task force should be clear that it will not consider storage as it pertains to transmission planning, instead focusing on how to get it unfettered access to the wholesale market.

Fernandes responded that the group should not limit its consideration of possible storage benefits. "Storage as transmission is a very viable business model," he said.

"Storage is not wires. It's a substitute," Franks countered.

Fernandes said storage-owning stakeholders have "been having the discussion with MISO on storage acting as wires" and the group should consider all storage, whether it functions as a generation or transmission asset.

"Storage as a transmission asset should be on the table … and very much front and center in MISO because it's envisioned by FERC," American Transmission Co.'s Bob McKee said. "FERC has already said storage should be recognized as transmission."

MISO stakeholders also debated whether the group should only tackle grid-scale storage issues, leaving distributed energy resources unaffected. Fernandes said he had concerns with ignoring DER "considering it's a grid-scale storage developer that signs my checks."

The task force will meet again in late November to finalize a charter and agree on topics, while most of its substantive work will occur next year. Stakeholders will weigh in on the group's draft charter through Nov. 3. The task force is slated to meet through the end of 2018, when stakeholders will determine whether the group will be retired or extended.

NYISO News

New York PSC Adopts DER Rules, Sanctions ESCOs

By Michael Kuser

New York Public Service Commission (left to right): Diane Burman, Chairman John Rhodes, Gregg Sayre and James Alesi.

The New York Public Service Commission on Thursday enacted consumer protection standards for distributed energy resource suppliers.

The PSC's order also created a manual of uniform business practices, the first rule of which stipulates that "a DER supplier shall obtain a customer's consent to a sales agreement prior to billing a customer or enrolling a customer" in any program.

At the commission's monthly meeting in Albany on Thursday, Ted Kelly, assistant counsel for the state's Department of Public Safety, testified that "as DERs become an increasingly common and significant part of electric and gas service to customers, [the commission] has both the authority and the responsibility to ensure that customers participating in DER markets and programs understand the costs and benefits of their investments and are protected from confusion, fraud and abusive marketing." (See *Comprehensive DER Oversight Best, NYDPS Hears*.)

DERs take a broad range of forms, Kelly said, "from rooftop solar panels to smart thermostats, to energy-efficient and demand-responsive industrial equipment, to bio-digesters making energy from farm waste, to community-scale distributed generation projects."

The order requires residential customers be able to cancel a contract within three business days after its receipt without charge or penalty, and that the contract include essential information about pricing, cancellation rules, tax incentives, and details of the product or service provided.

PSC Chair John Rhodes said the order "provides a thoughtful and protective balance for New Yorkers and the timing is right. We are facing important and welcome growth in these resources, and we need to be in a position to provide protection for customers against untoward practices while pragmatically not burdening developers. I also find the initial focus on [community distributed generation] and mass market [distributed generation] makes all the sense in the world."

Penalties for a violation of the rules can range from a warning up to a ban from participation in any programs or markets authorized by the commission.

Continued on page 33

FERC Approves NYISO Tx Cost Recovery Changes

FERC last week accepted NYISO's proposed Tariff changes establishing a mechanism to recover costs for eligible transmission projects in the ISO's Comprehensive System Planning Process.

The commission's order accepted revisions to section 6.10 (Rate Schedule 10) and Attachment Y of NYISO's Tariff effective Oct. 18 (ER17-2327).

NYISO submitted the proposed revisions in August, arguing that since the commission approved the current Rate Schedule 10 in 2008, it has instituted new planning procedures that created gaps in its ability to fairly allocate transmission cost recovery.

The grid operator said the proposed Tariff revisions would "enhance and expand the applicability of Rate Schedule 10, so that it can be used for all regulated transmission projects in any of the three planning processes (i.e., reliability, economic and public policy-driven)."

The tariff changes replace its existing Reliability Facilities Charge with a new Regulated Transmission Facilities Charge that will allow NYISO to recover from load-serving entities — and pay to transmission developers — the costs associated with any regulated transmission project that is eligible for cost allocation and recovery under its Comprehensive System Planning Process.

While New York transmission owners generally supported NYISO's filing, they asserted that some language in the proposed revisions might inadvertently modify the abandoned plant costs that a TO or developer is eligible to recover under the state's reliability planning process.

The commission ruled that the TOs did not explain the basis for their position and, "given the lack of specificity" in their comments, there were no grounds for it to act on their concerns. The commission also said that it already made clear that it would "grant abandoned plant recovery on a case-by-case basis and that Order No. 1000 did not provide a blanket grant of abandoned plant recovery."

— Michael Kuser

NYISO News

New York PSC Adopts DER Rules, Sanctions ESCOs

Continued from page 32

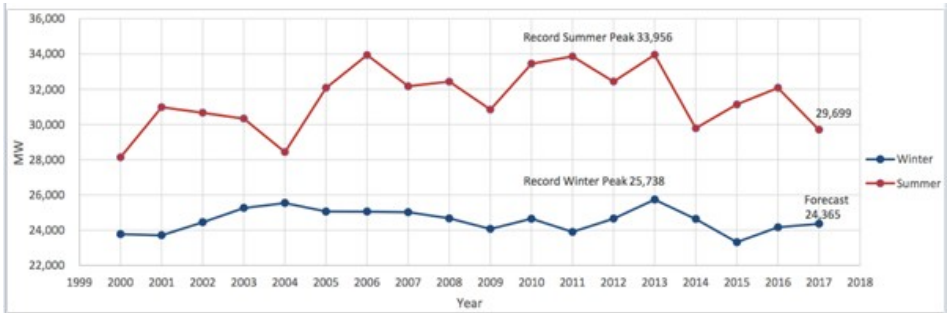
Reining in ESCOs

The PSC also said Brooklyn-based energy service company (ESCO) MPower Energy could be barred from operating in New York following more than 100 customer allegations of deceptive sales and marketing practices.

After investigating complaints dating back to 2015, the commission said MPower must justify within 30 days why it should be allowed to continue operating in the state. The PSC also gave the firm seven days to show why it should be permitted to serve low-income customers, whom the commission said are frequently the victims of aggressive and misleading sales practices by ESCOs. (See *NYPSC Limits ESCO Service, Sets New DER Compensation*.)

The commission also determined that three ESCOs — Just Energy NY, National Fuel Resources and Zone One Energy — can continue serving low-income customers, while it denied waiver requests for four others: Agway Energy Services, Stream Energy, South Bay Energy and New Wave Energy.

The PSC in December 2016 banned most ESCOs from serving low-income customers but said it would consider waivers for any company that promised to offer bill savings or that could guarantee benefits to those customers. A state court earlier this year issued a temporary restraining order on the ESCO ban, which has been since lifted. (See *Court Blocks NYPSC Order Barring ESCO Contracts*.)



New York state historic coincident peaks | *New York PSC*

'Yes' to Community Choice Aggregation

The PSC approved the nonprofit Municipal Electric and Gas Alliance (MEGA) to implement a community choice aggregation (CCA) program for several Upstate New York municipalities.

Under the order, additional municipalities will be allowed to form such programs in the future, which "enable communities to take greater control of their energy choices through a transparent and competitive process driven by the consumers themselves," Rhodes said.

Commissioner Diane Burman asked whether CCAs were subject to the just-issued rules for DER. Kelly said they would be if they included a DER component.

Utilities Prepped for Winter

The state's major energy utilities expect to have adequate fuel supplies on hand for the coming winter, the commission heard.

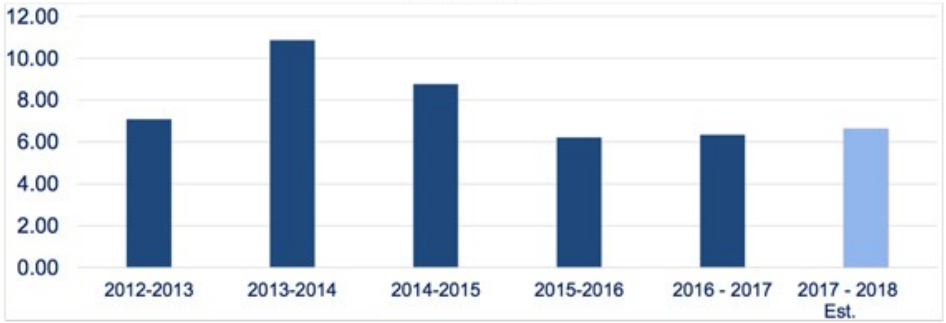
"Each utility has a unique mix of assets to serve a unique mix of customers," said Cynthia McCarran, PSC deputy director for natural gas and water. In her winter preparedness report, McCarran highlighted the efforts by some utilities, notably Consolidated Edison and New York State Electric and Gas, to focus on using demand response programs and so-called "non-pipes alternatives" to meet growing space and water heating needs.

"We anticipate energy consumers will benefit from adequate capacity and supply if we see a harsher-than-expected season," Rhodes said.

The report said that natural gas bills in general are projected to be slightly higher this winter than historical averages and compared to last winter, which was warmer than normal. On the electric side, this winter's commodity prices statewide are projected to be slightly higher than last winter, but significantly lower than the historical average.

Commission staff reported that major dual-fuel generation owners are continuing to follow the lessons learned from the harsh 2013-14 winter, including topping off fuel oil storage tanks ahead of the season, making firm arrangements for fuel oil replenishment, and ensuring that plant equipment has been prepared for winter operations.

"The electric utilities have continued to perform well in reducing the electric supply price volatility of their full service residential customers," McCarran said. "The utilities have hedged approximately 70% of their estimated statewide full service residential energy needs to protect against unexpected electric market price swings that could occur this winter."



New York statewide weight average of full service residential supply price in winter months (cents/kWh) | *New York PSC*

PJM News

RTOs Reject NOPR; Say Fuel Risks Exaggerated

Continued from page 23

180 days from the effective date of any final rule to submit compliance filings.

"[The] deadlines are simply not realistic and attempting to impose them would not be reasoned decision-making," the ISO said. "The NOPR's approach would distort, if not destroy, wholesale market signals needed to attract and retain resources required for reliability."

The ISO called the proposed grid resiliency pricing rule "flawed" for being premised on inaccurate assumptions and statements as they relate to New York.

"The NOPR does not establish that its proposal is appropriate or that 'grid resiliency' issues should be addressed the same way in different regions," said the filing, adding that the grid operator "is not aware of any imminent emergency likely to develop on the wholesale electric system that necessitates drastic and immediate action."

All resource adequacy criteria have been satisfied in New York and are expected to continue to be satisfied for the foreseeable future, said the ISO. For example, on Jan. 7, 2014, New York set a new record winter peak load of 25,738 MW during the polar vortex, and "NYISO met all reliability criteria and reserves requirements without activating emergency procedures at any time during the winter operating period. It did so despite significant generator capacity derates on some of the coldest days, including generation resources that would appear to qualify under the NOPR as 'eligible grid and reliability resources.'"

The ISO said it has made improvements to its energy and ancillary service markets and incorporated features into its capacity market rules "that reflect the importance of resiliency to withstand severe weather events," including basing the downstate installed capacity demand curves on peaking plant designs that include dual-fuel capability.

PJM

PJM agrees there is an issue with maintaining reliability, but not the one suggested by the department.

"The DOE didn't exactly get it right in the way it attempted to articulate the problem," Stu Bresler, PJM senior vice president of operations and markets, said Thursday.

During a special conference call to preview the RTO's plan for responding to FERC's request for comments on the NOPR, Bresler said that the real issue is energy price formation. PJM has been working on that topic for more than a year to respond to concerns over public-policy initiatives impacting market prices.

CEO Andy Ott made similar observations during a media call on Monday, calling it "a tall order" to implement the proposal "and then expect the competitive market to continue to function effectively."

"The DOE proposal, which essentially is the cost-of-service type of mechanism, we don't believe is workable. We don't believe that that is an appropriate response," Ott said. "We believe [it] is contrary to law and will not really solve any problems. … A better and least-cost solution would be to do proper valuation of resource attributes through a market construct."

Andy Ott | © RTO Insider

Ott said the proposal is discriminatory because it is exclusive to certain technologies, rather than the service provided to the grid, and only in RTOs with capacity markets — such as PJM.

"PJM does have an abundance of coal and nuclear plants that are in the merchant category, so … it does look like this is certainly targeted at the PJM region," he said. "We do say that in our comments that this proposal does seem to be focused on this region."

Bresler said that the NOPR — which cited natural disasters and the 2014 polar vortex to argue that units with large on-site fuel stockpiles should be subsidized to save them from retirement — misses the mark. (See *FERC's Independence to be Tested by DOE NOPR*.)

"The point is that just maintaining a whole

Continued on page 56

PJM Board Approves $1 Billion in Tx Projects

The PJM Board of Managers authorized $1 billion in transmission projects at its meeting Oct. 17.

The projects include new construction, end-of-life replacements and upgrades to address reliability criteria violations and relieve congestion throughout the RTO's 13-state footprint, which includes D.C. The board approved upgrades in areas served by American Electric Power; American Transmission Systems Inc.; Commonwealth Edison; Dominion Energy; Duke Energy Ohio & Kentucky; East Kentucky Power Cooperative; Pennsylvania Electric; and Public Service Enterprise Group.

"Maintaining the reliability of the grid is paramount and involves continuously reviewing small and large transmission projects," PJM CEO Andy Ott said in a statement.

The two costliest projects are both in PSEG's zone: one in northern New Jersey near New York City and one in the southern part of the state near Philadelphia. The northern project will consist of a 69-kV transmission network at an estimated cost of $197 million, while the southern project will consist of another 69-kV estimated at $98 million. Constructing a substation in ComEd's zone will cost about $90 million.

The approvals also include results from the first proposal window of the 2017 Regional Transmission Expansion Plan, which closed on Aug. 25. PJM had requested proposals to correct 40 reliability violation flowgates identified in a reliability analysis for 2022. The RTO received 51 proposals from 10 entities addressing nine target zones and added five additional "immediate need" baseline upgrades that will be performed by incumbent transmission owners. (See "RTEP Window Results," *PJM PC/TEAC Briefs: Sept. 14, 2017*.)

