RTO Insider

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NC Health Official Resigns in Dispute with Gov. over Duke Energy Coal Ash

By Ted Caddell

CHAPEL HILL, N.C. — A dispute between North Carolina's governor and a veteran state scientist over Duke Energy's coal ash practices has exploded into the public, with the scientist's boss resigning in protest.

The state epidemiologist, Dr. Megan Davies, resigned Wednesday night, after Assistant Environmental Secretary Tom Reeder and state Health Director Randall Williams posted a statement criticizing her staffer's concerns. The statement said toxicologist Ken Rudo's "questionable and inconsistent scientific conclusions" had "created unnecessary fear and confusion among North Carolinians."

Last year, Rudo balked at putting his name on a letter downplaying the risk of groundwater contamination near Duke power plants, despite being pressured by higher-ups in a meeting that he said included Gov. Pat McCrory, a Republican and former Duke Energy executive. McCrory has denied taking part in the meeting.

In her resignation letter, Davies was blunt. "I cannot work for a department and an administration that deliberately misleads the public," she wrote.

McCrory and his administration have been

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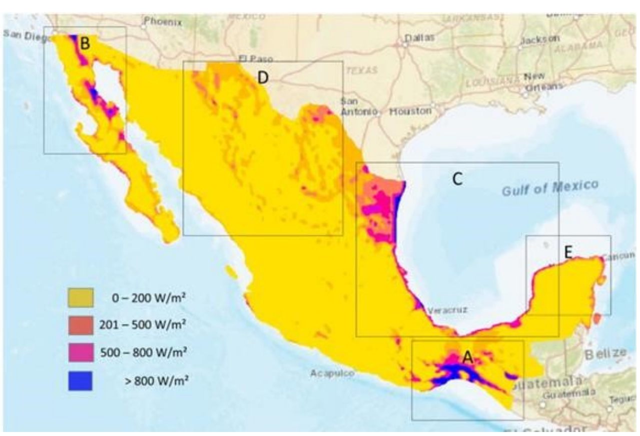
Energy Wildcatter Hopes to Make His Mark in Emerging Mexican Market

By Tom Kleckner

With its electricity demand projected to grow 3 to 4% annually, the expected retirement of 10 to 15 GW of fossil plants, a commitment to add 1 GW of wind power annually and off-peak prices as high as $65/MWh, Mexico presents an appealing target to generation developers.

And Mannti Cummins wants a piece.



Squares indicate zones with high wind potential: (A) Isthmus of Tehuantepec, (B) Baja California, (C) the Gulf Coast of Mexico, (D) the Northern region and (E) the Yucatan Peninsula.
Source: Renewable and Sustainable Energy Reviews

A certified public accountant by training, Cummins now calls himself a wildcat wind-energy developer, having developed more than 1,000 MW and $2.2 billion worth of wind projects in the U.S. and Mexico.

"Get in early, get in cheap," he said in describing his strategy. "Hopefully, it'll be a good market position with relatively few dollars spent."

For now, however,

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RTO Insider Top 30: Revenues, Earnings Down in Q2

Entergy Rides Acquisition, Rate Hike to Big Profit

By Rich Heidorn Jr.

The second quarter wasn't a great one for most companies in the *RTO Insider* Top 30, as revenues declined 2% compared with 2015 while profits dropped 15%.

Twelve companies reported increases in revenue, while 15 reported reductions and three were unchanged. The outliers were WEC Energy Group and Avangrid, which saw revenues soar because of acquisitions.

Eleven companies reported an increase in profits while 19 showed declines. FirstEnergy, NRG Energy, Centerpoint Energy and Calpine reported quarterly losses.

It was a *really* bad quarter for FirstEnergy, which reported a $1.1 billion loss, much of it related to the pending closure of five coal-fired units. The company said it plans to rid itself of its merchant generation and

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Energy Wildcatter Hopes to Make His Mark in Emerging Mexican Market

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Cummins and other developers are finding that a lack of transparency and uncertain rules are making their efforts anything but a sure bet.

Cummins, who grew up near the Gulf of Mexico, has made his home in Mexico for the past decade and speaks Spanish fluently enough to have completed a course in energy law from Mexico's Escuela Libre de Derecho law school. He helped develop that country's first two managed health care insurance firms and served as their CEO.

In his spare time, Cummins has been an avid surfer. He's also been known to play Billy Idol's "White Wedding" on his accordion.

Having made his mark in industries on both sides of the border, Cummins has jumped headlong into the Mexican energy market, which opened to national and international wholesale competition earlier this year.

Focus on Renewables

For the time being, much of the market's focus is on renewable energy. Mexican President Enrique Peña Nieto in June joined President Obama and Canadian Prime Minister Justin Trudeau in pledging to generate half his country's power from clean-energy sources by 2025, accelerating its 2013 pledge to produce 35% of its energy from renewable sources by 2024.

Cummins notes that Mexico's definition of "clean-energy sources" does not include natural gas or nuclear energy. The Ministry of Energy's National Electricity System Development Program projects Mexico will need more than 20,000 MW of clean energy over the next 15 years, part of an estimated $62.5 billion in private investment in the energy industry by 2018.

"Every year, Mexico has … to add 1,000 MW of wind power," said Cummins, currently director of Energia Veleta, S. de R.L. de C.V. (which translates as wind vane energy) in Monterrey, Mexico.

Cummins

Market Phase-In

Mexico's wholesale market will be implemented in phases through 2018. It consists of short-term markets (day-ahead, hour-ahead, real-time and ancillary services), medium-term auctions (three-year energy and capacity contracts), long-term auctions, financial transmission rights auctions, a capacity-balance market and the 20-year clean-energy certificates — instruments equivalent to 1 MWh of energy from clean sources — market that Cummins and other developers have their eyes on.

In the first clean-energy auction in March, about 80 firms offered more than 200 bid packages, with contracts awarded to Enel Green Power, Acciona, Jinko Solar and other players.

Cummins said state-owned Comisión Federal de Electricidad (CFE), Mexico's only utility, saw some solar projects bid as low as $40/MWh, lower than the utility had expected. All told, CFE awarded 5.38 million MWh of contracts, with almost 75% of those going to solar developers. A second auction will be held in September.

Because bidders were required to have a financial guarantee of about $40,000/MW to participate, Cummins lamented, the wildcatters were priced out.

"I wanted to bid in March, but I couldn't find

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Correction

A brief in last week's edition incorrectly stated that PJM's expected administrative rate for 2017 will be $0.37/MWh. PJM expects the rate to be between $0.34/MWh and $0.36/MWh.

RTO Insider Top 30: Revenues, Earnings Down in Q2

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transition to a "fully regulated company." (See FirstEnergy Posts $1.1B Loss, Eyes Exit from Merchant Generation.)

NRG said most of its second-quarter net loss of $276 million ($0.61/share) — worse than its $9 million loss a year ago — resulted from impairments and losses on asset sales. (See NRG Continues to Pare Down Businesses, Affirms Guidance.)

