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

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ISO-NE Capacity Prices Fall 25%, Lowest Since 2013

By William Opalka

Prices dropped by one-quarter to $5.30/kW-month in ISO-NE's capacity auction last week, the lowest clearing prices since the RTO eliminated its price floor after the 2013 auction.

Forward Capacity Auction 11 easily surpassed the 34,075 MW of resources needed for the 2020/21 capacity commitment period, with a total of 35,835 MW. Unlike in recent auctions, the RTO said, no new large power plants qualified, nor did any large power plants announce their retirements beforehand. However, 640 MW of new energy efficiency and demand response resources cleared, the equivalent of a new generating plant.

Three new power plants cleared in FCA 10 last year, which had a clearing price of $7.03/kW-month. That followed two consecutive record-breaking years, topped by the record $9.55/kW-month in 2015. (See *Prices Down 26% in ISO-NE Capacity Auction*.)

Falling prices are "the result of competition to provide plenty of the capacity that we need in New England," Robert Ethier, vice president of market operations at ISO-NE, said at a news briefing Thursday.

Continued on page 16

Industry Pitches Wall Street

Investor-owned utilities and the nuclear energy industry made their annual pitches to Wall Street analysts in New York last week. On Thursday, Nuclear Energy Institute CEO Maria Korsnick (above) made her case that nuclear power has a future with low natural gas prices — and without the Clean Power Plan. On Wednesday, officials of the Edison Electric Institute said IOUs will fight any federal tax overhaul that doesn't preserve deductions for interest and property taxes.

Read our briefings on pages 5-7.

MISO Auction Redesign in Limbo After FERC Rejection

By Amanda Durish Cook

CARMEL, Ind. — MISO will likely fall back on its existing Planning Resource Auction design next year after its Competitive Retail Solution failed to win FERC approval, but the RTO says the door is still open on instituting a locational auction construct.

At the Resource Adequacy Subcommittee meeting Wednesday, MISO officials were tight-lipped on whether they would seek rehearing on FERC's Feb. 2 order or what approach they might pivot to in stakeholder discussions this year. (See *FERC Rejects MISO's 3-Year Forward Auction Proposal*.)

While MISO Executive Director of Market Design Jeff Bladen discussed the possibility of rehearing, he stopped short of saying that the RTO would file a request. He also said the reliability issue in MISO's competitive retail areas remains.


Bladen

"It's important to remember that there is a 30-day period where any party to the filing can request rehearing. Effectively, the docket remains open until then," Bladen said. "I certainly would not prognosticate on if anyone would request a rehearing and what FERC would do with that … but I don't want to be too opaque. MISO still recognizes that some things need to be fundamentally changed."

While he didn't rule out changes for the 2018/19 planning year capacity auction, Bladen said a retooled auction design by next year is unlikely. Bladen also said a "one size fits all" auction approach isn't likely given the differing state regulatory structures in MISO.

"It's pretty clear the proposal we made with the forward auction is not implementable on the timeline we proposed. It's impossible for me to answer the hypothetical on what's possible between now and the 2018/19 auction, but it's hard to see [auction changes] implemented before then," he said.

Continued on page 30

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IN THIS WEEK'S ISSUE

RESISTANCE
BY STEVE HUNTOON

Electric Cars – Three Ugly Facts

One would have to live under a rock to not know about the Second Coming of electric cars.[1] (The First Coming 100 years ago is pictured below.)

Virtually every auto maker has announced plans, and the media have anointed their inevitability. As *The Wall Street Journal* proclaimed recently, "The car of the future will be electric …"

But to paraphrase Thomas Huxley, the great tragedy of reality is the slaying of a beautiful hypothesis by an ugly fact.

In the case of electric cars there are not one but three ugly facts. First is that they cost a lot more than gasoline cars and that's not going to change for a long time. Maybe never.

Second is that they tend to contribute to global warming more than gasoline cars.

Third is that they cause more death and disability than gasoline cars.

Let me walk you through this great tragedy of reality.

First ugly fact: Electric cars are and will be much more expensive — indefinitely. Ignore the media hype and consider peer-reviewed academic articles, like one by researchers from the University of Chicago and the Massachusetts Institute of Technology in the *Journal of Economic Perspectives* last year, showing that electric cars are far out of the money for customers on a total cost of ownership basis.[2] Basically, the high cost of batteries trumps (sorry, couldn't resist) the lower cost of electricity relative to gasoline.

And here's the killer — it ain't going to get much better for the next 10 years — if ever. Even if battery costs drop precipitously from the current $325/kWh to $125/kWh (an Energy Department "target"), oil prices would still need to rise to $115/barrel for electric cars to make sense. There is a fascinating chart in the Chicago/MIT paper (pictured below) showing the break-even relationship between battery costs and oil prices.

Neither battery costs nor oil prices are likely to align for electric cars. Battery costs seem to be plateauing above $300/kWh. Tesla's Powerwall 2 has debuted at $321/kWh even if one generously gives its inverter a $1,000 value.[3]

As for oil, the futures price is below $60/barrel through 2025, about half of what oil would need to cost in order for a battery cost of $125/kWh to break even.

To summarize, the electric car propulsion system is *400% out of the money*, with little prospect of making that up any time soon, if ever. And the recharging time and location problems still need to be solved.

So, yes, Tesla and others will sell their electric cars as Veblen goods[4] in the hundreds of thousands. But *tens of millions* of cars sold every year will continue to run on gasoline.

Second ugly fact: Electric cars exacerbate global warming. Surprised? It's important to remember a couple things. One, converting raw fuels to electricity is inefficient. Two, the fuels generating electricity when an electric car is charging tend to be the worst from an environmental perspective.

There is only one study I can find that was sufficiently "granular" to do carbon emission analysis on this hard reality basis. It is a paper published in another obscure periodical, the *Journal of Economic Behavior & Organization*, with the engrossing title: "Spatial and Temporal Heterogeneity of Marginal Emissions."[5]

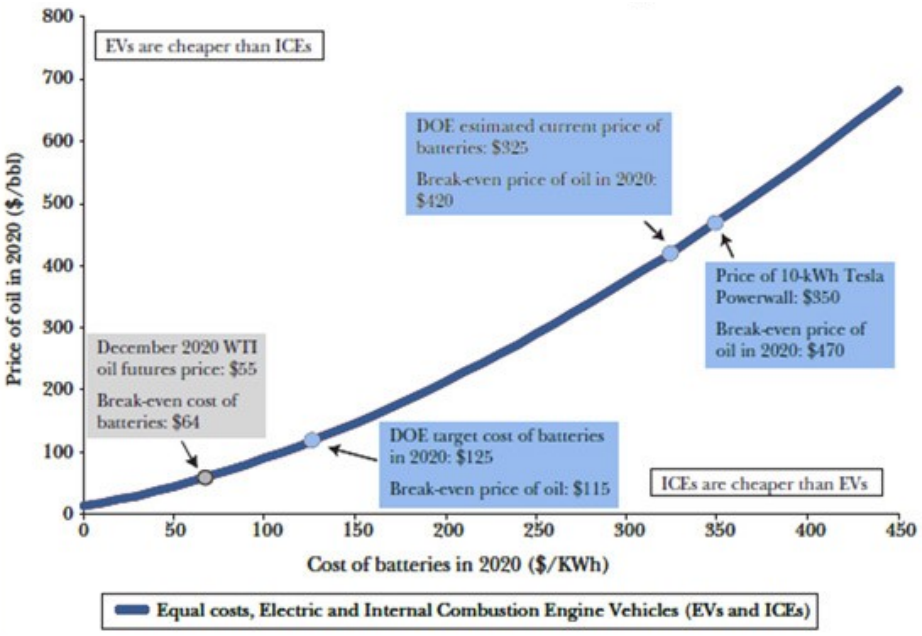
Buried in excruciating detail is the hard reality. The average rates of carbon dioxide emissions on an apples-to-apples kilowatt-hour basis are:

- Electric car: 2.10 lbs/kWh.
- Comparable gasoline car: 1.79 lbs/kWh.
- Comparable hybrid: 1.13 lbs/kWh.

So if you buy an electric car instead of a comparably sized gasoline car, you will most

Continued on page 4

1922 Detroit Model 90 | *Detroit Electric*



Break-even oil and battery costs | *Journal of Economic Perspectives*

RESISTANCE
BY STEVE HUNTOON

Electric Cars – Three Ugly Facts

Continued from page 3

likely make global warming worse. And an electric car instead of a hybrid would be twice as bad.

Third ugly fact: Electric cars cause much more death and disability (euphemistically, "human toxicity potential") from the mining of heavy minerals and graphite. This has received anecdotal attention in *The Washington Post* and other media, but there is an empirical study by Arthur D. Little showing that the aggregate "days of life impact" in terms of death and disability are 30 for an electric car (with a 50-kWh battery in 2025) versus six for an equivalent gasoline car.

So to sum up, electric cars cost more, contribute to global warming more and hurt more people than gasoline cars.[6]

So if you buy an electric car instead of a comparably sized gasoline car, you will most likely make global warming worse.

May I make a modest proposal if you care about the environment and don't want to hurt people? Take the money you would have overspent on an electric car and spend it on (1) a renewable energy supply option from your utility or other electric supplier, (2) a hybrid car and/or (3) high efficiency appliances and lighting such as LED bulbs.

You may not have the coolest toy in the neighborhood, but the planet and your fellow humans should thank you.

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

[1]Here I mean battery-powered electric cars, not driverless cars or hybrid cars.

[2]http://pubs.aeaweb.org/doi/pdfplus/10.1257/jep.30.1.117.

[3]$5,500 minus $1,000 divided by 14 kWh is about $321/kWh. The inverter value may be high; Tesla isn't charging anything less if you get the DC version without the inverter.

[4]Veblen goods are commodities for which demand is high because of their high prices and perceived status.

[5]http://environment.yale.edu/kotchen/pubs/cars.pdf.

[6]http://www.adlittle.us/uploads/tx_extthoughtleadership/ADL_BEVs_vs_ICEVs_FINAL_November_292016.pdf.

EEI Pledges to Fight Elimination of Tax Deductions

Moeller Discusses FERC Appointments

By Rich Heidorn Jr.

NEW YORK — Investor-owned utilities will fight any tax overhaul that doesn't preserve deductions for interest and property taxes, the head of the Edison Electric Institute told Wall Street analysts Wednesday.

As the nation's "most capital-intensive industry," electric utilities hope to convince Congress and President Trump that they should be treated differently from others when it comes to eliminating deductions, EEI CEO Tom Kuhn said.

"We can make a case that we're different," Kuhn said. His argument: Current tax policies allow utilities to reduce their weighted average cost of capital, saving ratepayers money.

EEI said that while it supports simplifying the tax code, broadening the tax base and reducing rates, it will seek to preserve the federal income tax deduction for interest expenses and state and local taxes (primarily property taxes), as well as maintain parity between dividend and capital gains tax rates.

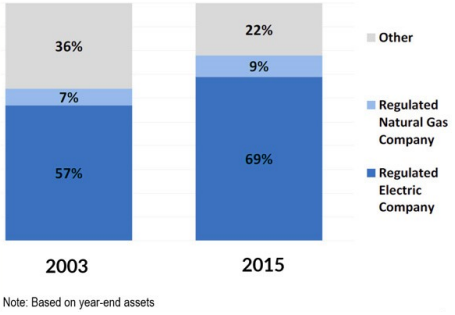
It also will fight to continue tax "normalization" rules, which require state regulators to treat tax benefits to customers in the same way that the recovery of the cost of the associated property is treated.

Normalization spreads the tax benefits associated with assets over the same time period that the costs of those assets are recovered from customers. "It is critically important to maintain tax normalization to the extent that accelerated depreciation or other investment incentives are retained in the tax code," EEI said in a position paper.

About 100 analysts attended the annual briefing at the tony University Club off Fifth Avenue, about a block from Trump Tower.

Kuhn said a group of utility CEOs traveled to D.C. a few days after Trump's inauguration to make their case to White House officials and congressional leaders. "We're going to be in the front of the curve" in lobbying, he promised.

Although tax reform wasn't a major issue in the fall elections, Kuhn said he sees the call by the president and Congress for change as reminiscent of the conditions in 1986, before President Ronald Reagan's tax package was approved.



Between 2003 and 2015, investor-owned utilities increased the regulated share of their balance sheets from 64% to 78%. | *EEI Finance Department*

"Tax reform doesn't happen very often — every couple of decades," he cautioned, adding that a tax initiative will likely be a back burner issue until Trump and Congress act on replacing the Affordable Care Act. "I don't think it's going to be an easy lift."

One wild card is the proposal by prominent conservatives, including former secretaries of state George Schultz and James Baker III, for a carbon tax. "It's really early in the debate right now," Kuhn said of the proposal, noting questions about how the proceeds for the tax would be spent.

Convincing Regulators on Capital Spending

EEI projects that its 44 investor-owned utilities made a record $120.8 billion in capital spending in 2016, up from $103.3 billion in 2015. Of that, 35% was spent on generation (up from 32% in 2015), while transmission dropped to 17% (from 18%), and distribution was unchanged with a 26% share. Much of that spending has been on smart grid improvements.

What are ratepayers getting for their money? Job growth, resiliency and economic benefits from shorter outages, said David Owens, EEI's executive vice president for business operations and regulatory affairs.

EEI officials said the increase in smart grid technology — along with stronger wires and poles, use of robocalls and improved situational awareness — helped utilities in the Southeast restore power to all customers within two days after Hurricane Matthew in fall 2016.

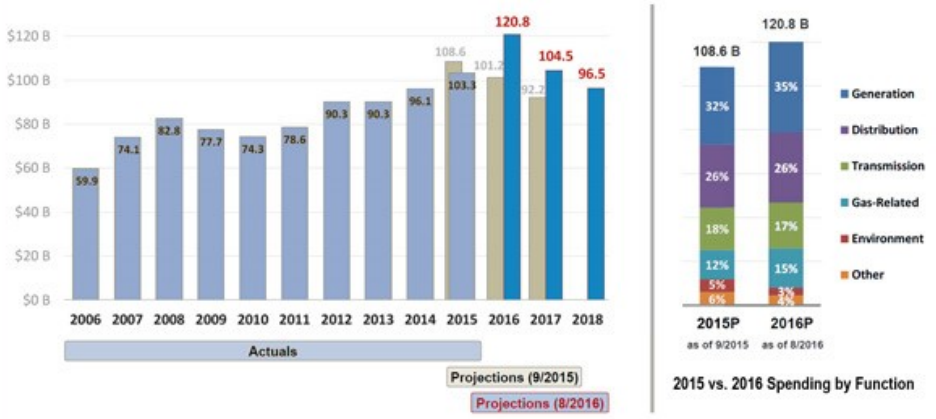
About 70 million smart meters have been deployed to date — representing 60% of U.S. households — up from 32 million in 2012, when Superstorm Sandy knocked out power to millions along the East Coast for as long as two weeks.

"We've got to demonstrate [to regulators] that there's a whole string of benefits that accrue" from smart grid investments, said Owens, a long-time EEI official who has announced he will retire June 30. "We've got to demonstrate to the regulator that there's a fair way to allocate those costs. If you're rolling in those costs, you've got to be able to demonstrate that all the customers benefit. If you're not rolling them all in, you have to charge that individual customer."