— Rory D. Sweeney

PJM News

MRC/MC Preview

Below is a summary of the issues scheduled to be brought to a vote at the Markets and Reliability and Members committees Thursday. Each item is listed by agenda number, description and projected time of discussion, followed by a summary of the issue and links to prior coverage in *RTO Insider*.

RTO Insider will be in Wilmington, Del., covering the discussions and votes. See next Tuesday's newsletter for a full report.

Markets and Reliability Committee

2. PJM Manuals (9:10-10:00)

Members will be asked to endorse the following proposed manual changes:

A. Manual 11: Energy & Ancillary Services. Revisions, which also include changes to the Operating Agreement (OA) and Tariff, were developed to address capping of intraday offers. The current rule offer-caps units that fail the three-pivotal-supplier test, but prohibits reapplying the cap during the unit's day-ahead commitment or minimum run time. The changes would re-evaluate capped units when offers are updated. The changes would also apply to self-scheduled resources. (See "Debate Continues on Intraday Offers," *PJM Market Implementation Committee Briefs: Oct. 11, 2017*.)

B. Manual 11: Energy & Ancillary Services. Revisions developed for the offer-verification process and offer-capping logic as part of implementation of FERC Order 831. The Independent Market Monitor, which disagrees on some parts of PJM's proposal, will offer comments. (See "Debate Continues on Intraday Offers," *PJM Market Implementation Committee Briefs: Oct. 11, 2017*.)

C. Manual 14B: Regional Transmission Planning Process. Revisions developed to add information related to contingency definitions.

D. Manual 19: Load Forecasting and Analysis. Clarifies when load drop estimates are produced and includes updates from a periodic review of the manual. (See "Cleared PRD Forces Manual Revisions," *PJM PC/TEAC Briefs: Sept. 14, 2017*.)

3. Balancing Ratio (10:00-10:20)

Members will be asked to endorse Tariff revisions addressing the calculation of the balancing ratio used in determining the market seller offer cap (MSOC) for the 2018 Base Residual Auction, along with an associated problem statement and issue charge. PJM is concerned that there have been no penalty assessment intervals as needed to determine the balancing ratio. The problem statement and issue charge are meant to address the issue permanently. (See "Give me a B…," *PJM MRC/MC Briefs*.)

4. Distributed Energy Resources Update (10:20-10:40)

Members will be asked to endorse a proposed Distributed Energy Resources (DER) Subcommittee charter. A proposed revision that was not considered friendly by other stakeholders is being offered as a separate version. (See "Amendment on DER Charter Sparks Debate," *PJM MRC/MC Briefs*.)

5. 2017 Installed Reserve Margin Study Results (10:40-10:50)

Members will be asked to endorse the 2017 installed reserve margin (IRM) study results. (See "IRM Reductions," *PJM PC/TEAC Briefs: Sept. 14, 2017*.)

6. Restoration Planning Generator Data (10:50-11:00)

Members will be asked to endorse OA revisions associated with PJM sharing of restoration planning generator data with Transmission Owners. (See "TOs to Receive Confidential Generation Data for System Restoration," *PJM Operating Committee Briefs: Sept. 12, 2017*.)

Members Committee

Consent Agenda (2:20-2:25)

Members will be asked to endorse:

B. Tariff and OA revisions to clarify definitions, as recommended by the Governing Document Enhancement & Clarification Subcommittee.

1. RPM Market Seller Offer Cap (1:25-1:45)

Members will be asked to endorse proposed provisions for calculation of the balancing ratio used in determination of the MSOC for the 2018 BRA. (See MRC agenda item 3 above.)

2. Intraday Offer Capping (1:45-2:00)

Members will be asked to endorse OA and Tariff revisions associated with capping of intraday offers. (See MRC item 2A above.)

3. 2017 Installed Reserve Margin Study Results (2:00-2:15)

Members will be asked to endorse the 2017 IRM study results. (See MRC item 5 above.)

— Rory D. Sweeney

MISO, PJM Reverse Support for Lone Interregional Tx Project

Continued from page 30

analysis, even if the GDLF test wasn't an issue.

Wind on the Wires' Rhonda Peters asked for the reason behind the change in rating to the line.

"We can't always be perfectly coordinated," Worcester said, adding that he didn't know why Ameren upgraded the rating. MISO interregional coordinator Adam Solomon said his RTO could investigate the change.

Worcester said MISO could pursue the Thayer-Morrison project in its separate process. MISO has said it may consider the project for its annual Market Congestion Planning Study next year.

The RTOs' next interregional market efficiency project proposal window required under FERC Order 1000 opens in November 2018. Stakeholders have until February 2019 to submit project suggestions.

In the meantime, Solomon said both MISO and PJM staff would work together on ways to improve the process behind their coordinated system plan.

SPP News

Colorado Regulators Talk Governance with SPP, Mountain West

By Tom Kleckner

DENVER — SPP and Mountain West Transmission Group representatives worked hard Friday to allay concerns of Colorado regulators who fear they could lose some jurisdictional authority over Mountain West members should the group eventually join the RTO.

The chief argument to sway regulators to support membership? The effectiveness of SPP's multistate Regional State Committee, which has primary responsibility for cost allocation, financial transmission rights, resource adequacy and remote resources planning within the RTO's current 14-state footprint.

Colorado Public Utilities Commissioners (left to right) Frances Koncilja, Jeff Ackermann and Wendy Moser. | *© RTO Insider*

Sensing apprehension on the part of some Colorado Public Utilities Commissioners, Sam Loudenslager, SPP's principal regulatory analyst, encouraged the commissioners to join the RSC.

Sam Loudenslager | *© RTO Insider*

"In my experience, the more participation by [regulatory] staff, the more value they see by participating in the RSC," he said. "Other states will make decisions that affect you if you're not at the table."

Commissioner Wendy Moser asked if that meant out-of-state regulators would be making decisions that would affect Colorado. She also expressed concerns that the PUC's RSC membership might violate the state's open meeting laws.

"The [RSC] will not trump [your jurisdiction]," Loudenslager responded. "I'm saying decisions will be made that affect your region, outside the boundaries of Colorado, whether you're there or not."

The information session, focused on transmission, governance and regulatory filings, was the third held by the Colorado PUC. The commission has jurisdictional authority over Xcel Energy's Public Service Company of Colorado (PSCo) and Black Hills Energy, two of the eight Mountain West members seeking to join SPP.

A Separate SPP?

But Mountain West is already asking SPP to make a series of concessions that would preserve consensus decisions its members have already made.

First, the group wants the RTO to expand the RSC to include a group consisting of just the Western states, resulting in a single committee with two regional divisions. The west side of the RSC would provide guidance on regional planning, cost allocation design, congestion cost hedging and resource adequacy.

Second, Mountain West has requested that SPP perform a loss-of-load-expectation (LOLE) analysis for its footprint, which could potentially be used to support establishing a Western regional resource adequacy requirement.

The group has also proposed a Westside Transmission Owners Committee (WestTOC) that would have decision-making authority over cost allocation, zonal changes and transmission revenue requirements.

Kenna Hagan, Black Hills Energy (left); and Carrie Simpson, Xcel Energy | *© RTO Insider*

"I know it sounds like, 'Geez, you're just trying to set up a separate RTO in the West and functionally run it differently,'" said Kenna Hagan, Black Hills' senior manager of planning, policy and strategy. "We're only asking to change a small percentage of the governing documents. … We would be adopting the majority of everything SPP has."

Carrie Simpson, Xcel's senior manager of market operations, said the WestTOC is necessary to protect decisions the members have made over the past four years to eliminate pancake rates and improve their service. Joining an RTO was one of those decisions. (See *SPP, Mountain West Integration Work Goes Public*.)

"SPP has a member-driven process, and we want to use as much of that as we can, but there are certain things we've identified to modify, in order to move forward," Simpson said, referring to cost allocation and transmission planning. "These are issues we've negotiated that we need to preserve in order to make this work."

Hagan, who said during an Oct. 16 meeting before SPP members in Little Rock that it's not "all or nothing," said the WestTOC

Continued on page 37

SPP NEWS

Colorado Regulators Talk Governance with SPP, Mountain West

Continued from page 36

would allow Western transmission owners to make decisions collectively, "not as individuals with competing interests."

"We've worked so hard to get here, we want to continue going forward," Hagan said.

Tri-State Generation & Transmission's Chris Pink told the commissioners that Mountain West is also proposing the creation of separate FERC Order 1000 planning regions that will work with other planning regions in the Eastern and Western Interconnections. The discrete grouping will preserve the importance of local planning and involvement in the Colorado Coordinating Planning Group, he said.

"There will be a regional evaluation of local projects under SPP, but that doesn't mean the authority of Mountain West owners, stakeholders and other groups collaborating in the planning process goes away," Pink said. "This will make the process even better."

"We're trying to optimize the region for how the system would operate in the market, which would be a single region too," said Antoine Lucas, SPP's director of transmission planning. "We would be using the same model sets, the same future assumptions … but outside the East and West, we would be conducting interregional planning with those areas contiguous to us."

Pink said SPP's uniform interconnection process will provide one evident change for independent power producers. Within the Mountain West, IPPs follow different processes to connect generation to the grid.

"Under SPP, [the interconnection process] will be same and it will be consistent. I view this as a benefit," he said. "The key is that there is going to have to be some sort of a transition. How that transition occurs still has to be worked out."

PUC Chair Jeff Ackermann asked whether there would be a systemwide cost allocation once transmission planning has been completed and projects built.

"No one has a crystal ball for how the system will operate in the future," said Black Hills' Dan Kline. "There have been plans, theories and ideas about this super-voltage overlay that could eventually break down the need for DC ties in the middle of the country. Certainly, should the system develop to the point where the DC ties are no longer needed, that would be something we would want to take a look at."

Cultural Fit

Kline told Ackermann that Mountain West selected SPP as its potential RTO because of the "broad-based discussion and negotiation" among participants.

"Everyone had a different thought as to what the best solution was," Kline said. "Ultimately, the additional benefits SPP brought to the table with respect to the dispatch across DC ties, [and] their overall culture of responsiveness and collaboration" helped Mountain West members make their choice, Kline said.

"Each company had its own evaluation," said Xcel's Joe Taylor, one of the primary leads in Mountain West's integration efforts. "We got together and said, 'Who could we reach consensus around?' SPP was the entity the 10 companies could go forward with."

SPP's Lanny Nickell and Xcel Energy's Joe Taylor share a laugh. | © *RTO Insider*

SPP Vice President of Engineering Lanny Nickell later told *RTO Insider* that Kline and Taylor's comments made him feel proud.

"Our culture is something we have worked hard with our members to develop. We haven't done it alone," he said. "It's something that sets us apart from other RTOs. What we do is not that different from other RTOs, but how we do it is."

SPP expects to file Tariff revisions with FERC that incorporate changes to the governing documents following RTO board approval, which could come next summer. FERC's review is expected to take 60-180 days.

Xcel and Black Hills are planning ask the Colorado PUC to approve their integration into SPP and put in place cost-recovery rate mechanisms. The companies will file separately but are flexible about timing their filings with SPP's FERC filing or 60 days later, allowing for any "deficiencies" to be addressed.

SPP has added a section to its website devoted to Mountain West's integration to help stakeholders and others keep up with developments.

"I feel like I'm in Niagara Falls drowning," said Commissioner Frances Koncilja, who facilitated the session.

Koncilja said the PUC will schedule at least three more information sessions, with the hope of getting a FERC commissioner to attend one of them. Later sessions will be devoted to a cost-benefit analysis of integration and Colorado-specific issues.

SPP's Lanny Nickell makes a point as the Colorado PUC listens. | © *RTO Insider*

SPP News

MOPC Briefs

Stakeholders Unable to Reach Consensus on Network Load

LITTLE ROCK, Ark. — SPP stakeholders narrowly rejected a Tariff change last week that would have established a 1-MW threshold for reporting behind-the-meter network load, despite having directed a working group to settle the policy debate over the resources' inclusions and exclusions.

The debate goes on.

"We've been working on this for three, four years," said Southwestern Public Service's Bill Grant during the Markets and Operations Policy Committee meeting Oct. 17. "If we can't reach consensus, we should take it to FERC."

At issue is how members report — or don't report — the network load, and who has jurisdiction over that reporting.

The Regional Tariff Working Group (RTWG) attempted to settle that issue with a revision request (RTWG-RR241) that expanded the Tariff to govern the inclusion of generation on the load side of a discrete delivery point.

The revision would include in a retail customer's network load calculation any BTM output at a discrete delivery point and in front of the customer's meter. The calculation would also include any BTM generator — or combination of generating units — with a nameplate rating greater than 1 MW.

The revision would exclude BTM generation that is used for emergency backup operations and is not synchronized to run in parallel with the grid.

Golden Spread's Mike Wise questions SPP's definition of behind-the-meter load. | © RTO Insider

"The way we talked about this years ago, the megawatt exemption would be used and useful behind discrete delivery points, not behind the meter," said Golden Spread Electric Cooperative's Mike Wise. "Those of us in the hinterlands end up subsidizing [other entities' transmission bills] because we don't have any huge loads. If you're going to use that [exemption], use the nodal pricing point. It's really important to have the number of generators out there aggregated up, so you're not going beyond 1 MW. We believe FERC will see it that way too."

"If that generation is wholly consumed behind the retail meter, it should not be counted as network load," said Oklahoma Gas & Electric's Greg McAuley. "There's enough diversity in this system where a 1-MW generator or larger somewhere is not going to make that much of a difference. We do not want FERC regulating activity behind the retail meter, period.

"We decided the FERC precedent was pretty clear, that all generation behind a discrete delivery point should be included, but not behind retail meters unless a resource behind that meter is conducting wholesale transactions," McAuley continued. "We came down on the side that no exclusion [behind wholesale meters] is appropriate, but then this 1-MW behind the retail meter came up."

OG&E takes the approach that it only reports the generation it owns. The company's RTO policy director, Jake Langthorn, said the company files an annual report of every megawatt it sells.

"If it's behind the retail meter, and generated and consumed there, OG&E doesn't own it," Langthorn said. "We don't own it, we're not going to report it."

"We've been reporting that behind-the-meter generation since Day 1. If I'm reporting the load and you're not, then that's a problem for me," Grant said, offering a different perspective. "You've got everyone at the table saying they're reporting BTMG differently. You can tell this is an issue. I don't know where to go from here except file a 206 complaint, and that's a shame."