Centerpoint, which has utilities in Arkansas, Louisiana, Minnesota, Mississippi, Oklahoma and Texas, reported a net loss of $2 million ($0.01/share), compared with a profit of $77 million ($0.18/share) in 2015. The company said its results were dampened by a $16 million drop in income from Enable Midstream Partners, a gas gathering and processing limited partnership with OGE Energy. The company has offered to sell its 55.4% stake to OGE. (See CenterPoint Abandons REIT Plan; Offers Stake in Gas Partnership to OGE.)

Calpine showed a net loss of $29 million ($0.08/share) versus a profit of $19 million ($0.05/share) a year earlier. The company blamed mark-to-market losses resulting from increases in forward power and natural gas prices. It also said increased hydroelectric generation in the West contributed to lower energy margins for its gas-fired fleet, although this was partially offset by an increase in generation in Texas.

The companies showing the biggest revenue declines in the quarter were Calpine, NRG, NextEra Energy and Public Service Enterprise Group, each of which was down more than 10%.

NextEra

NextEra said revenues dropped to $3.82 billion in the quarter, a 12% reduction from a year earlier. Its Florida Power & Light saw a 2.5% drop in retail sales, despite adding 65,000 more customers, due to mild weather.

NextEra Energy Resources, the company's competitive energy unit, saw operating revenue drop to $970 million from $1.27 billion, due in part to hedging losses and the sale of 3,000 MW of natural gas generation in Texas. It also reported lower revenues from wind assets, which it attributed to lower output and reduced state and federal tax credits.

The company said it expects to add about 2,500 MW of contracted renewable generation in 2016, which would boost its renewable portfolio to 16,000 MW.

Last month, the company, which was rebuffed in its effort to buy Hawaiian Electric, reached an agreement to purchase Dallas-based Oncor in an $18.4 billion deal. (See NextEra Reaches Deal for Oncor.)

PSEG

PSEG reported second-quarter net income of $187 million ($0.37/share), a 46% drop from a year earlier. Operating earnings — which exclude the nuclear decommissioning trust, mark-to-market accounting and material one-time items — were flat year-over-year at $289 million ($0.57/share).

Public Service Electric and Gas' expanded capital investment program goosed its net income of $179 million ($0.35/share), an increase from the $167 million ($0.33/share) for 2015.

Weather-normalized electric sales for the 12 months ending June 30 were down 0.2% versus a year earlier despite an increase in the number of customers, because of increased energy efficiency and reduced industrial demand.

PSEG's wholesale power unit, which earned $166 million ($0.33/share) a year ago, had a net loss of $11 million ($0.02/share) as output dropped 6% because of mild weather, low gas prices and a decline in PJM capacity revenues.

PSEG Power also took a hit from an extended refueling outage at the Salem 1 nuclear unit for repairs. The outage dropped the average capacity factor for the company's nuclear fleet to 83% for the quarter, down from 86% a year earlier.

PSE&G line workers perform upgrades
Source: PSE&G

PSEG's Peach Bottom nuclear plant, however, increased its output following modifications that increased its capacity by 130 MW.

Output from its combined cycle fleet declined to 4.4 TWh from 4.6 TWh because of mild weather, while low gas prices reduced the dispatch of its coal-fired units, which saw production drop to 0.9 TWh from 1.3 TWh.

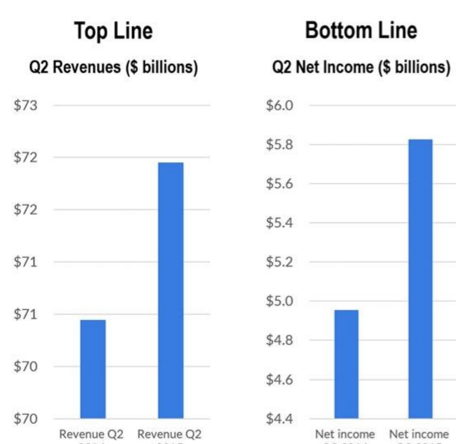
CEO Ralph Izzo said the company was maintaining its operating earnings guidance for the year 2016 ($2.80 to $3/share). "However, reaching the upper end of guidance will be difficult even with improvements seen in the power markets, expectations for warm summer weather, normal operations and management of O&M for the remainder of the year," he said.

Entergy

Entergy had a big earnings surprise, reporting second-quarter net income of $572.6 million ($3.11/share), almost tripling analysts' expectations of $1.05/share, as polled by Thomson Reuters.

"We continue to make progress toward

Continued on page 4



Source: Company filings

Union Power combined cycle plant *Source: Entergy*

RTO Insider Top 30: Revenues, Earnings Down in Q2

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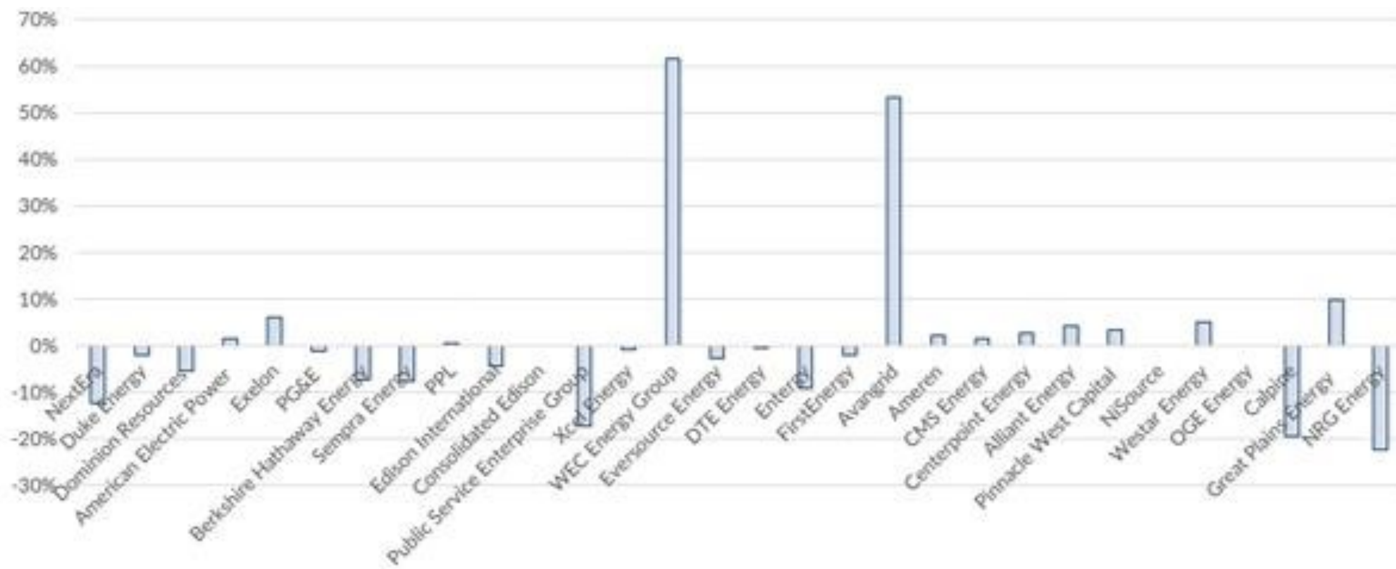
meeting our objective of steady, predictable growth at the utility while reducing our [Entergy Wholesale Commodities] footprint," Entergy CEO Leo Denault said.