FERC's Future

Former FERC Commissioner Philip Moeller, EEI's senior vice president for energy delivery and chief "customer solutions"

Continued on page 7



EEI Finance Department, company reports, S&P Global Market Intelligence (August 2016)

Nuclear Industry Seeks to Remain Relevant

By Rich Heidorn Jr.

Though its generators emit no carbon, the nuclear industry finds itself — like coal — struggling to remain relevant in the electric business.

The U.S. has lost eight plants totaling almost 4,800 MW since 2013, and at least three more (3,500 MW) are expected to retire by 2025. Any boost that the industry hoped to get under the Clean Power Plan likely evaporated with the election of Donald Trump.

But at the Nuclear Energy Institute's briefing to Wall Street last week, CEO Maria Korsnick insisted things are getting better — or are about to. The industry is "reaching a tipping point as policymakers have come to appreciate the risk of losing nuclear plants," she said. Last year, she added, "we began to see the ocean liner change its bearing."

Mixed metaphors notwithstanding, 2016 did bring some welcome news, as New York and Illinois approved zero-emission credits that will provide billions in additional revenue for Exelon's James A. FitzPatrick, R.E. Ginna, Clinton and Quad Cities plants — assuming the state plans withstand legal challenges. Korsnick also talked about "policy opportunities" for similar supports in Connecticut, Ohio, Pennsylvania and New Jersey. (See *Connecticut Lawmakers to Draw Up Millstone Rescue Plan*.)

The Tennessee Valley Authority's 1,123-MW Watts Barr 2 went into service in June, the first new nuclear plant in two decades. Combined with South Carolina Electric & Gas' Summer Units 2 and 3 and Southern Co.'s Vogtle Units 3 and 4 — which are expected to go into service by 2021 — the new plants will add 5,500 MW of nuclear capacity..

In addition, six proposed nuclear units received licenses from the Nuclear Regulatory Commission last year: Austin Energy, CPS Energy and NRG Energy for South Texas Project Units 3 and 4 (February 2016); Duke Energy Florida, for Levy Units 1 and 2 (October 2016); and Duke Energy Carolinas, for William States Lee III Units 1 and 2 (December 2016). This followed DTE Electric's May 2015 license for Enrico Fermi Unit 3.

Last month, NuScale became the first company to apply to NRC for a small modular reactor (SMR) design certification. NuScale has its first SMR customer, Utah Associated Municipal Power Systems, and should be able to put plants into service by the mid-2020s, NEI said. "These are designs that use their smaller size to maximize safety and rethink how nuclear plants could be configured. They will offer flexibility in deployment and operation," she said.

'A Very Good Business Proposition'

Getting licensing approval isn't easy or cheap. But the bigger challenge will be convincing regulators and financiers that nuclear plants can be built in the future without long construction delays and massive cost overruns — and that they can compete against combined cycle plants during a period of near-record low gas prices.

Nuclear power still provides almost one-fifth of U.S. electricity production. And it will certainly have a role for years into the future. Virtually all of the reactors in the U.S. have received license extensions to boost their lifespans to 60 years and some plants may seek another 20-year extension.

But with the expected loss of Pilgrim and Oyster Creek in 2019 and Diablo Canyon by 2025, the U.S. will have lost a net 2,800 MW since 2013.

"The static, top-heavy, monstrously expensive world of nuclear power has less and less to deploy against today's increasingly agile, dynamic, cost-effective alternatives," wrote Jonathon Porritt, former chairman of the U.K.'s now defunct Sustainable Development Commission, in the forward to the 2015 World Nuclear Industry Status Report.

"It may seem strange to think about the construction of more nuclear plants at a time of low natural gas prices and slow load growth," Korsnick acknowledged. "But like other major infrastructure investments, it is critical to anticipate gaps with long-term planning and early investment."

Korsnick defended cost overruns at the Summer and Vogtle projects, saying the first generation Westinghouse AP1000 models are providing "lessons learned" for future development and that "schedule challenges are not unusual."

She cited as an example the placement of the 1,000-ton CA20 module in the AP1000. "It took over 15 hours to place it in position for Vogtle 3," she said. "The same task took less than an hour for Unit 4."

And thanks to a lucky circumstance — a lower cost of capital than assumed — Summer and Vogtle are "still a very good business proposition, and a better proposition than promised to the customer," she insisted.

Korsnick

Yet one analyst in the audience noted that Toshiba — which purchased Westinghouse in 2006 hoping to capitalize on a nuclear "renaissance" — has indicated it is quitting the nuclear construction business because of its experience in its current projects. The company is expected this week to announce a write-down of as much as $6.1 billion to cover cost overruns — more than it paid for Westinghouse.

Korsnick responded with a glass-half-full view, noting the company has not indicated it will quit nuclear engineering or procurement.

The Long Game and Short Game

Korsnick said the industry must play "the long game and the short game" — both preserving existing capacity and ensuring the U.S. has the talent and infrastructure to remain a player in the future.

The 2016 World Energy Outlook from the International Energy Agency forecasts an 80% increase in nuclear power generation worldwide by 2040. But nearly two-thirds of the plants currently under construction are using Russian or Chinese designs — largely because the two countries are host to 27 of the 39 plants now being built.

What the U.S. industry could use is something like the carbon tax proposed by what *The Washington Post* called "senior Republican statesmen" including former secretaries of state George Schultz and James Baker III. Under the proposal, carbon would be taxed at $40/ton, with proceeds returned to citizens: about $2,000 annually in dividends for a family of four, the group says.

Policy Initiatives

Even supporters of a carbon tax don't expect it to happen any time soon, however. As a result, the industry's best near-term hope may be to seek support for additional

Continued on page 7

EEI Pledges to Fight Elimination of Tax Deductions

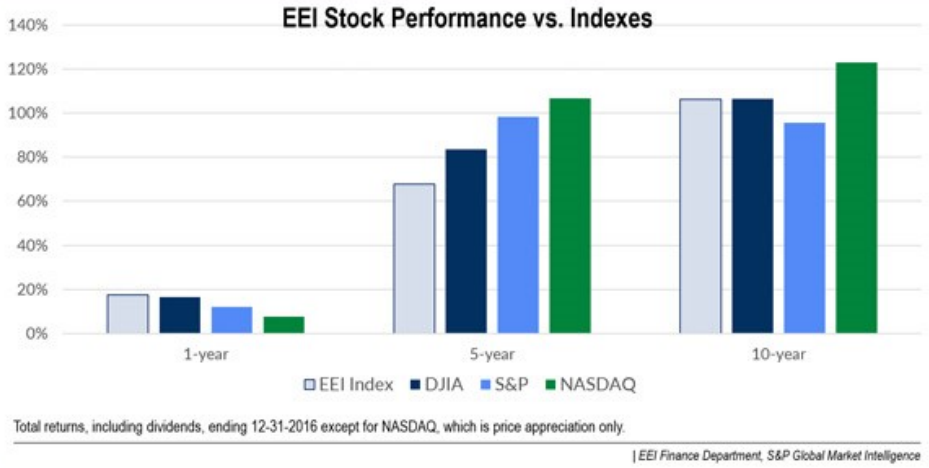
Continued from page 5

officer, commented on prospects for restoring the quorum lost Feb. 3 following the resignation of former Chairman Norman Bay.

FERC canceled its Feb. 16 meeting and said no monthly agenda meetings would be scheduled until a third commissioner is confirmed to join acting Chairman Cheryl LaFleur and Commissioner Colette Honorable. FERC's annual joint meeting with the Nuclear Regulatory Commission will be held as scheduled on Feb. 23.

"Realistically, the most optimistic scenario I would say would be [to have] multiple slots filled in 60 days. But that's very optimistic," Moeller said, adding that a candidate who has already cleared the FBI background check could be installed more quickly. Among those rumored as a candidate for the commission is former Texas regulator Barry Smitherman.

Moeller predicted the new commission will seek to ensure that wholesale markets recognize the reliability value nuclear generators provide as baseload resources, citing financial supports approved in Illinois and New York. (See related story, *Connecticut Lawmakers to Draw Up Millstone Rescue Plan*, p.15.)



Moeller also said the new commission may revisit Order 745, which required RTOs to pay demand response the same LMPs as generation, and Order 1000, which he said "has not provided the certainty for transmission planning that FERC intended." (See *FERC Won't Revisit Demand Response Pricing*.)

He also called for the commission to "update" its interpretation of the Public Utility Regulatory Policies Act. (See *FERC Conference Debates PURPA Costs, Purchase Obligations*.)

EEI will be urging the commission to change its discounted cash flow model for calculating returns on equity "to attract additional capital to the transmission system," Moeller said.

In June 2014, Moeller voted with LaFleur and former Commissioner Tony Clark to apply to electric utilities a two-step DCF process that incorporates long-term growth rates. The new formula has resulted in numerous ROE reductions.

Nuclear Industry Seeks to Remain Relevant

Continued from page 6

revenue streams in recognition of its lack of carbon emissions, as the states have begun to do, or its "resiliency" value — nuclear plants' ability to run for more than a year without refueling; the price hedge it provides as an alternative fuel against a natural gas price spike.

NEI pointed to FERC's actions to improve price formation. "Accurate price formation in the energy markets is particularly important, because a baseload nuclear plant derives most of its revenue from the energy markets," Korsnick said.

The group is also looking to RTOs such as PJM, which is planning to release a white paper on resiliency in March that should provide encouragement to the industry. The PJM effort, like New England's Integrating Markets with Public Policy initiative, is an attempt to get ahead of, or at least catch up to, states looking to take action.

Jobs

For state legislators and regulators, the appeal of retaining an at-risk nuclear plant goes beyond climate change concerns.

According to NEI, a two-unit plant creates the equivalent of 1,000 jobs for 60 years. "When a nuclear plant closes because the markets do not fully value the services they provide, the negative economic consequences of these shutdowns cascade. In many areas, the local nuclear power plant is the economic anchor of the community."

The 2014 shutdown of Entergy's 630-MW Vermont Yankee pinched the economy of Vernon, Vt., a town of 1,200, with housing prices and sales in the region falling.

Entergy had paid about $1.1 million in annual property taxes to Vernon, nearly half the town's tax revenue. Entergy's "tax stability payments" to aid the transition ratchet down before ending after 2022.

Dominion's Kewaunee plant had provided $350,000 in annual utility tax revenues for Carlton, Wisc., more than half of its budget. The closure of the plant triggered a tax hike on residents and a fight over the tax assessment of the 900-acre plant site on Lake Michigan.

New Role for Nukes

While the industry seeks to prevent more plant closings, it also is looking at changing its role to complement intermittent renewables.

"Some [plants] will make electricity around the clock. Others will produce electricity when it's needed, then produce other products when it is not," Korsnick said. "Some will supply the transportation market. Nuclear electricity will charge batteries, and nuclear process heat will make alternative fuels. Some reactors will make fresh water. Some will drive industrial production. Some reactors might even produce energy from today's used fuel, reducing the disposal burden."

Modest Optimism, Lingering Questions at Transmission Infrastructure Summit

By Wayne Barber

WASHINGTON — Modest optimism about the Trump administration's infrastructure plans was tempered with questions about leadership at FERC and other federal agencies at a gathering of transmission developers, RTO officials and environmentalists last week.

The first National Electric Transmission Infrastructure Summit, held Feb. 9-10 by Americans for a Clean Energy Grid, also heard concerns over how to pay for grid modernization in a time of anemic load growth. The organization, an initiative of the Energy Future Coalition, has held regional transmission conferences, but this was its first national event.

The coalition was formed in 2002 by former Sen. Tim Wirth, a Colorado Democrat; Republican C. Boyden Gray, who served as White House counsel to President George H.W. Bush; and Democrat John Podesta, a former aide to Presidents Bill Clinton and Barack Obama who chaired Hillary Clinton's 2016 presidential campaign.

Lack of Load Growth

"I'd love to have more load growth. It ain't going to happen," Craig Glazer, PJM's vice president for federal government policy, told the gathering.

Glazer

Weak load growth will make it more complicated to finance upgrades for aging transmission, and the lack of a federal carbon tax or renewable mandate is making it difficult to integrate renewable generation, Glazer said.

Much of the current grid was built during the 1950s, 60s and 70s, with the deployment of coal and nuclear power plants, said ITC Holdings Executive Vice President and COO Jon Jipping. Now that many of those big baseload stations are being retired, much of the new generation — mostly natural gas or renewable energy — is in different locations that require new transmission, Jipping noted.

From the podium and on the sidelines, speakers said that while they like the Trump administration's pro-growth rhetoric, they are also anxious to see FERC restored to full strength and who will be the key lieutenants to energy secretary nominee Rick Perry.

> ***"I'd love to have more load growth. It ain't going to happen."***
>
> **Craig Glazer, PJM**

Speakers also cited concerns over cost allocation, regional planning and the shortcomings of FERC Order 1000.

Wade Smith, senior vice president of grid development for American Electric Power, said his company has made transmission a higher investment priority than generation in recent years as it focuses more on regulated utility operations.

Modernization is needed because much of the AEP grid is 70 years old, and yet it integrates 9,000 MW of wind, Smith said.

While much of the U.S. electric transmission system was built in the mid-20th century, the infrastructure components are inspected every year, said Rudy Wynter, National Grid's president of FERC-regulated businesses. The grid was built in big chunks and it will largely be rebuilt in large chunks, Wynter said. This includes not only renewable integration but also preparing for more electric vehicles and offshore wind power, he added.

Siting Authority

During one session, SPP CEO Nick Brown was interviewed by former FERC Chairman James Hoecker, now senior counsel for WIRES Group, which represents transmission developers and utilities. Hoecker stressed the importance of adding three commissioners to get FERC back to full strength. With only two commissioners since the Feb. 3 resignation of former Chairman Norman Bay, FERC lacks a quorum. (See *FERC OKs Pipelines, Delegation Order Before Losing Quorum*.)

Hoecker and Brown discussed FERC's inability to gain "backstop" siting authority, saying it's still very difficult to prevent individual states from blocking a project. The Energy Policy Act of 2015 amended the Federal Power Act to give FERC the authority to site electric transmission lines blocked by states, but court rulings have blocked the commission's attempts to use it, prompting some in Congress to propose additional legislation strengthening FERC's authority.

Brown said that Order 1000 hasn't really helped SPP much with large regional projects.

"We need to decide what we want this grid of the future to look like," Glazer said. For example, should it be a "localized grid" that can harness distributed generation? he asked. "There's an added complication; it's not even clear who is in charge," Glazer said. FERC, state utility commissions and governors all have a say in siting decisions, he said.

If each governor is asked what infrastructure projects they want, the country will end up with a lot of state-based projects, not interstate ones, Clean Line Energy Partners President Mike Skelly said.

Perhaps the new mantra is "we're going to make transmission great again," Skelly said. The power to select infrastructure projects should not be taken away from transmission planners and placed in the hands of Congress, he said.

