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ISSN 2377-8016 : Volume 2017/Issue 36 September 12, 2017

McIntyre to Senate: 'FERC does not Pick Fuels'

By Michael Brooks

WASHINGTON — President Trump's nominee for FERC chair brought little comfort to Republican senators seeking assurances that, under his leadership, the commission would look into shoring up uneconomic coal plants.

"FERC is not an entity whose role includes choosing fuels for the generation of electricity," Kevin McIntyre, cohead of law firm Jones Day's global energy practice, said at his Senate Energy and Natural Resources Committee confirmation hearing Thursday. "FERC's role, rather, is to ensure that the markets for the electricity generated by those facilities proceed in accordance with law."

McIntyre was responding to a question from Sen. John Barrasso (R-Wyo.), who asked if he agreed with acting Chair Neil Chatterjee's belief that so-called baseload power — coal and nuclear plants — needed to be "properly compensated" to recognize their


Richard Glick (left) and Kevin McIntyre are sworn in at their Senate confirmation hearing. | © RTO Insider

value to "reliability and resilience." (See Coal Seeks 'Resiliency' Premium; FERC 'Fuel Wars' Coming?)

"I think, overall, the FERC's role should be to take a hard look at these very important questions and determine where FERC's jurisdiction actually gives it a role in making decisions that could ensure that there's a proper attention to the reliability and resilience impacts of what is traditionally thought of as baseload generation," he said.

Later, Sen. Angus King (I-Maine) urged McIntyre to "just go with the science" when it came to baseload generation, expressing concern that the term had become politicized.

"FERC does not pick fuels among different generating resources," McIntyre responded. "And so it's important that it be open to, as you say, the science, which I would expand somewhat also to include the characteristics of reliability and the characteristics of economics."

The other nominee being considered for the commission, Richard Glick, echoed McIntyre's position. He told Barrasso that a recent U.S. Energy Department study of the electric grid determined that the loss of baseload generation had not impacted reliability, "but they also suggested it was something to keep an eye on and look for in the future."

"So I think both FERC and the Department of Energy need to keep an eye on it and continue to study the matter," said Glick, currently general counsel for the Democrats on

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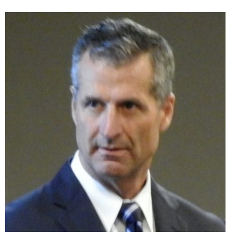
NYISO Stakeholders Talk Details of Carbon Charge

By Michael Kuser


NYISO CEO Brad Jones | © RTO Insider

ALBANY, N.Y. — NYISO stakeholders on Wednesday offered broad support for incorporating a $40/ton carbon charge into the ISO's markets, but some expressed concern over how the costs of New York's decarbonization effort would be allocated.

The comments came at a Sept. 6 public hearing jointly run by NYISO and the New

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Witnesses Offer Alternate Realities on Need for PURPA Reform

By Rich Heidorn Jr.


Terry Kouba, Alliant Energy

A House Energy panel last week heard two alternate realities on the need for reforming the 1978 Public Utility Regulatory Policies Act (PURPA).

The solar energy industry told members of the House Energy and Commerce Committee on Sept. 6 that the law remains as important as ever, despite federal subsidies, competitive markets and falling PV prices. Utility witnesses,

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IN THIS WEEK'S ISSUE

COUNTERFLOW
BY STEVE HUNTOON

Vogtle, the Law of Holes, and Two Modest Proposals


Huntoon

The Vogtle nuclear project in Georgia is looking like an object lesson in the failure of regulation (and a vindication of competition).

What went wrong? Traditional regulatory policy is that new utility investment didn't get billed to utility customers unless and until it's actually in service and thus "used and useful" to utility customers.

But nuclear advocates argued that the lead time and risk of nuclear plants were so great that construction costs ought to be guaranteed, and in some cases charged to utility customers, long before the plants are completed.

This fundamentally and completely changed the investment calculus for utilities interested in nuclear plants, with the potential for enormous returns on billions of dollars. The key was to get legislators and/or regulators to go along.

Once they did, nuclear plant development became a no-lose proposition for the utility.

Selling Vogtle

Vogtle is an example of the problem. If you go to Southern Co.'s Georgia Power website right now (at least when this column went to print), the utility tells you: "There are many great benefits to nuclear power: it's inexpensive…"[1]

Inexpensive? Lazard's highly regarded "Levelized Cost of Energy Analysis" of different energy sources shows nuclear at about *twice* the cost of the major competitors: natural gas combined cycle, wind and utility-scale solar.[2]

Georgia Power also claims Vogtle is needed because of future electric demand: "By 2030, electrical demand is projected to increase 27% in the Southeast."[3]

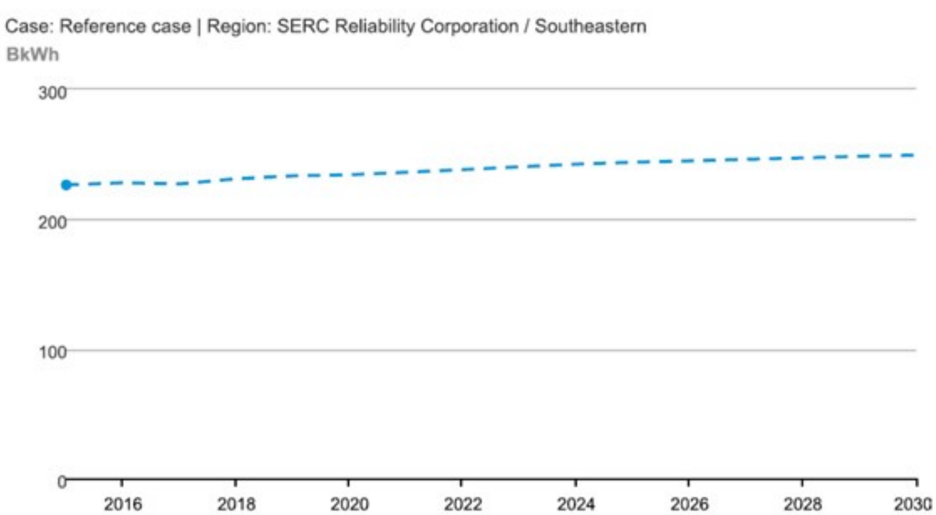
Below is the Energy Information Administration's projection of Southeast electric demand through the year 2030.

Do you see the 27% increase? Me neither.

If Vogtle ever made sense, that ended years ago when it became evident that natural gas prices would stay relatively low, that load growth would slow, and that Vogtle costs would escalate.

How Competition is Different

Competitive businesses pull the plug all the time on investments that aren't working out (as NRG Energy did for its proposed nuclear plant in Texas in 2011 — six years go — at no cost to consumers). But utilities don't have a reason to pull the plug if they win either way.



SERC Reliability Corp. regional electricity demand | *EIA*

This is the fundamental difference from competitive markets, where bad investments are investor burdens, not utility customer burdens.

The Georgia (Vogtle) and South Carolina (V.C. Summer) utilities kept on spending billions of dollars that their customers are on the hook for.

The Westinghouse Electric bankruptcy ripped the veil off the likely cost of completing the projects. Since the "inexpensive" and "load growth" justifications for the plants have disappeared, pulling the plug is the obvious resolution.

But as seen in South Carolina with the Summer project cancellation, there can be political blowback against cutting losses because so much has been spent already.[4]

This ignores the law of holes: If you're in one, stop digging.

$23.6 Billion in Excess Costs

Sunk costs are sunk (maybe they never should have been sunk, but they're sunk now). So they shouldn't be considered in deciding whether to keep digging — either as a reason to keep digging or as a reason to stop. Only future costs should matter.

Here's how to look at the "go"-"no go" decision on Vogtle: We start with Georgia Power's forecasted project cost for its 45.7% share, $12.17 billion,[5] and subtract its project costs incurred to date (sunk costs), $5.844 billion, for a net of $6.326 billion in "cost to complete" from this point forward.[6] Scale Georgia Power's cost to complete up for the other owners' shares to get the total project cost to complete, from this point forward, of $13.842 billion.

Add $700 million in income tax allowance for Georgia Power's return, to get $14.542 billion.[7]

Subtract a $745 million cancellation cost (avoided if Vogtle is not canceled) to get a $13.797 billion cost to complete less avoided cancellation cost. Do *not* subtract the Toshiba parent guaranty payments, because they are owed regardless of whether the project is canceled or not.[8]

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COUNTERFLOW
BY STEVE HUNTOON

Vogtle, the Law of Holes, and Two Modest Proposals

Continued from page 3

With me so far? Net project cost to complete, from this point forward, is $13.797 billion. Divided by 2,204 MW of net electrical output is $6,260/kW.

With that we can use Lazard's LCOE analysis to get a levelized cost of energy for completing Vogtle. The $6,260/kW cost to complete Vogtle is way above the low of $5,400/kW in Lazard's nuclear capital cost range.

So being favorable to a case for completing Vogtle, we can take the low end of Lazard's nuclear LCOE range, $97/MWh, and compare it to the midpoint of Lazard's natural gas combined cycle LCOE range, $63/MWh, for an excess cost of Vogtle of $34/MWh.

We can take that excess cost for Vogtle of $34/MWh, times 8,760 hours, times Lazard's 90% capacity factor, times Vogtle 2,204 MW net capacity, times 40 years, and conclude that the cost to complete Vogtle, from this point forward, would impose excess costs of $23.6 billion on Georgia consumers over the next 40 years.[9]

Non-Economic Justifications

With the economics of Vogtle long gone, non-economic justifications have emerged. For example, a Georgia Public Service Commissioner argued in an Aug. 18, 2017, *Wall Street Journal* op-ed that "nuclear reactors produce isotopes needed for medical imaging and cancer treatment."

The fact is that virtually all medical isotopes are produced in specialty reactors — not utility nuclear units.[10] The existing Vogtle units have never produced medical isotopes, and there are no plans for new Vogtle units to do so.

Then there is the fuel diversity argument. But Georgia Power says that it has "A Diverse Portfolio" now.[11] With little load growth (as shown above), and major coal plant retirements behind it, Georgia Power can't possibly need Vogtle to maintain a diverse portfolio.

And as for nuclear having carbon-free emissions, if that is a major consideration, wind and solar are about the half the LCOE under the Lazard analysis.

Two Modest Proposals

If the Vogtle owners and Georgia think nuclear power has unique and important value, here's a modest proposal. It is staggering in its simplicity: Exelon throws the Vogtle owners the keys to its Clinton and Quad Cities nuclear plants. The plug is pulled on Vogtle.

Think about it. Illinois consumers save $2.35 billion they no longer have to pay to save Clinton and Quad Cities, which Exelon would have closed without the subsidies.

Georgia consumers avoid $23.6 billion in excess costs they would bear by completing Vogtle.

Win-win.

Don't like that one? Here's another. Suspend Vogtle for 10 years. Georgia Power's consultant, Black & Veatch, estimated that would cost $112 million,[12] which is a dirt cheap way to hold off making a possible huge mistake. Georgia Power said it rejects that option because Westinghouse's AP1000 design isn't being pursued anywhere else "*in the United States*," and therefore Westinghouse would not maintain the design and vendors would stop making components.

Assuming for the sake of argument that design and component capability would be forever lost by deferral if no AP1000 reactors were to exist anywhere, that just won't be the case. Four AP1000 reactors are being completed in China right now, and more AP1000 reactors are planned elsewhere in the world.[13]

They just don't make sense here.

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

[1] https://www.georgiapower.com/about-energy/energy-sources/home.cshtml

[2] https://www.lazard.com/media/438038/levelized-cost-of-energy-v100.pdf (page 2). Lazard does not adjust for the capacity value of non-dispatchable intermittent resources like wind and solar. But the price difference between nuclear and wind/solar is so vast that even after adding some capacity cost, wind and solar would remain much cheaper than nuclear.

[3] https://www.georgiapower.com/about-energy/energy-sources/nuclear/overview.cshtml

[4] One Georgia Public Service Commissioner is quoted as saying: "I do want to see this project completed. I do not like to see failure." http://www.ajc.com/business/georgia-power-told-its-homework-vogtle-nuke-options/mnHqeJ7BdDza0U25xAxfbP/. I would submit that failure is making a decision that is not in the interests of Georgia consumers.

[5] Using Georgia Power's latest forecasted project cost is being favorable to a case for completing Vogtle, given the long history of underestimating project cost. The Vogtle owners recently selected Bechtel Corp. as the new construction contractor. It appears Bechtel has provided no cost or schedule guarantees.

[6] These figures are from Table 1.1 of Georgia Power's Aug. 31, 2017, filing with the Georgia Public Service Commission in Docket No. 29849, except that financing costs to date of $1.4 billion come from Southern's Form 10-Q for Q2 2017 (page 38). Financing costs must be included because capital isn't free. If financing costs are ignored, then among other things, two projects costing $1 billion in capital — one which takes 12 years to construct (like Vogtle) and one which takes three years to construct (like a natural gas combined cycle plant) — would be treated as equivalent.

[7] The *Atlanta Journal-Constitution* reports that Georgia Power's estimated financing costs, $3.4 billion, do not include an income tax allowance; the newspaper estimates financing costs with income tax allowance of $4.1 billion. http://www.myajc.com/business/georgia-large-power-users-save-hundreds-millions-plant-vogtle-charges/HDujkq5qiDx3GVotFcIS9L/. The income tax allowance is not applicable to the other Vogtle owners because they do not pay income taxes, so it is added to the total project cost to complete rather than scaled up for the other owners' shares.

[8] "The guarantee obligations continue to exist in the event of cancellation." Southern's Form 10-Q for Q2 2017 (page 38).

[9] Georgia Power presents completely different results in its recent filing with the Georgia PSC (referenced in a preceding footnote). But its numbers come out of a black box. And no analysis by a third-party economic consultancy is provided to inform or support the "go" decision of the Vogtle owners.

[10] http://www.nature.com/news/reactor-shutdown-threatens-world-s-medical-isotope-supply-1.20577

[11] https://www.georgiapower.com/about-energy/

[12] Exhibit 6 of above-referenced Georgia Power's filing with the Georgia PSC.