One step to shrinking that footprint came earlier this month, when the company agreed to sell its FitzPatrick nuclear plant in New York to Exelon for $110 million. The plant, which Entergy had planned to close, had a net book value $143 million. (See *Entergy Sells FitzPatrick to Exelon*.)

Net revenue was boosted by the company's acquisition of the 1,980-MW Union Power combined cycle plant in Arkansas, Entergy Arkansas' rate increase and higher industrial sales. The company cited strong demand from petroleum refiners who "continued to operate at high capacity levels compared to last year."

Looking forward, the company also noted that it awarded itself contracts to build generation following competitive solicitations for Entergy Louisiana and Entergy Texas.



Q2 2016 revenue % change vs. 2015 *Source: company filings*

The *RTO Insider* Top 30

Rank*	Company	Market Cap. ($ billions)	Revenue Q2 2016 ($ billions)	% change vs. 2015	Net income Q2 2016 ($ millions)	% change vs. 2015
1	NextEra	58.47	3.82	-12.4	540	-24.6
2	Duke Energy	57.23	5.48	-2.0	509	-6.3
3	Dominion Resources	47.89	2.60	-5.5	452	9.4
4	American Electric Power	33.13	3.89	1.6	502	16.7
5	Exelon	32.37	6.91	6.1	267	-58.2
6	PG&E	32.2	4.17	-1.2	210	-48.3
7	Berkshire Hathaway Energy	N/A	4.12	-7.4	545	-3.9
8	Sempra Energy	26.78	2.18	-7.6	17	-94.3
9	PPL	24.84	1.79	0.6	483	-163.8
10	Edison International	24.82	2.78	-4.5	307	-24.6
11	Consolidated Edison	24.11	2.79	0	232	5.9
12	Public Service Enterprise Group	22.31	1.91	-17.3	187	-45.8
13	Xcel Energy	21.75	2.50	-0.8	197	-0.1
14	WEC Energy Group	19.75	1.60	61.6	182	124.6
15	Eversource Energy	18.19	1.77	-2.7	204	-1.8
16	DTE Energy	17.38	2.26	-0.4	152	39.4
17	Entergy	14.26	2.46	-9.2	573	284.7
18	FirstEnergy	14.19	3.40	-2.0	(1,089)	-682.4
19	Avangrid	13.58	1.44	53.4	102	827.3
20	Ameren	12.39	1.43	2.1	147	-2.0
21	CMS Energy	12.31	1.37	1.5	124	85.1
22	Centerpoint Energy	9.66	1.57	2.6	(2)	-102.6
23	Alliant Energy	9.02	0.75	4.2	86	23.3
24	Pinnacle West Capital	8.68	0.92	3.4	121	-1.3
25	NiSource	8.05	0.89	0.0	29	-203.2
26	Westar Energy	7.57	0.62	5.1	72	13.5
27	OGE Energy	6.21	0.55	0	72	-18.3
28	Calpine	4.61	1.16	-19.4	(29)	-252.6
29	Great Plains Energy	4.38	0.67	9.8	32	-27.9
30	NRG Energy	3.93	2.64	-22.4	(276)	2,966.7
	TOTAL		**70.44**	**-2.1**	**4,947**	**-15.4**

Methodology

The RTO Insider Top 30 includes the largest companies (by market capitalization) with significant presence in the seven RTOs and ISOs in the U.S. Since initiating the Top 30 in the first quarter, we have added Great Plains Energy and eliminated National Grid, a U.K.-based company that does not report its results quarterly. Expect more shuffling if Great Plains wins regulatory approval for its proposed acquisition of #26 Westar Energy.

*Rank is by market capitalization.

CAISO NEWS

CAISO Refines Cost Allocation Proposal for Expanded BA

By Robert Mullin

CAISO met with stakeholders last week to refine a proposal for allocating costs of new transmission facilities in an expanded balancing authority (BA) that would include areas of the West outside California.

ISO staff laid out options for creating "default" cost allocation provisions, a requirement under FERC Order 1000, at an Aug. 11 working group.

Under CAISO's proposal, "new facilities" would include new construction, additions and upgrades approved through the transmission planning process for an expanded ISO.

It would apply the transmission access charge (TAC) only to ISO-wide — or "regional" — projects meeting at least one of three criteria:

- Receives a rating of 200 kV or more;
- Facilitates a connection between two sub-regions; or
- Creates, supports or helps increase intertie capacity with a neighboring balancing authority area.

The proposal also creates a new category of "sub-regional" transmission projects excluded from the ISO-wide TAC, including facilities under 200 kV, as well as those constructed or approved before expansion. Costs for those projects would be allocated entirely to the sub-region requiring the project — such as PacifiCorp's service territory or the current CAISO BA.

Planning Process

CAISO staff told stakeholders that the TAC proposal is predicated on the assumption that the ISO's current planning process is "a reasonable model" for expansion.

"We redesigned our [planning process] in 2010 and we think it's a good model," said Lorenzo Kristov, CAISO principal of market infrastructure and policy. "There's no reason to think it wouldn't work with expansion."

That detail is important because the decision-making approach under the current planning process underpins the framework for the ISO's proposed default cost allocation scheme.

CAISO breaks down projects into three categories: reliability-driven, policy-driven, and economically driven.

ISO transmission planners run a proposed project through three stages of analysis, first determining the project's reliability benefits, followed by an assessment of how the project helps fulfill state objectives for increased renewable generation. A third stage examines the economic benefits of the project.

Some projects may have more than one driver.

"We want to avoid tagging projects as just being economic or policy — the world doesn't work that way."

Neil Millar, CAISO

"We want to avoid tagging projects as just being economic or policy — the world doesn't work that way," said Neil Millar, the ISO's executive director of infrastructure development.

Economically driven projects must produce total benefits exceeding the project's cost — demonstrating a benefit-cost ratio of 1.0 or greater. To calculate those benefits, the ISO relies on the transmission economic assessment model, which considers savings from more efficient dispatch, reduced line losses and congestion and increased resource adequacy.

While the ISO said it weighs economics in its evaluation of any proposed project, reliability- and policy-driven projects don't have to meet the same threshold as economically-driven projects.

"We look at it this way so that people don't think we can kill a project just for economic reasons, because it might meet a reliability and policy need," Millar said.

The analytical approach underlying the planning process would inform the ISO's proposed default cost allocation scheme under a redesigned TAC.

Benefit-Cost Ratio

Under the TAC proposal, costs for a project — including those for a reliability- or policy-driven project — with a benefit-cost ratio of 1.0 or greater would be allocated to sub-regions in proportion to the total economic benefits assessed for each sub-region.