Continued on page 9

Hoecker (left) and Brown | *© RTO Insider*

Modest Optimism, Lingering Questions at Transmission Infrastructure Summit

Continued from page 8

Skelly and others cautioned the Trump administration not to skimp on project reviews or stakeholder input. The key is that all projects must have "timelines" for regulatory approvals to avoid infinite delays, he said.

The executive director of the AFL-CIO's Industrial Union Council, Brad Markell, said the labor movement agrees with the need for "hard timelines" to shorten the permit process.

Markell said that labor unions have been in contact with the Trump administration on potential infrastructure efforts.

"From our point of view, more power for the federal government and less power for the states [on electric infrastructure] would be a good thing," he said.

Others deemed that unlikely. "I think we're stuck with the system we have," Glazer said.

Environmentalists Weigh In

Liese Dart, senior energy advisor for The Wilderness Society, said her organization favors prescreening certain public lands for development suitability.

Mary Anne Hitt, executive director of the Sierra Club's Beyond Coal campaign, said that — contrary to what conference participants may have heard — her organization doesn't oppose all power lines, only those that appear aimed to "prop up fossil fuels."

Hitt

The environmental group opposed the abandoned "coal by wire" Potomac-Appalachian Transmission Highline (PATH) project in PJM. On the other hand, it has backed the Plains and Eastern Clean Line Project, designed to move renewable energy from Oklahoma to Tennessee.

Hitt said she was concerned that President Trump's nominee for EPA administrator, Scott Pruitt, opposed Clean Line in 2015 as Oklahoma attorney general.

Hitt also said the Sierra Club has concerns about the Gateway West project, a proposal by PacifiCorp and Idaho Power to build about 1,000 miles of high-voltage transmission through Wyoming and Idaho. She said PacifiCorp has been slower than some Western utilities in reducing its coal use and slower than the Sierra Club would like in expanding its renewable resources.

Grid Security

When it comes to protecting the grid, Brown said much of the discussion seems to be centered on preventing cyber intrusions. Perhaps the discussion should be less about how to keep cyber intruders out than to minimize the damage and restore order once they disrupt the system, the SPP official said, likening the approach to "insurance."

But he said winning regulatory approval for equipment such as spare transformers may be difficult.

"I believe we are going to have to spend much more money on spare equipment, and that's going to be tough to sell," Brown said. "We are unwilling to spend that kind of money for spare equipment because it is not 'used and useful.'"

SPP Chief Reticent on Mountain West

Brown declined to reveal much about the status of the Mountain West Transmission Group's discussions about joining SPP.

Mountain West, a partnership of seven transmission-owning entities within the Western Interconnection, revealed the discussions in January. It said if the talks with SPP are not successful, it would likely explore joining another RTO. (See *Mountain West to Explore Joining SPP*.)

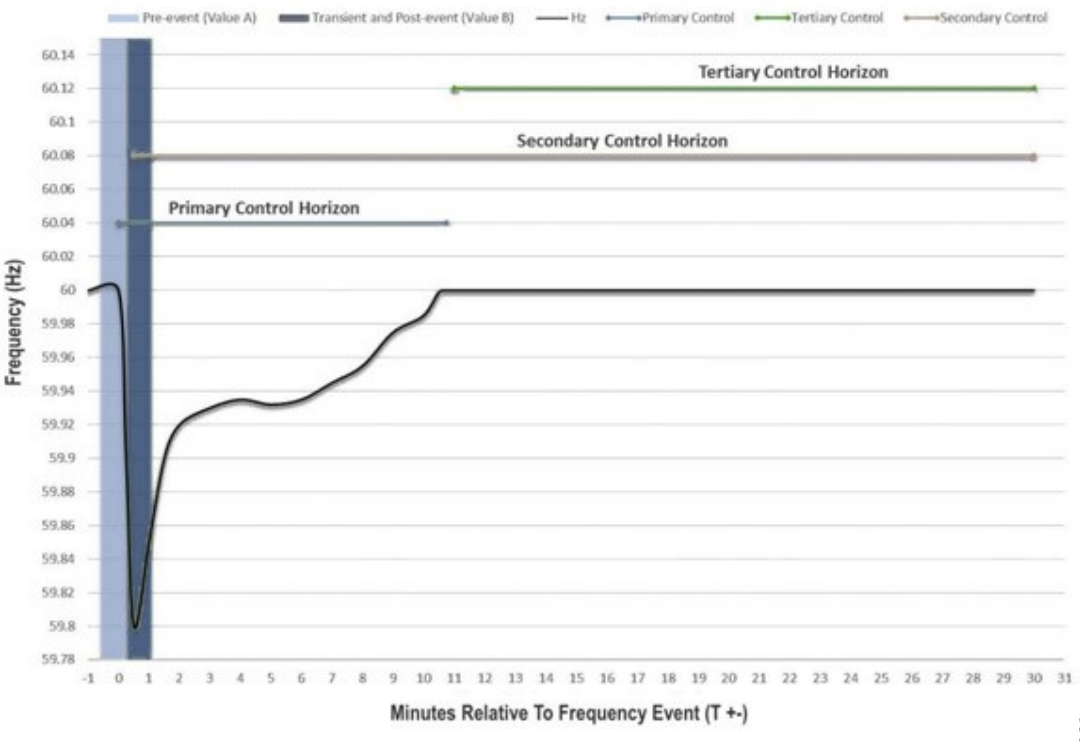
In response to a question about whether Mountain West was attracted by SPP's cost-allocation system, Brown replied, "You'd have to ask them."

"We're excited about it," Brown said of the talks, before cautioning, "Nothing is signed."

CAISO News

CAISO Takes First Stab at Defining Frequency Response Market

By Robert Mullin



CAISO is seeking to develop a market mechanism to compensate resources for responding to frequency dips during the "primary" control horizon — just moments after the onset of the event. | *CAISO*

CAISO's first pass at soliciting stakeholder input on its primary frequency response product initiative generated a wide-ranging discussion about an obscure but increasingly important aspect of the ISO's operations.

"We know that [primary frequency response] is important to your fundamental role as a balancing authority, and currently there are no financial incentives to provide this critical service," Alex Morris, director of policy and regulatory affairs at the California Energy Storage Association (CESA), said during a Feb. 9 presentation to a stakeholder working group convened to lay the foundation for a market proposal.

"And I don't mean to be trite, but what we're seeing from the data is that it's no longer workable to assume the primary frequency response service will be provided — quote — 'for free,'" he added.

Inertial Response

By "free," Morris was referring to the fact that grid operators have benefited from the "inertial" frequency response capability inherent in the operation of most conventional generators, which can automatically vary their turbines' rotational speed and output based on the pull of load, functioning as a damper for frequency excursions on the grid.

Nonconventional technologies such as wind and solar resources have little or no inertial response to momentary changes on the grid. Late last year, FERC proposed revising *pro forma* generator interconnection agreements to require all newly interconnecting facilities, including renewable generators, to have primary frequency response capability (RM16-6). (See *FERC: Renewables Must Provide Frequency Response*.)

"It's probably been great that for many decades [frequency response] came along as part of the generation fleet for free and that's how it worked, but unfortunately we're in a different era with a different grid and we need to wrestle with this problem," Morris said.

NERC reliability standard BAL-003-1.1, which was phased in between November 2015 and last April, requires each balancing authority area (BAA) to carry sufficient capability to respond to a frequency event. Meeting that requirement will become increasingly difficult as California's 50%-by-2030 renewable portfolio standard drives increased penetration of renewable resources.

The NERC rule requires BAAs to respond to a deviation within about 20 to 52 seconds of occurrence. That rapid reaction requires a resource to automatically detect under-frequency and autonomously ramp its output without receiving a market signal or manual instructions from the ISO.

Procurement Needed

An issue paper published by CAISO in December laid out the ISO's deteriorating frequency response performance in recent years and raised the alarm of further declines. (See *CAISO Seeks Primary Frequency Response Market*.)

"Without explicit procurement of primary frequency response, the ISO cannot position our fleet in a way that will provide sufficient frequency response," said Cathleen Colbert, senior market design and regulatory policy developer at CAISO. "We need to also mitigate the risk of noncompliance" with the NERC standard.

For the current compliance period, the ISO issued a competitive solicitation to external BAAs to essentially procure an adjustment on its frequency response reporting. (See *FERC Accepts CAISO Contracts for Imported*

Continued on page 11

CAISO News

CAISO Takes First Stab at Defining Frequency Response Market

Continued from page 10

Frequency Response.)

"We're concerned about continuing to rely solely on procuring this adjustment in the long term," Colbert said. Instead, CAISO seeks to provide internal generators with the ability to compete against external BAAs to provide the service.

In his presentation to the working group, Morris sketched out a preliminary proposal in which the ISO would develop a product that would incentivize frequency response capability and performance while compensating resources for their opportunity costs — for example, forgone energy market revenues.

Under the plan, the CAISO day-ahead and real-time markets would solve for current constraints and products while also reserving capacity from resources capable of providing primary frequency response. The market would compensate those resources for the service, as well as the energy injected during a frequency deviation event, similar to the energy settlement for regulation service resources that follow a dispatch order.

Regulation Service

"I thought that regulation was simply a zero-energy service," said Mark Smith, vice president of government and regulatory affairs at Calpine.

George Angelidis, a principal at CAISO, explained that the energy a regulation service provider gives and takes from the grid should, in theory, sum up to zero, which is why regulation is considered a control service rather than an energy service.

"But there's a capacity behind it, and through the energy provision, you provide the control service, but the expectation is that over a long period of time it's more or less a zero-energy service," Angelidis said.

"The general high-level view is that this resource is sitting at the ready — [and] frequency drops," Morris continued. "The resource autonomously bursts out energy to provide the primary frequency response. In so doing, it's giving energy to the grid. It may be appropriate to compensate [the resource] for the energy it gave to the grid."

Biddable or Not?

Morris acknowledged that he avoided taking a position on whether frequency response provision should be biddable in the market on a standalone basis.

"I think as long as it's being solved for inside the market — it's co-optimized among the many other constraints in the market — then the opportunity cost of providing this service is then reflected," Morris said. "So there would be some element of payment for providing this service, whether that's just an opportunity cost, if any, or not."

Jan Strack of San Diego Gas & Electric questioned the effectiveness of a "non-biddable" solution.

"The issue is, if you don't have a bid, I think the market has no ability to select," Strack said. "Which [resource] would it select? There's no way to know. So I think you inevitably end up with a capacity offer situation just like you do with regulation."

"I hear you," Morris responded. "But I also think just the information about the energy costs will inform the optimization, similar to how with the [CAISO] flexible ramping product you can bid your flexible ramping capability for zero dollars, but you also have an energy bid, so [the market] knows if you have an opportunity cost."

Smith wondered whether a generator that did not receive an award would be allowed to disable its frequency response capability, as it would automatically respond to an event.

"Basically, we make sure that you provide the service all the time, but if while you provide the service you suffer a lost opportunity cost for it, then you will be compensated adequately for it," Angelidis said, adding that disabling that capability could run "contrary" to a generator's interconnection agreement.

In comments filed with CAISO, Seattle City Light — which currently provides the ISO with transferred frequency response under a yearlong contract — said it hoped the ISO would develop a market mechanism that would allow transferred capability to compete with internal resources.

Mike Benn, energy trade policy analyst at Powerex, backed up City Light's position.

"We're supportive of what CESA said to co-optimize the procurement of frequency response in real time, but we think there would be a gap there and we'd like a forward procurement mechanism as well, similar to the [resource adequacy] construct," Benn said. "So you could go out and procure on a year-ahead basis, and then they could procure from internal [resources], or they could also go and procure from external BAs."

The "gap," according to Benn, stems from the fact that short-term procurement of frequency response won't guarantee resources will be available on a given day and might be insufficient to spur development.

"The transferred response from external BAs is a yearly product," Benn said. "So in that way, when you get to real time, you've guaranteed that the resources are available."

Benn pointed out that the absence of a forward procurement option would exclude the participation of external resources because NERC's frequency response reporting requirement is based on an annual obligation that cannot be transferred on a daily basis. FERC recognized this fact on Feb. 2, when it approved the terms of CAISO's transferred frequency response contracts with City Light and the Bonneville Power Administration. (See *FERC OKs CAISO Frequency Response Contract Terms*.)

"I think the two processes — a market mechanism and a transferred frequency response mechanism — aren't mutually exclusive, and it's probably good to think about them in that sense," said Andrew Ulmer, CAISO director of federal regulatory affairs. "From a relatively non-engineering, non-market design perspective, I think of both as insurance mechanisms."

CAISO has asked stakeholders to submit comments on the primary frequency response initiative by Feb. 23. A second working group meeting on the issue will be held on a date yet to be determined.

CAISO News

CAISO Issues Final Plan for Small TO Interconnection Costs

By Robert Mullin

CAISO has issued a draft final proposal to prevent smaller transmission owners from bearing the high costs for network upgrades needed to interconnect generation serving load outside of their service territories.

While the latest revision keeps its focus on the specific circumstances faced by Valley Electric Association, it would also provide CAISO the flexibility to apply the proposal's principles to similar TOs seeking entry into the ISO in the future.

The most recent, and likely final, proposal settles on one of two plans spelled out in the last iteration, with some refinements. (See *CAISO Refines Small Generator TO Interconnection Plan*.)

That plan (referred to as "Option A") would require CAISO to determine on a case-by-case basis whether a candidate TO should be allowed to fold low-voltage generator interconnection costs into high-voltage transmission revenue requirements. Doing so would diffuse the costs among the ISO's full rate base to avoid saddling small TO ratepayers with outsized fees.

Under the proposal, CAISO will make its determination based on whether the TO is:

- Very small relative to other TOs, with a gross load of 2 million MWh or less (currently about 2.2% of the load of the ISO's largest TO);
- Located in a renewable resource-rich area gaining "elevated" interest for generator procurements; or
- Not subject to a renewable portfolio standard or does not need the new interconnecting generation to meet that requirement.

CAISO rejected a more "formulaic" Tariff-based "Option B" that included the last two provisions but would have had the Tariff specify that a small TO's gross load be no larger than 5% of that of the largest TO.

"Rather than trying to develop Tariff provisions that could address every potential unique circumstance, this [Option A] proposal specifies guiding principles the ISO would apply on a case-by-case basis to alleviate unintended adverse impacts for each unique" participating TO, CAISO said.

The option would require ISO management and staff to apply the principles to determine the "appropriate treatment" of each small TO and then seek approval for its recommendations from the Board of Governors and FERC.

CAISO dismissed the contention of some stakeholders who preferred Option B out of concerns that a case-by-case review could bog down the interconnection process.

"The ISO does not agree with the argument that Option A would cause delays since any ISO decision and subsequent FERC approval could be combined with the [TO] application process when a new [TO] joins the ISO," CAISO said.

Valley Electric, CAISO's only out-of-state member, serves 45,000 customers and about 100 MW of load in a 6,800-square-mile region along the California-Nevada border. The cooperative last year agreed to sell its 230-kV transmission network to GridLiance for $200 million. (See *Valley Electric Approves Sale of 230-kV Network to GridLiance*.)

The utility's service area has high potential for the development of new renewable resources that would serve more populous areas of the ISO. Two projects with a total capacity of 100 MW await interconnection with the Valley Electric system, with more slated to enter the queue, according to the ISO.