The measure failed on a roll call vote, receiving only 54.6% of the votes in favor. When the MOPC in July directed the RTWG to address "inconsistency and uncertainty" over which BTM generation qualifies as network load, it did so by a margin of 0.2%. (See "MOPC Suggests 1-MW Threshold for Network Load," *SPP Markets and Operations Policy Committee Briefs: July 11-12, 2017*.)

OG&E's David Kays, the RTWG's chair, shut down a suggestion that RR241 be tabled until the next MOPC meeting. He noted that this was the third time the working group has prepared a revision request, SPP has given its legal opinion, the MOPC has provided direction and the RTWG has codified the language.

"The thing [we've] struggled with is that every time we showed up [for a meeting], someone had a different carveout," he said. "You open it up to a comment period, you're right back here. I don't know what 90 days solves."

After the MOPC meeting, Kays sent an email to MOPC Chair Paul Malone and SPP COO Carl Monroe, the staff secretary, to request a task force be formed to take the next stab at developing a policy that ensures consistency.

Monroe later told the Strategic Planning Committee that staff would draft and share its view of how the issue should be developed.

Stakeholders Try Again with Resource Adequacy Changes

In the wake of FERC's second rejection of SPP's proposed resource adequacy requirement (ER17-1098), the working group responsible for the Tariff change will begin the process of drafting a new revision request to address the commission's denial. (See *FERC Again Rejects SPP's Resource Adequacy Revisions*.)

In the meantime, it will be business as usual for the SPP market, according to Municipal Energy Agency of Nebraska's Brad Hans, chair of the Supply Adequacy Working Group (SAWG). The 10.7% capacity margin, which is equivalent to a 12% planning reserve margin, will remain in effect along with other criteria, and SPP will continue to follow the reporting timeline of the proposed change.

The SAWG plans to bring a new revision request to the RTO's January leadership meetings. It hopes to make another FERC filing in February.

"It will be a whole new filing," Monroe said. "We're trying to work with FERC in order to get these things forward in a way that we will get an approved filing. If we go outside that, we run the risk of getting rejected again."

FERC said SPP's proposal was "inadequate,"

Continued on page 39

SPP News

MOPC Briefs

Continued from page 38

failed to include a requirement that all power purchase agreements be backed by verifiable capacity to meet the RTO's resource adequacy requirement (RAR), and omitted provisions to allow the RTO to verify the agreements are backed by capacity.

The commission called SPP's proposed treatment of firm power purchases and sales in its determination of net peak demand unduly discriminatory, and that it had not supported its proposal to publicly post a list of all load-responsible entities that have not met their RAR.

Left to right: Duke Transmission's Bob Burner, SPP COO Carl Monroe, MOPC Chair Paul Malone and Vice Chair Todd Fridley. | © RTO Insider

"The issue is: How do you enforce the [RAR's] criteria: through a contract enforcement or through a penalty?" said SPP General Counsel Paul Suskie. "The question is how do you enforce it, and that's at FERC."

A task force spent more than two years developing the resource adequacy package, which is projected to reduce SPP's capacity needs by about 900 MW and save members $1.35 billion over 40 years. The board and stakeholders approved the package in January. (See "Stakeholders Endorse 12% Planning Reserve Margin, Policies," *SPP Markets and Operations Policy Committee Briefs*.)

SPP's Kelley 'Undeterred' by Missouri Projects' Rejection

Saying he was "undeterred" by FERC's rejection of a pair of joint projects (ER17-2256, ER17-2257), SPP Director of Interregional Relations David Kelley said he will take another shot at developing an acceptable regional allocation of the projects' costs.

FERC said SPP's proposal for regionwide/load-ratio share funding for its portion of two projects with Associated Electric Cooperative Inc. (AECI) and City Utilities of Springfield, Mo., had not shown they were "roughly commensurate with the projects' benefits." (See *FERC Rejects Cost Allocation for SPP-AECI Seams Project*.)

The proposed projects would add a new 345/161-kV transformer at AECI's Morgan Substation and uprate an existing 161-kV Morgan-to-Brookline transmission line, while also installing a new 345-kV 50-MVAR reactor at City Utilities' existing Brookline substation. SPP would be responsible for $17.1 million of the projects' estimated $17.1 million to $18.75 million cost, as the benefits would accrue to the RTO.

"We've identified a good project that needs to be constructed. They're the right projects," Kelley said. "My goal is to try and bring back another plan of action you guys can consider at the January meeting."

FERC's order does not preclude SPP from making additional filings supporting regional funding or proposing a new cost allocation for the projects. Kelley said he will continue conversations with AECI, City Utilities and RTO stakeholders in order to better justify regionwide cost allocation or develop another cost allocation proposal for the projects.

"It's really a cost allocation issue" on SPP's side," Kelley said.

During a separate discussion on proposed adjustments to the 2018 Integrated Transmission Planning Near-Term (ITPNT) assessment, City Utilities' Jeff Knottek recommended adjusting the scope of the assessment to include the Brookline remedy as a "persistent operational need," and identify the appropriate solution within the ITPNT portfolio. The motion passed with four abstentions.

The Transmission Working Group in September agreed to rebuild the assessment's planning models, which will extend the 2018 ITPNT's completion from April to July 2018.

Separately, the MOPC accepted the Seams Steering Committee's recommendation of an interregional project with MISO, although the project has since been turned down by the RTO. (See *SPP Glum as MISO Axes Last Interregional Project*.)

"It takes two to dance, and we don't have a dance partner," said American Electric Power's Jim Jacoby, the SSC Chair. "Without MISO, it's a dead project."

Z2 Resettlements Add $6.2M in Net Credits

Staff's resettlement of Z2 credits for sponsored transmission upgrades has resulted in an additional $5.1 million in total net credits receivable for the March 2008-August 2016 historical period, a 2.5% increase from $203.4 million to $208.5 million.

The September 2016-August 2017 resettlement period resulted in a 1.7% increase, from $64 million to $65.1 million.

The resettlements were necessary because of billing disputes, "minor" software defects and problems in calculating the present value of creditable balances, staff told members in July. (See "More Z2 Woes; SPP to Resettle 9 Years of Data," *SPP Markets and Operations Policy Committee Briefs: July 11-12, 2017*.)

Continued on page 40

SPP News

MOPC Briefs

Continued from page 39

Members will only be charged or credited the difference between the resettlements and the initial settlement of the Z2 crediting process.

Individual company results were posted on Oct. 13. Staff said 16 quarterly installments remain on payment plans, with the next invoices going out Nov. 3. Those invoices will include the resettlement net amounts.

AEP's Richard Ross explains the Marker Working Group's recent work. | © RTO Insider

Registered Entities Transitioning from SPP RE

SPP RE President Ron Ciesiel updates members on transition to new REs. | © RTO Insider

SPP Regional Entity President Ron Ciesiel reminded members that applications to join new REs are due at NERC by Oct. 31. As of Oct. 17, he said, the commission had received only 40 applications.

The SPP RE announced its dissolution in July, addressing FERC and NERC concerns over its reliability oversight role. (See *SPP to Dissolve Regional Entity*.)

That move forced the SPP RE's 120 registered entities to transition to others, a process NERC is managing. Entities should pick a new RE by Dec. 31, 2018, though Ciesiel hopes to complete the process next summer.

"Every entity should have been contacted by NERC multiple times," Ciesiel told members.

He reminded members that the SPP RE is still the compliance and enforcement authority for its registered entities. "We're in business as usual," he said.

SPP has joined ReliabilityFirst but will also have to register in other REs where it does business.

Generator-Interconnection Task Force Extended for 1 Year

Members approved the Generator Interconnection Improvement Task Force's (GIITF) request to spend an additional year developing a three-stage study process that would replace SPP's current process built around feasibility studies, preliminary and then definitive interconnection system impact studies, and facility studies with multiple entry points.

The group is proposing stages devoted to thermal and voltage analysis, stability analysis and a facilities study. The task force's chair, Sunflower Electric's Al Tamimi, said the simplified process would be easier for SPP to administer and simpler for customers to understand and navigate.

Tamimi said by tying financial security to upgrade cost allocation, the proposal would encourage customers to weigh the risks of proceeding at an earlier stage and reduce the number of interconnection requests being withdrawn late in the process.

The GIITF also requested a stakeholder group with "appropriate background and expertise" be tasked with re-evaluating the purpose, scope and study requirements of network resource interconnection service to align it more closely with SPP's current and future market structure. MOPC Chair Malone said he would work with staff to put together a task force.

The MOPC also approved the group's recommendation to publish study models earlier in the process and eliminate the "standalone" analysis to reduce study costs and improve timeliness. SPP's Tariff requires each interconnection request be evaluated as if it is the only request in the queue, although binding results are based on cluster evaluations.

MOPC Says Goodbye to Two Member Reps

Jake Langthorn says good-bye to the MOPC. | © RTO Insider

The MOPC said goodbye to two veteran representatives: Vice Chair Todd Fridley, who is retiring from Transource Energy but will begin a new career with Public Service Company of New Mexico, and OG&E's Langthorn, who is retiring at the end of the year.

"I remember when [SPP CEO] Nick Brown was a staff engineer," Fridley said in thanking the committee and SPP for their support. "That's how far back I go."

Langthorn said that while he is ready for retirement, he has always enjoyed his work.

"This is the middle of the country. This is the heart of the country," he said, referring to SPP's flyover country footprint. "We really make a difference for people."

MOPC Clears 8 Revision Requests

The MOPC approved a measure targeting potential gaming related to the regulation deployment adjustment settlements charge type. The revision (MWG-RR243) minimizes credits and maximizes charges related to the charge type, using the lesser of the as-

Continued on page 41

SPP News

MOPC Briefs

Continued from page 40

dispatched energy offer curve and mitigated energy offer curve for the regulation-up adjustment, and the greater of the as-dispatched offer curve and mitigated energy offer curve for the regulation-down adjustment.

Keith Collins, executive director of SPP's Market Monitoring Unit, recommended the change, saying manipulation of regulation-down offers has cost the market more than $1 million in recent years. He said that combined with MWG-RR242, which was on the consent agenda, the change addresses the MMU's gaming concerns.

The MOPC passed two other Market Working Group revision requests, with a total of five abstentions:

- MWG-RR231: Removes locally committed resources from the economic mitigation tests and creates a 10% cap for resources committed for local reliability. Addresses the practice among some resources of "self-mitigating" to pass the conduct threshold test and avoid possible mitigation with by submitting competitive energy offers 10% above the mitigated offer.
- MWG-RR239: Allows market participants to incorporate fuel cost uncertainty into their mitigated offers, recovering the difference between forecasted and actual costs.

Members also unanimously approved five RRs on its consent agenda:

- MWG-RR235: Corrects RR200, which removed bilateral settlement schedules (BSSs) at hubs and generation settlement locations from the over-collected losses (OCL) distribution calculation. The RR modifies two equations in RR200 to accurately reflect its true intent.
- MWG-RR236: Changes the commercial model implementation from a bimonthly process to monthly. Previously implemented on only even-numbered months (February, April, etc.), the process hindered market participants with contracts becoming effective at the beginning of the year from submitting model updates on the remaining odd-numbered months.
- MWG-RR242: Adds a fourth criterion, based on a resource's cleared energy offer, for prioritizing the order in which they are deployed for regulation-up and regulation-down and addressing a potential gaming opportunity. The higher the offer, the less likely a resource will be deployed for regulation-up, and the lower the offer, the less likely it will be deployed for regulation-down.
- RTWG-RR238: Addresses the financial exposure to SPP and its market participants stemming from a defaulting transmission customer avoiding responsibility for the full amount owed for the full term of a service agreement. The change also restricts the ability of SPP, transmission owners and transmission customers from recovering attorney's fees related to performance of a service agreement, and clarifies that each party to an arbitration under the Tariff is responsible for its own fees.
- RTWG-RR244: Eliminates credits from new upgrades that do not add transfer capability under Tariff Attachment Z2, and eliminates credits from short-term service under the same attachment, as recommended by the Z2 Task Force. (See "Z2, Two Other Task Forces Expire," *SPP Board of Directors/Members Committee Briefs: July 25, 2017*.)

— Tom Kleckner

SPP News

SPP Tx Owners Take Zonal Placement Concerns to FERC

By Tom Kleckner

LITTLE ROCK, Ark. — Kansas City Power & Light is making good on its promise to take legal action against SPP for how the RTO allocates costs to network customers after a new transmission owner joins an existing transmission zone.

The utility has joined with 11 other TOs to file a Section 206 complaint with FERC against a "loophole" in SPP's Tariff that forces customers within an existing zone to pay a share of the legacy costs for transmission lines newly integrated into the zone. That practice, the complainants say, runs counter to the "no legacy cost shift" protections SPP has established to prevent cost shifting between zones.

The Oct. 13 complaint says SPP's Tariff is unjust and unreasonable and suggests the RTO modify its rules to ensure that facility costs are borne by customers for whom the facilities were planned.

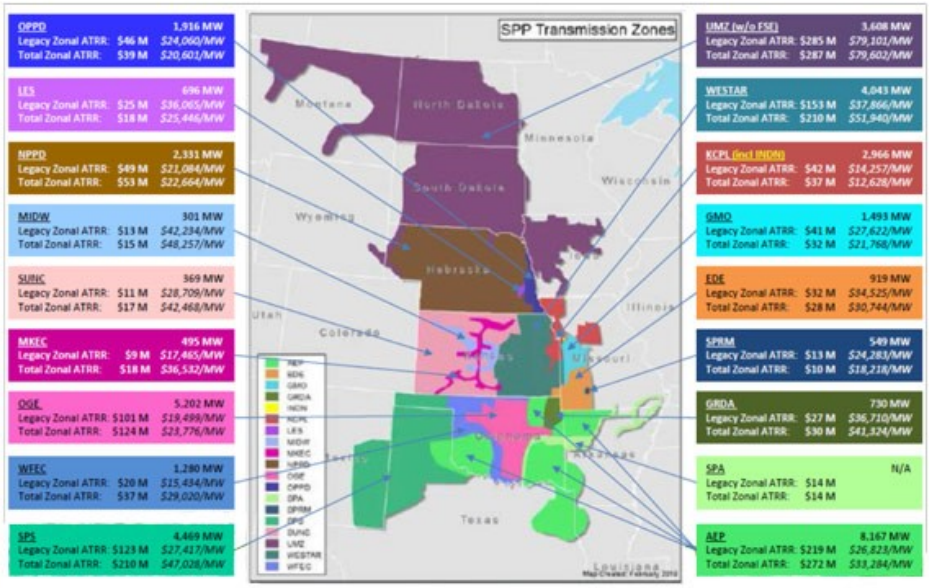
Joining with KCP&L are American Electric Power (on behalf of subsidiaries Public Service Company of Oklahoma and Southwestern Electric Power Co.); City Utilities of Springfield, Mo.; KCP&L Greater Missouri Operations; Nebraska Public Power District; Oklahoma Gas & Electric; Omaha Public Power District; Southwestern Public Service (SPS); Sunflower Electric Power; Mid-Kansas Electric; Westar Energy; and Western Farmers Electric Cooperative.