For projects with a ratio less than 1.0, a portion of the cost would be allocated across sub-regions according to financial benefits, under the assumption that even uneconomic projects provide some economic benefits for market participants. Leftover charges — representing the portion of the costs not covered by economic benefits — would be assigned to the sub-region responsible for the reliability need or policy mandate driving the project.

In cases where multiple sub-regions derive policy or reliability benefits, leftover costs would be allocated in proportion to the total internal load for those areas during the year in which the project is placed into service, according to the proposal.

"The economics would be used to allocate the first tranche of needs, and then the incremental policy or reliability needs would be allocated on an incremental basis," Millar said.

The ISO is also considering a concept by which the avoided costs for a reliability- or policy-driven alternative would be factored into a sub-region's total benefits calculation for a proposed project.

A potential downside: A sub-region's TAC allocation could rise based on the assumed cost of a "hypothetical" project.

"Is the avoided cost of a hypothetical sub-regional alternative an appropriate basis for cost allocation?" the ISO asked stakeholders.

Feedback

"This looks good [as] a conceptual idea," said David Oliver, a managing consultant with Navigant. "But we're talking about transferring money in sub-regions and that's often not a fun thing to do."

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CAISO NEWS

CAISO Plans to Protect Small Utilities from High Network Upgrade Costs

By Robert Mullin

A new CAISO proposal seeks to shield smaller participating transmission owners from outsized network upgrade costs for interconnecting generation built to serve load outside that TO's service area.

"The issue is — to what extent should a local area incur costs for resources that are clearly not serving that area?" Neil Millar, CAISO executive director of infrastructure development, said during an August 8 call to discuss the proposal.

"Network upgrades on low-voltage facilities for [TOs] with a relatively low rate base can significantly increase costs [for those PTOs]," said Steve Rutty, the ISO's director of grid assets. "Similar upgrades would not have much of an impact" on larger TOs.

The proposal stems from the situation confronting Valley Electric Association, which serves 45,000 customers located in a 6,800-square-mile region straddling the California-Nevada border. The utility — CAISO's only out-of-state member — has about 100 MW of load. Two projects awaiting interconnection will bring 100 MW of new generation into Valley's territory, with more entering the queue, according to Rutty.

"So we're looking at hundreds of megawatts for an area with just 100 MW of load," Rutty said.

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

Postage Stamp Rate

Unlike CAISO's high-voltage TAC, which is allocated to all ISO ratepayers at a "postage stamp" rate based on the aggregated revenue requirements of all TOs owning high-voltage lines, the low-voltage TAC is charged only to customers within the service area of the TO owning the facilities.

That arrangement could impose an unfair financial burden on ratepayers served by small TOs such as Valley.

"[I]f a large generator or a large number of generators with significant low-voltage network upgrade costs interconnect to a [TO] with a relatively small rate base, that [TO's] rate base may increase significantly and can result in rate shock to its ratepayers," the ISO said in its straw proposal.

The ISO estimates that $25 million in network upgrade costs would boost Valley's low-voltage TAC from $6.26/MWh to $12.13/MWh — a 94% increase.

"There's a considerable amount of interest in Valley for renewables," said ISO attorney Bill Weaver. "If all the projects come online, $25 million is not unreasonable to expect."

But those projects will not provide a "commensurate benefit" for the utility's ratepayers, CAISO said.

The ISO has proposed two options to address the issue, which it expects to occur again if the ISO expands into other areas of the West and takes on additional small TOs.

The first option would allow a TO to roll "generator-triggered" low-voltage network upgrade costs into its high-voltage revenue requirement for recovery through its high-voltage TAC. The rationale: Any new generation will provide energy for the entire ISO market or support policy goals such as resource adequacy, reliability and increased renewables.

Under this scenario, $25 million in upgrades

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CAISO Refines Cost Allocation Proposal for Expanded BA

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LS Power Vice President Sandeep Arora said, "I think this is very encouraging — the entire approach of looking at a transmission project not just fitting into one bucket but looking at the various benefits a project brings."

The ISO said updating the TAC plan is a "central policy element" in the development of a Western RTO. Utility commissions in five states must grant approval before Portland-based PacifiCorp can join the ISO. The cost allocation scheme is likely to weigh heavily in regulators' decisions.

CAISO planners initially expected to wrap up the TAC proposal in time to present it to the ISO's board of governors in late August, in concert with a push to submit an RTO governance plan to California lawmakers before the end of this summer's legislative session. (See: *CAISO Floats Latest Cost Allocation Plan for Expanded Balancing Area.*)

The ISO got more breathing room after Gov. Jerry Brown's Aug. 8 decision to postpone efforts to win legislative approval to expand the ISO until early 2017. (See: *Governor Delays CAISO Regionalization Effort.*)

"Last time we had a meeting on this topic … we were still contemplating taking this to the board at the end of August, as ridiculous as that sounds," CAISO's Kristov said.

Instead, the ISO is likely to continue work on the proposal for the rest of the year, Kristov said.

> **"I think this is very encouraging — the entire approach of looking at a transmission project not just fitting into one bucket but looking at the various benefits a project brings."**
>
> **Sandeep Arora, LS Power**

CAISO NEWS

CAISO Plans to Protect Small Utilities from High Network Upgrade Costs

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in the Valley area would translate into a 1.5-cent/MWh — 0.14% — increase in high-voltage TAC rates shared by all ISO ratepayers.

"This option would apply to all PTOs, is straightforward and would be fairly simple to implement," the ISO said.

"This raised the question of whether local upgrades are helping the local area — which

Valley Electric Association, which joined the ISO in 2013, serves about 45,000 customers in its 6,800-square-mile territory. *Source: CAISO*

brought up the issue of some kind of cost sharing," Millar said. "Which brought us to option two."

The second, more complicated, option would split cost recovery for low-voltage upgrades between a TO's low-voltage and high-voltage TACs. The split would be assessed in such a way as to cap increases to a TO's low-voltage revenue requirement and TAC. Any amount above the cap would be applied to the TO's high-voltage revenue requirement and thereby rolled into the ISO's TAC.

Three Options

The ISO is considering three methods for calculating the split:

- Place a cap on the cost share of interconnection-driven upgrades assigned to a TO based on a percentage — possibly 5% — of the TO's low-voltage base rate. TO's with smaller base rates would be capped at significantly lower amounts than the larger investor-owned utilities.
- Limit incremental increases to a TO's low-voltage revenue requirement based on a percentage of the TO's annual low-voltage revenue requirement.
- Limit incremental increases in the revenue requirement to a percentage of the high-voltage TAC revenue recovered from the TO's ratepayer base.

"This last method would make sense because it limits exposure of a local area group of customers to a percentage of their high-voltage TAC payments," the ISO said. "As such, a utility twice the size of another could reasonably absorb twice the local impact of interconnection-related low-voltage network upgrades compared to a utility with a much smaller customer base."

"We want to know the justification for the proposal," said Lanette Kozlowski, director of regulatory relations at Pacific Gas and Electric. "Is it just the rate impact for the customers of [Valley Electric]?"

"That's overly simplistic," said Millar. "The cost issue certainly puts a spotlight on it, but it's more about resources being developed in an area that won't be serving that area."