[13] http://www.reuters.com/article/us-westinghouse-nuclear-idUSKCN11M1Q7

CAISO NEWS

FERC Approves Powerex EIM Agreement

By Jason Fordney

FERC last week approved CAISO's agreement for integrating Canadian power marketer Powerex into the Western Energy Imbalance Market (EIM) (ER17-1796).

According to the Sept. 7 order, the ISO is working with Powerex to develop a participation framework that addresses the company's unique situation as a Canadian entity. Powerex is the marketing arm of provincially owned BC Hydro, a generation owner and transmission provider that operates under the jurisdiction of the British Columbia Utilities Commission.

"CAISO explains that BC Hydro will not assume a participant role or undertake commercial activities in the EIM," FERC said. "However, CAISO states that BC Hydro will supply certain data and information directly to CAISO that is needed for Powerex's participation." CAISO is developing a data sharing agreement for that purpose.

FERC staff last month provided qualified approval for Powerex's EIM implementation agreement but cautioned the plan could be subject to further scrutiny after restoration of the commission's quorum. (See *Wary FERC Approval for Powerex EIM Agreement*.) Powerex, which currently markets power across the U.S. and as far south as Mexico, brings the EIM increased access to about 17,000 MW of generating capacity, about 12,000 MW of which is hydro.

Powerex is slated to join the market in April 2018 and will pay a fixed implementation fee of $1.9 million, a figure based on the company's portion of the estimated $19.6 million CAISO would incur if it were to reconfigure its real-time market to incorporate all balancing authorities in the Western Electricity Coordinating Council.

Southern California Edison, Pacific Gas and Electric and other EIM participants raised concerns about provisions in the implementation agreement that could require modification to include participation by additional parties, as well as potential changes to the EIM framework needed to integrate the company into the market.

FERC said those concerns are "premature, given that CAISO and Powerex have not yet developed or proposed the specific terms and conditions of the framework under which Powerex will participate."

"We expect CAISO to follow through with its commitment to consider the issues raised by commenters and to engage in outreach and dialogue with interested stakeholders as the framework is developed," the commission said.

The participation agreement framework will allow voluntary offers from residual BC Hydro generation, intra-hour deviations in load and generation in the BC Hydro balancing authority area and transmission arrangements to support EIM transfers.

CAISO NEWS

Monitor Critical of CAISO Commitment Cost Mitigation Plan

By Jason Fordney

CAISO's Department of Market Monitoring on Friday amplified its opposition to a fundamental aspect of the ISO's plan for mitigating market power in generators' commitment costs.

The department told the Market Surveillance Committee on Friday that it "fundamentally disagrees" with the Commitment Cost and Default Energy Bid Enhancements (CCDEBE) initiative. The program, which CAISO Senior Market Policy Developer Cathleen Colbert outlined in a presentation, is designed to better reflect unit commitment costs and overhaul how the ISO calculates the default energy bid (DEB) used for units with market power.

The Monitor had previously raised concerns with the CCDEBE proposal, which would apply to both the ISO and the Western Energy Imbalance Market (EIM). (See *CAISO Monitor Says Bid Rule Changes Flawed*.)

The debate has large financial implications for EIM power sellers subject to default bidding, such as Berkshire Hathaway Energy entities PacifiCorp and NV Energy, which last month asked FERC to lift their DEB restrictions. (See *Berkshire Companies Request EIM Rate Authority*.) The restrictions also apply to Arizona Public Service.

"We think there are a lot of questions left on the dynamic mitigation," the department's Michael Castelhano said. The Monitor has urged splitting the proposal into two parts and getting a new process for reference levels in place by fall 2018. Then commitment cost bidding and mitigation could be addressed "in a more robust way than we have been able to do so far," Castelhano said.

The ISO has suggested it will use a static competitive path assessment (CPA) on a seasonal basis to determine which constraints should be tested for commitment cost market power. In other CAISO proceedings, stakeholders have proposed eliminating the CPA because it is designed for the seasonal level and not a daily or hourly market.

The static CPA often fails to capture market power for commitment costs, which potentially has more financial impact than missing market power for energy costs, Castelhano said. "You will never get the models right," he told ISO officials.

"Conceptually, we would support the opposite approach," he said, which would assume the paths are competitive unless proven otherwise. "We really think that is the right thing to do in this situation."

"We think it is really important that this is vetted and [discussed] in the stakeholder process," Castelhano added. He said it appears the ISO is adapting energy market mitigation methods for commitment costs.

Energy market mitigation has to do with the effect of market power on LMPs, while commitment cost mitigation asks how different constraints affect the likelihood of a resource to be committed, he said in the presentation. "You are not starting with the right question," he told ISO officials.

CAISO says its goal is to submit the proposal to the EIM Governing Body for an advisory vote on Oct. 10 and to the Board of Governors for approval on Nov. 1.

CAISO NEWS

EIM Participants Seek Resource Test Tweaks

By Jason Fordney

SEATTLE — Western Energy Imbalance Market (EIM) resource sufficiency tests are generally working, but fluctuating load forecasts are a major challenge in passing the tests, market participants said in a regional forum Thursday.

Participants in CAISO's regional EIM market must pass a series of resource sufficiency tests, including a balancing test for energy, a capacity test and a flexibility ramping test. Market participants discussed possible enhancements at the Regional Issues Forum held in conjunction with the EIM Governing Body meeting the day before.

The forum meets three times a year and includes 10 representatives from various sectors who discuss topics outside of the normal ISO stakeholder process. The sectors include transmission-owning utilities; power producers and power marketers; public interest groups; publicly owned utilities; and neighboring balancing authorities.

The EIM is integrated with CAISO's market but only includes the ISO's real-time functionality and not that for the day-ahead market. The sufficiency test is one of a series of processes meant to ensure that EIM entities have sufficient generation to supply the real-time market in the absence of providing day-ahead schedules. (See *CAISO: Don't Lean on EIM for Capacity*.) The ISO performs the test ahead of the market run for each operating hour.

While the general structure of the resource sufficiency framework is sound, it could be enhanced, said Powerex trading manager Mike Goodenough. Powerex does not yet participate in the EIM but is slated to join next April. FERC on Thursday approved the company's implementation agreement for joining the market, which was first conditionally approved by FERC staff in August. (See *Wary FERC Approval for Powerex EIM Agreement*.)

Goodenough said the level of required resource sufficiency should not be changed because different balancing authority areas (BAAs) have different capacity and flexibility challenges. Raising the requirement might increase costs for entities that don't have surplus capacity, and decreasing it might reduce flexibility costs but remove opportunities to sell capacity and energy.

The workability of the program could be improved, and "we think we should work toward getting more transparency and metrics around those tests," Goodenough said.

Possible improvements include adjusting the timelines of the tests so entities know their specific requirements and can obtain needed capacity or flexibility. There are questions as to whether some BAAs are failing in hours when they should have passed, and others are passing when they should have failed, he said. He suggested more granular data from CAISO and historic analysis by the Department of Market Monitoring on whether the required quantities have been consistent with demand and imbalance requirements in BAAs.

Arizona Public Service's EIM project manager Moe Sakkijha said his utility worked with CAISO to address the fact that the ISO's load forecasts can fluctuate up to 300 MW. APS in June also began providing the ISO with hourly load forecasts to assist in modeling. CAISO has agreed to freeze the load forecast to help with the resulting uneconomic dispatch, Sakkijha said, but he is not sure when the ISO plans to implement the change.

"A very important issue for the EIM entities was freezing of the load forecast," he said. APS is also bidding solar and wind resources into the EIM to improve the results for the sufficiency tests for capacity, balancing and flexibility. The company is working with some utility scale solar sources to be able to automatically respond.

Left to right: Anderson, Sakkijha and Goodenough | © RTO Insider

Kathy Anderson, Idaho Power system operations leader, said that her company has not begun participating in the EIM but already has some concerns. (See *Idaho Power Inks Agreement to Join Western EIM*.)

"A lot of conversations with the entities that are live [in the EIM] give me some concerns, especially when we start talking the moving target of the load, and chasing that," she said. Idaho Power has hydro, wind, natural gas and coal, but a lot of EIM resources will be non-run-of-river hydro.

Idaho Power also plans to have one coal plant and some natural gas participate in the EIM, but not its wind and solar. The hundreds of megawatts of wind and solar in its BAA under Public Utility Regulatory Policies Act contracts can only be dispatched for reliability. Hydro flexibility limitations because of fish protection requirements and other regulations at its 1,400-MW Hells Canyon facility will be one challenge in passing resource sufficiency tests, and the plant is also affected by seasonal challenges, and regulations.

The changing load forecast is a big issue, she said, and "it is hard enough to be a balancing authority without continually chasing a number just to pass the test," she said.

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CAISO NEWS

EIM Body Approves Generator Loss Modeling Plan

By Jason Fordney

SEATTLE — The Western Energy Imbalance Market (EIM) Governing Body on Wednesday approved a CAISO proposal allowing market participants to take part in a program that models generator outages and the impact of remedial action schemes (RAS) on market operations.

© RTO Insider

Cooper

The current market structure only addresses cases in which a transmission line goes down, potentially causing overflow on other lines. The new method reflects how the system will react to the loss of generation, CAISO Manager of Market Policy Design Brad Cooper said at the Governing Body meeting.

"It should result in a much more efficient market solution than just using offline tools and manual actions," Cooper said, and be "more efficient and transparent as to what is happening." The CAISO Board of Governors will vote on the rule changes later this month, after reviewing a more comprehensive package that would bring the measures into the ISO's day-ahead market. The changes must also be approved by FERC.

The ISO currently uses manual, out-of-market dispatches to manage generator contingencies and RAS, which are protective processes that automatically disconnect generators or load in order to prevent transmission line overload in the event that another line goes out. The new method will update the ISO's security constrained economic dispatch by modeling the loss of generation within the dispatch, as well as modeling the loss of transmission and generation because of RAS operations. The program effectively incentivizes generator participation in RAS.

"The proposed changes result in an update to the congestion component of the locational marginal price so that it considers the cost of positioning the system to account for generator contingencies and remedial action scheme operations," the ISO said in its final proposal. "A remedial action scheme-connected generator will potentially receive higher energy prices than generators not connected to a remedial action scheme at the same bus because a remedial action scheme-connected generator does not contribute to binding emergency limits."

CAISO says the new method will better reflect congestion in localized prices and improve generator dispatch.

Market participants had some misgivings about the new functionality when it was unveiled by CAISO. (See *Stakeholders Wary of CAISO Contingency Modeling*.) The ISO first presented the proposal in an April 2016 issue paper and drafted a final draft proposal on July 25 of this year.

> **"It should result in a much more efficient market solution than just using offline tools and manual actions."**
>
> **Brad Cooper, CAISO**

Allowing EIM entities to model generator contingencies and RAS falls within the Governing Body's "primary" approval authority, while it approved the general design of the proposal under its "advisory" capacity. CAISO's Market Surveillance Committee and Department of Market Monitoring support the new program.

Southern California Edison expressed concerns over what it considered to be the anomalous effects of the changes on CAISO's interconnection process — but that would not apply to EIM entities not subject to that process, Cooper said.

"We disagree with Southern California Edison in any case," regarding the effects of the new functionalities, he said.

Governing Body Chairman Doug Howe asked if the modeling would be totally voluntary and queried Cooper as to the trade-off between the benefit and cost of the proposal.

"That is something we consider in everything we develop," Cooper said. "We are convinced that the benefits justify the costs." He confirmed the program is voluntary and is part of larger improvements to market operations.

ERCOT NEWS

Seasonal Forecasts: Sufficient Generation for Fall, Winter

ERCOT's latest resource adequacy forecasts project the Texas grid will have sufficient installed generating capacity this fall and winter, despite the destruction wrought by Hurricane Harvey.

Pete Warnken, ERCOT's manager of resource adequacy, said staff studied several scenarios that could affect the availability of generating resources. The results were favorable.

"[We] do not currently anticipate any systemwide issues," Warnken said in a statement Thursday. "Even in the most extreme scenarios considered, there were ample operating reserves."

The fall seasonal assessment of resource adequacy (SARA) report shows nearly 86 GW of capacity available for a predicted peak demand of just over 56 GW. The final fall SARA, covering October and November, includes 3 GW of new generation added since the preliminary report in May.

Exelon accounted for 2.2 GW of the new generation, adding gas-fired combined cycle units at plants near Houston and Dallas. More than 837 MW of new wind and solar resources are expected to contribute 374 MW to covering the fall peak, based on capacity factors.

The preliminary winter SARA report projects a record peak of more than 61 GW, beating ERCOT's all-time record of 59.7 GW, set in January. The report, covering December through February, anticipates almost 85 GW of capacity being available.

ERCOT will release the final winter SARA in early November.

Harvey Restoration Efforts Continue, but Numbers Down

ERCOT said last week that while Hurricane Harvey's restoration efforts will continue for an "extended period" in some areas, the number of affected transmission facilities and generation resources has decreased considerably since the storm hit the Texas Gulf Coast on Aug. 25.

The ISO said Friday that one 345-kV line still remains out of service. However, the grid has remained stable and the competitive markets have continued to operate normally, it said.

Most of the remaining outages are in Rockport and Aransas Pass, where the storm's eye made landfall. AEP Texas said 15,000 of its remaining 16,600 outages were in the Rockport-Aransas Pass area as of Friday afternoon. The utility said it may take an "extended amount of time" to reconnect power to some homes and businesses damaged by Harvey.

CenterPoint Energy said about 3,200 customers remained without power in the Houston area Friday afternoon. The utility has been forced to route power from a flooded distribution substation to a nearby temporary substation in west Houston.

Most of CenterPoint's customers without service live near the overloaded Barker Reservoir. The U.S. Army Corp of Engineers has been releasing water to save the reservoir's structural integrity.

Entergy reported about 2,300 customers out of service in Southeast Texas as of Friday afternoon.

Southern Cross Offers Suggestions for its Market Participation

Stakeholders on Thursday discussed potential definitions and market participant categories during a workshop for the Southern Cross Transmission Project, which could become ERCOT's first merchant DC tie operator.