The companies contend SPP's zonal integration decisions create unjustified rate increases in the form of cost shifts between customers. Their complaint says the Tariff is unduly discriminatory because the cost shift burden is not evenly distributed and the disparate rate treatment is not based on any differences in service or the customers.

The cost shifts are contrary to FERC's policies on transmission pricing, cost allocation and RTO membership, the utility said.

Fairness Issue

"This is a fairness issue," said KCP&L's Denise Buffington, the utility's director of energy policy and corporate counsel. "You should not decouple the costs from the decision to build for a specific set of customers."



Note: SPP Zonal ATRR & Load Information based on data in RRR file for rates effective April 1, 2017.

The recent creation or expansion of multi-owner zones has highlighted various notice and equity issues that did not exist in historical single-owner zones, Buffington said. She suggested modifying SPP's license plate rate design to address the increasingly common integration of smaller TOs into existing zones.

Buffington first introduced a Tariff revision request in 2016 to address the gap she said exists between the zonal placement decisions for new TOs and the cost effects of those decisions.

After receiving pushback from SPP and members, she revised her proposal to establish a mechanism holding customers of an existing zone harmless from network integration transmission service (NITS) rate increases of more than 2% or $1 million (whichever is lower). The Markets and Operations Policy Committee and the Board of Directors rejected the proposal in July. (See *SPP Board Rejects Changes to Tx Zonal-Placement Rules*.)

"You can be sure it will be argued about at FERC," Buffington warned at the time.

The complaint suggested to FERC that SPP maintain separate NITS rates for the new and existing TOs upon integration. Customers of the new entity would pay its annual transmission revenue requirement (ATRR), and customers of the existing TO would continue paying the same rate previously paid based on the existing ATRR.

Public power entities have consistently opposed the transmission-owning members' suggestions, saying it would discourage smaller entities from building transmission and getting cost recovery. FERC is already considering several cases involving cost shifts (ER16-204, ER17-2020).

"We're still reviewing the 87-page filing, but it appears similar to the proposal KCP&L made in the SPP stakeholder process … and addresses a topic already under review by FERC," said Brett Hooton, vice president of South Central MCN, which is involved in one of the dockets. "The proposal included in the complaint is discriminatory, anti-competitive, and undoubtedly unjust and unreasonable."

The Missouri Public Service Commission intervened in the docket (EL18-20).

Z2 Complaints

Xcel Energy on Oct. 10 filed a Section 206 and 306 complaint against SPP on behalf of SPS, its Texas-based utility. The complaint said SPP had violated its Tariff by assessing Attachment Z2 credit payment obligations to SPS in a manner that is "inconsistent with

Continued on page 43

SPP News

SPP to Consider Tx Planning Policy for Energy-Only Resources

By Tom Kleckner

LITTLE ROCK, Ark. — SPP staff agreed last week to bring stakeholders a strawman proposal addressing concerns over the RTO's transmission planning policy for energy-only resources.

Under current rules, capacity resources must go through transmission-service study (TSS) processes, while wind farms and other energy resources can bypass the TSS process and participate in the market, often creating transmission congestion. Stakeholders said the discrepancy creates uncertainty regarding future resource development as well as concerns over the fairness of cost allocation.

"It will take some time … to bring you something that will be a good strawman for you to start poking holes at," COO Carl Monroe told the Strategic Planning Committee on Thursday, offering to deliver an update at its January meeting.

Staff will attempt to define the treatment of capacity and energy-only resources in the long-term planning process, taking into consideration reliability, public policy and economic concerns. It may also work to create incentives to generation-interconnection customers to proactively pursue upgrades needed to improve the deliverability of energy-only resources, and possibly develop a mechanism to treat all resources as firm capacity.

Antoine Lucas, SPP's director of transmission planning, said things changed when tax incentives led to a rush of wind energy on the RTO's system.

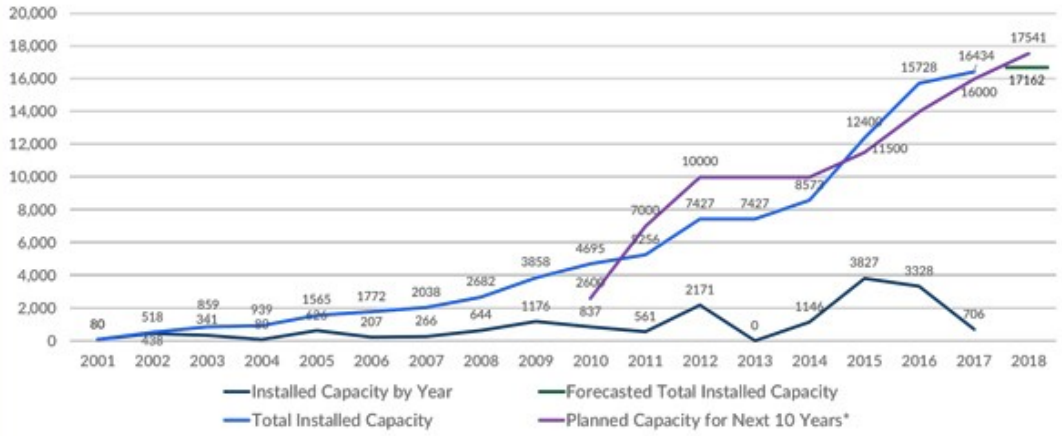
"Once the markets developed, we started running into blurred lines between what's firm and what's non-firm capacity," he said. "It used to be black and white. If it's a capacity resources, it was a firm service. You issued physical curtailments, with priority going to those firm resources. That's not the most economical way to handle resources."

Dogwood Energy's Rob Janssen agreed with the need for a strategic vision, saying cost-allocation problems that have cropped up in recent years are "issues of [SPP's] success."

"We had a goal to build a robust transmission system, and we built it out to accommodate 12 to 15 GW of wind," he said. "We made it work, but we haven't stopped to re-evaluate our goals and needs now, and we're seeing the cracks in the system. We need to step back and clearly identify our goals. How much more renewables do we need? Do we want to pay for those?"

SPC Chair Mike Wise, of Golden Spread Electric Cooperative, thanked the committee for the robust discussion, saying it was "pulling the scabs off several issues."

"Little things can be dealt with here and there, but we need to keep the overall strategic picture in mind," he said. "Let's not just resolve this issue, but let it take us into the next world."



*Business as usual/reference case for economic studies only. Sensitivity case wind levels not included.

| *SPP*

SPP Tx Owners Take Zonal Placement Concerns to FERC

Continued from page 42

the SPP Tariff, violates the filed rate doctrine, is inconsistent with SPS' network transmission service agreements with SPP and is otherwise unjust."

Xcel requests that FERC find as unjust and unreasonable SPP's $12.8 million net assessment to SPS for historical revenue credit payment obligations (CPOs) and ongoing monthly charges of approximately $485,000 for current CPOs and amounts uplifted. The company is seeking to have SPP recalculate the CPOs for SPS' transmission service reservations, recalculate the historic and ongoing Z2 charges, and provide refunds to SPS with interest.

KCP&L, American Electric Power and Westar Energy have all intervened in the proceeding (EL18-9).

SPP's process for assigning financial credits and obligations for sponsored upgrades under Attachment Z2 of its Tariff has bedeviled the RTO and members for almost two years. Last year staff identified about $200 million in revenue credits to be collected for transmission upgrades under its Tariff's Attachment Z2, which details how to reimburse network upgrade sponsors. The bills covered eight years of credits and obligations for 2008-2016, when staff failed to apply credits, complicating the task of trying to accurately compensate project sponsors and claw back money from members with debts for the upgrades. (See "Z2, Two Other Task Forces Expire," *SPP Board of Directors/ Members Committee Briefs: July 25, 2017*.)

SPP News

FERC Again Rejects SPP Rules on ARRs, LTCRs

By Rich Heidorn Jr.

FERC on Thursday again ordered SPP to rewrite its rules on auction revenue rights (ARRs) and long-term congestion rights (LTCRs), saying the RTO's proposed grandfathering provisions would "inappropriately extend practices that the commission finds unjust and unreasonable" (ER17-1575).

In a related order, the commission also rejected SPP's proposal to provide ARRs and LTCRs to network service customers subject to redispatch on the same basis it provides them to customers not subject to redispatch (EL16-110). The commission ordered SPP to revise its Tariff to apply to network service customers subject to redispatch the same limitation on ARR and LTCR eligibility that the RTO currently applies to point-to-point service customers subject to redispatch.

SPP had drafted the Tariff language after the commission ordered a Section 206 inquiry in September 2016 in response to complaints by Southern Co., the American Wind Energy Association and the Wind Coalition. (See *SPP Hopes Congestion Rights Rule Change Wins FERC OK*.)

In Thursday's orders, FERC approved SPP's proposal to grandfather ARRs and LTCRs that have already been granted to network customers with service subject to redispatch. But the commission said it was not reasonable to extend the grandfathering provisions through July 15, 2017, as SPP had proposed as a transition to new ARR/LTCR eligibility rules.

SPP said it wanted to ensure that customers that contracted for network service subject to redispatch — service that is "confirmed" but has not commenced — remain eligible for ARRs for the full term of their service agreement.

The commission said that proposed revisions to section 34.6 of SPP's Tariff were unjust and unreasonable because they would allow the RTO to provide ARRs and LTCRs to network service customers subject to redispatch while necessary transmission upgrades are constructed on the same basis it provides ARRs and LTCRs to firm transmission customers not subject to redispatch.

FERC said SPP must not allocate ARRs to customers with network service subject to redispatch on the same basis as firm transmission customers not subject to redispatch, "except for those times and amounts not subject to redispatch." LTCRs also are barred for network customers subject to redispatch.

But the commission approved grandfathering ARRs and LTCRs already granted for network service subject to redispatch under the current language of section 34.6. "Allowing customers with network service subject to redispatch to retain their already-granted ARRs for the periods of time and the amounts of service subject to redispatch obligation and to retain their already-granted LTCRs, while preventing the future allocation of ARRs and LTCRs to such service on the same basis as firm transmission customers not subject to redispatch, appropriately balances the interests of network customers with service subject to redispatch who were granted ARRs and LTCRs based on SPP's interpretation of its Tariff with the need to prevent ARRs and LTCRs from continuing to be awarded in an unjust and unreasonable and unduly discriminatory or preferential manner," the commission said.

In related orders, FERC also:

- Clarified that its Sept. 23, 2016, order did not prevent customers from seeking relief or address any retroactive relief (ER16-1286-002, EL16-110-001);
- Rejected Southern Co. unit Alabama Power's allegation that SPP violated its Tariff by treating customers with network service subject to redispatch as eligible to receive ARRs and LTCRs (EL17-11); and
- Rejected a complaint by Buffalo Dunes Wind Project asking the commission to order SPP not to allocate new ARRs or LTCRs to network service customers subject to redispatch for the 2017-2018 allocation year (EL17-69).

FERC Orders Section 206 Proceedings for 5 SPP TOs

FERC on Thursday ordered Federal Power Act Section 206 proceedings for five SPP transmission owners seeking to develop projects under the RTO's Order 1000 competitive solicitation process.

The commission accepted revised formula rate templates and protocols for ATX Southwest (ER15-1809-001, EL18-12); Transource Kansas (ER15-958-003, EL18-13, ER15-958-004); Midwest Power Transmission Arkansas (ER15-2236-001, EL18-14); and Kanstar Transmission (ER15-2237-001, EL18-15, ER15-2237-003). But the commission ordered 206 proceedings because the companies' filings did not provide for inclusion in their annual updates sufficient descriptions and justifications for the allocation of costs between them and their affiliates.

FERC also set a 206 proceeding for South Central MCN, saying its revised protocols "attempt to define the scope of future filings" under FPA Section 205 (ER15-2594-003, ER17-953, EL18-16). The commission said South Central had provided an adequate description of its cost allocation methodology as required by an order in October 2015.

— *Rich Heidorn Jr.*

FERC NEWS

New England, SoCal Gas Supplies Top FERC Winter Concerns

By Rich Heidorn Jr.

Presenting winter reliability reports to FERC were (left to right): Peter Brandien, ISO-NE; Wes Yeomans, NYISO (partially hidden); David Souder, PJM; Richard Doying, MISO; Bruce Rew, SPP; and Nancy Traweek, CAISO. | *© RTO Insider*

WASHINGTON — Gas supply for New England and Southern California is the top reliability concern for the coming winter, FERC officials said Thursday.

Commission staff said they saw no major risks of significant disruptions this winter but that they would be closely monitoring gas supplies in the Northeast and the area around California's Aliso Canyon storage facility.

Robert Powelson | *© RTO Insider*

"You'd probably be the market that keeps me up at night," Commissioner Robert Powelson told ISO-NE Vice President of System Operations Peter Brandien at the commission's monthly open meeting, where officials of all six FERC-jurisdictional RTOs and ISOs gave their annual presentations on winter preparedness.

Brandien earlier had pronounced himself "cautiously optimistic."

Bull's-Eye

Peter Brandien | *© RTO Insider*

"I always feel like I have a bull's-eye on me when I come down to talk about these things," Brandien said, prompting laughter.