"How is this going to align with the other utilities where you're connecting to the network and it's being fully paid for by the project?" asked Don Davie, vice president with Wellhead Electric. "What are you thinking about for cost-causation for the actual project?"

"We're not really going to propose shifting the costs to interconnection customers," Millar said.

ISO staff plans to submit a final plan to the Board of Governors in December. Stakeholders must submit comments about the straw proposal by Aug. 19.

CAISO NEWS

PG&E Files Diablo Canyon Shutdown Request

By Robert Mullin

Pacific Gas and Electric filed with California regulators last week to shut down the state's last remaining nuclear power plant by the end of 2025.

The application also asks the state Public Utilities Commission to approve a joint proposal that the utility forged with environmental, labor and anti-nuclear groups to replace output from the 2,240-MW Diablo Canyon facility with a portfolio of renewable resources, energy efficiency measures and energy storage.

PG&E announced the closure in late June, saying the plant's full output would no longer be needed in light of dramatic changes in California's energy market, which increasingly is putting a premium on flexible resources over inflexible baseload generation. (See: *PG&E to Shut Down Diablo Canyon, California's Last Nuclear Plant*).

In its filing, the utility also pointed out the uncertainty of its future supply needs, with customer demand being undercut by improvements in building efficiency, increased adoption of rooftop solar and the growth of alternative energy suppliers such as community choice aggregators (CCA).

"As a result of the rapidly changing California energy landscape, Diablo Canyon will not be needed at the end of the license period," the utility wrote.

The joint proposal accompanying the filing includes three tranches to procure energy efficiency and greenhouse gas-free resources between 2018 and 2045.

The first tranche is intended to reduce load before Diablo Canyon retires through a competitive solicitation to add 2,000 GWh worth of energy efficiency to PG&E's service territory by 2024. The company is seeking PUC authorization to recover $1.3 billion to administer the program over seven years through a "public purpose program" rate component.

Included in the second tranche is a solicitation for 2,000 GWh of carbon-free energy to be delivered between 2025 and 2030, with renewable resources, energy efficiency and other technologies eligible to bid. PG&E is seeking to recover part of the costs associated with this tranche from a "clean energy charge" allocated to the utility's bundled electric and direct access customers as well as to CCA customers. Renewable procurement costs would also be recovered from an additional fee assessed on customers who depart from PG&E.

Diablo Canyon nuclear plant *Source: PG&E*

The third tranche includes PG&E's voluntary commitment to increase its renewable portfolio standard to 55% over the 2031-2045 period — five percentage points above the current 2030 mandate.

The joint proposal also includes provisions for PG&E to recover costs related to winding down Diablo Canyon's operations.

PG&E is asking the PUC to approve a two-way balancing account to implement yearly rate adjustments to recover the costs and allow the plant's book value to be depreciated to zero by the time it closes. The utility is also seeking have ratepayers cover $53 million in costs previously incurred in efforts to renew the plant's operating license beyond 2025.

PG&E has requested a decision by the CPUC by June 2017.

ERCOT NEWS

ERCOT Surpasses 70,000 MW Again, Sets Six Hourly Peak Demand Records

By Tom Kleckner

ERCOT has broken the 70,000-MW barrier for the first time, setting six new systemwide hourly peak demand records last week.

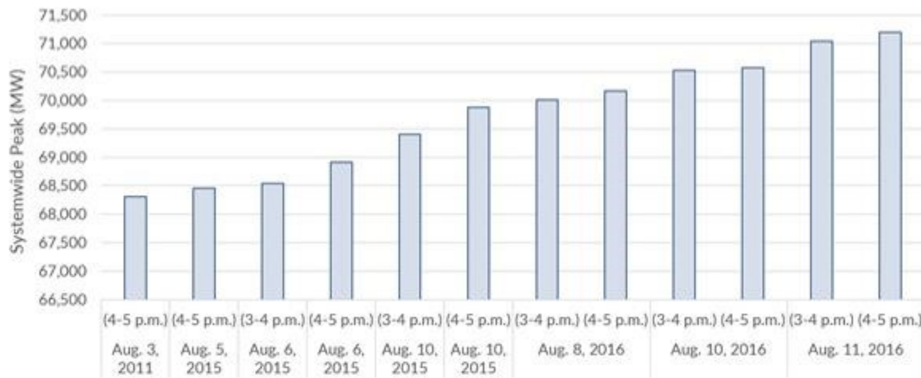
The Texas grid operator registered its latest record peaks Thursday when system load reached 71,197 MW between 4 and 5 p.m., after having climbed to 71,043 MW between 3 and 4 p.m.

That smashed records set Wednesday (70,572 MW) and Monday (70,169 MW), which had bettered the previous mark of 69,877 MW set last August. The grid fell short of another record Friday, peaking in the 4 p.m. hour at 70,343 MW.

Real-time settlement prices spiked to $220.37/MWh systemwide at 2:15 p.m. Thursday. The Rayburn load zone was still settling at $228.72 at 4 p.m., with the Whitetail Wind Project in the congested North zone offered into the market at as much as $1,000.14 during the 4 p.m. hour.

ERCOT's peak demand first surpassed 70,000 MW between 3 and 4 p.m. Monday, before setting a short-lived record between 4 and 5 p.m.

With triple-digit temperatures settling over the state, the Texas grid operator expected load to peak above 70,000 MW again Thursday between 4 and 6 p.m. Whether it sets a new record remains to be seen.



ERCOT systemwide peaks (MW) *Source: ERCOT*

"Welcome to August," ERCOT CEO Bill Magness told the Board of Directors Tuesday morning. "Usually, peak records set in August don't normally last."

Magness was quick to note ERCOT did not have to call an emergency alert Monday, saying, "It was a great performance by the system and the people who make it work."

"These hot summer days always put our grid to the test," said ERCOT's director of system operations, Dan Woodfin, on Wednesday. "We have had sufficient generation available to carry us through these high-demand periods."

The Texas grid operator also set a new weekend peak demand record Sunday when it hit 67,000 MW.

Staff said it expects consumption to drop this week and believes it has sufficient generation as long as resources are available. ERCOT's final summer Seasonal Assessment of Resource Adequacy said the ISO had 78,434 MW of generation capacity available and projected a peak summer demand of 70,588 MW.

Board of Directors Briefs

Board Rejects RMR Mitigated-Offer Appeal, Lets Stakeholder Process Move Forward

ERCOT will rely on its stakeholders to improve its reliability-must-run (RMR) practices after a second rejection last week of a protocol change that would allow the economic dispatch of RMR units.

The ISO's Board of Directors on Aug. 9 rejected NRG Texas and Reliant Energy Retail Services' appeal of a nodal protocol revision request (NPRR) addressing how RMR units are priced and dispatched. The appeal was shot down by an 11-3 vote, with one abstention.

The two companies also lost an appeal in July to the Technical Advisory Committee (TAC) after the revision request failed to clear the Protocol Revision Subcommittee (PRS). (See "Pricing Change on RMR Units Rejected, Appealed to ERCOT Board," *ERCOT Technical Advisory Committee Briefs*.)