The ISO does not currently include DC tie operators as market participants, but the project's developer is working to define language that would allow the proposed DC tie with the Eastern Interconnection to take

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ERCOT NEWS

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part in the market. The HVDC transmission project would be capable of shipping more than 2 GW of electricity between the Texas grid and Southeastern markets.

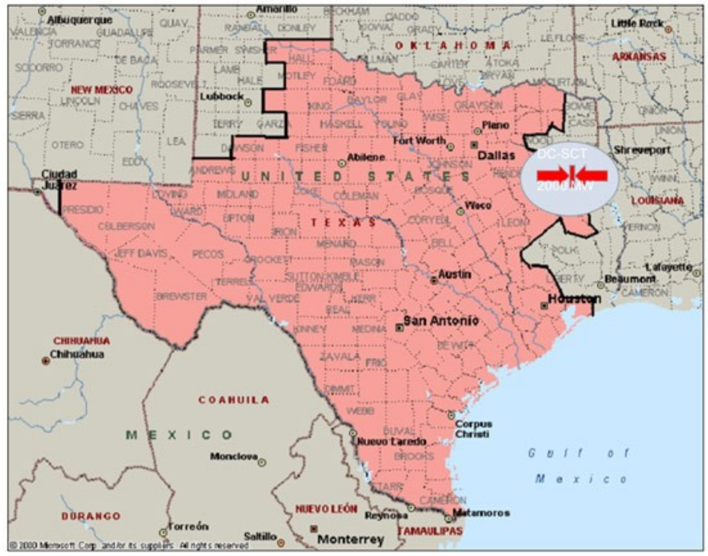
"There's a way to do this that would probably make sense," Cratylus Advisors' Mark Bruce said, speaking for Southern Cross Transmission (SCT). "We have a bunch of boxes that Southern Cross can't check [on the market participant agreement form]. [The tie] doesn't serve load, [and] it doesn't buy or sell energy. 'DC tie operator' would describe the function we're registering for. We think that's a good place to start."

The project would link ERCOT to the Eastern Interconnection through a 345-kV line, owned by Garland Power & Light, that connects with a convertor station just across the Louisiana border. SCT would build a 400-mile, 500-kV DC line to connect with Southern Co.'s existing 500-kV system in Alabama.

SCT envisions ERCOT qualified scheduling entities (QSEs) buying capacity on the line similar to how they do on the ISO's existing five DC ties. The company would not participate in the settlement process, but the QSEs would. Southern Cross would not have a Texas tariff or collect transmission rates, leaving the QSEs responsible for paying transmission service charges for use of the ERCOT system.

"Users of the Southern Cross line are going to pay for this equipment in the capacity charge. ERCOT ratepayers aren't going to be paying for any of this," Bruce said.

He suggested protocol language for a DC tie operator as a market participant that "has completed applicable registration and approval for the purpose of operating a DC tie interconnected to the ERCOT transmission grid." Bruce also drafted bylaw language for a definition of an independent DC tie operator, suggesting it be any transmission and distribution entity or affiliate that "owns or operates" a DC tie interconnected to ERCOT's grid or is "preparing to own or operate" such a tie.



Southern Cross DC tie | *ERCOT*

Bruce said SCT would fit best in ERCOT's investor-owned utility segment. He pointed out the company is investor-owned and a "public utility" under the Federal Power Act, although not under Texas law. Its only function in ERCOT is operating a high-voltage transmission facility, he said.

ERCOT staff will now work with SCT to develop and submit the appropriate revision requests to the Protocol Revisions Subcommittee for its November meeting. Market participants were invited to provide feedback and input from the workshop, along with other comments for consideration prior to sponsoring the appropriate revision requests.

The Public Utility Commission of Texas opened a pair of dockets for the SCT proposal. Docket 45624 approved Garland P&L's application for the 345-kV line, which has an established route. Project 46304 establishes the PUC's 14 directives for integrating and operating the project as a part of the ERCOT system and within its market construct.

Southern Cross obtained final FERC 210/211 orders and agreements in 2014 for interconnection to and transmission service in ERCOT that maintain its FERC jurisdictional status quo.

Developers hope to begin construction in 2019 and commercial operation in the third quarter of 2022. They are working to obtain a siting certificate for the line's Mississippi portion from the state's Public Service Commission. Louisiana does not require a siting certificate.

— Tom Kleckner

ISO-NE News

ISO-NE Visits Vermont to Discuss Tx Planning

WOODSTOCK, Vt. — ISO-NE officials came to Vermont on Thursday to discuss how FERC Order 1000 has affected transmission planning in the region.

ISO-NE Vice President for External Affairs and Corporate Communications Anne George gave a presentation on the grid operator's role in implementing Order 1000, along with updates on the RTO's preparations for Forward Capacity Auction 12, the Integrating Markets and Public Policy (IMAPP) initiative and its 2018 budget.

Vermont Gov. **Phil Scott** also addressed the Sept. 7 meeting of ISO-NE's Consumer Liaison Group.

Here are the highlights of what we heard.

Order 1000 and Public Policy Tx Projects

In April, the D.C. Circuit Court of Appeals rejected separate challenges by New England Transmission Owners and state officials to Order 1000, including FERC's elimination of federal rights of first refusal (ROFR) for incumbent transmission owners and one aspect of the public policy transmission planning process. (See Court Rebuffs New England TOs, Upholds FERC ROFR Order.)

Jason Marshall, general counsel for the New England States Committee on Electricity (NESCOE), said during a panel discussion that the ruling on the public policy process, while denying the petition, had "at least provided what we wanted: a ruling that ISO New England does not have to choose a public policy project as part of the Order 1000 process."

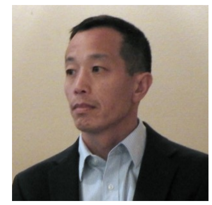
The court also ruled that "ISO-NE has no role in setting public policy for the states."

Liaison Group Chair **Rebecca Tepper**, chief of the energy and telecommunications division in the Massachusetts attorney general's office, brought up the transmission projects proposed in response to the Massachusetts solicitation for 9.45 TWh a year of Class I renewables (wind, solar, hydro or energy storage). (See Hydro-Québec Dominates Mass. Clean Energy Bids.)

"What's confusing to people is that none of these projects are 'public policy' projects that have gone through the Order 1000 process," she said. "People are trying to understand what kinds of projects these transmission projects are [under the FERC Order 1000 construct] and who's going to pay for them."

ISO-NE Consumer Liaison Group crowd | © RTO Insider

Marshall responded that if a transmission project arises out of a state-run request for proposals, it would be one of two types. "It could be a public policy upgrade, which has to go through the Order 1000 process. Alternatively, it could be an elective transmission upgrade, and that's a separate category that's not regionalized, not socialized across New England to all consumers. That's the difference."



Colin Owyang, general counsel of Vermont Electric Power Co. (VELCO), said he believed that the Massachusetts projects were mostly outside the three categories. "I think of the public policy upgrades as regional public policy decisions, so if there were a New England governing body ... and if they were to collectively agree on a mutually acceptable public policy, then it would go through the [Order 1000] process."

In addition to its own RFP, Massachusetts has teamed with Connecticut and Rhode Island on a separate solicitation. (See *Second Circuit Upholds Conn. Renewable Procurement Law*.)

Owyang said that states may have believed that if they went through FERC's process, they would lose control of projects. As a result, he said, that's why he thinks they run their own RFPs "over on the side."

Developer Balancing Act

VELCO negotiated the compensation to Vermont — a total of $136 million spread evenly over 40 years — for the New England Clean Power Link, which includes a submarine cable under Lake Champlain and a smaller overland section connecting with a substation in Ludlow. Transmission Developers Inc. has fully permitted the project to bring 1,000 MW of hydropower, solar and wind from Canada with its partner, Hydro-Québec. The Vermont section of the line is 154 miles long.

Another developer, Stephen Conant of Anbaric, asked how developers could justify making Massachusetts residents pay a "tax" to Vermont for letting energy cross the latter state. Owyang said he would not put it so "flippantly," calling the payments fair

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ISO-NE NEWS

ISO-NE Visits Vermont to Discuss Tx Planning

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compensation and a necessary cost of doing business.

"As a developer, what you have to balance is how do you get your project developed [and] how do you get it built on time," added TDI CEO Donald Jessome. "There's going to be costs, whether those are capital costs or operating costs, property taxes — you could go down a whole laundry list of different issues that you have to take into account. Ultimately, if the benefits don't outweigh the costs of the project, you're just not going to go forward.

"There are going to be costs, there are going to be community issues and we have to take all of that into account," Jessome continued. "If we priced it wrong, we will lose the [Massachusetts] RFP."

Mary Ellen Paravalos, vice president for ISO, siting and compliance at Eversource Energy, also appeared on the panel moderated by Guy Page, communications director of Vermont Energy Partnership.

Vermont's Clean Energy Economy

Gov. Scott said that one in 16 workers in Vermont are employed in clean energy, the highest ratio of any state in the U.S., he said.

"We're going to need all those workers and all that knowledge because we have a goal of getting 90% of our energy needs from renewable resources by 2050," he said. "As daunting as that might sound, I believe it's achievable."

Scott highlighted how investments in clean energy are also changing the state's electric grid, which frequently sees its lowest net load in the middle of the afternoon because of the amount of solar on the system. The peak hour is now after sunset, once the solar resources stop producing.

As the state encourages people to switch to electric vehicles, the resulting increase in electrification calls for smarter load management and rate design, partly "to ensure that we don't increase peak demand or make the Northeast less competitive than it already is in terms of rates," Scott said. "Also, when we talk about changes in how people consume power, we need to be certain we aren't hurting the most vulnerable. We can't have regressive policies that add costs onto people who can't afford to pay, or hurt folks who are working third shift, for instance, and can't change the timing of their electrical usage."

Scott said that while modernizing the grid and how people use electricity, planners shouldn't ignore more traditional resources such as baseload hydroelectric. Vermont has a long history of working with Hydro-Québec, he noted.

"We first started importing power from Quebec in the late 1980s through Highgate, Vt.," Scott said. "A few years later we hosted the first DC line into New England from Quebec through the Northeast Kingdom of Vermont [Essex, Orleans and Caledonia counties], and through to northwestern New Hampshire. We now have a number of companies looking to use Vermont as a conduit to transfer more power from Quebec to help our friends and neighbors in Massachusetts. And as unbelievable as this may sound to anyone who has done work in this state, Vermont has already fully permitted one of those projects, TDI's Power Link."

Scott said that TDI worked with host communities and "now enjoys significant support in our state and a clear path to construction. In my view, the Clean Power Link is a smart, common sense and very affordable solution for Massachusetts and New England. It provides economic and environmental benefits for both states, and it shows how a region can work together to accomplish energy goals."

— Michael Kuser

ISO-NE News

ISO-NE Files Cluster Study Rules; Window to Open in Nov.

By Rich Heidorn Jr. and Michael Kuser

ISO-NE hopes to open a window in November for Maine wind generators interested in joining a cluster interconnection system impact study. The RTO filed its proposed clustering methodology for FERC approval on Sept. 1, requesting approval by Nov. 1 (ER17-2421).

The filing culminates an 18-month effort to assess new 345-kV AC transmission circuits that could connect to areas in northern and western Maine with the largest number of requested new generation interconnections. (See *ISO-NE to Offer Clustered Interconnection Requests in Maine*.)

System Planning Director Al McBride presented a description of the filing and the study plans at Wednesday's Planning Advisory Committee meeting.

The clustering approach will involve two phases: a regional planning study, followed by a cluster system impact study of multiple projects that will share the costs for common upgrades.

The Maine Resource Integration Study will be used as the regional study for the first two clusters being considered for development:

- A radial double-circuit 345-kV AC line between the Maine Yankee generating plant to a new substation at Pittsfield, with a new 345-kV line and three additional substations north of Pittsfield and ending near the Canada border. The estimated cost is $1.31 billion.
- A radial 345-kV AC line north of the Larrabee Road substation to near the New Hampshire border at an estimated cost of almost $521 million.

The estimates include a shared cost of $108 million for a new 345-kV line from Coopers Mills to Maine Yankee (line 392) that is needed by both radials. Costs would be allocated using the distribution factor methodology or the late-comer cost allocation rules.

The latecomer provision was developed to prevent free-riders with later interconnections from making use of the clustering upgrades. It would require interconnection customers that connect within 10 years of the cluster upgrade's in-service date to share in the cost of the upgrades.

Planners estimate the combined clusters could accommodate about 1,900 MW of generation with a maximum of about 1,200 MW on either radial.

The northern cluster projects could accommodate up to 350 MW of additional generation without any new lines south of Pittsfield, assuming the Surowiec-South line remains at 1,600 MW. The maximum is limited by N-1 and N-1-1 violations on lines south from Orrington. Doing the project without the double circuit while increasing Surowiec-South to 2,200 MW would permit 675 MW in additional generation.

The clustering methodology received support from 95% of the Participants Committee in February.

Generators joining the study will be required to post a "very significant financial commitment" — the lesser of $1 million or 5% of the customer's estimated costs for the upgrade, McBride said.

If either cluster is less than fully subscribed, the RTO will allow resources to withdraw to avoid a higher cost allocation.

"If the cluster doesn't fill … we're going to be continuing coming back to the PAC" for other solutions, including a potential HVDC project, said McBride.

The RTO also could open a second cluster window next year following the award of contracts in Massachusetts' solicitation for 9.45 TWh a year of Class I renewables (wind, solar, hydro or energy storage). The winning projects are scheduled to be chosen by Jan. 25, with contracts completed and sent for state regulators' review by April 25. (See *Hydro-Québec Dominates Mass. Clean Energy Bids*.)

McBride said ISO-NE doesn't want to delay the first study window until after the solicitation because of the number of Maine wind generators ineligible for the cluster study whose interconnection costs might be affected by the cluster projects. "Their studies shouldn't be held up any further," he said.

FERC Orders Tech Conference on Algonquin No-Notice Changes

By Michael Kuser

Responding to protests by National Grid, energy shippers and local distribution companies in New England, FERC on Friday ordered a technical conference on Algonquin Gas Transmission's proposal to change the terms of its no-notice services (RP17-808).