While the 2014 polar vortex jolted PJM and others to tighten rules ensuring generators' reliability, ISO-NE has been dealing with the issue since the 2004 "cold snap," he said. New England produced 49% of electricity using gas in 2016, up from 15% in 2000.

Since a second scare in winter 2012-13, the RTO has been relying on temporary winter reliability measures that encourage gas operators to have dual-fuel capability and access to LNG. The temporary program will give way to the Pay-for-Performance rules beginning June 1, 2018, that contain stronger capacity market incentives for securing fuel.

Brandien said tight pipeline capacity and limited visibility into LNG shipments remain his region's concern.

"I think we're pretty much coordinated-out," he said when asked if additional gas-electric coordination would help New England. "The problem is we have full pipes."

Brandien said the additional pipeline capacity provided by Spectra Energy's Algonquin Incremental Market project in January has been offset by the retirement of the 1,500-MW coal-fired Brayton Point Power Station at the end of May.

"I actually was encouraged when I saw that some of the [gas] future prices for New England were higher than other places because those are the kind of things that are going to incent some contracts or some arrangements to be made to get [LNG] ships moving to New England," he said.

Gas availability also could be a concern for New York City, which gets 95% of its generating capacity from gas or dual-fuel plants, said Wes Yeomans, NYISO's vice president for operations.

The ISO's 90-10 base case for the winter shows a statewide capacity margin of more than 11,000 MW, but that drops to 7,000 MW if generators receive only firm gas supplies and less than 4,300 MW if all gas is lost.

CAISO

The reduced capacity of the Aliso Canyon gas storage facility following the 2015 leak also was the subject of concern.

Sixty-two of the facility's 114 wells were taken out of permanent operation. As a result, FERC staff said, the Southern California Gas system has 65 Bcf in storage, the lowest on record for this time of year since at least 2001 and far below its five-year average of 118 Bcf.

Although there were no supply interruptions this summer, staff said, Aliso Canyon's limited storage "could challenge regional stability and increase natural gas and electricity prices" this winter. "The recent outages of SoCalGas Line 235-2 and Line 3000 may also limit flexibility in the region. This risk could also be magnified by upstream pipeline issues, like further outages or wellhead freeze-offs."

Nancy Traweek, CAISO's executive director of system operations, said California's wildfires are not currently a threat to transmission but are having an impact on distribution.

Continued on page 46

FERC News

FERC OKs Cost Allocation on Va. Tx Undergrounding

By Rory D. Sweeney

FERC last week decided a seven-year-old dispute over the cost allocation for three Virginia Electric Power Co. transmission undergrounding projects, ruling the costs should be shared by all VEPCO network integration transmission service customers with loads in the state.

The commission reversed some findings from an administrative law judge's 2016 initial decision while upholding the remainder (EL10-49-005). The commission also denied requests for rehearing of its March 2014 order that said VEPCO loads outside Virginia could not be allocated the incremental costs of the undergrounding, which was ordered by the state (EL10-49-004).

At issue was whether Old Dominion Electric Cooperative and North Carolina Electric Membership Corp. should be required to pay the additional costs of undergrounding VEPCO's Pleasant View, DuPont Fabros and Garrisonville projects.

"The cost impact of the state's actions is stark: Approximately 64% of the collective total costs of the projects — almost $150 million — was incurred to place the lines underground," the commission said. "Considering the three projects together, placing the lines underground nearly tripled construction costs."

The commission reversed Administrative Law Judge Michael Haubner's determination on calculating the costs to be allocated to the two utilities for the projects, ruling that it should only include depreciation, return on capital investment, income taxes, accumulated deferred income taxes and property taxes.

It also reversed the judge's determination that the methodology used to allocate the underground component of project costs should be used for future capital expenditures that don't increase the projects' capacity. FERC affirmed, however, its 2014 ruling on cost allocation, the ALJ's determination that future capital expenditures that increase the projects' capacity are beyond the scope of the proceeding and its determination of refunds, which are dated to March 17, 2010.

VEPCO must submit tariff revisions and rebill customers within 30 days, and file a refund report within 60 days.

The commission rejected challenges to its March 2014 order, which concluded that the undergrounding costs could not be collected from out-of-state loads because the additional cost was necessitated by state requirements, not reliability needs. The projects created "systemwide benefits," so the costs should be allocated among wholesale customers rather than just retail, the commission said.

"The commission is not limited to adopting only a remedy put forward in the complaint or in briefing, as the rehearing applicants allege," FERC said. "The commission has considerable discretion in fashioning remedies and can base that remedy on the record developed."

New England, SoCal Gas Supplies Top FERC Winter Concerns

Continued from page 45

Fuel Diversity not Cited

Neil Chatterjee | *© RTO Insider*

One subject that was not raised as a reliability concern by the RTO officials who spoke to FERC was fuel diversity and the continued retirement of coal generation — an issue cited by Energy Secretary Rick Perry in his call for price supports for coal and nuclear plants. FERC Chairman Neil Chatterjee on Oct. 13 praised Perry for raising the issue. (See *FERC Chair Praises Perry's 'Bold Leadership' on NOPR*.)

In a press conference after the meeting, Chatterjee said the RTO officials were only some of those whose views will be considered by the commission in the Notice of Proposed Rulemaking (RM18-1).

"We will find out from a variety of stakeholders whether there are conditions today or in the future that we need to consider," he said. "Perhaps the fuel mix is working for them today. As market conditions continue to change, we don't know what the future will hold. As some of these assets are retired, that will change the fuel mix.

"We need to be constantly vigilant and monitor the grid, monitor market changes, to ensure that this winter and beyond we don't have circumstances that could lead to catastrophic outcomes."

Chatterjee said he was withholding judgment on whether high penetrations of wind pose a reliability concern.

Bruce Rew, SPP's vice president of operations, said the RTO was forecasting a new wind penetration record of 66% Friday. Thanks to accurate forecasting, Rew said, the RTO has already handled penetration of 55% wind and wind output swings of 10,000 MW within a day "without any problems." The region has added 3,000 MW of wind capacity since last winter.

[As it turned out, wind peaked at 13,039 MW in SPP Friday, short of the 13,342 MW record set Feb. 9.]

"We're going to make a fact-based determination based on what the record reflects," Chatterjee said. "I certainly respect the gentleman's opinions, and I will defer to his expertise as well as others to make that assessment."

Comments on the rulemaking were due Monday.

On Thursday, a bipartisan group of eight former FERC commissioners — including former Chairmen Elizabeth Anne (Betsy) Moler, James J. Hoecker, Pat Wood III, Joseph T. Kelliher and Jon Wellinghoff — filed joint comments saying that Perry's proposal would be "a significant step backward from the commission's long and bipartisan evolution to transparent, open, competitive wholesale markets."

"The commission's adoption of the published proposal would instead disrupt decades of substantial investment made in the modern electric power system, raise costs for customers and do so in a manner directly counter to the commission's long experience," they said.

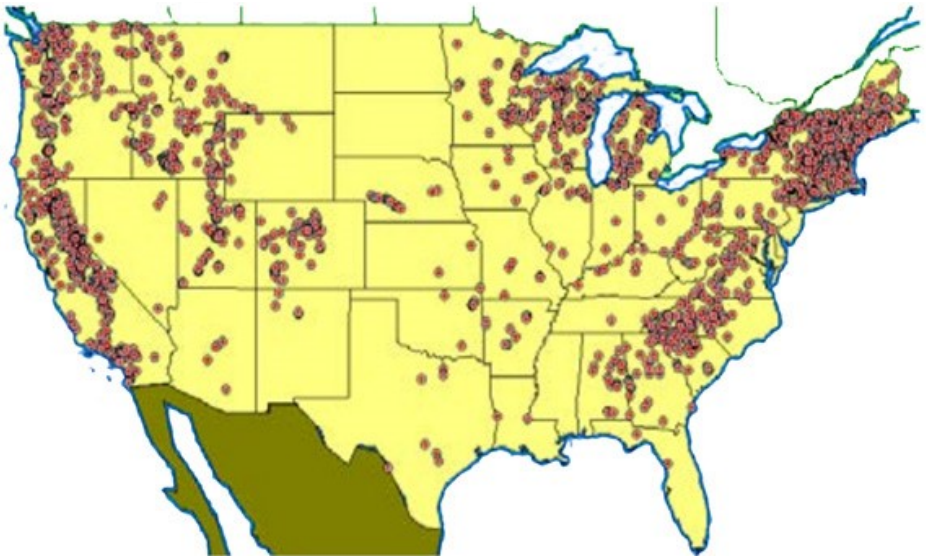
FERC News

FERC Sets 40-Year Term for Hydro Licenses

By Rich Heidorn Jr.

WASHINGTON — FERC on Thursday set a 40-year default term for hydropower licenses, a move it said will reduce administrative costs and encourage dam owners to upgrade capacity and make environmental or recreational investments.

"This is quite a big deal, because we're changing a policy we've had in place for several decades," said Commissioner Cheryl LaFleur.



Hydroelectric dams under FERC jurisdiction | *FERC*

The commission's policy statement (PL17-3), which will apply to original licenses and license renewals, also set conditions under which it will consider terms longer or shorter than 40 years:

- If necessary to coordinate license terms for projects located within the same river basin;
- When a different term is included in a "generally supported" and "comprehensive" settlement agreement that does not conflict with terms for projects in the same river basin; and
- When an applicant requests a longer term based on "significant measures" voluntarily implemented during the prior license term or expected to be required for renewal. The commission has previously found that the construction of pumped storage facilities, fish passage facilities, fish hatcheries, recreation facilities, dams and powerhouses warranted longer license terms.

FERC regulates more than 2,500 dams with 55,800 MW of capacity, more than half of all hydroelectric capacity in the U.S. The Federal Power Act allows the commission to issue original licenses for up to 50 years and

Continued on page 48

FERC Seeks Cyber Controls on Portable Devices; Sets GMD Plans

By Rich Heidorn Jr.

WASHINGTON — FERC on Thursday proposed rules to prevent malware from infecting "low impact" computer systems through transient electronic devices such as laptops and thumb drives.

The Notice of Proposed Rulemaking would approve critical infrastructure protection reliability standard CIP-003-7, a response to an order issued by FERC in January 2016 (RM17-11). (See *FERC Postpones Action on Supply Chain Protections*.)

In addition to setting controls on devices frequently connected and disconnected from low-impact Bulk Electric System (BES) facilities, the NOPR also requires such facilities to have a policy for declaring and responding to "exceptional circumstances."

High- and medium-impact BES cyber systems already have rules for responding to "exceptional circumstances," which include situations that impact BES reliability or pose the risk of injury or death and cybersecurity incidents requiring emergency assistance.

The NOPR also directs NERC to revise the standard to provide objective criteria for electronic access controls for low-impact systems and add ways to mitigate the risk of malicious code introduced by third-party transient electronic devices, such as scanning devices prior to use.

GMD Order

In a separate order, FERC approved NERC's preliminary geomagnetic disturbance (GMD) research work plan and ordered it to file a final plan within six months (RM15-11-002).

NERC's GMD work plan, which it developed in collaboration with the Electric Power Research Institute and its GMD Task Force, identified nine research areas and sets an estimated time frame for their completion. It was developed in response to the commission's September 2016 order requiring grid operators to assess and protect against the threat of GMDs. (See *FERC Approves GMD Reliability Standard*.)

Thursday's order sets the priority in which NERC should conduct the GMD research, saying it should first seek to improve earth conductivity models for studies of geomagnetically induced currents. The commission cited the models' importance in completing the GMD vulnerability assessments required by reliability standard TPL-007-1.

It said the second priority should be improving harmonics analysis "because the synergistic effects of harmonics during GMD events are not well understood."

FERC News

FERC Backs off Nonpublic Utility Refunds in MISO, SPP

RTOs to Develop Proposals with Stakeholders

By Michael Brooks

FERC said Thursday it will let MISO and SPP work with their stakeholders to determine whether the RTOs should require refund commitments from their transmission-owning nonpublic utility members.

In agreeing to hold in abeyance Section 206 proceedings on the issue, FERC ordered the RTOs to file proposals by Feb. 28, 2018 (EL16-91, EL16-99). FERC additionally required them to submit reports updating the status of their endeavors by Dec. 15.

The commission, however, rejected claims by MISO, electric cooperatives and nonpublic utilities that it lacked the authority to order changes in the RTOs' governing documents to require refund commitments. While the Federal Power Act explicitly limits FERC's jurisdiction to public utilities — a limitation the commission had acknowledged in its July 2016 order initiating the 206 proceedings — the co-ops argued that the commission's actions amounted to a "work around," or an indirect order. (See *Co-ops, MISO, SPP Urge FERC Restraint with Nonpublic Utilities*.)

Citing federal court rulings, FERC reasserted that once a nonpublic utility's transmission revenue requirement becomes a component of an RTO's rates, the commission can "'analyze and consider the rates of [nonpublic] utilities to the extent that those rates affect jurisdictional transactions' through their inclusion in the RTO's rates."

"The proposal as laid out in the July 2016 order gives nonpublic utility transmission owning members the choice to leave SPP if SPP membership is no longer financially advantageous," FERC said, using identical language in its order regarding MISO. "The commission is, however, under no obligation to permit nonpublic utilities that choose to become members of SPP and to recover revenues through the SPP Tariff to collect unjust and unreasonable rates through an RTO's jurisdictional tariff without any consequence.

"We acknowledge … that we lack the statutory authority to order nonpublic utility transmission owners to make refunds. Instead, the refund commitment would serve as a condition precedent for nonpublic utility transmission-owning members to recover revenues through the SPP Tariff associated with service provided due to their status as transmission-owning RTO members and based on a choice they made to become members."

FERC Sets 40-Year Term for Hydro Licenses

Continued from page 47

renewals for between 30 and 50 years. There is no minimum license term for original licenses.

The commission's policy on renewals had been to set a 30-year term when there is little or no new construction or environmental mitigation required; a 40-year term for projects with a "moderate" amount of such activities; and a 50-year term for projects requiring "an extensive" amount of such activity.

The change resulted from the commission's November 2016 Notice of Inquiry, which followed licensees' complaints that the commission should consider longer license terms to recognize settlement agreements, prior investments, relicensing costs and losses in generation value resulting from environmental measures. (See *FERC Considers Change to Hydro License Rules*.)