Under CAISO's Tariff, a TO must reimburse its generator interconnection customers for the costs of local reliability and deliverability network upgrades necessary to connect a resource to the transmission network. The TO can then seek regulatory approval to roll those reimbursement expenses into its rate base, passing them on to ratepayers through either a high-voltage or local low-voltage transmission access charge (TAC). The ISO considers any line under 200 kV to fall into the latter category.

While the high-voltage TAC is allocated to all ISO ratepayers at a postage-stamp rate based on the total revenue requirements of all TOs owning high-voltage transmission, the low-voltage TAC is charged only to customers within the service area of the TO owning the facilities.

That arrangement could burden ratepayers in low-population service areas who are forced to bear the low-voltage network upgrade costs for generation intended to serve other locales attempting to meet renewable goals.

CAISO is asking stakeholders to submit comments by Feb. 22. ISO management seeks to present a plan for board approval in March.

CAISO has developed the small transmission owner generator interconnection proposal to accommodate Valley Electric Association, which faces high network upgrade costs for resources intended to serve other load centers. | *Valley Electric Association*

ERCOT News

Texas PUC Delays Assignment of LP&L Study Costs

By Tom Kleckner

The Public Utility Commission of Texas last week granted Lubbock Power & Light's request to delay a decision on who will pay for studies related to the municipality's planned move to the ERCOT grid.

In a letter to the commission, LP&L asked that the assignment of study costs be held until ERCOT and SPP can finish separate cost-benefit studies on the potential move (Project 45633). The municipality said the two grid operators have not agreed on a common assumption for gas prices, "a key variable," and said that the studies will indicate "the extent to which the LP&L integration into ERCOT would benefit customers in both systems."

"Deciding who should pay the cost of the studies now, in the absence of that information, would mean assigning the cost of the studies to LP&L before it is known whether consumers in SPP and ERCOT would benefit from the transition," LP&L said.

Nelson

"I'm OK with waiting," said Chair Donna Nelson during the PUC's Thursday open meeting, echoing the position of the other two commissioners.

LP&L announced in September 2015 it planned to disconnect 430 MW of its load from SPP and join ERCOT in June 2019. An ERCOT analysis completed last June indicated it will cost $364 million and take 141 miles of new 345-kV rights of way to incorporate LP&L into the Texas grid. Both ERCOT and SPP are currently conducting separate studies on their systems with and without LP&L's load. (See *Texas PUC OKs ERCOT, SPP Studies on Lubbock Move*.)

The utility, which plans to conduct its own study, said it "continues to expect that, on a net basis, the system transition that LP&L seeks will present quantifiable benefits to consumers in both the SPP and ERCOT systems."

In a separate letter to the PUC laying out their respective study scopes, ERCOT and SPP estimated the combined analyses would cost between $225,000 and $255,000. The grid operators said they have assigned internal project codes to track the hours incurred for the studies and promised a final accounting to the commission.

Commissioner Ken Anderson noted SPP planned to perform its production-cost analysis with and without forced generation outages, but ERCOT would do so without taking the outages into account. Asked what the likely variance would be, ERCOT Senior Director of System Planning Warren Lasher said he didn't think it would be a "game-changer."

"You will be able to look at the two results and be able to see the difference, but often, it's not going to change your decision," Lasher said. "ERCOT doesn't do this because it is complicated to do. You need to have very accurate data regarding outage rates, which is something we've had significant difficulty getting from market participants."

Lasher said the difference in outage-rate data may also be "a function of the different market designs we have in the SPP region and the ERCOT region."

The grid operators' studies are expected to be completed by midyear.

Hand-Held Devices Allowed to Enroll Retail Customers

The commissioners adopted a change to the PUC's administrative rules that will allow retail electric providers (REPs) to use laptops, tablets, smart phones and other hand-held devices to enroll customers (Project 45625).

The rulemaking came with a warning, however. "I'm going to be watching," Nelson said.

The PUC chair added language that requires the REPs to "accurately and truthfully answer any questions" when giving customers an opportunity to review the enrollment documents.

"To the extent we get complaints about this, it's not going to be something we look on favorably," she said. "We want to make sure the customers get what they need."

SPS Details Winter Storm Restoration Effort

Southwestern Public Service briefed the PUC on its recovery efforts following January's winter storm, which left 58,000 of its customers in the Texas Panhandle without service and damaged 7,500 poles and other structures.

Evan Evans, SPS regional vice president of rates and regulatory affairs, said the company was prepared for the storm and its forecast of one-tenth of an inch of ice. The storm began with rain Jan. 13, transitioning into freezing rain and bitter cold through Jan. 15 that resulted in up to 3 inches of ice

Continued on page 14

Working to restore service after the January 2017 ice storm | *SPS*

ERCOT News

Texas PUC Delays Assignment of LP&L Study Costs

Continued from page 13

in some areas.

"It was a major ice storm … the worst residents said they had seen in over 50 years," Evans said.

SPS used almost 1,100 employees, contractors and mutual aid partners to restore service to all its customers by Jan. 23. Evans said cellphone communication problems and waiting on electricians to repair damage on the customers' lines and meters slowed the restoration effort.

Evans said the company upgraded its infrastructure standards in 2014 and will look for ways to improve its communications and further harden its facilities. He pointed out some neighboring utility customers are still waiting for service that may still be a week or two away.

"Your team did a tremendous amount of work in very dangerous conditions," Commissioner Brandy Marty Marquez said.

"I'm amazed that you have people that have been out [of power] for seven days asking us if we were OK," Evans said. "They see us working around the clock."

SPS

Fines Approved, Cybersecurity Program OK'd

The commission's consent agenda included approval of fines against Luminant Energy and Oncor Electric Delivery, once sister companies under bankrupt Energy Future Holdings.

Luminant agreed to an administrative penalty of $170,000 for not updating its ancillary service schedules 11 times in 2015 after ERCOT issued instructions to do so (Docket 46724). Oncor agreed to a $288,500 penalty for falling short of benchmarks on the length and frequency of outages for 2015 (Docket 46733).

The PUC also gave Executive Director Brian Lloyd the authority to negotiate and implement a contract to develop "a comprehensive cybersecurity and physical security outreach program" for Texas utilities, cooperatives and municipalities (Docket 46773).

ISO-NE News

Connecticut Lawmakers to Draw Up Millstone Rescue Plan

By William Opalka

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HARTFORD, Conn. — Supporters of the Millstone nuclear power plant last week issued impassioned pleas for Connecticut legislators to save the plant but were short on details on how to provide enough revenue to keep it operating beyond 2021.

Those supporters were speaking at a Joint Committee on Energy and Technology hearing to discuss a preliminary bill, which, for now, merely says its purpose is "to provide a mechanism for zero-carbon electric generating facilities to sell power to electric utilities." Sen. Paul Formica (R), committee co-chair and lead sponsor of the bill, said the hearing was intended to gather input from different constituencies.

While plant owner Dominion Resources has not said that it will close the Waterford facility, the company has acknowledged that the plant is under financial stress because of record low power prices set by cheap natural gas.

"We need to gather all the facts because we need a baseload power source here in Connecticut," Formica said. "But if this baseload goes away, what happens to rates?"

Millstone can produce 2,111 MW, or about half of the state's energy needs.

Bill co-sponsor Melissa Ziobron, a Republican representative from the nearby 34th District, said her husband has worked at the plant for 20 years.

"The premise of Millstone closing is real," Ziobron said. "It is present for our family and 1,200 others." She and others said the plant's closure would devastate the economy of southeastern Connecticut.

An aborted plan introduced at the end of last year's legislative session is presumed to be the starting point in any current deliberations to help Millstone. In the waning hours of that session, the Senate unanimously passed a measure that would have allowed the plant to bid into the state procurement process now reserved for renewable energy, large-scale hydropower and trash-to-energy facilities.

The bill passed the Senate without any hearings, but time ran out for the House of Representatives to act.

Elin Swanson Katz, the state's consumer counsel, took no position on the bill, but she said her office is pleased with the mechanisms the state has put in place for long-term energy procurement to protect ratepayers.

"These processes have been highly competitive and well managed," Katz said.

John Erlingheuser, associate state director of advocacy at AARP, called the bill "a special deal that has the same impact as a subsidy" that effectively reclassifies 50% of the state's generation as renewable energy.

Dominion contends that the policy is justified.

"If Connecticut wants the lowest-cost, longest-term resource that also meets its environmental and economic goals, the solicitation process has to be expanded," Kevin Hennessey, the company's director of state policy for New England, said in written testimony.

Power producers say that reverses 20 years of progress in building competitive markets in the region.

"Proposals to selectively grant some resources preferential treatment without regard for the impact of doing so on the rest of the power supply system risk highly adverse and likely irreversible consequences," the Electric Power Supply Association wrote.

Eric Brown, general counsel for the Connecticut Business and Industry Association, disputed those who said Dominion needs to open its books to justify the policy change.

"We don't need to see their books," Brown said. "The marketplace has sent a very clear message: Nuclear power is struggling throughout the country. We're losing plants in New England. That's the best kind of evidence."

Dominion commissioned a recent study indicating that state carbon emissions would increase by 2.5 million tons if the plant retired and was replaced by natural gas-fired generation.

Roddy Diotalevi, senior director of sales and external relations for UIL Holdings, said that Millstone is important in helping the state reach its environmental goals but that the costs to keep the plant running are still unknown.

"UIL remains concerned about the impact that these above-market payments will have on ratepayers and the negative effects that a long-term obligation and financial liability would have on the utility," Diotalevi said.

Millstone and NextEra Energy's Seabrook plant in New Hampshire are soon to be the only remaining nuclear plants in New England. Vermont Yankee closed two year ago, while the Pilgrim station in Massachusetts will shut down in 2019. New York's nuclear fleet has been saved by a state subsidy, but that program is currently being litigated.

ISO-NE News

ISO-NE Capacity Prices Fall 25%, Lowest Since 2013

Continued from page 1

Although the auction did not have large, significant new resources, "we did have a lot of smaller, other resources clear in the auction," Ethier added.

The clearing price will be paid to all resources in all three capacity zones in New England and 1,035 MW of imports from New York and Quebec. Imports from New Brunswick, totaling 200 MW, will receive $3.38/kW-month. That price is lower because of excess capacity available over a 200-MW tie line.

The total cost this year is about $2.4 billion, down from last year's $3 billion and 2015's $4 billion.

Ethier said the lower prices allowed ISO-NE to acquire more than the minimum target to give it flexibility and to enhance reliability. Almost 40,500 MW — 34,505 MW of existing capacity and 150 new resources totaling 5,958 MW — qualified. (See *ISO-NE Capacity Requirement Shows Flat Demand, More Solar*.)

Several oil-fired units dropped out of the auction, "well under 200 MW" in the aggregate, officials said, but they remain available in the energy market. "We have not yet received any retirement notices from them," said Stephen Rourke, vice president of system planning.

Note: Graph reflects systemwide prices for existing resources.
• FCA 7 (delivery year 2016/17): System prices were set by the $3.15/kW-month floor price; new resources in Northeast Massachusetts/Boston cleared at $14.99/kW-month.
• FCA #8 (delivery year 2017/18): New resources cleared at $15/kW-month.
• FCA #9 (delivery year 2018/19): The Southeast Massachusetts/Rhode Island zone cleared at $17.73 kW-month for new resources and $11.08/kW-month for existing.

ISO-NE

The total available to more than 3,200 MW, or about 9% of the total capacity market.

In addition, demand reductions from the RTO's forecast of behind-the-meter solar PV growth reduced the capacity target by 720 MW.

Six megawatts of new wind and 5 MW of new solar resources cleared the auction, bringing their totals to 137 MW and 66 MW, respectively.

ISO-NE said it will file the results with FERC at the end of the month, hoping for acceptance that traditionally occurs in June. The commission is operating without a quorum and would not be able to approve FCA 11 results on time if they are contested.

"We've thought about it, but it's not a big concern, yet," Ethier said.

MISO News

MISO South-to-Midwest Transfer Limit Upped for 2017/18 PRA

Retirement Process to Synch with PRA

By Amanda Durish Cook

CARMEL, Ind. — MISO's South-to-Midwest transfer limit for the 2017/18 Planning Resource Auction will be 1,500 MW, an increase of more than 600 MW over last year's auction because of a decrease in firm export and wheel-through reservations. The limit reflects the 2,500-MW cap prescribed by MISO's settlement with SPP, reduced by 1,000 MW of reservations.

MISO is modeling two sub-regional resource zones for the 2017/18 PRA: MISO South (local resource zones 8, 9 and 10) and MISO Midwest region (zones 1-7).

The Midwest-to-South limit for the 2017/18 PRA will hold at 3,000 MW, with zero reservation offsets.

Reddoch

The RTO had previously predicted a 984-MW South-to-Midwest limit and a 3,000-MW Midwest-to-South cap. (See *MISO to Use Same Sub-Regional Limit Rules for 2017/18 PRA*.)

Aligning Attachment Y Process with PRA

MISO is looking to align its Attachment Y retirement process with the PRA timeline, implementing a recommendation from the Independent Market Monitor's 2013 State of the Market Report.

At the Feb. 8 Resource Adequacy Subcommittee meeting, MISO adviser Joe Reddoch said the RTO is considering extending a cancellation period offered to retiring resource owners to align with the release of the upcoming PRA results to give owners a limited window to change their minds regarding retirement.

The Monitor recommended improving the alignment of the PRA and the retirement process so that a unit that has filed retirement plans can defer the retirement date if it clears in the auction. It also said system support resource (SSR) units should retain their interconnection service after their contracts end to allow the "broadest possible participation" in the PRA.

Reddoch said MISO has not yet settled on the length of the cancellation window extension.

The RTO is also contemplating removing the distinction between suspension and retirements in favor of a single deactivation status, Reddoch said. The change would eliminate "conflict between documented plans and the owners' actual intentions," he said. The change would simplify the process between temporary, uncommitted shutdowns and pending retirements, according to MISO.

RTO officials said the change would reduce uncertainty in planning processes, with baseline reliability projects being reprioritized if not needed because of a later rescission. Upgrades needed for new generation interconnections would be determined by the known plans of retiring generators.

The issue will be discussed at the Feb. 15 Planning Advisory Committee meeting and referred to the Steering Committee for assignment to a parent committee, Reddoch said.

Stakeholders, MISO at Odds over Resource Adequacy Survey Changes

By Amanda Durish Cook

CARMEL, Ind. — MISO is looking to improve its annual resource adequacy survey by expanding the scope of potential projects included in the report, but some stakeholders are still questioning the survey's credibility.

The survey — a joint undertaking between MISO and the Organization of MISO States — tracks resource adequacy through reports made by load-serving entities. The 2016 survey forecasted a possible capacity shortfall in the RTO by 2018. (See *OMS-MISO Survey: Generation Shortfall Possible*.)

The RTO wants to include more potential future resources in the survey's regional and zonal weighted averages, Darrin Landstrom, MISO's resource forecasting adviser, said during a Feb. 8 Resource Adequacy Subcommittee meeting.