NRG drafted NPRR 784 earlier this summer as ERCOT was in the process of issuing and extending into 2018 an RMR contract for the company's Greens Bayou Unit 5, a 371-MW gas plant near Houston. (See "Board Expands Greens Bayou RMR Contract to 2018," *ERCOT Board of Directors Briefs*.)

The protocol change would have allowed security constrained economic dispatch (SCED) of RMR units to relieve transmission congestion, after all other capacity available for transmission congestion relief had been exhausted. It would have applied only when generator offers are mitigated due to inadequate competition.

RMR units are currently subject to the same offer mitigation as other units in such a situation, with Greens Bayou Unit 5 likely being offered at around $50 to $60/MWh. When there is adequate competition, RMR units are offered at $9,000/MWh under either the status quo or the proposed change.

The revision request would have required all RMR units to be offered at the highest possible price that would still allow SCED to dispatch the unit for congestion. In Greens Bayou's case, the estimates are as high as $700/MWh.

NRG's Bill Barnes said the proposed change raised a pricing policy question that is fundamental to the energy-only market design. "The energy-only market requires effective pricing, and it does so all the time … ," he said.

"It sends a signal for existing resources to remain in the market or exit if they're uneconomic. Second, it provides incentives for new investment. Locational price signals are equally important as systemwide price signals."

Air Liquide's Phillip Oldham advocated

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TAC's position by urging the board to reject NRG's appeal, given the "important stakeholder input" provided by its failure at TAC and PRS. He reminded the directors that RMR protocols are currently being reviewed and asked they let the process play out.

"We believe [784] is inconsistent with market principles that have been in place," Oldham said. "We fundamentally disagree, even at the most basic levels, about what an RMR is. It is not a generation issue. It's a transmission issue."

Oldham said the revision request doesn't support resource-adequacy objectives, noting Greens Bayou Unit 5 is an RMR for local reliability, not systemwide capacity. He also pointed to the $590 million Houston Import transmission project as the RMR "exit strategy" for the Houston area, a position later supported by ERCOT's COO, Cheryl Mele.

"Using the RMR to set high prices in Houston between now and 2018 will not incentivize new resources because a transmission solution is already in process," Oldham said.

ERCOT Director Nick Fehrenbach, the City of Dallas' manager of regulatory affairs and utility franchising, said he had received calls from his consumer market segment members worried about the revision request's consequences.

"They're concerned about the impact this could have on load in the Houston area," he said. "It's simply a short-term solution before we get the Houston Import project built. I don't think this is a smart move."

ERCOT's RMR contract with Greens Bayou requires the ISO to pay $3,185/hour for the duration of the agreement and an incentive factor of as much as 10% to reserve the unit's capacity.

"As you saw in the debate … there's some sense of urgency around looking at this," said ERCOT CEO Bill Magness when the smoke had cleared. "[RMR] is an important reliability tool, but it's a relatively blunt instrument. It is a large bundle of issues, but one that we believe, with a lot of effort and focus from stakeholders and staff, we can get some items to the board for consideration fairly soon."

TAC Chair Randa Stephenson of the Lower Colorado River Authority was reminded her committee had predicted NPRR 784 would be a "hot topic" six months ago. She said stakeholders have been "digging into the protocols" and existing parameters as they try to improve the RMR process.

At a workshop in May, stakeholders identified 18 RMR-related issues, giving priority to the following three:

- A timeline on notifications suspending operations;
- Studies, processes and criteria used to identify whether a resource is needed for RMR service; and
- Capital contributions to an RMR unit.

Several NPRRs are currently being developed that address the RMR process, timeline and notice. Stephenson said the timing of a staff-drafted revision request modifying the current RMR process has yet to be determined, but other NPRRs will bubble up through the stakeholder request during the next six months.

Last month, ERCOT also issued a request for must-run alternative resource proposals that offer more cost-effective solutions (defined as more than $1 million in savings) than Greens Bayou. Responses are due Aug. 24, with any agreements to be announced Oct. 7.

IMM Notes 26% Drop in Real-Time Prices

The Independent Market Monitor reported that the growing abundance of Texas' wind resources helped cut load-weighted real-time prices 26% in the first half of 2016 compared with 2015.

IMM Director Beth Garza said ERCOT's real-time prices have averaged $20/MWh through June, compared with $27/MWh for the same period last year. She called the number "momentous" but said prices will increase "as you factor in the effects of last month and going into August."

Garza said ERCOT's wind fleet has grown so much that in June there was never less than 3,500 MW available. She said average capacity factors and energy totals have been higher per MW of nameplate capacity this year, thanks to ERCOT's recent transmission buildout.

"And the preliminary data in July shows the wind will be higher than it was in June," she said. " … People are building more of it, so we get more energy."

ERCOT's generation-interconnection status report shows more than 10,000 MW of wind generation due to come online through 2018.

Garza's report also noted that ERCOT's ancillary service (AS) costs at mid-year have increased $0.05/MWh over 2015, even though the ISO is procuring fewer such services. She said the IMM will continue to

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2016 YTD real-time price average *Source: ERCOT*

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monitor the AS market to determine the cause of the increase.

Magness Reports Favorable Financials to Board

Magness said August's searing temperatures are expected to make up for milder conditions earlier in the year. The ISO's net revenues were $4.9 million over budget through June, despite being $2.5 million behind on administration fees. Those numbers are currently projected to finish $7.5 million and $0.5 million over budget, respectively.

The president's report also addressed the July 7 Energy Management System (EMS) outage and TAC's concerns that ERCOT did not communicate quickly enough with the market. (See "Committee Discusses July 7 System Outage," *ERCOT Technical Advisory Committee Briefs*.)

"It's always a balance of not wanting to speak until we know what's going on, but that's something we're working on," Magness said. "It was a human error event, and we took responsibility for that. We've changed the process to make sure that is not an error we're going to see again."

Magness also took time to recognize the 170-person team behind ERCOT's recent EMS upgrade. The four-year project went live June 16 following 84,000 person-hours of work, coming in under budget and ahead of schedule.

"The EMS upgrade was one of those processes that's described as performing brain surgery on the pilot while he's flying the plane," he said.

Board Approves 8 Protocol Revisions, 2 Other Changes

The board approved seven NPRRs, a system-change request (SCR) and revisions to the Planning Guide (PGRR) and the Resource Registration Glossary (RRGRR). NPRRs 696 and 738 were the only two revision requests that received any opposing votes.