In June, Algonquin asked the commission to approve an update its no-notice services, last changed in 1993, to reflect its "current practices and operational requirements" and eliminate requirements the company said have become outdated with automation and faster forms of communication.

The changes would clarify that customers under Algonquin's AFT-E and AFT-ES rate schedules seeking no-notice service must have nominated and scheduled an equal quantity of gas on a pipeline upstream of Algonquin for that day.

It also would specify that the right to change primary delivery points under AFT-E/ES only applies to temporary capacity releases.

On July 27, commission staff issued a delegated order accepting Algonquin's filing but suspending the changes until Jan. 1, 2018, subject to refund and further commission order.

Janice K. Devers, Algonquin's director of tariffs, told *RTO Insider* that "the commission's directive to convene a technical conference was not a surprise. There is a probably a desire on their part to get clarification on the issues prior to the end of the suspension period on Jann. 1, 2018."

Energy shippers Direct Energy Business Marketing and Shell Energy North America

Continued on page 14

ISO-NE News

PAC Briefs

Tx Planning Guide Revised with Addition of Probabilistic Methods

Stakeholders will have 15 days to comment on ISO-NE's reorganized transmission planning guide, which will reduce the existing guide's more than two dozen sections to four. It will be organized like a transmission needs assessment or solutions study report: Introduction; Modeling Assumptions; Reliability Criteria and Guidelines; and Analysis Methodology.

Lead engineer for system planning Steve Judd, who presented the new guide to the ISO-NE Planning Advisory Committee on Wednesday, said the need for the reorganization became apparent when staff found it difficult to identify the proper section for adding a new probabilistic methodology for creating base case dispatches.

Since the guide's creation in 2013, Judd said, new information was added as additional sections at the end of the document. As a result, the current guide's 26 sections are "in no cohesive order," he said.

The new methodology (section 2.2.2 of the revised guide) aims to develop a "same-probability" curve to describe the combined likelihood of certain levels of load and generation unavailability.

Planners will use the curve to determine the representative amount of generation in megawatts to be modeled as out of service in the transmission needs assessment for the study area. Instead of modeling a particular number of generators out of service, the new concept models a representative quantity of generation as being unavailable.

Planners based the load level probability on the most recent capacity, energy, loads and transmission (CELT) forecast and 17 summer weeks of distribution curves.

The 15-day comment period will be triggered when the guide is posted, Judd said.

Stakeholders Seek Briefing on SOARES

Analysts conducting ISO-NE's 2017 System Operational Analysis and Renewable Energy Integration Study (SOARES) will brief PAC stakeholders at a future meeting, Director of Regional Planning and Coordination Michael Henderson said.

Stakeholders requested the briefing by professor Amro M. Farid and his team at the Thayer School of Engineering at Dartmouth after Henderson reviewed the SOARES scope of work Wednesday.

ISO-NE spokeswoman Marcia Blomberg called SOARES "a key element" of Phase II of the 2016 New England Power Pool Scenario Analysis/Economic Study, which is focused on regulation, ramping and reserves. The study will address the reduction in traditional thermal generation that provide inertia and other reliability services.

No date has been set for the briefing. The SOARES project is expected to be completed by the end of the year.

Eversource Spending $22.7M to Replace 3 Transformers

Eversource Energy presented its plans to replace three aging transformers at a cost of a cost of about $22.7 million.

Eversource Director of Transmission System Solutions Bob Andrew said the three

	Generation/Supply	Load/Demand
	Past	
	Thermal Units – Few, Well-Controlled, Dispatchable Resources	Conventional Loads – Fairly slow Moving, Highly Predictable, Always Served
	Future	
Well-Controlled & Dispatchable	Thermal Units – Potential Erosion of Capacity Factor	
Stochastic/Forecasted	Solar & Wind Generation – Variability can cause unmanaged grid imbalances	Conventional Loads – Continuing source of variability and uncertainty

Fundamental changes in grid dynamics | *Thayer School of Engineering*

are among eight General Electric transformers aged 30 to 45 years in its system, half of which have shown significant deterioration. One, at Scobie Pond, N.H., was replaced after it failed in March following a short-lived refurbishment. Two new units will replace transformers at Littleton and Deerfield, N.H. In addition, a new spare transformer will be purchased to replace one that took the place of a fourth aging unit.

Cost allocation for the new transformers will be subject to review by the RTO's Reliability Committee, Andrew said.

The four transformers' internal insulation had deteriorated, resulting in the formation of methane and ethane in the transformers' oil. Eversource will monitor the remaining four GE units for future trouble.

Andrew said the RTO has discussed the issue with GE. "The response was typical of the [original equipment manufacturer] with 30-year-old equipment: 'Of course, you should buy one of our new transformers and replace it.'"

— Rich Heidorn Jr. and Michael Kuser

FERC Orders Tech Conference on Algonquin No-Notice Changes

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claimed the revisions to rate schedules AFT-E and AFT-ES would unnecessarily limit the availability of no-notice service by implementing more restrictive eligibility criteria, undercutting the commission's policy of providing shippers with greater scheduling flexibility.

National Grid asserted that Algonquin had failed to show that the proposed tariff changes are just and reasonable. The company also said that it relies on the right to call on reserved capacity on an intraday basis without needing to submit nominations prior to the start of the gas day. The company said that helps it meet shifting daily demand from its predominately low-load-factor residential and small commercial customers.

Sprague Operating Resources, which operates refined products and materials handling terminals, filed a letter in support of the protests.

In its Sept. 1 order, the commission said it lacked enough information to determine whether Algonquin's proposed tariff changes are just and reasonable. The commission said that discussion at the conference would not be limited to the issues identified in the order.

MISO NEWS

MISO Makes Case for $130M Market Platform Upgrade

By Amanda Durish Cook

CARMEL, Ind. — MISO's proposed multi-million-dollar spend to upgrade — and then replace — its market platform will yield a nearly threefold return within 12 years, stakeholders heard this week.

Ramey

The $130 million invested to extend the current system and implement a new platform would reap $341 million in net benefits by 2030, MISO Vice President of System Operations Todd Ramey said during a Sept. 6 workshop in which RTO officials laid out the business case for replacing the system.

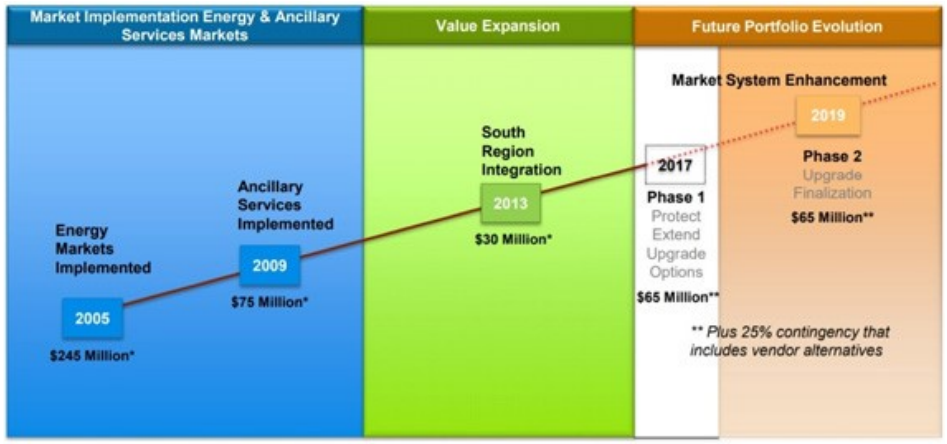
MISO's Board of Directors in June approved the first phase of the upgrade, enabling the RTO to commit $65 million to lengthen the life of its current market platform by at least five years. Another $65 million will be needed to create a new, modular market platform, the final design for which is slated to emerge in 2019. (See *MISO Sets Target for Market Platform Upgrade Decision*.)

Countdown to Obsolescence

Since 2005, MISO has spent about $350 million to develop and expand its market system, which was built using technology from the 1990s. The RTO predicts it has five to seven years before evolving cybersecurity standards and increasing market complexity render the system obsolete, no longer able to clear the day-ahead market. Current vendor General Electric also plans to end support for the existing platform around that time.

Early-stage prototypes of the new computer system will be released in 2018 and 2019 for stakeholder scrutiny, said MISO Executive Director of Market Design Jeff Bladen. The RTO will begin to swap out market components by 2020 and fully migrate to the new modular computer system by 2023, he said.

"The goal is for a modular system ... that is much less brittle than the existing system," Bladen said, adding that the new system will shed the "hub and spoke" software format of the current system in favor of a "data integration layer" that can run several applications simultaneously while isolating the impacts of market changes so other programs are not affected.



MISO market timeline | *MISO*

Bladen said MISO's current system cannot accommodate the "plausible" scenario in which hundreds of storage assets begin participating in the market over the next few years. It's also unable to manage the "added scale and added scope of the existing market, let alone the security posture we would like to have as we look over the horizon," he said.

The current system also cannot support some planned market enhancements — such as a price spread product, which will have to wait for the future platform, Ramey said. MISO expects the need for new ancillary services — including the recent additions of enhanced combined cycle modeling, a ramp capability product and extended locational marginal pricing — to only increase in the future.

"In a world where resources will continue to multiply and resource size will continue to decrease, the ability to handle more of them and in a more automated fashion" is a must, Bladen said.

Big Effort

Bladen said MISO is currently assembling a team of employees led by Ramey to oversee the replacement.

"This is going to be at least as big an effort as the original market roll-out," he said.

MISO plans to issue a request for proposals for a system replacement this month. The RTO is looking for a resilient platform that can handle an evolving energy portfolio with increased energy storage and distributed energy resources, possible footprint expansion and future market products — and include security that can stand up to cyber threats, according to Bladen.

Under the near-term preserve-and-protect plan, MISO "is going to wring the very last degrees of usefulness out of the current system," Bladen said.

Indiana Utility Regulatory Commission staffer Dave Johnston asked if the platform changeover would require MISO's Independent Market Monitor to upgrade its own software. The Monitor has functions that run alongside MISO's day-ahead market to enforce market mitigation when necessary.

Bladen conceded the possible need for an upgrade in order to ensure the IMM's continued operation. And although "it's very early in the process," the Monitor's IT staff may begin to work with MISO staff on the issue, he said.

MISO will convene another stakeholder workshop in late October to discuss how

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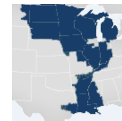
MISO NEWS



FERC Blocks MISO Plan to Shorten Queue Negotiations

By Amanda Durish Cook

FERC has rejected a MISO plan to shorten the number of days allowed to customers negotiating a generator interconnection agreement during the interconnection queue process.

The commission on Thursday ruled that MISO did not provide "sufficient support" for Tariff revisions that would have required that GIAs be negotiated and executed within 90 days, down from the current 150 days (ER17-1728). Negotiation and execution represent the last steps in the RTO's interconnection queue process, occurring after impact and feasibility studies have been completed.

FERC said MISO failed to demonstrate that the shorter agreement process would give interconnection customers sufficient time to sort out final details on new generation projects.

In its filing with FERC, MISO said that, after the commission's January acceptance of a leaner 460-day interconnection queue (ER17-156), the RTO realized that it also must "proportionally" reduce the amount of time allotted to crafting and signing GIAs — or risk exceeding the new queue timeline by about two months.

"Without reducing this piece of the timeline, the [generator interconnection process] will last for 520 days instead of 460," MISO claimed.

The RTO had sought approval to pare down all three queue stages, with negotiation cut from 60 days to 45; execution of a customer agreement reduced from 60 days to 30; and transmission owners given 15 days to sign off on an agreement instead of 30 days.

MISO had argued that the 460-day timeline approved by FERC "specifically contemplated a reduction in the [agreement] negotiation and execution timeline from 150 days to 90 days."

The commission responded that a diagram proposing a general, 90-day agreement process was only attached to testimony in the queue reform changes, and not reflected in MISO's Tariff changes. FERC also said its approval of the new queue process hinged on shortening the definitive planning phase of the queue — where restudies most often occur — and did not focus on altering the interconnection agreement process.

MISO's filing framed the changes as "limited revisions … to improve and clarify the language implementing the commission's recently approved interconnection queue reforms." But FERC responded that the RTO's characterization of the filing as merely a "cleanup" filing to reflect Tariff revisions was incorrect.

Several MISO members — including multiple wind developers — protested the shorter deadlines, arguing that the RTO was attempting to put the entire onus of a shorter queue on interconnection customers while making no sacrifices itself. Those members pointed out that they have already agreed to increased financial milestones and shorter time frames to review the results of system impact studies, and that MISO should now focus on shortening the timeline it gives itself to conduct studies during the definitive planning phase. The wind developers also said MISO is already failing to implement the more streamlined queue, with a backlog similar to that which dogged the old queue process now threatening the 2020 commercial operation deadline imposed on developers seeking the production tax credit.

Other members said the back-to-back 60-day negotiation and execution periods are crucial because that's when facility costs are finalized and the companies obtain board approval of the project.

MISO last month told stakeholders to prepare for imminent delays while it studies an unprecedented influx of prospective projects that last year entered the queue. (See *MISO Still Working Through New Queue Implementation Plan*.) Under the previous process, proposed projects routinely took as long as two years to be ushered through. (See *FERC Accepts MISO's 2nd Try on Queue Reform*.)

MISO also asked FERC for permission to give interconnection customers fewer days in which to modify their selected level of network resource interconnection service so that any change did not occur after the conclusion of the final system impact study. FERC did not address the proposed change in its decision to reject the RTO's broader proposal.

MISO Makes Case for $130M Market Platform Upgrade

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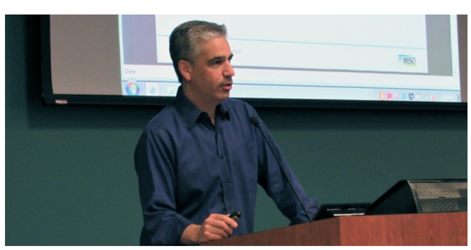
RTO members' current software might interact with a new market platform, Bladen added.

Customized Energy Solutions' David Sapper urged MISO to share regular updates with the stakeholder-led Finance Subcommittee. "They've all signed nondisclosure agreements, and MISO can be candid with them," Sapper said.