Landstrom said the survey currently counts only future resources that have already executed a generator interconnection agreement. The RTO is also considering rolling a 35% share of the capacity from resources sitting in the definitive planning phase of the interconnection queue into the survey's low-certainty resource total.

Using a sample of natural gas projects entering the queue in 2012, 37% failed after entering the definitive planning phase, while 26% ultimately executed generator interconnection agreements. According to Landstrom, the sample left MISO with a possible percentage somewhere between a conservative 26% success rate to a best-case 63% (assuming every project that enters the definitive planning phase will sign a GIA).

MISO's use of the 35% value in the 2017 survey would be re-examined next year after the RTO completes the launch of its new queue process.

The RTO had additionally considered the idea of including in the survey projects in the system planning analysis stage of the interconnection queue, active projects in the queue that have yet to sign interconnection agreements and planned projects not yet in the queue.

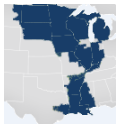
Some stakeholders argued that the 35% figure was arbitrary.

"Ultimately, the OMS-MISO survey is a range of possibilities," responded Laura Rauch, MISO manager of resource adequacy coordination.

Asked by RASC Chair Gary Mathis whether the proposal had OMS's support, Bonnie Janssen of the Michigan Public Service Commission responded that the proposal largely represented the RTO's work.

Continued on page 18

MISO News



MISO to Take Case-by-Case Approach on BTM Generators in Auction

By Amanda Durish Cook

CARMEL, Ind. — MISO has taken another shot at explaining how behind-the-meter generation will function in its markets, this time focusing on how those resources can participate in the upcoming capacity auction.

BTM generators identifying as load-modifying resources will be able to demonstrate deliverability for excess capacity in the 2017/18 Planning Resource Auction by meeting with staff for a case-by-case review, John Harmon, MISO manager of resource adequacy, said during a Feb. 8 Resource Adequacy Subcommittee meeting.

"We're going to need to talk with folks and work with them to determine [if] they have excess capacity and how do they go about demonstrating deliverability of power," Harmon said.

American Electric Power's Kent Felix asked if staff had any idea how many reviews it might conduct and what they might entail.

"It seems a little black box-esque," he said, adding that in some zones, a small amount of additional megawatts could impact clearing prices.

Harmon declined to comment on the scope or scale of the reviews, but he did say staff would review a generator's proof of deliverability of any excess capacity to determine an "interconnection service equivalency." If cleared, generators could then acquire transmission service for delivery.

For future planning years, MISO will require BTM generators to enter the interconnection queue and attain network resource interconnection service before entering the auction, Harmon said. The RTO will also schedule a discussion on possible "alternative deliverability" methods for BTM generation during May's RASC meeting.

Last month's educational workshop on BTM generation definitions raised questions about excess capacity deliverability and how generators could register in MISO's Open Access Same-Time Information System (OASIS), the first step in procuring transmission service. (See *MISO Behind-the-Meter Generation Definitions Create Confusion*.) The RTO allows BTM generation to register as a capacity or load-modifying resource to participate in the auction.

Harmon said BTM generators could be included in OASIS by adding their commercial pricing nodes to the system. Generators would have to take the extra step of contacting MISO to submit their existing nodes, he said.

Customized Energy Solutions' David Sapper asked if BTM generators would be guaranteed a reservation after contacting MISO. Harmon replied that they would enter MISO's system impact studies like any other generator entering OASIS.

Sapper also asked if MISO would let BTM generators create new commercial pricing nodes for OASIS recognition, claiming some generators might encounter a snag if they could not. MISO staff rejected that idea.

Stakeholders, MISO at Odds over Resource Adequacy Survey Changes

Continued from page 17

While stakeholders expressed concern that no planned resources in the definitive planning phase make it into the survey's high-certainty category, Landstrom pointed out that projects in the definitive planning phase with generator interconnection agreements are counted among high-certainty resources.

Rauch said MISO does not want to imply that planned projects are "a done deal" by assigning them high-certainty designations. She said the move could send the wrong signal to state regulators, who might reject other projects because they assume the likelihood of a planned project included in the survey with high-certainty status.

Wisconsin Public Service's Chris Plante said MISO might be able to issue information without editorializing by discontinuing high- or low-certainty designations, which some stakeholders think gives the survey a conservative bias that suggests a resource adequacy problem.

Mathis contended that people tend to pay attention to what's high-certainty rather than low-certainty.

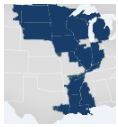
"Is the load growth in the survey high-certainty?" he jokingly asked.

Rauch said that while MISO is focused on signed and committed projects, the survey could concentrate more on a range of possibilities.

In filings made last year to oppose MISO's retooled auction design, the Coalition of MISO Transmission Customers and the Illinois Industrial Energy Consumers said the survey does not give a "complete reflection of the future capacity needs in the MISO region." Stakeholders also questioned why last year's capacity auction results showed a larger surplus than the survey results for a second year in a row.

Jeff Bladen, executive director of market services, said MISO "remains confident" that the survey is the best forward-looking predictor of resource adequacy.

MISO News



Market Subcommittee Briefs

MISO: Lack of Details in Storage Order a Plus

CARMEL, Ind. — MISO Executive Director of Market Design Jeff Bladen called FERC's recent storage order "very narrow in its focus" but that staff does not mind the sparse specifics.

The RTO is grateful that FERC didn't order it to develop new market products or services, Bladen said. (See *MISO Ordered to Change Storage Rules Following IPL Complaint*.)

Another benefit: The order's lack of detailed directives will allow MISO to continue its stakeholder-guided work on incorporating storage into its market.

"We certainly see this as aligned with our core guidelines," Bladen said at a Feb. 9 Market Subcommittee meeting. He didn't see the order requiring fundamental changes and didn't think it would be difficult for the RTO to create a compliance filing (EL17-8).

In response to a question from Xcel Energy's Kari Clark about whether MISO could implement new market rules within 60 days, Bladen said the window to submit a compliance filing is not a target for putting rules in place but a deadline to explain the RTO's plan of action.

Bladen also doesn't anticipate that the RTO's compliance filing would be at odds with future directives stemming from FERC's recent Notice of Proposed Rulemaking on storage (RM16-23, AD16-20).

5-Minute Settlements BPM due in Summer

MISO is drafting Business Practices Manual language implementing five-minute settlements to share with stakeholders by early summer.

In its Jan. 11 compliance filing, required by FERC Order 825, the RTO requested a March 1, 2018, implementation date for aligning settlement calculations with dispatch and pricing intervals, seven weeks after the order's projected date (ER17-778). John Weissenborn, MISO's director of market services, said the additional time is needed for "extensive software development and testing."

"We are working on developing some key milestones and project planning," added Weissenborn.

Under the revisions, MISO will settle excessive and non-excessive energy market trades, price volatility make-whole payments and real-time revenue sufficiency guarantee (RSG) make-whole payments on a five-minute basis. Weissenborn said some real-time settlements, like asset energy and net inadvertent distribution, will remain hourly. MISO also said it has been compliant with an Order 825 requirement for 15-minute interval interchange transaction settlements since mid-2015.

Weissenborn said the Tariff filing changes several mentions of "hourly" to "dispatch interval."

"We believe we are in compliance. If we've missed something, we'll file again," he added.

Bladen said MISO is "moving ahead with the implementation. … We'll be ready in March, barring something completely unforeseen."

Natural Gas Price Hike Raises December Energy Prices, RSG Payments

Higher gas prices drove systemwide average energy prices above $30/MWh across MISO in December, a 22.4% upsurge from November.

The $3.59/MMBtu average price in December was up 45% from November and 91% from December 2015.

MISO said the impact of high fuel prices on real-time energy price was mitigated "to some extent" by higher wind output and more resources back online after planned outages in the fall. However, the high gas prices led to "disproportionate increases" in RSG payments during the month, the RTO said.

Total real-time RSG make-whole payments totaled $7.1 million in December, a three-fold increase from November. Day-ahead RSG payments hit $6.5 million. MISO said most of its day-ahead payments were made to voltage and local reliability resources in MISO South, where emergency conditions in load pockets were declared on multiple days in early December.

During a Feb. 3 Markets Committee of the Board of Directors meeting, Independent Market Monitor David Patton said the high RSG payments were not unusual.

"When we see higher real-time prices rise, we see uplift and revenue sufficiency guarantee rise even faster," Patton said.

December saw a 99.9-GW load peak, higher than December 2015's 87.1-GW peak, Vice President of System Operations Todd Ramey said. Load averaged 76.9 GW for the month.

Total wind energy production in December was 5,687 GWh, the highest value ever recorded for MISO. Wind represented about 11% of the RTO's total energy output for the month.

— Amanda Durish Cook

PJM News

The Power of the NFL

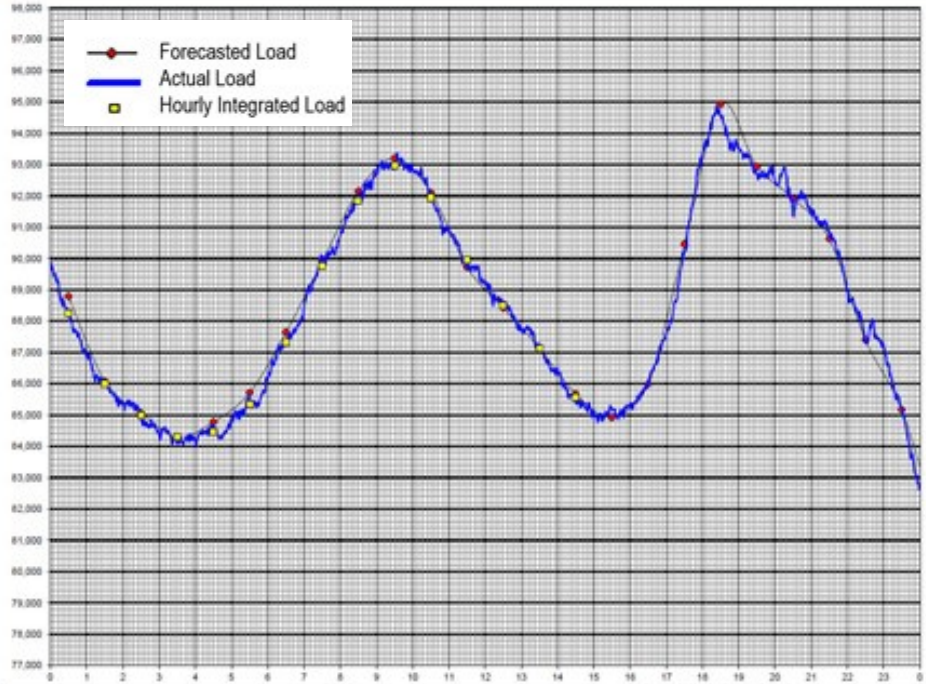
PJM Forecasts Dips in Load During Super Bowl

By Rory D. Sweeney

VALLEY FORGE, Pa. — If you thought the ending of Sunday's Super Bowl matchup was electrifying, you're not alone. The event had a noticeable impact on electricity demand.

Just after the game started at about 6:30 p.m. on the East Coast, PJM's demand dipped below the RTO's forecast by about 1,000 MW, or about 1%, when everyone dropped everything to watch.

It recovered and then jumped above the forecast around 8 p.m., roughly corresponding with halftime, when everyone took a break to do other things, like cooking wings or microwaving some more queso dip. The load then followed the forecast until the game ended around 10:30 p.m., when it again exceeded the forecast as everyone went back to their normal routine.



PJM load vs. forecast on Super Bowl Sunday (Feb. 5, 2017) | *PJM*

The "Super Bowl dip" is a phenomenon that many RTOs experience. In fact, ISO-NE examined it in a post it published on its website last week. Part of the reason PJM could predict the load with fairly good accuracy is because the RTO factored the phenomenon into its forecast.

But that isn't always the case. A similar event happened on Jan. 15, when the real-time load dropped about 2,000 MW, or roughly 2%, below the forecast around 6:30 p.m. ET, then jumped back up to the forecast around 8:30 p.m.

"It seems to have coincided with the end of the Green Bay [Packers]-Dallas [Cowboys] football game," PJM's Phil D'Antonio told the Operating Committee last week. "Apparently, that [playoff] game had enough attention that people were sitting in front of the TV. Then after the game, they went back to their normal lives."

D'Antonio, a manager of reliability engineering at PJM, explained that the "load deviation" caused alerts within PJM's control system. Ken Seiler, PJM's senior director of system operations, noted later that it caused an eight-minute spin response of almost 703 MW.

Operating Committee Briefs

PAH Simulation Estimates $13.5M in Nonperformance Charges

VALLEY FORGE, Pa. — A simulated performance assessment hour last summer would have produced nearly $13.5 million in nonperformance charges, resulting in approximately $1,283/MWh bonus payments for overperforming units, PJM's Joe Ciabattoni said at last week's Operating Committee meeting. (See *PJM Generator Notification Plan Gets Mixed Review*.)

The simulation, which was requested by stakeholders, was simplified to exclude bonus capping and excusals for shortfalls. "Just remember it's a simulation," PJM's Mike Bryson cautioned.

PJM used the 3-4 p.m. hour on Aug. 11, a $1,896.30/MWh penalty rate and Tariff formulas to determine the expected and actual performance. Of the 528 capacity resources, 176 combined for a total shortfall of 7,093 MW, while 306 exceeded their promised output by a combined 10,485 MW. There were 46 resources with neither a shortfall nor a bonus.

Fifteen resources would have been charged more than $250,000 each, with the highest individual charge calculated at almost $1.2 million. Twenty-five resources would have received more than 100 MW worth of bonus payments, with the largest individual credit equaling 601 MW. PJM also calculated separate numbers for just the Mid-Atlantic territory.

Stakeholders felt the broad focus left too much ambiguity. "To me, there are so many details left out that it raises more questions than it does provide answers," American Electric Power's Brock Ondayko said.

On some levels, PJM agreed. "I don't know if we consider this a good predictor of what to expect or not," PJM's Adam Keech said.

Later, PJM staff reviewed member responsibilities for several other components of Capacity Performance, including inputting

Continued on page 21

PJM NEWS

Operating Committee Briefs

Continued from page 20

real-time values such as minimum and maximum run times to reflect operational capabilities when the resource cannot operate according to its unit-specific parameters. The deadline for changing unit parameters for delivery year 2017/18 is Feb. 28.

"This is your opportunity to give us the rest of the story," Ciabattoni said.

The D.C. Circuit Court of Appeals is scheduled to hold oral arguments Feb. 14 on environmentalists' challenge to FERC's approval of CP. (See *Clean Energy Advocates Appeal FERC's Capacity Performance Rulings*.)

Stakeholders Debate Replacing Second Ramapo PAR

Stakeholders expressed concern over the costs of replacing a phase angle regulator that failed at Consolidated Edison's Ramapo substation last June.

That leaves just one PAR at the facility, but Con Ed is waiting for certainty on cost allocation before replacing the second one, PJM said. Without it, PJM's transfer capability into NYISO is limited by about 300 MW. The situation is complicated by the fact that Con Ed is ending its PJM membership in May with the termination of the Con Ed-PSEG "wheel." (See *NYISO Members OK End to Con Ed-PSEG Wheel*.)