The NOI generated more than 40 responses, most of which supported policy changes. Some complained that license applicants lack guidance on what measures will yield longer license terms. Others said that because the commission's policy is forward-looking, licensees delay seeking approval for capacity upgrades and environmental and recreational enhancements until they apply for a new license.

Some industry commenters complained that the license term cannot be used as a "bargaining chip" in settlement talks because the commission might reject that term; they also said the current policy penalizes well-maintained and low-impact projects that don't require substantial new investments and thus only receive a 30-year license.

Compromise

The 40-year default represents a compromise between industry stakeholders — who generally supported a 50-year default — and environmental groups and most federal and state resource agencies, who said making the default equal to the FPA's maximum would eliminate incentives for applicants to agree to mitigation measures.

"The resource agencies also contend that such policy would result in applicants focusing their license application study efforts on disproving project effects rather than on identifying potential mitigation measures," the commission said.

FERC staff expects more than 300 relicensing requests through 2025, which would have required case-by-case analyses under the current rules.

The commission said the change will provide licensees and other stakeholders with more certainty while reducing administrative burdens. Case-specific assessments will only be required for licensees seeking a term longer than 40 years that is not subject to a settlement agreement.

The new rules will apply to all licenses issued following publication of the policy statement in the *Federal Register*. Those with pending license applications can file petitions demonstrating why the commission should grant a term longer than 40 years or settlement agreements that include longer terms. "The commission, however, will not entertain applications to amend existing licenses to extend their license terms simply on the basis of this new license term policy," FERC said.

COMPANY BRIEFS

SCANA Asked to Stop Charging for Abandoned Nuclear Project

South Carolina Gov. Henry McMaster has written a letter to SCANA CEO Kevin Marsh, saying the utility should stop charging its customers $37 million a month for the abandoned project at the V.C. Summer Nuclear Station because "it's the right thing to do."

SCANA subsidiary South Carolina Electric & Gas and state-owned utility Santee Cooper halted the project earlier this year after the bankruptcy of lead contractor Westinghouse Electric.

SCE&G customers have paid nearly $2 billion for the reactors.

More: *The Associated Press*

Ameren Making $130M in Repairs To Missouri Nuclear Plant

Ameren is making nearly $130 million in repairs to the Callaway Energy Center, its nuclear plant in rural Callaway County, Mo.

The repairs include the first overhaul of the main generator since the plant began operating in 1984.

The plant shut down earlier this month for a regularly scheduled refueling and is expected to be offline for 60 days while repairs are made.

More: *The Associated Press*

Amazon Opens Massive Texas Wind Farm

Amazon CEO Jeff Bezos celebrated the opening of the company's biggest wind farm with a video of himself atop one of its more than 100 wind turbines and christening the structure by smashing a bottle of sparkling wine on it.

Amazon has a long-term agreement to buy 90% of the output from Amazon Wind Farm Texas, which is slated to have an annual output of more than 1 million MWh.

The wind farm is owned and operated by its builder, Lincoln Clean Energy.

More: *CNBC*

Energy Management Programs Growing, Participation Still Low

Utility-driven energy management programs are growing, although participation rates are still somewhat low, according to an energy-industry survey conducted by the Association for Energy Services Professionals in partnership with Essense Partners.

Only 31% of the more than 2,700 consumers surveyed for Trends in Energy and Demand Management had participated in a utility-run energy management program.

Over the last two years, 32% of the 164 utility professionals surveyed said program participation rates had grown from 3% to 10%, and 21% said participation rates had grown by more than 10%.

More: *Association of Energy Services Professionals*

Siemens May Cut Jobs in Power Turbine Business, Source Says

Siemens may cut thousands of jobs as part of plans to overhaul its power turbine business, a person familiar with the matter told Reuters.

The business is being affected by renewable energy growth, which is dampening demand for new coal and gas power stations.

The source said details of the changes at Siemens' Power & Gas division were still to be decided.

More: *Reuters*

AEP Ohio Seeks Proposals for Solar

AEP Ohio issued a request for proposals Wednesday for solar energy generation resources.

AEP is seeking proposals for up to 400 MW of solar energy resources, with preference given to sites that are in Appalachian Ohio, create permanent manufacturing jobs in the region and commit to hiring the state's military veterans.

Proposals are due Dec. 18.

More: *American Electric Power*

3rd Shareholder Sues over Westar-Great Plains Merger

A third shareholder has sued to stop Westar Energy's proposed $14 billion revised merger of equals with Great Plains Energy.

The lawsuit filed by Great Plains shareholder Steven Bushansky is nearly identical to a suit filed by Westar shareholder David Pill in late September. Both seek class-action status as well as an injunction halting the proposed merger and more information about the merger's financial effect. Westar shareholder Robert Reese also filed a lawsuit claiming that terms of the merger agreement are designed to fend off potential competing bidders that could be superior.

Shareholders of both companies are set to vote on the proposed merger at separate meetings on Nov. 21.

More: *Kansas City Business Journal*

US Solar Manufacturer Stion Ending Operations

American thin-film solar module manufacturer Stion confirmed that it is discontinuing its business operations.

In a letter signed by management, the company blamed "intense, non-market competition from foreign solar panel manufacturers, especially those based in China and proxy countries" for severely undermining the viability of its business.

The company, which stands to benefit from new solar tariffs that the U.S. International Trade Commission is in the process of recommending under the trade case brought by Suniva and SolarWorld Americas, is hoping to find a buyer.

More: *Greentech Media*

Dominion Seeks Proposals For Solar, Onshore Wind

Dominion Energy Virginia has issued a request for proposals for solar and onshore wind generation.

The utility is soliciting bids for energy, capacity and environmental attributes including renewable energy certificates for new solar and onshore wind facilities 10 to 150 MW in size. The facilities must be in Virginia and be interconnected to Dominion's transmission and/or distribution system. Proposals can be for power purchase agreements and/or the purchase of development projects.

Notices of intent to bid and confidentiality agreements are due by Oct. 27, 2017, with final proposals due on Dec. 1, 2017.

More: *Dominion Energy*

Federal Briefs

FERC Sets Path 15 Revenue for Hearing

FERC on Thursday denied a request from the owners of the DATC Path 15 transmission line in California to make an upward adjustment in its zone of reasonableness, used to determine the line's return on equity.

The commission also set for hearing and settlement judge proceedings a request to reduce its transmission revenue requirement by about $354,000. It did find that the resulting ROE should not exceed 13.5%, which is what the transmission owners requested.

DATC Path 15 is an 84-mile, 500-kV line along the existing corridor to relieve congestion that is 72% owned by Duke-American Transmission Co. The developer said it is reducing the transmission rate because it has no plans to invest significant capital in upgrading the line.

More: *ER17-998, EL17-61*

NRC Names New Senior Resident Inspector for Fermi

The Nuclear Regulatory Commission has named Tom Briley as the new senior resident inspector at the Fermi nuclear power plant.

Briley joined the commission in 2009 as a reactor engineer in the Nuclear Safety Professional Development Program and graduated in 2011. After successfully completing the agency's inspector qualification program, he served as a resident inspector at the Davis-Besse nuclear power plant.

Briley joins NRC resident inspector Phil Smagacz at Fermi.

More: *NRC*

Nuclear Waste Repository Slated To Get More Disposal Space

Federal contract workers are slated to begin mining operations at the Waste Isolation Pilot Plant in New Mexico for the first time in three years following a radiation release that contaminated part of the underground repository, the Energy Department announced last week.

The work to carve out more disposal space will begin later this fall and is expected to be completed by 2020, with workers removing more than 112,000 tons of salt, making way for several disposal rooms. Each room will have space for more than 10,000 drums containing up to 55 gallons of waste.

Mining for the new disposal area began in 2013 but was halted in February 2014 after a barrel of waste that was inappropriately packed at Los Alamos National Laboratory before being shipped to the repository released radiation.

More: *The Associated Press*

Report: Tax Reform Could Help Clean Energy

Conservative think tank American Council for Capital Formation released a report Wednesday showing how tax reform could help clean-energy technologies.

"Tax Reform and Clean Energy R&D" found clean-energy technologies would benefit from a more streamlined tax code, even if many of the sector's subsidies, including production and investment tax credits, were eliminated. It also finds that a combination of lower tax rates and eliminating the deduction on interest would correct what it says is a bias against equity financing.

More: *Axios*

US Coal Production Falls in First Half of 2017

U.S. coal production averaged 192 million short tons per quarter in the first half of 2017, marking a slight decline from the second half of 2016, according to data from the U.S. Energy Information Administration.

Production still exceeded levels reached in the first half of 2016.

The decline was driven by a weaker demand for steam coal, which in the first half of 2017 made up more than 90% of U.S. coal production and 30% of the U.S. electricity generation mix.

More: *U.S. Energy Information Administration*

Scientists Who Get EPA Grants Can't Sit on EPA Advisory Panels

Scientists who receive EPA grants will not be allowed to sit on the agency's advisory panels, Administrator Scott Pruitt announced last week.

Pruitt said the directive, which he will issue next week, aims to ensure that EPA receives independent, transparent and objective advice.

Andrew Rosenberg, director of the Center for Science & Democracy for the nonprofit Union of Concerned Scientists, said the directive is "utter nonsense" and that EPA grantees can't be compared with scientists whose research is backed by private industry. Scientists who served for no pay on these panels won't have any incentive to advise on critical public policy issues, he said.

More: *Bloomberg Environment*

EPA Ends Practice of 'Sue-and-Settlement'


Pruitt

EPA Administrator Scott Pruitt last week said he is ending the practice of "sue-and-settlement" in which the agency's settlement of lawsuits drove its rulemaking.

Under the new policy, EPA will publicize petitions targeting it, include states and regulated entities in settlements that affect them and publish proposed agreements to allow the public 30 days to comment.

Between 2009 and 2012, EPA settled more than 60 lawsuits with outside groups, resulting in more than 100 new regulations, according to the U.S. Chamber of Commerce, which has criticized the practice.

More: *Bloomberg Politics*

EPA Says Higher Radiation Levels OK in Nuclear Emergency

New EPA guidelines say that in the event of a nuclear power plant meltdown, emergency responders can safely tolerate radiation levels commensurate with thousands of chest X-rays.

The "guidance" on messaging and communications, dated September 2017, is part of a broader planning document for nuclear emergencies. A 2007 version of the same document said no level of radiation is safe.

"It's really a huge amount of radiation they are saying is safe," said Daniel Hirsch, the retired director of the University of California, Santa Cruz's program on environmental and nuclear policy. "The position taken could readily unravel all radiation protection rules."

More: *Bloomberg Technology*

STATE BRIEFS

Report: Unused Pipeline Capacity Cost New Englanders $3B

New England electricity customers paid $3.6 billion more for electricity than they had to over a three-year period, according to a report issued by the Environmental Defense Fund.

"Vertical Market Power in Interconnected Natural Gas and Electricity Markets" finds that on hundreds of occasions, Avangrid and Eversource Energy drove up prices by reserving natural gas pipeline capacity that they didn't use.

A spokeswoman for Eversource said the report was a "fabrication" and that the analysists didn't understand gas and electricity markets. An Avangrid spokesman said the company is following all rules and regulations.

More: *New Hampshire Public Radio*

ARIZONA

Governor Appoints Justin Olson to ACC

Olson

Gov. Doug Ducey appointed tax analysist and former state Rep. Justin Olson (R) to serve on the Corporation Commission last week, replacing Doug Little.

Olson served in the Legislature from 2011 to 2017 and later lost a primary election to serve in the U.S. House of Representatives. He currently works for the for-profit University of Phoenix. He will serve the remainder of Little's term, which ends in 2018, and stated he would run for a full term.

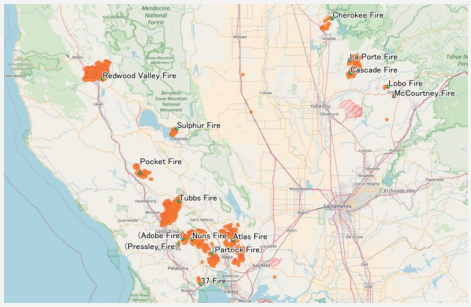
Little left the commission earlier this month to serve in the U.S. Energy Department.

More: *The Republic*

CALIFORNIA

Homeowners Sue PG&E over Wild Fire

A Santa Rosa couple filed suit against Pacific Gas and Electric last week, claiming its failure to maintain and repair high-voltage power lines resulted in the wild fire that destroyed their home and thousands of others in Sonoma County.



Map of wildfires in California, Oct. 7-14

Wayne and Jennifer Harvell allege in the suit filed in San Francisco County Superior Court that the fire started when the lines came in contact with drought-dry vegetation.

Todd Derum, Department of Forestry and Fire Protection division chief for Sonoma County, said it is too early to know what sparked several fires that started on Oct. 8.

More: *The Press Democrat*

ILLINOIS

ICC Adopts Rules on Marketing By Alternative Retailers

The Commerce Commission adopted rules on Thursday that significantly strengthen consumer-protection requirements governing sales and marketing by alternative retail electricity suppliers.

The ICC said the rules will ensure that consumers have information about power supplier options that enable them to compare offers and utility plans, and make better-informed decisions. The new marketing guidelines also will provide regulators with improved enforcement mechanisms, and require suppliers to take improved verification and quality control measures.

The commission acted following a spike in electricity prices during the winter of 2013-2014, which led to its Consumer Services Division receiving a sharp increase in public complaints about the marketing practices of certain retail electric suppliers.

More: *Illinois Commerce Commission*

MARYLAND

PSC Grants PEPCO Partial Rate Increase

For the second straight year, the Public Service Commission has granted PEPCO a rate increase less than the one it requested.

The commission agreed to allow PEPCO to increase its electric distribution rates by $33.9 million — about half the $68.6 million increase the utility sought.

The PSC said the increase, which went into effect immediately on Friday, was approved to help the utility pay off its spending on reliability improvements.

More: *Bethesda Magazine*

MONTANA

Wind Power Developer Sues PSC, Utility for Price Discrimination

A wind power developer is suing state regulators and the state's largest electric company, saying they are illegally setting lower contract prices that will kill any new independent renewable power projects in the state.