Bladen

MISO would consider that option, along with possibly providing updates to the Market Subcommittee, Bladen said.

RTO officials will also later this month provide the board with a project status report during a board meeting in St. Paul, Minn.

"We're going to have an ongoing conversation going forward," Bladen said. "We will take any feedback you have on the work we've done so far."

NYISO NEWS

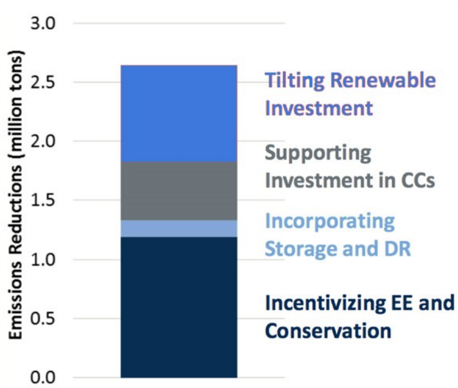
NYISO Stakeholders Talk Details of Carbon Charge

Continued from page 1

York Department of Public Service (DPS).

Rhodes

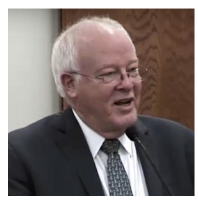
Both New York Public Service Commission Chair John Rhodes and NYISO CEO Brad Jones, who opened the hearing, signed off last month on a much-anticipated Brattle Group report on pricing carbon into generation offers and energy clearing prices. (See *NYISO Study Sees Little Cost Impact from Carbon Charge*.)



Incremental abatement induced by $40/ton carbon charge | *The Brattle Group*

Brattle's Sam Newell presented a summary of the report, saying more than 90% of the increased energy costs could be offset through carbon rebates to customers, reduced prices for renewable energy credits and zero-emission credits (ZECs), and improved investment signals. The report predicts the net impact on customer electric bills will be between a 1% reduction and a 2% increase.

Steps Forward



Weiner

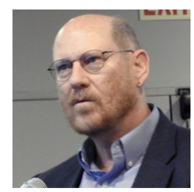
Scott Weiner, DPS deputy for markets and innovation, said the plan being developed by his agency, the ISO and the New York Energy Research and Development Authority envisions fossil fuel generators incurring a penalty based on carbon emissions levels. The carbon adder idea was prompted by the PSC's decision to subsidize the state's nuclear plants through ZECs.

Jones noted that New York hopes to implement the plan in the markets within three years, a time frame that Weiner called reasonable. Weiner said officials will have a clearer picture in January, after additional outreach.

As first steps, Weiner said, the DPS would seek stakeholders' comments on, and alternatives to, Brattle's proposal by Nov. 1. NYISO and the department will hold a series of technical conferences on the issue, with the first likely to be held around Thanksgiving, he said.

"The exact format has yet to be determined, but we have zeroed in on two topics. One is the issue of borders and seams ... and the second topic is revenue allocation," Weiner said.

Underselling Offsets?



Younger

During the hearing, Mark Younger of Hudson Energy Economics contended that the Brattle report understated the volume of expected offsets. Brattle did not account for the

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NYISO NEWS

NYISO Stakeholders Talk Details of Carbon Charge

Continued from page 17

New York Power Authority, "which has a lot of green resources also [selling] a fair amount of generation at market prices," he said.

The Brattle report concluded that a $40/ton carbon charge would raise energy prices by approximately $19/MWh on a load-weighted average basis, but that after accounting for static energy price offsets, net customer costs would rise only $6/MWh.

"And so, this is a source of revenues, certainly to the state, that could be used either to reduce taxes or to be rebating people, but that's not included anywhere in [the report's] estimate of savings and offsets against this $19/MWh cost," Younger said.

"As we get rid of net metering, we end up with a value stack, and part of the stack is a credit for CO_2 savings," he said. "And obviously the more the market represents the CO_2 savings, the less you have to essentially subsidize this behind-the-meter stuff, and that would be another savings because that would bring an out-of-market payment more directly into the market, and that's not captured anywhere."

While Newell conceded Younger's "good point," he said Brattle's goal was to make reasonable assumptions in the middle of the range of predicted outcomes.

Kelli Joseph, director of New York market and regulatory affairs for NRG Energy, pointed to the major challenge of the state trying to achieve a variety of goals through different methods. Among them: RECs, ZECs, the Clean Energy Standard and Reforming the Energy Vision.

"And is the $40 price sufficient to not only handle ZEC, but get 50% renewable and achieve whatever the REV goals are?" she asked.

Informing FERC

Schwall

Matthew Schwall, director of market policy and regulatory affairs for the Independent Power Producers of New York, referred to FERC's interest in price formation, a subject brought up at a May technical conference on harmonizing public policy with wholesale markets. (See *NYISO Sees Carbon Adder as Way to Link ZECs to Markets*.)

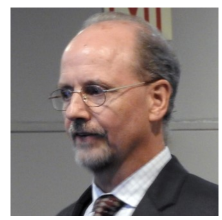
"FERC is looking for guidance," Schwall said. "Would it be possible for NYISO to work through its stakeholder process to come up with a conceptual filing to submit to FERC — prior to any Tariff filing, prior to coming to a complete market design — in order to get some guidance from FERC?"

NYISO Chief Information Officer Rich Dewey responded that in May the commission said that any proposal would require "a great deal of stakeholder support" to be successful.

"And we want to have the most thoroughly vetted design before we go down to FERC," he said.

Weiner added, "Importantly, nobody should assume that FERC is not aware of what we are doing here today and going forward. The DPS staff and NYISO staff have ongoing conversations with FERC staff, so they're well aware of this process, and I think it's fair to say they're encouraged by it."

Reconciling Competing Interests



Clarke

David Clarke, director of wholesale market policy for the Long Island Power Authority (LIPA), questioned the allocation of carbon costs, saying they might be disproportionately borne by consumers in southeastern New York.

"Right now, everyone has a *pro rata* share of REC requirements," Clarke said. "LIPA takes on a proportional share of those renewable energy requirements. ... Those collections are going down because the costs of the RECS are going down, but the collections from locational-based marginal prices are going up because you're [reducing] carbon. Those effects are not remaining in the same proportion and they have different effects for downstate New York than for upstate."

Newell said New York may want to consider allocating carbon revenues evenly to make up for the non-proportional impacts.

"The total wholesale cost, if it goes up about $20/MWh times about 150 TWh, that's about $3 billion in total wholesale costs, and then the carbon fund is about half of that, or about $1.5 billion," Newell said. "The incidence of who's seeing prices increase more or less is not even, and that is why you might want to consider [proportional rebates]," Newell said.

Weiner said the topic of revenue allocation

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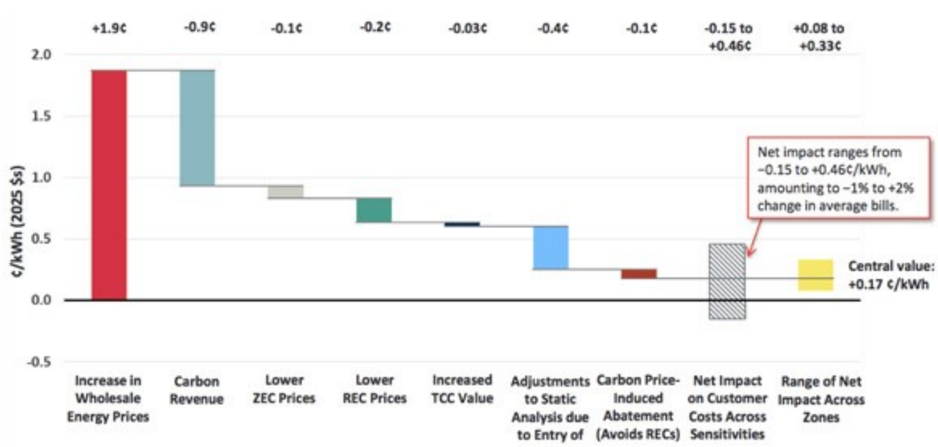

Impact on customer costs | *The Brattle Group*

NYISO NEWS

NYISO Stakeholders Talk Details of Carbon Charge

Continued from page 18

is key. "How do you divide it up? Is there a way to reconcile these competing interests? The status quo is the status quo, but maybe that's not the best way, either."

Reliability is Job One

Nachmias

Stuart Nachmias, Consolidated Edison's vice president for energy policy and regulatory affairs, said "markets have worked well in meeting the reliability needs of customers in the state but haven't yet incorporated clean energy goals."

The capacity markets address reliability, and Con Ed spends a lot of time trying to figure out how the energy market price impacts the capacity market, Nachmias explained. "And more importantly, how does that affect the resources we need for reliability to manage a variable future?" he said.

Dewey said reliability is always the grid operator's first concern.

"The reality is there's a lot more renewables coming onto our system, so we need to look at what changes might be necessitated in our existing market products and our existing capacity markets, energy markets or ancillary services to be able to accommodate that grid in the future," he said.

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Nuclear Power not 'Clean'

Manna Jo Greene, environmental action director for Hudson River Sloop Clearwater, said, "I implore you not to use the word 'clean' when talking about nuclear energy. I ask you to think about the communities who had the benefit of the goose that laid the golden egg for so many years and are now faced with massive amounts of high-level radioactive waste."

Azulay

Jessica Azulay, program director at Alliance for a Green Economy, echoed Greene's view and suggested that the DPS and NYISO consider a charge on other greenhouse gases, such as methane.

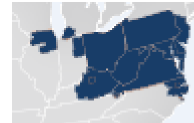
Erin Hogan, of the New York Department of State's Utility Intervention Unit, asked if Brattle could share the study's spreadsheet model, which might help the formation of independent proposals. Weiner said he didn't want to put Newell "on the spot ... but I think that's a very good point."

Hogan said she knew people had different perspectives: "Those who don't want combined cycle, those who don't want nuke, and there's those who don't want transmission, but they want the emissions to go down. The reality is ... the most challenging part is to maintain reliability, and the other part is to achieve the environmental goals, and the third part is trying to do this in the most cost-effective way possible.

"I'm asking people to come at it with a pragmatic perspective. Often people look at it as if we're going to optimize to achieve the perfect evolved frame. I think what we really do is choose the least imperfect solution."

NYISO's Rich Dewey (left) and Brattle Group's Sam Newell | *© RTO Insider*

PJM NEWS



Critics Protest PJM Dynamic Transfers Plan

By Rory D. Sweeney

PJM's proposal to create standardized contracts for establishing dynamic transfers with other balancing authority areas has provoked opposition from market participants, a neighboring ISO and the Independent Market Monitors for both PJM and MISO.

Critics of the proposed *pro forma* agreements for pseudo-tied resources filed protests with FERC over the past week — each with a different complaint (ER17-2291).

PJM and MISO both received stakeholder endorsement for their plan to establish agreements that would impose standard requirements on external units seeking to deliver power into PJM. The grid operators filed relevant revisions to their joint operating agreement on Aug. 1 (ER17-2218, ER17-2220).

MISO received conditional approval of its agreement from FERC on Aug. 9, although the plan has since been protested by American Municipal Power. PJM's proposal includes separate agreements for pseudo-ties and dynamic schedules and was filed with FERC on Aug. 11. (See *MISO-PJM Markets Meeting Addresses Seams Issues*.)

'Adverse' Impacts

In its protest, NYISO said it "is prepared to work with PJM to develop a mutually acceptable alternative," arguing that the current proposal "will likely cause adverse reliability impacts" and "exacerbate interregional seams." It said PJM's proposed pseudo-tie rules, which would require all dispatch control to be transferred to PJM from the RTO or ISO where the unit is located, "are fundamentally incompatible" with several NYISO practices, including financial transmission reservations, generator scheduling market rules and reliability operating standards. The rules would also conflict with the grid operators' interregional agreement and NYISO's Tariff, the ISO said.

The New York grid operator said PJM shouldn't be allowed to standardize pseudo-tie requirements. Any agreement should be "sufficiently flexible to accommodate regional differences at its borders" and require approval from the native balancing authority, it said. Under PJM's current plan, the native BA would only have to acknowledge awareness of the agreement between PJM and the unit but wouldn't have to be a party to it.

At recent stakeholder meetings, PJM staff have said they attempted to develop the agreements with input and endorsement from NYISO, but that the neighboring ISO refused to cooperate. Staff decided to move forward without NYISO's involvement.

IMMs Weigh In

While recognizing that PJM has attempted to address previous concerns, MISO Monitor David Patton contended that the plan still creates "substantial economic and reliability harm to the customers in [MISO and PJM] areas and [provides] no countervailing benefit that cannot be achieved by other means."

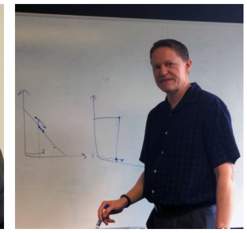
PJM's requirement of operational control creates a problem, he said, because the BA "most impacted by the generator and responsible for the generator interconnection and local impacts loses control of commitment and dispatch."

PJM Monitor Joe Bowring also filed comments opposing PJM's plan for operational control — but for the opposite reasons. He called the proposal "an improvement over the existing rules" but said it "needs to be substantially strengthened" because issues the Monitor has pointed out before "remain and are amplified."

Bowring reiterated an argument he's brought up repeatedly at stakeholder meetings: that the rules should be designed so that pseudo-tied units can serve as "complete substitutes" for capacity resources within the RTO's footprint. As such, he argued, the native BA should not be able to recall the unit. Otherwise, pseudo-tied units shouldn't be eligible to be capacity resources. The agreement would allow native BAs to supersede PJM's control during two emergency conditions.

Bowring's filing requests removal of that exemption, along with allowances for suspension or termination of a pseudo-tie.


Bowring


Patton

The provisions create "substantial uncertainty as to whether a pseudo-tied external capacity resource can be available and under the dispatch control of PJM when needed. As a result, pseudo-tied external capacity resources cannot be considered a complete substitute for internal capacity resources," he said. "If external capacity resources cannot be full substitutes for internal capacity resources, they are inferior products and should not be permitted in the PJM capacity market because they will suppress the price for internal resources and result in an inefficient market outcome."