The grid operators are considering modifications to their joint operating agreement to develop a cost recovery mechanism for replacing the PAR. The methodology would be used for future cost sharing as well.

The PARs were added in 1988 to control loop flows that had undermined the reliability benefits of the Branchburg-Ramapo 500-kV line, which was built in response to the 1965 Northeast blackout. The current agreement splits costs of the two PARs 50-50 between NYISO and PJM.

Stakeholders were quick to question the financial implications of the proposal, including how much it would cost and what PJM's thoughts were on a likely cost allocation agreement.

"We do not have any preconceived notions of how that would work," PJM's Stan Williams said, adding that the replacement would cost $10 million to $20 million. He confirmed PJM's plan to consider the changes through a problem statement and issue charge.

Williams also acknowledged that some of the PARs' main benefits have been "muted" since they were initially implemented. The second PAR reduces the risk of sustained customer outages during severe weather, but that happens "rarely," he said. Additionally, the loop flows that originally necessitated the PARs have been reduced.

PJM has conducted modeling both for the operational baseflow that will replace the wheel with one PAR, or two PARs, PJM's Paul McGlynn said. However, PJM's current planning parameters for the upcoming Base Residual Auction assumes two PARs, he said.

The grid operators are planning joint stakeholder meetings on the issue, likely beginning in March, Williams said.

New Regulation Rules Improving ACE Control

Month	Average Mileage Ratio
January 2016	3.80
February 2016	2.67
March 2016	2.44
April 2016	2.74
May 2016	2.45
June 2016	3.61
July 2016	2.44
August 2016	2.57
September 2016	2.93
October 2016	2.44
November 2016	2.76
December 2016	2.42
January 2017	5.17

PJM

Recent changes to regulation signals and operational requirements are improving area control error (ACE) statistics, PJM's Eric Hsia said. (See "Regulation Requirement Changing from 'Peak' to 'Ramp,'" *PJM Operating Committee Briefs*.)

The average of the median daily ACE has been cut in half since the new signal was implemented and the monthly average mileage ratio has more than doubled. That indicates a larger utilization of Regulation D resources and better alignment of Regulation A signals with unit ramps, PJM said.

"We're moving the Reg-D resources more aggressively," Hsia said.

Modeling Improvements Reducing Balancing Congestion

PJM's efforts last year to improve the alignment between its day-ahead and real-time modeling has reduced balancing congestion, PJM's Nicole Scott said.

The RTO calculated impedance differences to compare the planning model versus the model used by operators, Scott said, and used summer 2015 peak base cases as a benchmark. Staff has worked to improve the parity between the models by correcting errors, increasing mapping of transmission facilities, refining processes and providing additional training, she said.

The goal is "normalizing the two models to get them to look the same," PJM's Mark Sims said. "If we tried to do this five years ago, we would [have struggled], but everything lined up [now]."

Among additional initiatives for 2017, PJM plans to create an alarm warning when a model is out of compliance.

Committee Endorsements

The Operating Committee endorsed by acclimation:

- A *pro forma* agreement for new pseudo-ties. The agreement would define the general rules for new pseudo-ties into PJM and essentially standardize the process. (See *PJM, MISO Go Quiet on Pseudo-Ties; Reach Interface Pricing Accord*.)
- Sunsetting the Metering Task Force, whose work was completed with revisions to metering standards and requirements in Manual 1. (See "No Objections to Metering Revisions," *PJM Markets and Reliability and Members Committees Briefs*.)

— Rory D. Sweeney

PJM News

MIC Briefs

Loss of Quorum Means Filings to Become Effective Unless FERC Staff Acts

VALLEY FORGE, Pa. — PJM's Jen Tribulski explained the rulemaking implications of FERC's lack of quorum at Wednesday's Market Implementation Committee meeting, using the RTO's seasonal capacity proposal as an example.

In January, PJM filed a response to questions from the commission. "The response resets the 60-day time clock for that proceeding," Tribulski said.

If FERC doesn't act by March 24, the proposal will go into effect and be implemented for the Base Residual Auction in May. The commission, which was already shorthanded with two open seats, lost its quorum when former Chairman Norman Bay resigned Feb. 3. However, in one of their last actions before Bay left, the commissioners issued delegation authority to staff.

That gives staff several alternatives "to keep that rate before the commission review instead of letting it go into effect by law," Tribulski explained. One of those options is letting the rules go into effect but suspending their implementation, she said. That suspension can last up to five months.

Later, staff gave updates on several other FERC matters impacted by Bay's resignation, including a Notice of Proposed Rulemaking on uplift, implementation of Order 831, which doubles the "hard" offer cap for day-ahead and real-time markets to $2,000/MWh, and the commission's rulings on fuel-cost policies and financial transmission rights allocations and forfeitures.

Meter Correction Initiative OK'd

Stakeholders approved by acclimation a problem statement and issue charge proposed by the North Carolina Electric Membership Corp. that could result in a monthly meter correction for pseudo-tied generation and dynamic schedules. The intent is to develop a process through which the unit owner's calculation for the amount of power that flows over its pseudo-tie can be aligned with PJM's calculation every month.

Unlike generators connected directly to the PJM system, there is no mechanism for meter correction at the end of the month for pseudo-tied generators and dynamic schedules, creating the risk of incorrect compensation, NCEMC said.

The proposal that had initially been introduced focused only on pseudo-tied generation, so American Municipal Power's Ed Tatum questioned how dynamic schedules would be treated. "Is there a thought we'd be treating dynamic schedules like pseudo-ties?" he asked.

PJM's Ray Fernandez acknowledged that the RTO is "trying to treat them in a manner as pseudo-ties" but said it was seeking the approval so the Market Settlement Subcommittee could begin analyzing it.

PJM Looking to Avoid Lump-Sum Billing on New Black Start Units

The RTO is working with the Independent Market Monitor to develop a consensus proposal on annual revenue requirements for new black start units, PJM's Tom Hauske said.

"The whole intent here is we're trying to minimize the billing impact on the load from having this new unit come in," he said.

The collaboration received support from members. "I like when you guys get together and talk, so thanks," Old Dominion Electric Cooperative's Steve Lieberman said.

"As [a load-serving entity], our guys are getting tired of getting hit with these big lump sums," Tatum said.

The collaboration has resulted in the addition of a new design criteria concerning fuel tanks at the request of Monitor Joe Bowring. All oil-fired generating units have a "minimum tank suction level". PJM's accounting method would allow for recovery of fuel storage costs for the full tank's minimum suction level, but the black-start unit only requires a small fraction of that. Bowring's proposal would be to reduce the cost recovery to just the amount needed for the black start unit.

GT Power Group's Dave Pratzon argued that discussion was out of the scope of the revenue requirements. "We're not talking about changing the cost components," he said. "It's totally worthy of discussion, but it shouldn't be in this because it's going to delay customers getting the black start they need."

Calpine's Dave "Scarp" Scarpignato agreed.

Reviewing new black start unit revenue requirements is an annual process that happens every May, Hauske said. The determinations go into effect on June 1. There's only one unit currently having its costs reviewed, he said, but PJM plans to offer an RTO-wide request for proposals for new units at the end of the year. The last such RFP added 20 units, he said, but PJM expects about three this time. (See *PJM: Black Start Sources Ready to Replace Retiring Coal*.)

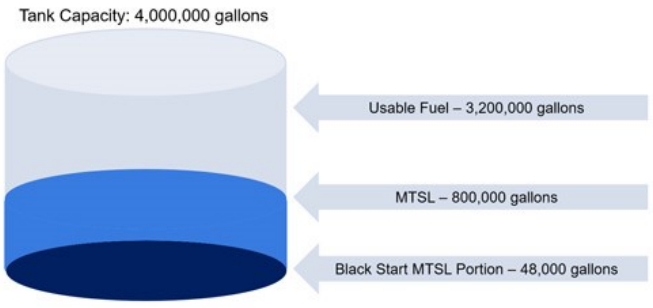
No New IARRs this Year, but Con Ed's to be Redistributed

PJM's annual analysis found that there are no incremental auction revenue rights to be awarded this year, PJM's Xu Xu said. However, with Consolidated Edison terminating its PJM membership, the company's IARRs need to be reallocated by May 1.

IARRs are awarded when regional or lower-voltage facilities are upgraded after the annual ARR process is completed.

PJM's Tim Horger said the reallocation of Con Ed's IARRs will be based on the Schedule 12 regional cost allocation process. "It will be a small value, but it's a value that has to be reallocated," he said. "Everyone will automatically get another slice of the ARRs with Con Ed gone."

— Rory D. Sweeney



The Monitor's explanation of how minimum tank suction level should work for black start units. | *Monitoring Analytics*

PJM News

PC/TEAC Briefs

Planning Committee

Endorsements Sail Through by Acclimation

VALLEY FORGE, Pa. — Stakeholders moved quickly through PJM's requested endorsements at Thursday's Planning Committee meeting, approving all three by acclimation. In addition to largely administrative updates to Manual 22, the committee endorsed:

- The sunsetting of the Earlier Queue Submittal Task Force, whose Tariff revisions went into effect on Nov. 1. The revisions allow PJM to start feasibility studies sooner and allocate review and study costs to interconnection customers rather than socializing them. "The big problem is that there were [project] requests that were deficient at the end of the window … that's what was bleeding into the feasibility window," PJM's Andrew Gledhill explained. (See "Stricter Standards OK'd for Project Queue Submittal," *PJM Markets and Reliability Committee Briefs*.) James Manning of the North Carolina Electric Membership Corp. supported the changes but requested that there be a "feedback loop" to ensure the rule changes are successful in incenting customers to file their requests sooner. PJM said it would provide updates.
- Exempting certain transmission substation equipment from competitive bidding. Brenda Prokop of ITC Holdings thanked PJM staff for making sure the revisions got completed.

PPL Removing Jenkins SPS

PPL's Jenkins special protection scheme, which was installed to protect against overloads on the Susquehanna-Jenkins 230-kV line, is being removed because the line is being rebuilt. The line will be out of service from March through December.

Planning Coordination with MISO Improved

PJM and MISO filed joint operating agreement revisions for the targeted market efficiency project process with FERC on Dec. 30, PJM's Chuck Liebold said.

"That was a big need. That should be a very beneficial change to expedite the analysis," Liebold said. "In the past, it has taken months and months to put together an interregional case."

Previously, PJM and MISO used incompatible analysis criteria. "Now we can go after any type of project on our border and go after whatever is truly the most cost-efficient project," he said.

Stakeholders asked why there wasn't a common interregional model. Liebold explained that FERC set it up so that interregional planning is developed from each RTO's regional planning process, so it would be impossible for them to be the same.

"We're not disputing MISO's assumptions or MISO's processes. … If their stakeholders have decided that's the basis on which to go forward on a particular study, they can do that. … I think our responsibility is to make sure … that we come up with the best solution that satisfies the [needs] on both sides," Liebold said.

Transmission Expansion Advisory Committee

New Proposal Shaves $78M from PSE&G Switch Fix

PJM told the Transmission Expansion Advisory Committee it has developed an alternative solution to address the fire hazard at Public Service Electric and Gas' Newark transmission switch that would cost $275 million, saving $78 million from a proposal outlined previously.

Planners said the switch is considered at the end of its life and failure to replace it could result in a fire that could engulf the substation, which was built in 1957.

A fire would threaten a nearby school and healthcare facility as well as possibly cut service to 300 MVA of load, including Newark City Hall, Rutgers University facilities, Prudential Center, several data centers and two train lines.

A proposal outlined last August called for building a new gas-insulated switch station adjacent to the existing switch at a cost of $353 million.

The new proposal modifies the scope and layout, reducing constructability concerns. PJM said it would save $18 million in direct costs and $60 million in risk contingency expenses. It would be fully energized by June 2021.

PJM Recommends Spending $10M to Correct AEP Voltage Problem

PJM said it is recommending installing 300-MVAR reactors at American Electric Power's Ohio Central and West Bellaire 345-kV substations at a cost of $5 million each.

Planners said the reactors were needed to correct high voltages on the extra-high-voltage system in AEP's service territory during light load conditions. PJM is targeting a Sept. 1, 2018, in-service date.

— Rory D. Sweeney

PJM News

PJM Making Cost Consciousness a Focus for RTEP Redesign

By Rory D. Sweeney

VALLEY FORGE, Pa. — PJM has made several changes to its proposed planning process for competitive transmission projects in response to stakeholder feedback, staff said Friday.

At a special Planning Committee meeting on redesigning the Regional Transmission Expansion Plan and the Transmission Expansion Advisory Committee, PJM's Fran Barrett said the RTEP "is not just about [FERC] Order 1000."

"The RTEP has been in service for 18 years. It's served us well, but the market is changing," Barrett explained. "We have heard you. [The redesign] is not just going to be about technology. It's going to be about timing; it's going to be about interactions." (See *PJM Proposal Would Lengthen Reliability RTEP Cycle*.)

The changes would be detailed in a proposed Manual 14F. Among the changes is considering cost containment in the project selection phase, the details of which have not been finalized. "At this point, we have not made an effort to [separately] define 'cost cap' and 'cost-containment mechanism,'" PJM's Mike Herman said.

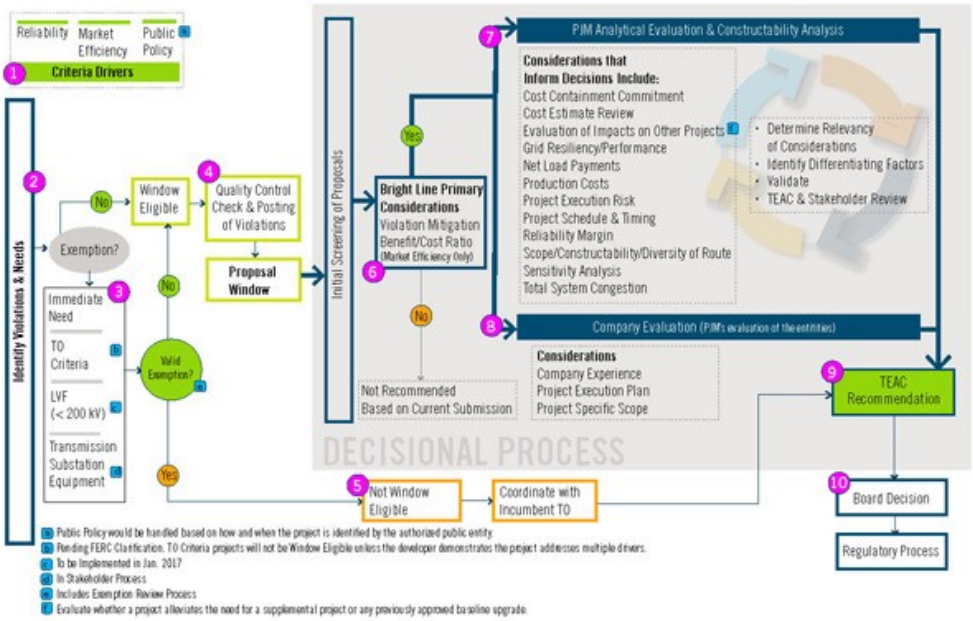
Alex Stern of Public Service Electric and Gas cautioned against creating a "race to the bottom" by selecting projects for having the lowest cost cap.