- NPRR696: Establishes price corrections following a SCED failure by correcting prices for settlement intervals corresponding to the active watch period, giving market participants transparency to known prices that reflect the last good SCED execution.
- NPRR738: Excludes intervals from performance calculations when an emergency response service generator is unable to meet its obligations due to transmission or distribution service provider (TDSP) outages.
- NPRR747: Proposes new definitions related to voltage profiles, defines various entities' responsibilities for voltage support and clarifies that the interconnecting transmission service provider or its designated agent may modify a generation resource's voltage set point.
- NPRR767: Changes the eligibility check for the startup portion of the reliability unit commitment make-whole payment. Resources with lead times longer than six hours may submit a settlement dispute to have their resource-specific startup times considered when determining eligibility for including startup costs in the make-whole payment calculation.
- NPRR770: Adds visibility and situational awareness to the market by posting the aggregate number of telemetered resources and their statuses to the ancillary services capacity monitor.
- NPRR771: Clarifies that TDSPs must ensure an electric service identifier has been created in ERCOT systems before initiating electric service at a premises to avoid transactional, billing and out-of-sync issues.
- NPRR774: Removes duplicate language regarding the calculation of seasonal transmission-loss factors.
- PGRR046: Aligns the planning guides with NERC's TPL-007-1 reliability standard related to geomagnetic disturbance events by specifying a process for developing geomagnetically-induced system models.
- RRGRR009: Adds three categories of data to the Resource Registration Glossary: Voltage limits for transmission level equipment at generator substations; geomagnetically-induced currents and the presence of blocking devices to allow identification of vulnerabilities due to geomagnetic disturbances; and a most limiting single element (MLSE) allowing a resource entity to identify an MLSE on lines it doesn't own.
- SCR789: Updates the network model management system topology processor to add a software tool commonly used by transmission-planning entities in ERCOT.

— Tom Kleckner

ISO-NE NEWS

ISO-NE Ordered to Justify Cost of Winter Reliability Program

By William Opalka

Following a directive from a federal appeals court, FERC ordered ISO-NE to provide more information proving that the 2013-14 winter reliability program resulted in just and reasonable rates (ER13-2266).

"ISO-NE should request from program participants information that will enable ISO-NE's [Internal Market Monitor] to evaluate the competitiveness of the program and whether any amounts exceeding a participant's cost of providing the winter reliability service are indicative of market participants exercising market power in that program," FERC wrote in the Aug. 8 order.

ISO-NE previously said such information was commercially sensitive and should not be disclosed.

Under the program, selected resources were compensated through a monthly payment derived from the resources' bids under an "as-bid" pricing mechanism, rather than a uniform clearing price, FERC wrote.

The program paid for demand response resources and some of the carrying costs for dual-fuel generators that stored oil on-site.

FERC granted ISO-NE expedited approval for the program in late 2013 due to concerns that the region might fall short of generation due to the retirement of coal-fired units and tight natural gas supplies.

Although ISO-NE estimated the program would cost no more than $43 million for up to 2.4 million MWh of energy, the RTO filed for approval of bids totaling nearly 2 million MWh at a cost of $78.8 million, which FERC accepted.

TransCanada Power Marketing argued that this cost disparity required more scrutiny and that the commission did not have adequate information to determine whether the bid results were just and reasonable.

After FERC denied a request for rehearing in 2014, the company appealed to the D.C. Circuit Court of Appeals. On Dec. 22, 2015, "the court agreed with TransCanada's argument that the record was devoid of any evidence regarding how much of the program's cost was attributable to profit and risk mark-up," according to the commission order.

The order directs ISO-NE to request from market participants the basis for their bids, including the process used to formulate the bids. The commission also required an analysis from the IMM and a recommendation from ISO-NE on the reasonableness of the bids within 120 days.

FERC also said ISO-NE "may choose to request" information justifying suppliers' bids in in the subsequent years' reliability programs.

MISO News

MISO to Begin Charging Tx Fees on PJM Exports

By Amanda Durish Cook

MISO last week filed revised Tariff language allowing it to recover costs for multi-value transmission projects that benefit PJM customers by charging a fee on exports to PJM (ER10-1791-003). The Aug. 12 compliance filing requested the new language be retroactive to July 13, 2016.

Last month, FERC partially lifted the three-year-old restriction on MVP allocations for exports in response to a 2013 remand from the 7th U.S. Circuit Court of Appeals. (See *FERC Looks Again at Export Pricing for MISO MVPs*.)

The commission said it was persuaded by the large-scale wind buildout "capable of serving both MISO's and its neighbors' energy policy requirements."

It also cited "the reported need of PJM entities to access those resources; and the reported need for MISO to build new transmission facilities to deliver the output of those resources within MISO for export."

"Given these changes, it is appropriate to allow MISO to assess the MVP usage charge for transmission service used to export to

Foundations are laid for Ameren's Illinois Rivers transmission project, a 345-kV line stretching from West Adair, Mo., to Sugar Creek, Ind. The line consists of five multi-value projects, and portions are expected to come online as early as this year. *Source: Plocher Construction*

PJM just as MISO assesses the MVP usage charge for transmission service used to export energy to other regions," FERC concluded.

MISO created the MVP category six years ago for projects that address more than one reliability or economic need across multiple transmission zones. The RTO originally intended to allocate project costs to all of its load and exports, but FERC excluded the export charge because of concerns over rate pancaking.

Chris Miller, FERC's liaison to MISO, said the RTO removed Tariff language that had prohibited it from charging exports. Affected portions include Attachment MM, Schedule 26-A, Schedule 39 and Attachment L.

MISO also made an informational filing in early August detailing multi-value, market efficiency and baseline reliability projects approved during the Transmission Expansion Plans in 2014 and 2015 (ER13-186, ER13-187). While 140 baseline reliability projects were approved in the two years, only one market efficiency project was greenlit.

The RTO did not approve any MVPs in 2014 or 2015. It said its $6 billion 2011 MVP portfolio — 17 projects in various transmissions zones over nine states — left only local reliability projects to be addressed for the time being.

Three of the projects are in service, with the remainder scheduled to be operational in three to five years.

Michigan Asks: Will the Lights Stay on if Nukes Go Dark?

By Amanda Durish Cook

Concerned about the impact of plant retirements in the state, Michigan officials have asked MISO to conduct a reliability analysis that assumes simultaneous outages at the Palisades and Fermi 2 nuclear plants.

Entergy's Palisades plant on Lake Michigan and DTE Energy's Fermi 2 on Lake Erie — both in MISO's Zone 7 — are capable of generating a combined 1,855 MW.

In a letter to MISO, Michigan Public Service Commission Chairwoman Sally Talberg and Valerie Brader, executive director of the Michigan Agency for Energy, said they wanted to understand what would happen in the summer of 2018 if Michigan experienced another event like it did in the summer of 2012 when the two nuclear plants were out of service while MISO was under a hot weather alert.

MISO spokesperson Andy Schonert said the RTO was reviewing the request.

The state officials said it was "crucial" for Michigan to know its vulnerabilities and whether it still could ensure reliability. They asked MISO to assess the zone's internal generating capacity and available contracted capacity as well as how much generation could be imported from outside the state.

Fermi 2 nuclear plant *Source: DTE Energy*

"We did not pick this scenario randomly," Brader said. "In the summer of 2012, we had outages at two nuclear facilities while MISO was under a hot weather alert. Despite those outages, we were able to keep the lights on. Now we have a lot fewer plants operating. We want to know if the lights would stay on if we had the same thing happen in the summer of 2018."

Talberg said the assessment would be "a valuable tool" for future PSC planning. She noted Michigan already relies on out-of-state imports to meet its reliability requirements.