Other Protests

Several municipal power organizations, cooperatives and transmission companies also filed protests. Like Bowring, Cogentrix Energy Power Management supports standardizing pseudo-tie rules but opposed the suspension and termination provisions.

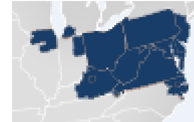
"PJM should not be permitted to suspend or terminate a pseudo-tie on any lesser basis than it may suspend or terminate an internal generator's interconnection rights," Cogentrix wrote.

The generator, which owns a pseudo-tied unit in Tilton, Ill., also took issue with what it believes is an insufficient transition period and argued that a pseudo-tie should have just one comprehensive agreement among RTOs. PJM's proposal — which stemmed from the inability for PJM and MISO to agree on terms — would require a unit to obtain separate agreements with each grid operator for the same pseudo-tie.

The Illinois Municipal Electric Agency argued that the proposal is the most recent in a series of changes that has made it "increasingly more difficult and more costly" for IMEA to use its generation units in MISO to self-supply its customers in PJM. The border situation developed in 2004 when

Continued on page 21

PJM News



Critics Protest PJM Dynamic Transfers Plan

Continued from page 20

Commonwealth Edison migrated from MISO to PJM.

"Like erosion at a beach caused by a succession of waves, each new set of restrictions imposed by PJM, culminating with the current pseudo-tie 'wave,' contributes to the erosion of IMEA's statutory protections," IMEA staff wrote.

IMEA also contended that its type of pre-existing exception should be grandfathered.

The Northern Illinois Municipal Power Agency said that units with existing pseudo-ties shouldn't be subject to PJM's proposed administrative fees in signing the standardized agreement. The agency serves load in PJM but has an ownership stake in a generation resource in MISO that is partially pseudo-tied.

AMP's protest acknowledged that it endorsed a previous version of the proposal, but that the filed version doesn't resolve all pseudo-tie issues as it purports to. The utility criticized the filing as "one more piecemeal effort to address these issues" and requested several changes on indemnification, agreement termination and authority to determine payments.

North Carolina Electric Membership Corp. took issue with PJM "unmooring" the agreement from the RTO's Tariff definition of long-term firm point-to-point transmission service. PJM has previously attempted to impose a five-year service requirement for pseudo-tied units that goes beyond the one-year requirement in the Tariff, and the co-op expressed concerns the RTO might use the agreement to lengthen the requirement if it is not linked to the Tariff definition.

Several intervenors urged deferring a decision on the agreements until other dockets focused on pseudo-ties have been addressed. Patton estimated there are "at least" 10 such proceedings and seconded MISO's request for a technical conference on the issue.

"Determinations by the commission in those other dockets will invariably affect evaluation of the changes proposed in this proceeding," he wrote.

Several of those dockets are complaints regarding double assessment of congestion management charges (EL16-108, EL17-29, EL17-31). PJM and MISO have developed a solution that they believe addresses the problem and will be seeking stakeholder endorsement in two phases.

> **"Like erosion at a beach caused by a succession of waves, each new set of restrictions imposed by PJM, culminating with the current pseudo-tie 'wave,' contributes to the erosion of IMEA's statutory protections."**
>
> **Illinois Municipal Electric Agency**

EKPC Gets PURPA Exemption; Still on Hook for 2 QFs

By Rory D. Sweeney

FERC last week granted East Kentucky Power Cooperative an exemption from being required to purchase power from Public Utility Regulatory Policies Act qualifying facilities larger than 20 MW — but not in time for the cooperative to avoid such purchases from two solar projects within its territory.

The 1978 federal law requires that utilities — including municipals and cooperatives — purchase electricity from QFs at the utility's "avoided cost." QFs were defined as cogenerating plants and small power producers under 80 MW. FERC Order 688, issued in October 2006, granted utilities the ability to disregard the requirement for QFs over 20 MW if they can prove the facilities have nondiscriminatory access to the wholesale markets. As a PJM member, EKPC argued that QFs in its territory have that access.

FERC agreed, but it declined to backdate the approval far enough for EKPC to avoid contracting with two solar projects.

"Until a utility applies for termination of the PURPA mandatory purchase obligation, and the commission grants such application, a QF has the statutory right to pursue a contract or other legally enforceable obligation with that utility," FERC said.

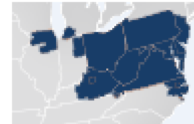
The 80-MW Bluebird Solar and 60-MW Blue Jay Solar projects notified EKPC in December and March, respectively, of their intention to sell their entire output to the cooperative at the avoided cost rate.

EKPC argued that it first requested an exemption from the PURPA rules last November, which would have relieved the cooperative of any responsibility to buy from the solar projects. However, the commission's lack of a quorum earlier this year caused the request to languish and eventually be denied by FERC staff once its 90-day time frame for action had passed.

The cooperative refiled the request on June 9, arguing that the effective date for the exemption should start from the November filing because it was reasonable to believe that FERC would have approved it with a quorum.

The commission rejected EKPC's argument and set the effective date for June 9.

PJM NEWS



Post-'Wheel' Changes Spark PJM Member Concerns

By Rory D. Sweeney

When Consolidated Edison last year canceled a decades-old arrangement with Public Service Electric and Gas to wheel 1,000 MW of power from upstate New York to New York City via northern New Jersey, the move appeared to free up transmission capacity in the northeast corner of PJM. (See *NYISO Members OK End to Con Ed-PSEG Wheel*.)

PJM stakeholders are finding out that's not so.

The cancellation forced operational changes that caused PJM to remodel phase-angle regulator (PAR) flows along the New York-New Jersey border — and along the PJM-NYISO seam — that will reduce transmission limits and increase the region's LMPs. (See "'Wheel' Replacement Reduces Transmission Limits," *PJM PC/TEAC Briefs: Aug. 10, 2017*.)

The modeling changes eliminate non-firm transmission service from the capacity emergency transfer limit (CETL) calculation and specify that adjacent non-PJM areas are not available to supply non-firm energy. In practice, the changes only affect operations along the NYISO interface, PJM's Mike Herman acknowledged. PJM's recent analyses as part of its Regional Transmission Expansion Plan have not indicated that external support is needed in any other region within its footprint, he said.

Con Ed subsidiary Rockland Electric objected to the revisions during an Aug. 30 educational session hosted by PJM. Rockland serves about 61,000 customers in northern New Jersey as part of Con Ed's Orange and Rockland Utilities subsidiary just across the New York border.

"It's very understandable that you wouldn't want to over-rely on [the PARs] to the extent that you had under the status quo," Con Ed's Diana Barsotti said. "We still oppose the deletion of language [in the manual] that has to do with modeling such support that may be reasonably expected in the future."

Barsotti requested a manual revision that provides a link to information about firm service interchanges.

Stakeholders had been confused by PJM's changes to CETL values posted in February and had asked the RTO to explain what alterations it made beyond eliminating non-firm imports.

PJM's Jonathan Kern acknowledged stakeholder concerns but said he was confident the "more conservative" recent assumptions are the most reasonable and don't depend on the same "extreme mathematical optimization" that the February numbers do. The new calculations also account for resource diversity, resource retirements and PAR-adjustment coordination.

"We've been planning the system for decades using a certain set of assumptions and it's taken us six months to hone in on what we feel is the best approach, so there were some growing pains," Kern said. "We decided it would be more realistic, practical and conservative from a PAR perspective to more closely align with how New York is planning their system and PJM is operating our system."

"There must be some number that can come in [through the PARs] in an emergency," said Dean Bickerstaff of Hartree Partners. "Even though I know you don't want to count on New York from a planning perspective, the real world would suggest there is some. … The market isn't just retiring resources up there [in New York]; it's adding resources as well. So to the extent that we would be good neighbors to them, I'm sure they would be good neighbors to us."

Herman clarified that PJM isn't planning to remove non-firm service from its capacity import limit (CIL) calculations.

"The inclusion of non-firm service is intrinsic to the CIL calculations," he said. "Utilizing a combination of firm transmission service as well as the non-firm energy purchase allows the CIL test to properly identify physical system limits. In PJM's analysis and experience, firm transmission service alone may not be enough megawatts to hit a physical limit. The purpose of this test is to identify what that physical transmission limitation is."

SPP NEWS

Seams Steering Committee Briefs

SSC Endorses Doomed Interregional Project

SPP stakeholders last week endorsed a proposed interregional project to be developed in partnership with MISO, despite the project's dim prospects.

The Seams Steering Committee unanimously agreed with staff's recommendation to endorse the $5.2 million Split Rock-Lawrence project in South Dakota, identified through the interregional process. It would have been the RTOs' first-ever interregional project, but staff told the Planning Advisory Committee last month that it no longer recommended moving forward with the initiative. (See *SPP Glum as MISO Axes Last Interregional Project*.)

MISO said its latest analysis of the project indicates the congestion on the 115-kV line is still manageable and that an alternative project could provide the RTO with at least the same benefit at a lower cost.

"It seems odd to endorse a project when we don't have a partner," said Jeff Knottek, director of transmission planning and compliance for City Utilities of Springfield, Mo., during the committee's Sept. 6 conference call.

"We were aware we could come down on different sides on this," said Adam Bell, SPP's interregional coordinator. "We didn't come to a point knowing MISO's decision until we were done with a majority of the analysis."

GridLiance's Bary Warren, who chaired the meeting, said the RTOs' coordinated study process identified a good project "from the SPP and MISO perspective."

"MISO stakeholders don't agree this is the best solution," Warren said. "From SPP's perspective, it appears this is a better solution for both RTOs."

David Kelley, SPP's director of interregional relations, said the South Dakota project could surface again in a future study. However, SPP's Tariff prevents the RTO from approving an alternative interregional project other than the one that advanced from the interregional study out of a regional review.

"We're recommending to you what we feel we're obligated to do under the process," he said.

Staff Prepping Response to AECI Project's Protests

SPP staff is preparing comments due to FERC on Sept. 12 in response to protests lodged by Xcel Energy Services and Westar Energy over a proposed interregional project with Missouri-based Associated Electric Cooperative Inc. (See "Board Reaffirms Seams Project with AECI," *SPP Board of Directors/Members Committee Briefs: July 25, 2017*.)

Last month, the RTO filed with FERC the terms and conditions of a cost-sharing and usage agreement among SPP, AECI and Springfield, as well as Tariff changes that would regionally allocate costs to the RTO's transmission customers (ER17-2257).

The $13.75 million project involves installing a new 345/161-kV transformer at AECI's Morgan substation and an uprate of a related 161-kV line, both near Springfield.

Westar asserts a lack of transparency regarding SPP and AECI's cost-sharing methodology and their negotiations.

Xcel protested the proposed allocation of the Morgan transformer's costs, noting the project is outside SPP's footprint and being allocated to members on a regional load-ratio share basis. It also says SPP's filings do not justify "a departure from the cost allocation methodologies" currently stipulated by the RTO's Tariff.

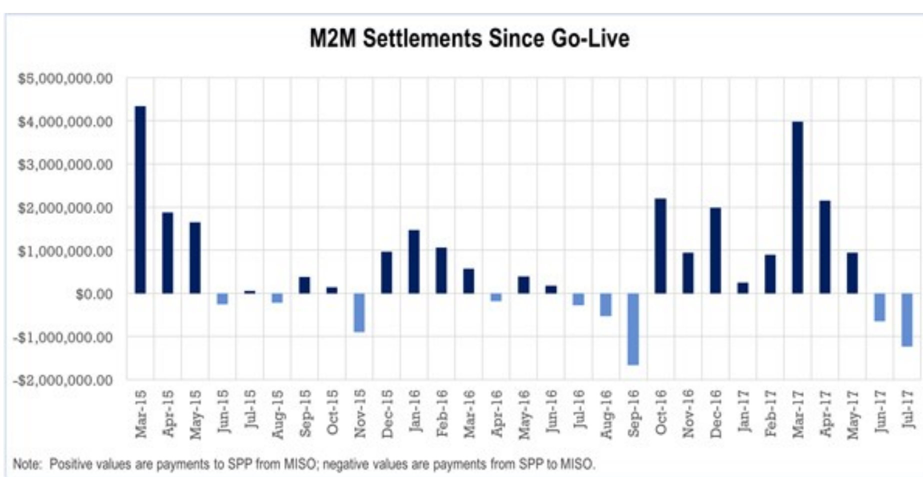
SPP Sends MISO $1.2M for M2M Settlements

SPP sent MISO $1.2 million in market-to-market (M2M) payments for June congestion on flowgates along the seam between the two RTOs. The payments reduced the net amount of settlements SPP has collected from MISO to $20.5 million — as of June — since the two began the process in March 2015.

Temporary flowgates accounted for most of the congestion, binding for 214 hours, 32% less than the month before, and resulting in almost $1.2 million in M2M settlement charges to SPP. Permanent flowgates were binding for 27 hours, giving MISO an additional $59,339.

More than half of the M2M settlements came over a MISO flowgate in northwest Iowa near the Nebraska and South Dakota borders. SPP was unable to commit enough generation during low-wind periods to compensate for outages in the area, resulting in 23 hours binding and $676,332 in charges.

— Tom Kleckner



SPP

FERC NEWS

McIntyre to Senate: 'FERC does not Pick Fuels'

Continued from page 1

the Senate committee.

The committee devoted less than half of the two-hour hearing to McIntyre and Glick, as it also considered two nominations to the Interior Department: Ryan Nelson to be solicitor, and Joseph Balash to be assistant secretary for land and minerals management. The committee's senators — some hailing from states with large swaths of federally owned land and sizable Native American populations, such as Alaska, Arizona, Nevada and New Mexico — had plenty of questions for the two Interior nominees about policies important to their constituents.

The two FERC nominees, on the other hand, found themselves declining to provide specific answers to many questions, citing ongoing proceedings and Notices of Proposed Rulemaking before the commission. Those questions covered issues such as price formation in energy markets, and eliminating barriers to distributed energy resources and energy storage.

Several Democratic senators asked the nominees about states' rights in enacting renewable portfolio standards. After discussions with the Interior nominees about her home state, Sen. Catherine Cortez Masto (D-Nev.) asked McIntyre and Glick for quick, yes-or-no answers to her questions.