GT Power Group's Dave Pratzon asked how the evaluation standards will be applied to what he called "squishy" situations, where the costs and benefits of a proposal might not be straightforward.

"How incidental a failure in PJM's initial study does someone have to have before" the project is rejected? he asked.

Herman agreed that more consideration could be applied to the issue but said the manual can't anticipate all possible situations. "I think we could get into lots of detailed discussions about 'odd' situations," he said.

Proposed changes to the workflow diagram include:



Decisional process map | *PJM*

- Removing supplemental projects as a criteria driver, a response to stakeholders who said such projects don't fit with market efficiency projects and should have their own diagram;
- Including a footnote that explains how public-policy decisions factor into the public-policy criteria driver;
- Adding "evaluation of impacts on other projects" into PJM's factors for consideration, with a focus on whether the proposal alleviates the need for a supplemental or previously approved baseline project; and
- Moving "stakeholder review" from the TEAC recommendation phase to one of the factors for consideration, to emphasize the importance of ongoing stakeholder feedback.

Stern reiterated his suggestion that the manual be limited to market efficiency projects.

"I'm not intending that we stop the discussions on reliability. In my mind, that's going to take longer," said Stern, who offered his own edits to the proposed manual.

"We thought there were a lot of similarities [between reliability and market efficiency projects] both on the front end and on the back end," Herman said. "They still fall within the same decisional thinking process. … We felt it made most sense to put it all together in one manual."

"We think it's prudent to put the language together so you can see the differences," Barrett added.

Other stakeholders agreed they preferred a single document. "That kind of leans me back toward 'Let's do this all together,'" PJM Public Power Coalition's Carl Johnson said.

"Can I just say 'what Carl said,' or do I have to repeat it?" Calpine's David "Scarp" Scarpignato said.

FirstEnergy's John Syner also leaned toward a single manual, but he said incumbents should be given "brownie points" such as basis points for their longevity and reliability.

"I don't know how you can put a manual together and be able to give all of those 'brownie points,'" he said, adding that it likely will need to occur during transmission owner prequalification and would require a Tariff change.

SPP News

RTO Juggles Seams Studies, Projects, Reviews

SPP will juggle a number of studies and reviews with its seams neighbors this year, following a 2016 filled with "lots of good stakeholder engagement."

Adam Bell, SPP's interregional coordinator, told the Seams Steering Committee last week the major effort could come with MISO. Besides the usual joint studies and regional reviews, the two RTOs could engage in a targeted market efficiency project (TMEP) study, similar to that between MISO and PJM. (See *MISO-PJM TMEP Projects Drop to Five*.)

Bell said he was not certain whether it would be separate from the joint study already planned for 2017 or rolled into it.

"We're still talking about it," he said.

SPP and MISO are already working on a targeted coordinated system plan (CSP) that is considering seven potential projects. If the two RTOs agree to move forward on any of the projects, SPP would conduct a separate evaluation allowing stakeholders and the Board of Directors to verify benefits and costs for the RTO. If none of the seven projects moves forward, the RTOs' staffs will use the CSP results as an input into the 2017 joint study. (See *SPP-MISO IPSAC Turns Attention to 2017 Study*.)

Bell said the joint study will begin in April and will be "a pretty lengthy process. … We both agreed to a broader, much more comprehensive look following the 2016 study."

The two RTOs will discuss that during their next Interregional Planning Stakeholder Advisory Committee meeting March 9 in Metairie, La.

SPP and Associated Electric Cooperative Inc. wrapped their joint CSP in January, identifying two projects near Springfield, Mo.: a 50-MVAR reactor at Springfield's 345-kV Brookline substation, and a new 345/161-kV transformer at an AECI substation and an uprate of a related 161-kV line.

The SPP Board of Directors and Markets and Operations Policy Committee both approved the project in January, but it must still go through a regional review.

SPP also meets twice a year with Southeastern Regional Transmission Planning process representatives. The organizations review their regional planning processes, determine whether a study is needed and, toward the end of the year, exchange data.

M2M Report

Staff's monthly market-to-market report showed MISO piled up its third biggest month yet of M2M payments to SPP in December, with 444 hours of binding resulting in a $1.98 million payment to its neighbor. Temporary flowgates again accounted for most of the payments, with 128 binding hours costing $1.65 million.

MISO has made $14.2 million in M2M payments since the two RTOs began the process in March 2015.

New Representatives Welcomed

The Seams Steering Committee welcomed two new representatives: Nebraska Public Power District's Dustin Betz and Empire District Electric's Tina Gaines.

Engineering Department Modernizes 2017 ITP 10-Year Report

SPP is using a new medium to explain its Integrated Transmission Planning (ITP) process: a web-based application summarizing a 200-page technical report with appealing graphics and less industry jargon.

Director Antoine Lucas and his transmission planning group developed the 2017 ITP10 story map to simplify the 2017 10-year assessment, which was presented to the MOPC and the board in January. Titled "Strengthening the Grid," it has been viewed almost 700 times since being published just before the Jan. 31 board meeting.

"We have a diverse audience of stakeholders, ratepayers and regulators," said Lanny Nickell, vice president of engineering. "It's crucial that we present the information on which they base their decisions in a way everyone can fully understand and appreciate, especially as our studies become increasingly more comprehensive and complex."

A team of SPP geographic information systems experts and analysts used the Environmental Systems Research Institute's Story Maps application to produce a contemporary web design with industry mapping tools already used to visualize Bulk Electric System components. Engineering and communications staff worked together to distill the 2017 ITP10's assumptions, approach and conclusions.

SPP Sets New Winter Generation Mark

SPP set another record for wind generation Feb. 9 when the footprint produced 13,342 MW of energy, smashing the previous record by more than 1,000 MW. The mark came at 9:34 p.m.

It was SPP's first wind record for 2017. It established six peaks last year, the last coming Dec. 30 at 12,336 MW.

— Tom Kleckner

2017 joint planning timeline | *SPP*

Exelon's Crane Reports 'Monumental Year'

By Ted Caddell

This time last year, Exelon had its hands full.

The company was deep in a problematic $6.8 billion acquisition of Pepco Holdings Inc. while bogged down in a two-front battle trying to get nuclear subsidies for plants in Illinois and New York.

Things look much brighter for the Chicago-based energy giant in early 2017.

First, the acquisition of PHI has closed, adding PEPCO, Delmarva Power and Atlantic City Electric to Exelon's stable of electric distribution companies.

Second — and against most odds — the company was able to convince Illinois and New York legislators to pass laws providing subsidies for its troubled nuclear plants.

And somewhere along the line, Exelon picked up yet another nuclear generating station, the James A. FitzPatrick station, from Entergy. The FitzPatrick deal is expected to close this spring, the company said.

As Exelon CEO Chris Crane put it during an analyst earnings call on Wednesday, "2016 was a monumental year for Exelon."

The company earned $410 million ($0.44/share) during the fourth quarter, compared to $347 million ($0.38/share) for the same period in 2015, missing analysts' expectations by a penny. Annual earnings came in at $2.5 billion, up from $2.2 billion in 2015.

"We made great progress in the ongoing transformation of our company, with a focus on meeting our commitments to stakeholders via the PHI merger and the creation of the [zero-emission credit] programs in both New York and Illinois that compensate our nuclear plants for their carbon-free attributes," Crane said.

The successful push for ZEC legislation reversed the company's decision to retire the Clinton and Quad Cities nuclear plants, saving $120 million in projected early retirement costs, Crane said. He also noted that Exelon's nuclear fleet had a 94.2% capacity factor for the year, up nearly 1 percentage point from the previous year.

All of the company's electricity distribution companies enjoyed fewer storms and therefore lower outage-related costs throughout the year, he said.

Looking ahead, company executives are eyeing legislative action in several other states — including Ohio, Connecticut, New Jersey and Pennsylvania — that could result in ZEC-style subsidies for nuclear plants there.

Joe Dominguez, Exelon executive vice president of governmental and regulatory affairs and public policy, described the company's approach to winning those concessions.

The first stage is "establishing a recognition that nuclear is the lowest-cost and most reliable zero-carbon option" for electricity customers.

"That's where we are in Pennsylvania," Dominguez said.

The next step: identify different "solution sets," such as the ZEC programs already adopted or including nuclear as a qualifying resource for renewable portfolio standards.

"And it's way too early for me to handicap where that discussion is going to go," Dominguez said.

Dominion Resources Changing Name to Dominion Energy

By Ted Caddell

Dominion Resources is changing its name to Dominion Energy to unify the look and brand of the holding company that now does business in 18 states.

The company said it wanted to bring all of its businesses under a single flag, especially since its $4.4 billion acquisition of Questar in September, which added 56 Bcf of gas storage and 3,400 miles of gas transmission.

Dominion operates natural gas and electric distribution companies in seven states, with 2.5 million electric customers in Virginia and North Carolina, 2.3 million gas customers in Idaho, Ohio, Utah, West Virginia and Wyoming. It also has 1.3 million retail energy and energy services accounts in 13 states.

The company owns 26,400 MW of electric generation, 6,600 miles of electric transmission and 14,600 miles of natural gas pipelines.

Dominion

Its newly branded Power Delivery Group, Power Generation Group and Gas Infrastructure Group will replace Dominion Virginia Power, Dominion Generation and Dominion Energy.

The new name — subject to stakeholders' approval at the company's annual meeting this spring — will be accompanied by a new logo: a blue "D" with energy-suggestive strips through it.

"Our company and our employees are proud of the work we have done in delivering energy for 119 years," CEO Thomas Farrell said in a statement. "Dominion Energy builds upon this equity, updates our company's look and unifies the company's brand across all of our lines of business."

"This is a good time to unify the brand, clarify the name and simplify the logo," said Kelly O'Keefe of Virginia Commonwealth University's Brandcenter, who worked on the branding project.

The branding announcement comes about a week after Dominion announced earnings of $457 million ($0.73/share) for the fourth quarter of 2016 and $2.1 billion ($3.44/share) for the year. The company earned $357 million for the fourth quarter of 2015 ($0.73/share) and $1.9 billion ($3.20/share) for that year.

Farrell used the earnings call to spotlight some of the company's accomplishments for the year, including adding 727 MW of solar to its portfolio, bringing it up to 1,400 MW; continued progress on its 1,588-MW combined cycle station in Greensville County, Va.; the connection of 11 new data centers; and the completion of $784 million in transmission projects, with another $800 million on the horizon.

COMPANY BRIEFS

Eversource Fires Back at Report Finding Access Northeast Unneeded

Eversource Energy, a primary backer of the Access Northeast project, has flatly rejected a report placing the long-term cost of the proposed pipeline at $6.6 billion, which is twice it and partners National Grid and Spectra Energy estimate.

The report, which was commissioned by environmental and consumer groups in Connecticut and Massachusetts, finds the project will be underused and unneeded because of an expected 27% drop in demand for natural gas to produce electricity at New England's generating plants over the next six years.

More: *Hartford Courant*

SoCalGas to Pay $8.5M Aliso Canyon Settlement

Southern California Gas agreed Wednesday to pay $8.5 million to settle a lawsuit over the four-month Aliso Canyon methane gas leak that was discovered in October 2015.

Under the agreement with South Coast Air Quality Management District, SoCalGas will pay $1 million for a health study; $5.65 million for emission fees, with $1 million of that earmarked to fund a renewable natural gas production project; $1.6 million to reimburse the regulatory agency for air monitoring costs; and $250,000 for the agency's legal fees.

More: *The Associated Press*

DTE Launches Pilot Clean Energy Program

DTE Energy is launching a pilot program that will allow customers to support clean energy in 5% increments for up to 100% of their power.

Under the MIGreenPower program, beginning in April, customers will have the chance to virtually receive some of their electricity from the Pinnebog Wind Project in Huron County, Mich., and three solar farms in Detroit and Lapeer, Mich.

A typical residential customer subscribing to an additional 25% of renewable energy will see a $5/month increase in their bill.

More: *Crain's Detroit Business*

Mission Solar Energy Pays Back Tax Abatements, Grants

Solar panel manufacturer Mission Solar Energy has paid back more than $665,000 in tax abatements and grant money after falling below employment levels necessary to maintain two separate economic development deals.

Mission paid the city of San Antonio more than $601,000 and Bexar County, Texas, $64,000 following two rounds of layoffs in September and January that affected 257 employees.

Under a 2013 deal with the city, Mission received a 100% tax abatement for 10 years and up to $400,000 in grants contingent upon maintaining 404 full-time jobs that pay $13.97/hour.

More: *San Antonio Business Journal*

New Volkswagen Unit Will Invest $2B in EV Infrastructure

Volkswagen Group of America announced last week a U.S. subsidiary, Electrify America, that will manage more than $2 billion in investments in zero-emission vehicle infrastructure and awareness programs as part of its court settlement on excess diesel emissions.

The unit plans to install more than 500 charging stations throughout the U.S., 300 of which will be in 15 metropolitan areas. It also plans to develop a high-speed, cross-country network consisting of more than 200 EV stations.

Long-time auto executive Mark McNabb, who has overseen the diesel settlement program, will serve as Electrify America's chief executive.

More: *Reuters*

Dynegy Completes Acquisition Of ENGIE's US Portfolio

Dynegy announced last week it has completed its $3.3 billion acquisition of ENGIE's U.S. portfolio, bringing its total generating capacity up to 31,000 MW.

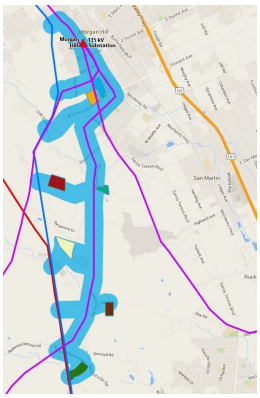
ENGIE's portfolio consisted of 9,017 MW of generation capacity, more than 90% of which is gas-fueled. The plants are located in the Texas ERCOT, PJM and ISO-NE markets.

FERC approved mitigation measures proposed by Dynegy to overcome market power concerns in PJM and ISO-NE. The commission found no competitive concerns over Dynegy's acquisition of ENGIE's assets in NYISO, MISO and CAISO.

More: *Dynegy*

PG&E's South County Power Connect Project on Hold

Pacific Gas and Electric's plan to build a new electricity substation and two new transmission lines in South County, Calif., is on hold while CAISO re-evaluates the project.



SCPC route map

The South County Power Connect project faces opposition because of the locations PG&E proposed for its substation. Five of the eight locations are in natural areas surrounded by wineries and wildlife, according to opponents.

The California Public Utilities Commission has not approved the project.

More: *The Morgan Hill Times*

Peabody Creditors File Emergency Appeal of Reorganization

Opposing creditors have filed an emergency appeal against the terms of Peabody Energy's proposed $1.5 billion private recapitalization, which the coal producer is seeking as part of a plan to slash $5 billion in debt and exit Chapter 11.

The plan could provide lucrative returns for early subscribers. But to sign up, creditors had to support Peabody's broader reorganization plan within days of its publication on Dec. 22, which was about one month before it went to bankruptcy court for approval.