In a lawsuit, Marty Wilde and his companies said the Public Service Commission collaborated with NorthWestern Energy to adopt rates for the utility that are triple compared to what renewable resources receive for the same product.

PSC spokesman Chris Puyear said the commission has been setting lower rates and stricter contract terms for what NorthWestern pays the independent producers, but that the rates reflect the regional market, which has an oversupply of electricity. He also said NorthWestern's price is based on the costs of the company's past investments, while the recent prices set for producers are based on the current market.

More: *KTVH*

Continued on page 52

STATE BRIEFS

Continued from page 51

NEBRASKA

EPA: Big Ox Plant Contributed to Toxic Odors

Big Ox Energy's renewable energy plant contributed to toxic odors that started last October, endangering the public and violating the federal Clean Air Act, EPA said in a report earlier this month.

In an Oct. 4 "letter of warning" to Big Ox, EPA Region 7 in Kansas City said that during a Jan. 10-12 inspection, investigators found that discharges of pollutants from the plant, alone or in conjunction with other sources, created toxic gases, vapors and fumes in quantities that could cause worker health and safety problems. EPA is forwarding its findings to the state Department of Environmental Quality to consider penalties.

More than two dozen South Sioux City families were forced to leave their homes last year due to putrid odors caused by sewer gas in a sewer line shared with the plant.

More: *Sioux City Journal*

TEXAS

Report: Consumer Complaints Drop to Post-Deregulation Low

The number of electricity-related complaints filed by consumers with state regulators dropped to a post-deregulation low, according to a new report from the Texas Coalition for Affordable Power.

Consumers filed 4,175 electricity-related complaints or inquiries with the Public Utility Commission for fiscal year 2017, compared with 4,835 for fiscal year 2016. That marks the lowest number since the state transitioned to its deregulated retail electricity market in 2002 and continues a generally downward trend of nearly a decade.

The decline in complaints parallels a trend of improving residential electric prices, which the coalition has documented in a separate report. But the coalition also has documented some comparatively better electric consumer outcomes in the years preceding the retail electric deregulation law.

More: *Texas Coalition for Affordable Power*

FERC Flooded with Comments on DOE NOPR

Continued from page 1

The rule "will produce numerous benefits for all Americans by preserving the continuing viability of critical coal-fired power plants," said the Kentucky Coal Association (KCA), which represents 120 companies in the No. 4 coal-producing state. "This will not only support a more reliable and resilient power grid but will also have a profound and positive impact in Kentucky and across America by preserving jobs and economic development."

The Nuclear Energy Institute embraced the cost-of-service compensation as a temporary measure "at least until other market structures are put in place that appropriately value the resiliency attributes that nuclear generation units provide."

The natural gas, solar and wind industries joined with the Electric Power Supply Association and other industry groups to blast the proposal as "a transparent attempt to prop up uneconomic generation … that is not otherwise needed for reliability."

RTO officials and their Market Monitors uniformly rejected the idea, with the ISO/RTO Council saying "the negative consequences of the NOPR … are obvious." PJM, ISO-NE and NYISO also filed their own comments in opposition. (See related story, *RTOs Reject NOPR, Agree to Study Resilience*, p.1.)

Energy Secretary Rick Perry before a House Energy and Commerce subcommittee earlier this month. | © *RTO Insider*

A bipartisan group of eight former FERC commissioners also blasted the proposal as a repudiation of 25 years of progress toward competitive markets.

Amory Lovins, cofounder of the Rocky Mountain Institute, derided Perry's proposal as employing "language urgent without evidence, alarmist without cause, and peremptory without authority."

Given the widespread opposition from all but the coal and nuclear industry — and the myriad questions about how the proposal would be implemented — it appears highly unlikely the commission will act to approve it on the accelerated schedule Perry had demanded, or that it would survive the almost certain legal challenges if it did so.

Perry directed FERC to complete a final rule within 60 days after publication of the NOPR in the *Federal Register*. The commission, an independent agency, is not required to approve the plan or follow his timeline. (See *FERC's Independence to be Tested by DOE NOPR*.)

Below, based on a review of more than 50 comments as of press time, is a summary of the feedback FERC received. Reply comments are due Nov. 7.

Is the Grid at Risk?

Perry said the rule was needed to ensure sufficient supplies of "essential reliability services," which NERC has defined as including voltage support, frequency services, operating reserves and reactive power. Just and reasonable rates for such generators would cover "its fully allocated costs and a fair return on equity," including operating and fuel expenses and the costs of capital and debt, the NOPR said.

KCA cited "the clear findings in the proposed rule that the nation's grid is at risk and that rule-secure resources are indispensable."

Continued on page 53

FERC Flooded with Comments on DOE NOPR

Continued from page 52

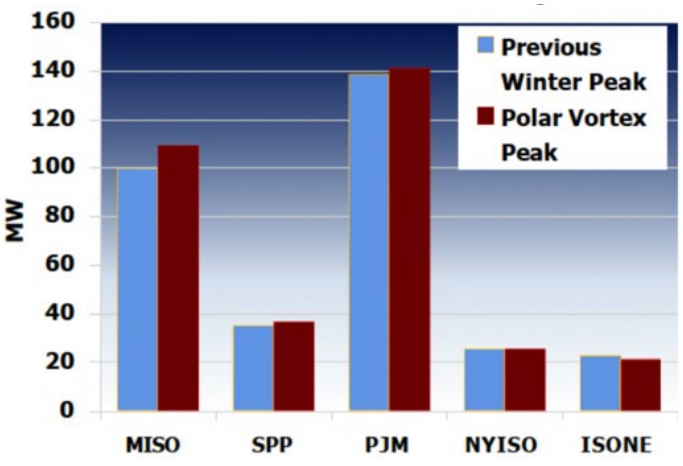
"The commission simply cannot carry out its mission without adopting rules that appropriately value fuel-secure generating facilities that are capable of producing electricity when fuel supplies are interrupted or unavailable," it said.

The Utility Workers Union of America (UWUA) cited a PJM analysis that it said concluded that "even moderate retirements" of coal and nuclear plants "would reduce PJM's fuel assurance capability by almost 30% if the units were replaced by natural gas."

"The country is at a crossroads, and urgent commission action is required before the value provided by critical baseload generation capacity is lost forever," the American Coalition for Clean Coal Electricity (ACCCE) and the National Mining Association said in a joint 64-page filing.

"We should not allow short-term prices to dictate significant changes in our generation fleet that will reduce the nation's resource diversity and grid resiliency," argued NEI, which said nuclear generation units have the highest capacity factors of all generating resource types. "Because of these attributes, nuclear power plants provide reliable baseload generation that stabilizes the grid and moderates price volatility."

The EPSA filing countered by citing a Rhodium Group analysis that concluded "0.00007% of customer-hours lost to outages were caused by fuel supply emergencies between 2012-2016, a period when 32% of the country's coal fired power units and 6% of its nuclear generating units were retired. The same period also featured two



| FERC

David Patton | © RTO Insider

of the coldest winters during the past 30 years in the Eastern United States, including the 2014 polar vortex.

"The vast majority of electric service disruptions in the United States are related to distribution or transmission outages, not unscheduled generation outages," they continued. "And virtually all of the customer-hours that were lost due to fuel supply disruption between 2012-2016 were related to a single incident involving one coal plant in Northern Minnesota."

David Patton, whose company performs market monitoring in MISO, NYISO and ISO-NE, acknowledged "there may be fuel supply contingencies or other contingencies that have not been fully considered by RTO planners or [NERC]." But he said, "To turn immediately to an out-of-market compensation scheme without considering the alternatives for addressing these issues through the RTO planning and market framework is both inefficient and ultimately unreasonable."

Will the Proposal Help Resiliency/Reliability?

Many commenters said the proposal would harm rather than help reliability.

"The NOPR proposal would provide compensation to particular units that may otherwise retire because they are older, less efficient and less reliable than newer units," the IRC said. "Supplanting newer, efficient units with older, less reliable ones in the markets will threaten reliability and market efficiency. This problem will be exacerbated because the NOPR does not outline any minimum performance standards or criteria for determining whether eligible resources are situated in an optimal location to support future reliability needs (including, particularly local reliability and voltage needs)."

Due to rule changes implemented since the 2014 polar vortex, the council said, "ISO-NE, NYISO and PJM have ably maintained reliability in their respective regions."

Is there a compensation problem?

Longview Power, operator of a five-year-old, 700-MW supercritical coal-fired plant near Morgantown, W.Va., which claims to be "North America's most efficient coal fired generator," said it has been undercompensated in the PJM market.

CEO Jeffery L. Keffer said the plant — which has a heat rate of 8,842 Btu/kWh, a 92% availability factor and emissions at least 70% lower than the U.S. coal fleet — is dispatched by PJM as a baseload unit whenever it is available and been awarded capacity payments through the 2020/21 delivery year. It also receives payments for reactive power and other ancillary services.

"However, the compensation paid to Longview for its reliability contributions and ancillary services is wholly inadequate. During 2016, when Longview's equivalent availability factor was over 92%, it received an average energy payment of only $27.50/MWh. Similarly, the 2017 average energy price paid to Longview is expected to be $28.63/MWh."

Patton said, however, that the proposal to guarantee full cost recovery of resources "that may be economic to retire will likely generate costs that vastly exceed any reasonable estimate of" the value of lost load. He questioned the notion that coal units were being forced into "early" retirement, noting that the average age of existing coal-fired plants in 2016 was 38 years, within the 35-50-year life span for those assets.

Impact on Wholesale Markets

Critics said Perry's call for "full cost recovery" for coal and nuclear units would reverse 25 years of competitive wholesale markets.

The R Street Institute, which promote free markets and limited government, praised the NOPR's call for market improvements such as improving pricing for reliability and resiliency services. "But the detailed problem statement, factual foundation and proposed policy remedies of the NOPR are

Continued on page 54

FERC Flooded with Comments on DOE NOPR

Continued from page 53

inconsistent with empirical evidence and principles of wholesale electricity market design," said Devin Hartman, electricity policy manager. "Motivations for market reforms should never aim to adjust compensation with a predetermined result — in this case preventing certain power plants from retiring. The rationale for markets is to let competitive forces determine resource allocations, which lowers costs and better manages risk than a pre-determined, centrally planned approach would."

"Proper valuation of coal baseload generation does not require the commission to abandon or 'blow up' the competitive electric markets," KCA insisted. "KCA and other supporters of a resilient grid and affordable baseload power are simply requesting that the commission ensure that competitive market based rules fairly compensate the benefits of baseload generation sources, which are the most cost-effective way to meet constant electrical demand so as to provide for just and reasonable rates to consumers and generators."

"Valuing coal and nuclear [electric generating unit] resiliency benefits is consistent with market evolution," wrote UWUA President D. Michael Langford. "Electricity market constructs can be modified — as they are so frequently to accommodate a variety of purposes — to efficiently operate while compensating for reliability services."

A bipartisan group of eight former FERC commissioners — including former Chairs Elizabeth Anne (Betsy) Moler, James Hoecker, Pat Wood III, Joseph T. Kelliher and Jon Wellinghoff — filed joint comments saying that Perry's proposal would be "a significant step backward from the commission's long and bipartisan evolution to transparent, open, competitive wholesale markets."

"The commission's adoption of the published proposal would instead disrupt decades of substantial investment made in the modern electric power system, raise costs for customers and do so in a manner directly counter to the commission's long experience," they said.

The former commissioners noted their role in issuing Order 888, which established transmission open access, and Order 2000, which defined the responsibilities of RTOs, saying their "shared collaborative mission across party lines and presidential administrations has been a model of good government." More than two-thirds of U.S. electric customers are now served by competitive wholesale markets.

"Widely diverse interests have invested tens of billions of dollars in both competitive and regulated infrastructure. Customers and the industry have benefited from lower costs and better, more reliable services. Technological innovation has swept the entire value chain."

They acknowledged that the markets have been impacted by federal tax subsidies for wind and solar generation, as well as "less overt benefits for oil, gas and coal extraction."

"The commission cannot ignore these interventions, and in fact, should actively inform legislators how such programs impact market operations. But one step the commission has never taken is to create or authorize on its own the kind of subsidy proposed here."

The IRC said Perry's proposed cost recovery "stands in stark contrast to other types of narrowly tailored cost recovery mechanisms like reliability-must-run (RMR) mechanisms."

"The negative consequences of the NOPR proposal are obvious. By affording certain generators guaranteed, full fixed and variable cost recovery for providing some undefined 'resiliency' benefit based on an arbitrary 'fuel-security' standard, the NOPR will shield eligible generators from the competitive forces that discipline market bidding behavior and ensure that market dispatch and prices are based on least-cost, security-constrained optimization of the resource portfolio."

Legal Questions

The Harvard Environmental Policy Initiative and Columbia University's Sabin Center for Climate Change Law said the NOPR is flawed because it doesn't prove the preliminary conclusion required by the Federal Power Act that current wholesale rates are not just and reasonable.

"This glaring omission dooms DOE's proposal under Section 206 of the Federal Power Act and allows the commission to issue a swift rejection without weighing in on the merits," Harvard's Ari Peskoe wrote. "The NOPR's observation that wholesale markets do not price 'resiliency' does not substitute for an explicit proposed finding that current rates are unjust and unreasonable. DOE does not define 'resiliency,' nor has the commission ever used that word in connection with wholesale rates. DOE's bare assertion that rates do not account for undefined attributes does not provide adequate notice necessary for meaningful public comments."

Justin Gundlach, staff attorney for the Sabin Center, agreed. "The commission should recognize [the proposal] as a politically motivated gambit to allocate resources to the support of coal- and nuclear-fired generating capacity," he said.

The IRC said the proposed requirement that RTOs submit compliance 15 days after the effective date of the final rule — 45 days after the rule is published — "is unreasonable and contrary both to commission policy and past practices."