"Do you agree that states have the authority to establish the resource mix that best serves their customers?" she asked, to which the nominees responded in the affirmative.

She also asked if they agreed that renewable resources can be reliably integrated. Glick noted that several states get at least half of their electricity renewables and that none have had any problems.

"In part due to actions taken by the FERC, renewable energy resources are making their way reliably to our grid," answered McIntyre.

Noting her state's adoption of a zero-emission credit program, Sen. Tammy Duckworth (D-Ill.) asked if they agreed that states were "the appropriate place for these types of policies to be decided."

"We do have a federal system of law," McIntyre responded. "FERC has its role and the states have theirs, and there's no question that the states have the absolute right to implement these renewable portfolio standards."

Committee members refrained from addressing some of the more controversial issues brought up during the May confirmation hearing for Chatterjee and Commissioner Robert Powelson — such as climate change and the Public Utility Regulatory Policies Act. (See No Fireworks for FERC Nominees at Senate Hearing.)

McIntyre (left) and Glick chat before the hearing begins. | © *RTO Insider*

Duckworth did ask about FERC's role in securing a cleaner environment. Both nominees asserted that FERC is not an environmental regulator, while also noting that the commission ensures that clean resources have nondiscriminatory access to the markets and that it is seeking to better integrate DER, storage and demand response.

Committee Chair Lisa Murkowski (R-Alaska) told reporters after the hearing that she hopes to advance McIntyre and Glick to the full Senate "late next week." Their confirmation would restore FERC to a full, five-member slate — which it has been without since the departure of Philip Moeller on Oct. 30, 2015.

COMPANY BRIEFS

Areva, Lightbridge Enter Nuclear Plant Fuel Joint Venture

Nuclear fuel developer Lightbridge and nuclear energy company Areva have agreed to a joint venture to commercialize and manufacture a new line of advanced metallic fuels for nuclear plants.

The fuels can be used in existing plants and facilities under construction to improve operating efficiency and safety. The venture, which is expected to launch in early 2018, will expand the fuels Areva offers for most reactor types.

More: *Charlotte Business Journal*

Enphase Names Badri Kothandaraman as New CEO

Kothandaraman

Rooftop solar installer Enphase Energy has promoted its operations chief Badri Kothandaraman to president and CEO. He succeeds founder Paul Nahi, who resigned as CEO and from the board, effective Aug. 8.

Kothandaraman served as Enphase's COO since April. He previously worked 21 years at Cypress Semiconductor until he left last September. During his previous five years there, he served as executive vice president for the 600-employee Data Communications division, and he also ran Cypress' 700-employee India business for the last four years of his service.

Kothandaraman's promotion makes him the second former executive from Cypress with a leading position at Enphase.

More: *North Bay Business Journal*

FirstEnergy Selling Natural Gas, Hydro Assets

FirstEnergy announced Wednesday it has entered a revised agreement to sell 1,615 MW of competitive natural gas and hydroelectric generation assets to a subsidiary of LS Power Equity Partners III for an all-cash price of $825 million.

Springdale Generating Facility

The agreement, signed on Aug. 30, affects six power stations in Pennsylvania and Virginia that are owned directly or indirectly by FirstEnergy subsidiaries Allegheny Energy Supply and Allegheny Generating.

The transaction involving the Springdale Generating Facility, the Chambersburg Generating Facility, Gans Generating Facility and Hunlock Creek is expected to close in the fourth quarter of 2017. The sale of the interests in Bath County Hydro and Buchanan Generating Facility is expected to close in the first quarter of 2018.

More: *FirstEnergy*

Dominion Pauses Plans for 5th Reactor at North Anna

Dominion Energy has paused its development of a fifth reactor at its North Anna plant, with the possibility that it could restart its efforts within the next 20 years.

This past spring, the Nuclear Regulatory Commission issued a combined construction and operating license for the new reactor, which allows Dominion the 20-year window.

The project is estimated to cost at least $19 billion, making it the most expensive single reactor construction project in the world to date. Dominion has reportedly spent more than $600 million on its development, and whether it will be able to recoup its development costs from ratepayers is an open question.

More: *Southeast Energy News*

Report: Utilities Planning BTM Energy Storage Programs

A recent study of 115 utilities by Smart Electric Power Alliance found that 72% plan to offer behind-the-meter energy storage opportunities for their residential customers, while 80% plan to offer programs to their commercial/industrial customers.

According to the report, in 2016, California was the leader in connecting energy storage, with 121 MW. Indiana and Ohio ranked second and third with 22 MW and 16 MW, respectively.

Currently, 622 MW of energy storage, producing 661 MWh, are currently online. Of that, 207 MW producing 257 MWh came online last year.

More: *pv magazine*

Bandera Electric to Electrify Rural Liberian Community

Bandera Electric Cooperative has been awarded a contract by the National Rural Electric Cooperative Association to electrify a rural community in Liberia that lacks basic access to electricity.

The nonprofit utility cooperative from Texas has designed for the community of Totota a 70-kW solution, which includes 220 solar panels and 90 kWh of lithium-ion battery energy storage, alongside diesel backup generation.

The total project will cost about $600,000, with NRECA pledging to fund about two-thirds. It will serve about 6,400 people.

More: *Energy Storage News*

Energy Northwest's Columbia Plant Back Online

Columbia Generating Station

Energy Northwest's Columbia Generating Station came back online Saturday following a shutdown Aug. 20 when an air removal valve in the nuclear plant's turbine building closed.

The closed valve caused loss of vacuum pressure in the system that turns steam back into water for reuse at the plant.

The valve was fixed, and most of the shutdown was used to filter iron, which entered the reactor water circulation system during recent maintenance work, out of the water system.

More: *The Associated Press*

FEDERAL BRIEFS

Report: Solar to Supply One-Third of World's Electricity by 2050

Solar energy will be responsible for about one-third of the world's global electricity supply by 2050, according to a new report by DNV GL.

"Energy Transition Outlook: Renewables Power and Energy" aims to forecast the "most likely" future for energy through to 2050. It finds that overall energy demand will stop growing within the next 15 years; much of the existing demand will shift to electricity; and that renewables will be responsible for 85% of electricity supply globally.

The report warns that the climate objectives of the Paris Agreement will not be met on the current trajectory.

More: *pv magazine*

Senate Panel Votes to Contribute $10M to UN Climate Agency

The Senate Appropriations Committee voted 16-14 Thursday to contribute $10 million to the United Nations' climate change agency.

The committee approved an amendment to restore funding for the U.N.'s Framework Convention on Climate Change in the State Department appropriations bill. Payments that the U.S. had made annually since joining the convention in 1992 had been slated to be eliminated.

President Trump sought to end U.N. climate funding in his first budget proposal earlier this year.

More: *The Hill*

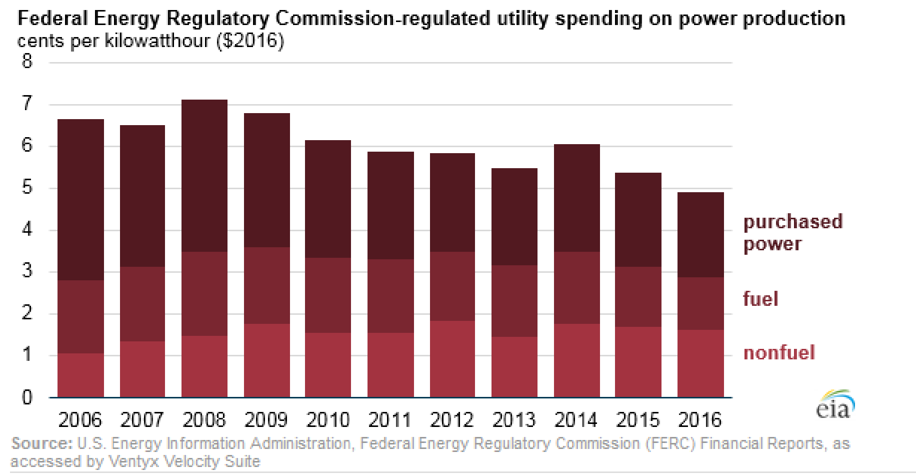
Electricity Sees Rising Delivery Costs; Declining Generation Costs

Over the past decade, electricity prices have reflected a decline in power production costs from 69% to 54% together with a rise in delivery costs, according to data from the Energy Information Administration.

According to the agency, electricity delivery costs have increased in real 2016 dollar terms from 2.2 cents/kWh in 2006 to 3.2 cents/kWh in 2016, which roughly offsets the decrease in the generation costs.

Administrative and general expenses associated with electricity also increased by 20% in real dollar terms since 2006, but they account for a smaller portion of the overall costs of providing electricity.

More: *Energy Information Administration*



Poll: 3 out of 4 Americans Support Net Metering

About three out of every four Americans support net metering policies, according to a poll by University of Michigan researchers.

The poll, conducted by the National Surveys on Energy and Environment, found strong support for net metering regardless of respondents' age, political party or belief in climate change.

It is believed to be the first nationally representative public opinion poll on the topic.

More: *University of Michigan*

TVA Says Coal Ash Removal Will Take 24 Years

The Tennessee Valley Authority last week said it will take 24 years to dig up and move all its coal ash at its Gallatin Fossil Plant as ordered by a federal court last month.

U.S. District Judge Waverly Crenshaw ruled in favor of two environmental groups and ordered the cleanup, saying the facility's unlined coal ash storage is leaking pollutants into the Cumberland River and violating the Clean Water Act. TVA has until early October to consider whether to appeal, a spokesman said.

TVA said the project's size makes it impossible to comply with the federal coal ash rule, which requires digging and disposal to be completed within 15 years.

More: *The Associated Press*

Moody's: Emissions Will Decline Despite Paris Withdrawal

Greenhouse gas emissions in the U.S. will continue to decline notwithstanding President Trump's stated intent to withdraw from the Paris Agreement, according to a new report by Moody's Investors Service.

Moody's found that greenhouse gas emissions will likely continue to decline because of economic trends as well as private and sub-national entities, such as states and cities, stepping in to compensate for the lack of federal carbon regulations.

"We do not believe that the global emissions pathway would be materially derailed over the coming decades even if the U.S. were to formally abandon its Paris Agreement commitments," said Rahul Ghosh, a senior vice president at Moody's.

More: *Moody's Investor Service*

James Danly Named General Counsel at FERC

Acting FERC Chairman Neil Chatterjee last week announced that James Danly has been named general counsel at the commission, effective Sept. 18.

Danly comes to FERC from the energy regulation and litigation group at Skadden, Arps, Slate, Meagher and Flom. Previously, he served as law clerk to Judge Danny Boggs at the 6th U.S. Circuit Court of Appeals.

More: *FERC*

STATE BRIEFS

NEVADA

Regulators Approve New Rules for Net Metering

To reboot the state's struggling rooftop solar industry, the Public Utilities Commission issued an order Friday implementing a net metering law signed by the governor in June and rejecting rate changes proposed by NV Energy.

In June, Gov. Brian Sandoval signed into law A.B. 405, which reinstates net metering compensation at 95% of the retail rate following a decline in the state's rooftop solar market after regulators voted in December 2015 to phase out net metering credits and hike fixed fees on all residential solar customers. Under A.B. 405, for every 80 MW of solar deployed, the export credit is set to decline by 7%, to a floor of 75% of the retail rate.

After A.B. 405 passed, NV Energy proposed new rates that solar advocates said would undermine the new law.

More: Greentech Media; Solar Industry

NEW YORK

PSC Directs Utilities to Sell Energy to Low-Income Customers

The Public Service Commission has directed traditional utilities to resume selling energy to roughly 200,000 low-income customers who previously opted to buy electricity or natural gas from energy service companies, while also blocking those customers from purchasing from ESCOs.

The transition, which begins Sept. 25 and is expected to take about two months, is intended to protect low-income customers from overpaying energy marketers, according to regulators.

The commission tried to block the purchases for a year but was delayed by legal challenges from ESCOs. On Sept. 1, the Appellate Division Third Department lifted a temporary restraining order and declined to suspend the commission's policy while ESCOs challenged it in court. The court's final decision on whether the policy is legal is not expected for several months.

More: syracuse.com

3 Clean Energy Projects In Albany Get $1.4M

Gov. Andrew Cuomo last week announced $1.4 million in funding for three clean-energy projects in Albany as part of the race-to-the-top competition, designed to accelerate energy efficiency in the state's five largest cities, outside of New York City.

The allocations include $500,000 to help connect 22 of the city's municipal buildings to the New York Power Authority's network operations center for real-time energy use monitoring; $416,000 for electric vehicle charging stations and a city vehicle fleet optimization project for about 100 city vehicles; and $500,000 for energy efficiency upgrades to several municipal buildings.

The projects are expected to reduce carbon emissions by 773 tons a year and save $240,000 in annual energy costs. Their total cost is estimated at approximately $2 million, offset by the $1.4 million in funds.

More: Gov. Andrew Cuomo

VERMONT

Regulators Approve Scaled-Back Security for Vermont Yankee

The Public Utility Commission has approved Entergy's plan to scale back its security zone at Vermont Yankee from 10.5 acres to 1.3 acres. The new plan is expected to take effect next year after Entergy finishes moving the plant's spent nuclear fuel into sealed casks.

Entergy stopped producing power at Vermont Yankee in December 2014 and wants to sell it to NorthStar Group Services by the end of 2018. Moving the plant's spent nuclear fuel into the casks is a prerequisite to the sale and the reason for the security change.

The plant's current protected area includes multiple buildings. The new zone encompasses only the plant's two fuel storage pads and a new central alarm station building. Entergy also plans to install security features such as a concrete vehicle barrier system, fencing, lighting, cameras and intrusion detection equipment.

More: VT Digger

WEST VIRGINIA

State Park System Leading the 'Charge' for EV Charging Stations

The state park system is poised to become the first in the U.S. with electric vehicle charging stations installed at all its guest lodges.

Nine of the state's 10 state park lodges have been equipped with at least three Tesla electric vehicle chargers and one EVlink universal charging station. The last holdout is North Bend State Park, which is expected to have four charging stations installed by the end of the year.

The charging stations are available free of charge to all drivers, regardless of whether they are state park lodge guests.