"The choice was to support the plan or suffer severe economic loss," an *ad hoc* committee of dissenting creditors said in a motion filed last week with the 8th U.S. Circuit Court of Appeals.

More: *Reuters*

FEDERAL BRIEFS

Wind Energy Finishes Q4 by Adding 6,400 MW of Turbines

The fourth quarter of 2016 was the second strongest quarter on record for the wind industry, with 6,400 MW of new turbines installed nationwide, according to a new report by the American Wind Energy Association.

Wind energy presently makes up more than 80,000 MW of capacity on the electric grid, coming in fourth behind coal, natural gas and nuclear, AWEA said.

"American wind power is on track to double our output over the next five years and supply 10% of U.S. electricity by 2020," AWEA CEO Tom Kiernan said in a statement.

More: *Fuel Fix*

Smitherman Under Consideration to Chair FERC


Smitherman

Citing an unnamed source, the *Houston Chronicle* is reporting that former Texas Railroad Commission Chairman Barry Smitherman is under consideration to be the next FERC chairman. Smitherman also served for seven years on the Texas Public Utility Commission.

According to the *Chronicle*'s source, Smitherman met with President Trump's transition team before Inauguration Day. Last month, he left his job at Houston law firm Vinson & Elkins, where he was a partner.

Smitherman declined to comment on the report. A FERC spokesman said it is unknown when a new chairman will be named.

More: *Houston Chronicle*

Study: Jobs in Solar Power Industry Increasing

Solar power provides 1.3% of electricity in the United States but creates one of 50 new jobs nationwide, according to a study from the nonprofit Solar Foundation. Total employment for the industry is 260,000.

"Solar employs slightly more workers than natural gas, over twice as many as coal, over three times that of wind energy and almost five times the number employed in nuclear energy," the report states. The only energy industry with higher employment is oil and petroleum, which exceed solar by 38%.

California is a solar job leader and accounted for 34% of new solar installations in 2016. States that have seen recent solar job growth are Texas, South Carolina, New Jersey, New York and Utah, the report states.

More: *Vox*

STATE BRIEFS

CALIFORNIA

PG&E: Rate Hikes Most Likely Behind Spikes in Bills


Hill

Two recent rate hikes and increased seasonal energy use are most likely the culprits behind higher-than-normal electric bills recently reported by Pacific Gas and Electric customers, according to a PG&E spokeswoman.

"Our rates have increased by 21% since last year," spokeswoman Deanna Contreras said. She said there was a rate increase in August for gas transportation and storage, followed by another increase in January.

State Sen. Jerry Hill is looking into the reported increase.

More: *KCBS*

Lawmakers Urge CEC to Re-evaluate Need for Puente

Three state lawmakers asked regulators last week to take time to consider environmental concerns and justify the need for the Puente Power Project before granting their approval.

The natural gas project, proposed by Southern California Edison for Ventura County, would provide power during peak use and replace two older gas-fired steam turbines in Mandalay Bay that operated at about 6.5% of their capacity in 2015, according to federal data.

The lawmakers' plea to the Energy Commission comes on the heels of a *Los Angeles Times* investigation that found the state's power plants are on track to be able to produce at least 21% more electricity than needed by 2020, based on official estimates.

More: *Los Angeles Times*; *Los Angeles Times*

Feinstein Backs Bill to Keep Aliso Canyon Closed

U.S. Sen. Dianne Feinstein (D) has announced her support for State Senate Bill 57, which would continue a moratorium on gas injections and withdrawals at Aliso Canyon until an independent study determines the cause of the 100,000-metric-ton methane gas leak that began in October 2015.


Feinstein

The announcement last Monday came on the final day for public comment on the leak. Officials with the state Division of Oil, Gas and Geothermal Resources and the Public Utilities Commission have recommended that gas injections resume, but at reduced amounts and lower pressure levels than those requested by Southern California Gas.

More: *Los Angeles Daily News*

Doctor Calls for Study on Effects of Aliso Canyon Leak

A Porter Ranch physician is calling for a long-term medical study on the health effects of the four-month Aliso Canyon methane gas leak in October 2015.

Dr. Jeffrey Nordella, who has followed almost 50 patients since the leak, said he's seeing abnormal pulmonary functions in

Continued on page 29

STATE BRIEFS

Continued from page 28

some patients and low red blood cell counts in others. He also saw a rare case of anemia that could be connected to toxic exposure when he reviewed files of residents whose family members died.

Because the size of the leak (100,000 metric tons of methane) was unprecedented, there are no past studies or research on the health effects of such an exposure.

More: *Los Angeles Daily News*

INDIANA

Lawmakers Consider Bill to Lower Net Metering

In a move that critics say will muscle out small solar companies, state legislators began debate Thursday on a proposed law that would lock in a substantially lower rate of reimbursement for net metering than what is currently guaranteed.

Utilities argue the state's net metering compensation is unfair because it requires them to pay solar panel owners for power at retail cost, which is more than it would cost them to produce the energy. They also point out that solar panel owners use their infrastructure to feed their excess power to the grid and argue that they should receive compensation.

Ryan Zaricki, who owns a solar panel installation company in Evansville that employs five workers during busy months, said the legislation would put him out of business in the long term.

More: *The Associated Press*

MAINE

Lawmaker Seeks to Ban Wind Project off Monhegan Island

Republican Sen. Dana Dow has submitted a bill aimed at keeping a proposed wind energy test area from being built at a state-approved location off Monhegan Island.

Dow

Dow said the project threatens migrating birds and the remote, rugged beauty of the area.

The project's developers, a consortium that includes University of Maine, Cianbro and Emera, hope to erect two floating towers that would hold turbines with blade tips that could reach 600 feet above the water.

More: *Portland Press Herald*

Large Businesses See 19% Jump in Electric Service Costs

Two companies have threatened to leave the state and take 400 jobs with them because of an average jump of 19% in what large employers in the central and southern part of the state are paying for electric service.

The increase on their Central Main Power bills is being driven by factors including the conclusion of refunds for transmission line investments and added money for the Efficiency Maine Trust.

The hike comes at a time when wholesale electricity prices in the region have been falling, according to ISO-NE. In 2015, prices were at their second-lowest level since 2003. Moreover, the state had the lowest industrial energy rate in New England at 9.16 cents/kWh, compared with the national average of 6.6 cents/kWh, according to U.S. Energy Information Administration figures for November 2016.

More: *Portland Press Herald*

MASSACHUSETTS

Judge to Grant Tennessee Gas Access to Forest

Tennessee Gas Pipeline Company, L.L.C. a Kinder Morgan company

A Superior Court judge said last week he intends to authorize a $640,000 settlement between the state and Tennessee Gas Pipeline that would, among other things, pay for acquiring conservation land for a 13-mile pipeline extension project that would run through about 2 miles of Otis State Forest.

Under the settlement, $300,000 will go to the Department of Conservation and Recreation to acquire nearby conservation land; $300,000 will be used for improvements to Otis State Forest; and $40,000 will be used to compensate property owners who granted pipeline easements.

Local group Sandisfield Taxpayers Opposed to the Pipeline has requested a FERC hearing, but because the commission does not have a quorum, a decision as to whether to grant a hearing can't be made at this time.

More: *The Berkshire Eagle*

MICHIGAN

Officials Continue Discussions on Future of Palisades Plant

Consumers Energy and the Public Service Commission remain in discussions regarding Consumers Energy's plan to end an agreement to buy electricity from the Palisades nuclear plant, with the commission wanting to decide by Aug. 31.

In 2007, Consumers signed a power purchase agreement, scheduled to expire in April 2022, for nearly all the plant's energy after selling the facility to Entergy, which wants to close the plant in October 2018. Consumers wants out of its agreement by May 31, 2018. According to Entergy and Consumers, closing the plant early will result in $344 million in gross savings.

On Jan. 6, Consumers responded to a series of questions from the commission about alternatives to closing the plant and how that would impact reliability and affordability. On Jan. 20, the commission issued a second order seeking more information about cost savings, reliability and risk management.

More: *MiBiz*

OHIO

AEP to Stop In-person Notifications for some Customers

AEP OHIO

Some 437 angry power customers will no longer need to be notified in person that their electricity will be disconnected for nonpayment, regulators said Wednesday.

These customers, who have been labeled "Code Red" by AEP Ohio, have engaged in conduct that poses a risk to utility personnel, such as brandishing weapons, damaging utility vehicles and siccing their dogs on workers.

State law requires customers to be notified in advance of their power being shut off. "Here we strike a balance between two key interests, ensuring that consumers' rights

Continued on page 30

STATE BRIEFS

Continued from page 29

are protected — specifically that customers are given sufficient notice before disconnection — and protecting AEP personnel from those customers whose threats create a risk of potential harm," Public Utilities Commissioner Tom Johnson said.

More: *Columbus Business First*

OKLAHOMA

Fallin Proposes Taxing Wind Production, Nixing Incentives

Fallin

Gov. Mary Fallin last week proposed a tax of 0.5 cents/kWh on electricity from wind power. She also wants to end tax incentives for the wind industry earlier than planned.

The proposed wind tax is five times higher than that of Wyoming, which is the only state that presently taxes wind production.

Fallin's budget proposal does not specify how she will sunset tax incentives. A zero-emissions tax credit is scheduled to end Jan. 1, 2021. That, together with a five-year property tax exemption for wind turbines that ended Jan. 1, provided incentives amounting to about $90 million in 2015.

More: *The Oklahoman*

OREGON

Bill Boosting Small-Scale Renewable Projects Meets Resistance

Proposed legislation that would carve out a portion of the state's renewable portfolio standard for small-scale projects is encountering pushback from the state's two biggest utilities, major industrial users and the Citizens' Utility Board with arguments that it will drive up costs.

H.B. 2136 would change the small-renewables mandate to actual energy sold instead of capacity. It would also grow the mandate from 6% in 2020, to 8% in 2025 and up to 17% by 2040. Advocates maintain it will diversify energy resources and encourage economic development.

Portland General Electric, one of the bill's opponents, said the bill would trigger the RPS cost cap and that ultimately would result in fewer renewables that PGE could develop in an affordable way.

More: *Portland Business Journal*

RHODE ISLAND

Decision on Proposed Burrillville Power Plant Expected Feb. 16

State regulators are expected to decide on Feb. 16 an application by Invenergy to build a 1,000-MW fossil fuel-fired power plant in Burrillville over the objections of the town's attorney.

At an Energy Facility Siting Board hearing last week, the town and the Conservation Law Foundation argued Invenergy's application was deficient and should be dismissed. The town maintains that Invenergy's plan to supply water to the plant is not viable, while CLF says Invenergy has repeatedly failed to supply necessary information to state and local agencies charged with reviewing the project.

In a development that undercuts Invenergy's argument that the region needs the plant in Burrillville, the second half of its power output failed to clear in ISO-NE's Forward Capacity Auction last week.

More: *Providence Journal; Providence Journal*

SOUTH DAKOTA

House Passes Nuclear Waste Projects Bill

A bill that would require the Legislature to approve nuclear waste projects in the state cleared the House of Representatives last week by an almost unanimous vote and is headed for the Senate.

Current law allows only the governor to approve nuclear waste projects, with the Legislature in advisory role.

More: *Watertown Public Opinion*

MISO Auction Redesign in Limbo After FERC Rejection

Continued from page 1

Some stakeholders asked if the auction would remain status quo until FERC regains its quorum. (See *FERC OKs Pipelines, Delegation Order Before Losing Quorum*.)

In the interim, MISO attorney Jacob Krause said, commission staff can delegate letter orders only for "non-controversial" filings.

Tim Bachus, MISO capacity market administration analyst, said MISO's 2017/18 PRA continues on schedule with about 750 load-modifying and external resource registrations submitted to date. MISO will release preliminary PRA data on Feb. 26.

The RTO is also entering the upcoming auction with two proposed rules still unresolved by FERC. The first sets a 50-MW threshold for physical withholding that now applies across a company's affiliates, while the second excludes demand response, external resources and energy efficiency resources from market mitigation measures in the auction (ER17-806).

Seasonal, Locational Talk Revisited

A locational construct might have a place in the 2018/19 capacity auction, whatever form that takes, but a seasonal construct will be put on hold, MISO staff said.

The RTO still sees value in creating external resource zones that would clear in its capacity auction, but it needs to finalize price and offer caps as well as a detailed clearing methodology.

Laura Rauch, MISO manager of resource adequacy coordination, solicited stakeholder feedback on the necessity of external zones, reviving a discussion that was deferred last fall.

"There's still a difference in treatment between external resources and internal resources," Rauch said.

The locational construct would create external zones, revise capacity import and export limits so external resources do not affect them or clear against local clearing requirements, and create capacity transfer

Continued on page 31

MISO Auction Redesign in Limbo After FERC Rejection

Continued from page 30

rights.

MISO is currently concerned that external resources may displace local resources needed for reliability and lower initial local clearing requirements.

Indianapolis Power and Light's Ted Leffler said that, in reviewing stakeholder comments, he didn't see "gung-ho" support for a locational construct. David Sapper of Customized Energy Solutions did not see a problem with external resources, nor did he think MISO's proposal would motivate new external entry into the auction.

"I don't think we can rule out that we have a disconnect in our treatment," said Rauch, who explained that a resource in Florida delivering megawatts to Indiana is not recognized by MISO as actually being in Florida and therefore could displace local resources.

"You're counting resources as being outside of an area as physically located inside the boundaries," Rauch said. Sapper countered that there are also external resources "across a river" that were built specifically to serve load outside their zones.

MISO is also proposing capacity transfer rights primarily for internal resources alongside the introduction of external zones. Rauch said the proposal needs more work and stakeholder input on details that would factor into granting rights, such as market participant-funded upgrades, zonal boundary changes, and historical and new supply arrangements.

Chris Plante with Wisconsin Public Service said MISO's comparability issue between external and internal resources could be addressed with the addition of capacity transfer rights for internal resources.

Assuming a 2018/19 implementation, MISO expects to review Tariff language by June and file a proposal with FERC by July, Rauch said.

Bladen said work on seasonal auction planning would continue deferral until "the back half of 2017." MISO does not expect to begin talking about a seasonal aspect to the value of capacity until summertime, and Bladen said implementation would occur only after the locational aspect becomes practice.

MISO pursued auction seasonality largely because it thought gas-electric coordination would become a more significant issue, but recent developments — such as the stay and unlikely revival of the Clean Power Plan and Illinois' recent nuclear legislation — will slow portfolio evolution away from nuclear to a more gas-centric fleet. (See *Illinois Lawmakers Clear Nuke Subsidy*.) The RTO also said that last year's push for a two-season definition — a four-month winter and eight-month summer — might have neglected to account for increasing shoulder peak loads. Bladen said maximum generation conditions have recently occurred during shoulder peaks in MISO South.

Madison Gas and Electric's Megan Wisersky asked that MISO not make "wholesale changes" based on recent MISO South shoulder conditions that might be a one-time issue.

Bladen said the RTO will evaluate its resource availability before resuscitating seasonal talk.

"Our sense of the issues has evolved," Bladen said. "Whatever solutions might be identified, we expect them to come after locational issues are implemented.'"