"The NOPR proposes a drastic redesign of existing competitive market structures but provides very little implementation details and no discussion about acceptable cost allocation for the proposal. Given the dearth of specificity in the NOPR, parties will be left guessing as to what might be an acceptable compliance proposal until such time as the final rule is issued. Giving only 45 days from that point will deny RTOs and ISOs adequate time to craft compliant policies and develop tariff revisions. Equally significantly, a 45-day window from issuance of the final rule to submission of compliance filings provides very little time for RTOs and ISOs to initiate stakeholder discussions, let alone time for the RTOs and ISOs to consider what are very likely to be highly disparate stakeholder views on the RTO/ISO's compliance proposal."

ACCCE and NMA asked FERC to find existing RTO tariffs unjust and unreasonable. "It is critical that the commission make such a finding, and direct RTOs and ISOs to modify their tariffs to ensure that existing coal-fired generators are able to fully recover their operating costs," they said.

The EPSA group filing said the proposal would "provide discriminatory compensation" to coal and nuclear generators. "The justification for the proposed payments — resiliency — is not well defined, nor does the DOE NOPR demonstrate that resiliency is lacking in the aforementioned regions," they said.

It was filed by 20 stakeholders, including the

Continued on page 55

FERC Flooded with Comments on DOE NOPR

Continued from page 54

Advanced Energy Economy and trade groups representing competing fuels and alternate resources (American Biogas Council, American Council on Renewable Energy, American Forest & Paper Association, American Petroleum Institute, American Wind Energy Association, Energy Storage Association, Natural Gas Supply Association and the Solar Energy Industries Association).

"This is what a very bad proposal can do," tweeted EPSA Senior Vice President Nancy Bagot. "Bring people together to save the electricity market!"

90-Day Fuel Supply

DOE would require a generator receiving "resilience" payments to have a 90-day fuel supply "enabling it to operate during an emergency, extreme weather conditions, or a natural or man-made disaster."

But commenters said the requirement is arbitrary.

Longview said it keeps 10 to 30 days of coal on hand. "Whether dealing with an extreme weather event, such as a 'polar vortex' or a terrorist attack, we see the likelihood of the event extending for 90 days as highly unlikely and particularly unprecedented. An event of this length would likely involve serious damage to the transmission grid, which means electric deliverability, not fuel supply, would be the limiting factor in supplying electricity to end users."

Monitor Patton said the 90-day supply requirement was indefensible, saying he is unaware of any credible contingency that would support the requirement. "Major pipeline repairs have generally been completed within a few weeks; extreme weather conditions typically last from three to 10 days. … On-site fuel supplies of oil or LNG can often be resupplied within a few weeks," he said. "To the extent MISO has had long-duration fuel-security issues, the issues have been with coal supply limitations due to railway congestion. ... Not one of [the large-scale outages since 1965] was impacted by lack of long-term fuel security."

Patton also dismissed the NOPR's effort to tie its concern to "the devastation from Superstorm Sandy and Hurricanes Harvey, Irma and Maria."

"In general, hurricanes are more likely to damage distribution and transmission systems and cause flooding at power stations, impacting resource types in specific locations rather than certain fuel types," he said. "In other words, these contingencies will generally affect all resources is certain areas, regardless of fuel type, even the resources that qualify as resilience resources under the NOPR."

Industry Groups' Response

The Natural Gas Supply Association said there is "no basis" for the NOPR and its proposed solutions. It said "no fuel source is failsafe," and that natural gas is a "reliability asset for the power sector," saying interstate pipelines delivered 99.79% of firm contractual commitments over the last 10 years.

WIRES, a transmission trade group, said it would oppose any FERC action that "retreats from the market-oriented and technology-neutral regulatory policies that the commission has fostered for a quarter century [or] fails to fully acknowledge the central role that development of robust electric transmission infrastructure must also play in any effort to make the grid more reliable and resilient."

The Edison Electric Institute asked FERC to clarify whether the rule changes would include only the Eastern RTOs or also CAISO and SPP, which have no capacity markets.

It said the commission "should institute an appropriate process to investigate potential issues related to resilience" and direct the Eastern RTOs "to evaluate what, if any, steps need to be taken within their markets to define the specific resource attributes and essential reliability services that may need to be valued in their market(s) and whether alternate compensation mechanisms are needed consistent with the market structure in the region."

Independent power producers were uniformly opposed, with filings by the New England Power Generators Association (NEPGA), the Independent Power Producers Of New York (IPPNY), PJM Public Power Providers and the Independent Power Producers of Ohio, Pennsylvania and West Virginia.

"New England and New York have long histories of developing market mechanisms to meet reliability," NEPGA and IPPNY said in joint comments.

"PJM has demonstrated that it will make modifications to the market design to address changing reliability needs of customers," said the IPPs from Pennsylvania, Ohio and West Virginia, citing the Capacity Performance rules enacted after the 2014 polar vortex. "In a perverse irony, the NOPR will likely harm grid reliability by chasing away the very innovation and investment in new generation needed to maintain the long-term integrity of the grid."

Customers' Response

The Industrial Energy Consumers of America said the proposal would raise costs for electric-intensive manufacturers, estimating a 1-cent increase in industrial electricity rates would increase its members' costs by $9 billion to $10 billion annually. "As a large stakeholder who consumes 26% of U.S. electricity and spends approximately $65 billion on electricity each year, the manufacturing sector is very concerned about this rule," said IECA President Paul Cicio.

In a joint filing, the Industrial Energy Consumers of Pennsylvania and the Pennsylvania Manufacturers Association said the rule "threatens to dramatically change the economic climate in Pennsylvania by increasing electric prices and undermining the numerous and relatively recent benefits being generated by the booming and prospering Pennsylvania shale gas industry."

The group noted that Pennsylvania consumers paid more than $12 billion in stranded costs to utilities in its transition to competition. "For many years after the legislation, the wholesale market prices were higher than those that the utilities used to calculate their stranded cost claims. The generation owners kept those additional profits."

The Kentucky Industrial Utility Customers took no position on whether the proposal

Continued on page 56

RTOs Reject NOPR; Say Fuel Risks Exaggerated

Continued from page 34

lot of resources with a 90-day fuel supply on site would not have relieved the problems with a majority of the outages during the polar vortex," Bresler said. "While the polar vortex did highlight the need for the markets to ensure that we are signaling the need for resources to be able to operate on peak days, just resources with long-term fuel supplies on site was not the majority of the issue."

During natural disasters, Bresler said, the main challenge is downed power lines, not generating plants being unable to run.

"Events like that … primarily affect the delivery system from supply to demand, not the supply resources themselves," he said, noting that some coal plants impacted by Hurricane Harvey this summer weren't able to run at full capacity because their coal piles were soaked.

"In the interest of framing the right problem, we will point out these things that we feel sort of led DOE down the wrong path as far as what the actual problem is," he said. "We will say, however, that there is an issue that we do need to address, specifically to the PJM region. And that is the fact that there are some instances in PJM where not all resources are valued appropriately for the fact that they are relied upon to reliably meet the demand. … We are concerned that resources right now may not be offering as much flexibility as they could provide because they don't have incentive to do it."

Using competitive markets to "transparently" price needs is "superior" to providing cost-of-service payments to certain unit types, he said.

"One concern we have with the DOE approach is it seems to imply that while we may need to keep some of these resources around to ensure reliability and resilience, so therefore let's keep them all," Bresler explained. "That again is, from our standpoint, inefficient from the standpoint of the cost to load. Whereas the markets, we believe, have done a very good job to provide the discipline for what really is necessary and what's not necessary and thereby not just provide efficient signals for entry, but also provide efficient signals for exit."

PJM's comments to FERC included a version of a proposal staff presented at its August meeting of the Markets and Reliability Committee. Bresler said the proposal will be revised and presented again at the Dec. 7 MRC meeting.

Ott acknowledged that PJM's comments don't reflect the perspectives of all its members.

"There really was no full vetting of these comments with stakeholders," he said. "One, there isn't sufficient time, and second is … PJM's comments are PJM's and we do not vet those through stakeholders."

In his comments to FERC, Monitor Bowring said approving the DOE proposal "would replace regulation through competition with an unworkable hybrid of competitive markets and cost of service regulation. The eventual result would be the demise of competitive markets in the PJM region."

"If the reliability rules need enhancement," he continued, "the reliability rules should be enhanced. The DOE proposal should be rejected. The PJM region needs more competition, not less."

Continued on page 57

FERC Flooded with Comments on DOE NOPR

Continued from page 55

should be adopted, but said if it is, FERC should consider a separate capacity market for grid reliability and resiliency resources. It also said the authorized return on equity "should be the minimum necessary to ensure that the fuel-secure generation does not retire prematurely. An ROE in the 2 to 4% range would accomplish that. Any positive return is better than losing money. If the ROE is set too high, then the affected merchant generators would have reduced incentive to seek a more permanent market-based solution."

Rule Defenders' Script

Coal state politicians, such as Republican Sen. Shelley Moore Capito and fellow members of the West Virginia congressional delegation, weighed in with support.

The proposal also found some unlikely defenders, such as the Cleveland branch of the NAACP, which said "the continued operation of the baseload coal and nuclear power plants translates into safer and more prosperous communities."

Several of the coal industry interests — including Camelot Coal, FreightCar America, Campbell Transportation and IBEW Local 50 — included identical language in their comments: "The preservation of certain plants will avoid the need to replace lost generation with imports and the associated construction of infrastructure to facilitate such importation. … Premature plant closures will deplete the stable of highly skilled (and specifically trained and experienced) employees, many of whom have lived in the region for several years and who take great pride in their work. … The baseload generation facilities that may be retired prematurely offer stability and optionality."

Many of them raised the threat of layoffs and lost tax revenue from plant closures.

The Utility Workers Union of America, which represents 50,000 electric, gas, water and nuclear industry workers nationwide, focused on the potential impact in Avon Lake, Ohio, where it said closure of a coal plant would result in reduced income and property taxes. A city councilman told Congress in 2012 that the plant's closure would force a 50% cut in the city's emergency medical service operating budget and a $4 million cut — 11% — for the local school district, forcing it to cut programs for special needs students.

Avon Lake power plant

Michael Kuser, Amanda Durish Cook, Tom Kleckner, Jason Fordney and Rory D. Sweeney contributed to this article.

RTOs Reject NOPR; Say Fuel Risks Exaggerated

Continued from page 56

The SPP Strategic Planning Committee meets in Little Rock, where the RTO's position was laid out. | *© RTO Insider*

MISO

MISO officials did not file their own comments but told stakeholders earlier this month that they would insist FERC respect the RTO's existing reliability process, and would study frequency control, ramping, voltage support, inertia and inertial response to identify the features of a "resilient" generator. (See *DOE 'Resiliency' Must Respect Planning, Research, MISO Says*; *MISO Ready to Define, Study 'Resiliency' for DOE*.)

SPP

SPP told stakeholders Thursday it would will join the IRC filing, pointing to what staff called "some pretty strong comments."

"The council does a really good job of laying out why this doesn't work from an RTO perspective," SPP General Counsel Paul Suskie told the Strategic Planning Committee.

"If you're a plant under the rule, your costs are totally covered," Suskie said. "Why would you do anything but bid zero into the market? It will drive costs down further and distort markets further."

Some stakeholders expressed discomfort with signing onto the IRC comments without seeing the language.

"The basic issue here is the subsidy," countered SPP Board Chair Jim Eckelberger, saying renewable energy tax credits had led to oversupply. "We don't want to screw up the market even more. We should take a strong stand here."

In its call for comments, FERC said the NOPR's scope applies to commission-approved ISOs and RTOs with capacity markets and day-ahead and real-time energy markets. Noting SPP's lack of a capacity market, Suskie said while it "appears this rule is not applicable to SPP," staff will work under the assumption that a final FERC rule could apply to the RTO.

Suskie said the proposed timeline for action is "impractical."

"Staff would recommend additional time to implement if the final rule applies to SPP," Suskie said, noting staff would have to compile a list of eligible facilities. "Staff is very concerned. … If you read what the intent appears to be, basically any coal or nuclear plant not [rate-based] within an RTO would have to be fully compensated."

Suskie asked who would determine a plant's rate of return and cost of capital.

"Traditionally, those things are decided at the commissions, not RTOs," he said. "How do you enforce a 90-day coal supply? How do you enforce whether a plant complies with environmental regulations?

"If this is applicable to SPP, it would be a big sea change," Suskie said.

Keith Collins, executive director of SPP's MMU, said his group agrees with much of what Suskie said, saying the NOPR is "proposing a solution to a problem that's not well defined."

The NOPR "doesn't define the problem well in a way that's actionable and measurable," Collins said. "When you actually read the [recent DOE grid study], it says more work needs to be done to value and define resiliency before you come up with solutions. What's included, what's excluded … it's hard to say."

Like Suskie, Collins said the 90-day timeline does not allow sufficient time to properly consider the NOPR.

"If there's a question to be raised, it can be answered over time, but we don't support what's going on," he said. "Competitive forces have been part of policy in the energy and electricity markets over the last 25 years. It will provide new technologies, batteries and the like, that will improve the resiliency for the grid in ways we're not aware of today.

"What the Energy Policy Act of 1992 did was promote competitive markets and open access," Collins said. "If someone can provide power cheaper than someone else, they should be able to do that. If I built a plant a while ago that's unprofitable, that's a signal. Resources are indicating they are not being able to recover their costs. We see the consequences of a policy like this with our negative pricing."

In his filing, Collins said "the SPP markets provide insight into the adverse consequences of policies designed to preserve capacity that would otherwise be uneconomic in typical ISO/RTO markets.

"The SPP market, which is dominated by vertically integrated utilities, provides an example of the potential difficulties that will be faced if the Proposed Rule is implemented," he wrote. "The SPP market has a considerably high capacity margin, currently trending above 40% compared to the 12% minimum requirement in the SPP Tariff. The excess capacity distorts price formation in the competitive market by encouraging price insensitive offer/bid behavior and mutes price signals for others type of generating technologies."

CAISO

CAISO said the rule would not apply to it because it does not have a capacity market or coal or nuclear resources that would be eligible for the proposed compensation. But it opposed the rule nonetheless, saying "there is no basis for a universal finding that having a 90-day, on-site fuel supply is essential for ISOs and RTOs to maintain grid reliability or resilience."

Rich Heidorn Jr. contributed to this article.

RTO Insider

Your Eyes and Ears on the Organized Electric Markets

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