More: Charleston Gazette-Mail

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who contended the bill is obsolete and an albatross for consumers, cited abuses of FERC's 1-mile and 20-MW thresholds for must-purchase requirements.

Rep. Fred Upton (R-Mich.) said the hearing would be "the first step in re-evaluating whether the intent and purpose of PURPA is still being met or if it has already been fulfilled."

For PURPA critics who were hoping for quick legislative action following the hearing, Clearview Energy Partners analyst Timothy Fox had bad news. He reduced Clearview's odds that Congress will enact changes to the law in 2017 from less than 30% to less than 10%.

"Yesterday's hearing reinforced for us the lack of consensus on, and narrow congressional interest in, PURPA reform," he wrote in an analysts' note. "We consider its best prospects for enactment to be in the context of a broad energy or energy and infrastructure package that we don't expect to see action on until 2018. In the meantime, we do not anticipate that the Federal

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Bankruptcy Court Advances Sempra Bid for Oncor

By Rory D. Sweeney

WILMINGTON, Del. — Sempra Energy moved a step closer to acquiring Texas utility Oncor after a U.S. bankruptcy judge on Wednesday approved the $9.45 billion agreement (14-10979).

The deal would give Sempra an 80% stake in the rate-regulated operations of the largest transmission and distribution utility in Texas. The deal must still be approved by the Public Utility Commission of Texas.

The utility has been the subject of a series of failed takeover bids since parent Energy Future Holdings, saddled with almost $50 billion in debt after poor bets on energy prices, declared bankruptcy in April 2014.

EFH announced the deal with Sempra three weeks ago in the same Delaware courtroom, after hedge fund Elliott Capital Management — the largest holder of EFH bonds — opposed as too low a $9 billion all-cash offer by Berkshire Hathaway Energy. Including debt, Berkshire's bid valued Oncor at $18 billion, while Sempra's values the utility at $18.8 billion. (See Sempra Outmuscles Berkshire for Oncor.)

'Largely Consensual'

"Unlike any proposal we've had in the past, this proposal has the support of one of the debtors' largest and most active creditors," Chad Husnick, an attorney representing EFH, told Judge Christopher Sontchi. "The Sempra transaction is the highest and best available transaction."

Husnick said the Sempra deal was "largely consensual" and prompted just one objection regarding how creditors would be compensated, a consideration that Sontchi said should be reserved for a confirmation hearing. That hearing would take place after the PUCT approves the deal.

"We'll try it again," Sontchi said in approving the documents, drawing laughter from the courtroom.

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

Sempra Energy

Sempra said it is committed to ensuring that Oncor remains independent, financially strong and based in Dallas with local management.

"Oncor is a well-managed, top-tier utility, operating in one of the strongest U.S. growth markets. We believe it will be an excellent strategic fit with our portfolio of utility and energy infrastructure businesses, while opening up a new avenue for our long-term growth," Sempra CEO Debra Reed said in a statement after the hearing.

The acquisition would allow Sempra to regain a foothold in Texas, where it once owned and operated 10 power plants and still maintains a 200-person Houston office to support marketing and development activities. (See Sempra Begins 'Listening Tour' of Key Stakeholders.)

With the approval in hand, EFH set an Oct. 30 voting deadline for its plan. EFH approved the deal in part because Sempra was willing to accept ring-fencing of Oncor — giving it independence from its corporate parent — and no assurance that it will get control of the 20% of Oncor now owned by Texas Transmission Holdings Corp.

Sempra is the fourth would-be suitor for Oncor. Dallas' Hunt Consolidated and Florida-based NextEra Energy saw separate bids fall apart in the face of the Texas PUC's calls for strict ring-fencing measures and a requirement that Oncor be run by a "truly independent" board with control over decisions on capital expenditures and operating expenses.

NextEra Termination Fee Battle

Wednesday's hearing also addressed EFH's upcoming legal battle with NextEra, which had offered $18.7 billion for Oncor but failed to win approval for the deal from the PUCT. EFH accused NextEra of failing to do its best to receive approval and sued the former suitor earlier this year to prevent any attempt by NextEra to claim the deal's $275 million termination fee. The trial is set to begin next April.

EFH filed for Chapter 11 protection in 2014 with roughly $42 billion in debt, which was then the eighth-largest bankruptcy in U.S. history. About $25 billion of the debt has been restructured by spinning off subsidiary Texas Competitive Electric Holdings, which split the company in half.

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Energy Regulatory Commission (FERC) will change its current light-handed approach to PURPA issues, allowing states to continue their efforts to modify their administration of the program."

Sen. Lisa Murkowski (R-Alaska), chair of the Senate Energy and Natural Resources Committee, also cautioned against expectations of quick action. Following the confirmation hearing for FERC nominees Richard Glick and Kevin McIntyre on Thursday, Murkowski told reporters that PURPA reform is too complicated to be dealt with as an amendment to the broad energy bill she and ranking member Maria Cantwell (D-Wash.) are sponsoring. She added that FERC has leeway to address some of the concerns over the act.

New FERC Commissioners Neil Chatterjee and Robert Powelson said at their confirmation hearing in May that it was up to Congress to authorize any major changes in PURPA. (See No Fireworks for FERC Nominees at Senate Hearing.) PURPA was barely discussed at Glick and McIntyre's hearing. (See related story, *McIntyre to Senate: 'FERC does not Pick Fuels'*, p.1.)

Abuses Cited

The hearing by the Subcommittee on Energy was the committee's fourth in its "Repowering America" series of fact-finding sessions that began last year on potential revisions to the 1935 Federal Power Act. (See RTOs to Congress: Don't Lose Faith in Markets.)

Several witnesses said PURPA, born out of the 1973 energy crisis, is no longer necessary in an era of bountiful natural gas supplies, low load growth and competitive wholesale energy markets.

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From left to right: Prager, Glass, Raper, Thomas, Kouba and Baas.

The utilities invited to testify came with wind and solar generation bona fides to make the case that renewables have accomplished the competitiveness PURPA was intended to create.

Terry Kouba, vice president of operations for Alliant Energy in Iowa, said his company has more than 1,000 MW of wind capacity from its generation and power purchase agreements and plans to spend $1.8 billion to add another gigawatt of wind by 2020. "Despite the market-driven deployment of renewable energy in Iowa, Alliant Energy is still subject to PURPA's mandatory purchase obligation, the federal implementation of which has increased electric costs for our Iowa customers," he said. "The law, therefore, can result in the deployment of less economic renewable generation in lieu of more cost-effective renewable generation procured in an open market."

Also testifying was Frank Prager, vice president of policy and federal affairs for Xcel Energy, the top wind generator in the U.S. with almost 6,700 MW operating and 3,400 MW under development. "Fully 65% of these existing and planned resources are owned by independent power producers," said Prager. "We are also a leading solar provider and expect to add 900 MW of solar to our already growing solar portfolio.

"PURPA represents an energy policy from another time and is inconsistent with the realities of today," Prager said. "PURPA incentivizes developers to build generation that is not needed and site it in locations where it provides no value to the grid. PURPA thwarts the opportunities of other independent power producers."

Gaming FERC Thresholds

FERC has ruled that wind farms of 20 MW or larger within ISO/RTO regions are presumed to have access to competitive markets and thus ineligible to force PURPA's must-purchase obligation on incumbent utilities. (See related story, *EKPC Gets PURPA Exemption; Still on Hook for 2 QFs*, p.21.)

But witnesses said qualifying facility developers are circumventing the 20-MW cap by creating separate corporate entities for individual turbines or small groups of turbines, or disaggregating large projects by siting turbines more than 1 mile apart. FERC has ruled that QFs located within 1 mile of each other are considered to be "located at the same site."

Kouba cited a 30-MW wind farm in central Iowa that was broken into 10 separate limited liability companies each owning a 3-MW turbine; a 28-MW wind farm with 14 LLCs; and a proposed 24-MW farm operated by 11 LLCs. "In none of the above examples is Alliant Energy able to challenge the presumption that these QFs are separate because of the safe harbor provided by FERC's 1-mile rule, which is irrebuttable," said Kouba.

He said that the 30-MW project is charging customers a 20% premium over market rates on a 10-year contract, while the developer of the proposed 24-MW project is seeking a rate of $49.50/MWh for 25 years rather than Alliant's avoided cost rate of about $25/MWh. "If they are successful, Alliant Energy's customers will pay more than $45 million more for energy than if Alliant Energy were to enter into a PPA obtained through a competitive process," he said.

Prager said Congress' addition of Section 210(m) to the FPA in the Energy Policy Act of 2005, which allows utilities in RTO markets to obtain an exemption from PURPA if the QF has nondiscriminatory access to the market, has been "helpful" but "inadequate" to address gaming.

"It does not apply to states in the West or South or other states that have not joined organized markets. Further, even in organized markets, FERC's 20-MW safe harbor still allows relatively large resources to avoid the discipline of the market and put their energy to the utility."

Impact on System Planning

In addition to imposing high-cost PPAs, critics say, QF developers also undermine system planning by connecting their generation at locations providing quick, cheap access, regardless of their impact on the grid. "The size and scale of these new PURPA projects often virtually guarantees the backflow of energy from the distribution system to the transmission system," Kouba said.

Prager cited a QF developer planning 480 MW of wind and solar power in a remote area of Colorado. "All of the transmission capability in that area is already fully subscribed by five solar facilities that are already under contract. This developer's QF projects could cause our customers to pay potentially hundreds of millions of dollars in transmission upgrades to deliver the QF's energy and cause us to curtail the output from the five existing solar facilities already in this area."

Utilities' Recommendations

The utilities called for repealing PURPA Section 210's must-purchase requirement, or expanding the exemptions from the requirement to non-RTO states with least-cost resource planning or competitive solicitation processes or where the utility does not need additional generation.

They also called for removing the 20-MW safe harbor or reducing it to 2 MW in organized markets. They said unsolicited QFs should be required to pay for transmission upgrades necessary to deliver their

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output.

And they said FERC should make it easier for utilities to challenge abuses of the 20-MW and 1-mile thresholds.


Raper

Idaho Public Utilities Commissioner Kristine Raper also was critical, saying PURPA contracts should be shorter to ensure avoided cost rates reflect changing energy prices and that FERC's 20-MW threshold should be expanded to include the Western Energy Imbalance Market (EIM).

She also questioned the value of QFs. "Even with the addition of large QF resources, the QF energy rarely displaces the need for a utility-scale project because renewable QF energy is largely intermittent — requiring baseload resources to ensure reliable service," she said. "So, the question must be asked: What costs are being avoided and how are ratepayers held harmless?"

She rejected developers' demand that PURPA support financing of QF projects. "Neither PURPA nor FERC regulations mandate that the terms of a QF contract allow the project to be financeable," she said. "If the market cannot support the cost of the project, then the project should not be built."

Industrials: We're Different


Thomas

Testifying for the Industrial Energy Consumers of America, Stephen Thomas, senior manager of energy contracts for paper manufacturer Domtar, called on policymakers to "recognize the differences between the types of qualifying facilities and only alter PURPA in a way that supports how the manufacturing industry uses PURPA."

Thomas said that even manufacturers with on-site power are net energy purchasers and thus worry about above-market avoided-cost contracts.

IECA said states should deduct the cost of natural gas back-up generation, transmission and other costs caused by renewable generators in developing QFs' avoided-cost rates. It also said renewable energy QFs should not be allowed to include production tax credits or the value of renewable energy credits into their price-based energy bids because it creates unfair competition for unsubsidized generation.

Waste-to-Energy Concerns


Baas

The committee heard a very different story from Darwin Baas, director of public works for Kent County, Mich., who said utilities are violating PURPA to the detriment of waste-to-energy (WTE) facilities like the one run by his county.

There are 76 WTE plants with capacity of 2,547 MW nationwide. But Baas said only one new greenfield plant has opened in the last 20 years because utilities refuse to sign PPAs with QFs or to offer pricing and contract lengths WTE facilities need.

"PURPA's purpose (and the FERC's corresponding oversight authority) to ensure that small QFs continue to have access and fair compensation are as necessary today as when PURPA was first implemented," Baas said. "The commission's policies implementing PURPA should strive to increase the ability of small QFs to provide baseload renewable power to energy markets."

Baas said his county's utility is attempting to reduce its PURPA contract price by 24%. "This will not allow me the revenue necessary to make routine capital refurbishments, forcing me to seriously consider premature closing," he said.

"Avoided costs paid to WTE QFs by utilities should incorporate short-run and long-run avoided costs for capacity and energy and include the value of other environmental and operational externalities such as the value of baseload renewable energy, diversity of generation mix, proximity to load centers for voltage and VAR support, [greenhouse gas] mitigation, landfill diversion, [and] reliable and resilient power."

Baas said the 20-MW threshold should be raised to 80 MW for WTE QFs.

Solar Industry Weighs in


Glass

Attorney Todd G. Glass of Wilson Sonsini Goodrich & Rosati, who testified for the Solar Energy Industries Association, said PURPA remains "fundamental to the ability of independent power, including the solar industry, to compete."

"Even under workable competition, some of PURPA's goals may be lost if left solely to the marketplace," he said. "As they seek to compete, independent developers are facing a return of the same tactics by the utilities and the state commissions as they experienced almost 40 years ago when the idea of independent generation was presented as a potential competitive solution to utility dominance."

He said some utilities refuse to negotiate with IPPs and instead require them to participate in solicitations that occur infrequently and whose terms may be drafted to disadvantage the utility's competitors. Utilities also can engage in discriminatory practices where they control the interconnection process, he said.

Glass disputed opponents' claims that PURPA forced utilities to purchase overpriced energy, saying it is a misconception that arose "before current technological innovations and efficiencies of scale drove down solar power prices."

He said PURPA remains essential to financing renewable projects. "Just as utilities can benefit from a 20-year depreciation schedule to finance the construction of their owned power plants, independent producers rely on the capital markets to provide long-term capital to support construction and development of generation projects. The PURPA backstop supports financing for almost every one of these projects, even projects that do not have a sales arrangement under the PURPA construct."

"If the market cannot support the cost of the project, then the project should not be built."

Kristine Raper, Idaho PUC