The Michigan PSC's five-year outlook through 2020 predicts "reliability challenges during periods of peak demand in the 2017-2018 timeframe" in Michigan's Lower Peninsula.

MISO NEWS

MISO Will Use ATC Plan to End Upper Peninsula SSR

By Amanda Durish Cook

Map shows ATC's transmission system in the western Upper Peninsula. The orange circles indicate how the load pocket will be split into two radially fed areas. Location of White Pine Unit 1 circled in blue on upper left of map. *Source: MISO*

MISO will ask FERC to end a system support resource agreement in Michigan's Upper Peninsula, saying its reliability concerns will be addressed by American Transmission Co.'s transmission reconfiguration until an upgrade expected in service by the end of 2020.

MISO said ATC's proposal to open transmission circuits and split the western UP load pocket into two radially-fed areas "avoids [the] risk of cascading loss of load during prior outages," allowing the termination of White Pine Unit 1's system support resource (SSR) agreement.

MISO plans to file to terminate the SSR agreement following a 90-day notice, Joe Reddoch of MISO's System Support Resource Planning Group said during a meeting of the West Technical Study Task Force Aug. 8. Reddoch said the two-radial configuration would be used only during planned outages or when one of the area's two 138-kV lines is unexpectedly out of service. The load pocket would be served by the remaining 138-kV line and the Conover 69-kV line.

ATC submitted the proposal to MISO in late July. (See *ATC Plan Could Eliminate White Pine SSR; Refunds Coming on Presque Isle?*)

"Some of these are day-long outages. I think the longest one we looked at is somewhere in the order of a week," Reddoch said.

MISO concluded the two-radial configuration would result in only a small increase in the risk of loss of load.

The load pocket in the western Upper Peninsula around White Pine — about 68 MW during shoulder periods and 80 MW in the summer — is supported by two 138-kV circuits and one 69-kV line. An outage of one 138-kV line followed by the loss of the second line "results in severe overloads and voltage collapse in the local load pocket," MISO said.

The RTO said ATC's plan would result in a "limited" increase in the risk of a consequential load shed, which could be managed within the RTO's planning and operating criteria, which allows mitigation through reconfiguration.

"From our perspective, this is an acceptable alternative," Reddoch said. "The radial reconfiguration isn't unheard of in the system. It may not be ideal, but it's certainly acceptable."

Richard Bonnifield, an attorney for White Pine Electric Power, said stakeholders were being "blindsided" by the introduction and acceptance of ATC's plan in the same stakeholder meeting and asked for a reliability impact analysis on the removal of White Pine. Reddoch said a reliability analysis would not provide any additional information and would serve only to "unnecessarily" delay implementing the solution.

Bonnifield fired back that the stakeholder process regarding the SSR removal was "unstructured." Other stakeholders asked for more time to assess the alternative.

"Our assessment does not require any extensive analysis. This reconfiguration is already in place for unplanned outages. This has already been an accepted process for unplanned conditions. I don't think we can conclude that it's not acceptable," Reddoch said. Ken Copp, a strategic technical advisor with ATC, confirmed that ATC's system in the western Upper Peninsula would return to a configuration prior to the 1990s when Wisconsin Electric Power Co. and ATC tied their lines together.

Some stakeholders asked Copp why the lines were tied together in the first place.

"Back in that day, contract paths were a big deal, especially for wholesale customers. It achieved some contract path goals, but we have to label that as anecdotal, not something that's documented," Copp said.

Some stakeholders said the transmission reconfiguration would not be as reliable as keeping the SSR in place.

Reddoch responded that the plan isn't in violation of planning criteria and presents a no-cost alternative for ratepayers. "It might not be ideal, but even an SSR isn't ideal," he said.

White Pine Electric Power requested retirement of White Pine Unit 1 in April 2014. The current SSR agreement was expected to last until 2017.

The long-term solution for the reliability concerns that gave rise to the SSR is a $100 million plan to convert the 75-mile, 69-kV transmission path from Lakota Road to Mass to Winona to 138 kV. The project, included in MISO's 2015 Transmission Expansion Plan, is slated to be finished in December 2020.

Angela Castle of the Michigan Agency for Energy said ATC's solution would be "much less onerous" on ratepayers.

Steve Leovy, a transmission engineer at WPPI Energy, told stakeholders that ATC presented the alternative solution despite not being directly affected by SSR costs.

"ATC isn't in this; they don't have to pay the SSR costs. Our ratepayers have to pay the SSR costs. We are supportive of this … and we don't take the increased risk of load loss lightly," Leovy said.

Reddoch said MISO will work with ATC in the coming weeks to revise the company's operating guide to remove White Pine availability and introduce the reconfiguration plan. Details of the revised operating guide will be kept confidential per MISO procedure.

MISO NEWS

RSC Briefs

MISO Preparing for Future Changes in Frequency Response

MISO wants to know how it can improve frequency response under an evolving generation fleet and is asking for stakeholder involvement to draft an issues statement.

"This isn't a new topic. The industry has been grappling with the issue for years," said Durgesh Manjure, MISO's manager of resource adequacy coordination.

Manjure said MISO hasn't encountered the frequency response challenges that other systems such as ERCOT have encountered.

"But that doesn't mean everything is fine and we won't have to introduce something to keep this reliable trajectory going forward," Manjure said during an Aug. 10 meeting of the Reliability Subcommittee (RSC). "By no means is this an issue now or next year, but I can't say that with the same level of confidence for five years out."

"By no means is this an issue now or next year, but I can't say that with the same level of confidence for five years out."

Durgesh Manjure, MISO

The RTO said that "opportunities exist to improve dynamic models" and performance measurement.

MISO said its changing fleet is driving the frequency response discussion, with coal taking an ever-shrinking share, while gas and wind sources climb. Manjure said MISO relies on coal for "most if not all" of its frequency response, but technological advancements are allowing other generation types to provide a governor-like response to a drop in frequency.

Between 2009 and 2015, MISO's coal generation capacity dropped from 71.8 GW to 65.2 GW, while wind capacity almost doubled from 7.6 GW to 15 GW. Natural gas, responsible for only 6% of MISO energy production in 2010, now claims 28%; coal's share fell from 73% to 45% over the same period.

According to NERC's State of Reliability 2016 report, frequency response reliability in the Eastern Interconnection is expected to decline from the approximate 2,500 MW/0.1 Hz in 2012 to a little more than 2,000 MW/0.1 Hz in 2019.

Manjure said MISO wants to know if its models accurately reflect actual systemwide performance and what fuel mix point would render MISO's frequency response inadequate. MISO is also asking if it needs to improve its tools that measure frequency response and revise Tariff or market mechanisms relating to frequency response.

"This is very high-level, very open to feedback," Manjure said.

Manjure asked for stakeholder input that will be used to shape an issues statement in the coming weeks.

Improvement to Pseudo-Ties Process on MISO Horizon

Kyle Abell of MISO's market planning division said MISO is trying to improve the congestion management process for its increased volume of pseudo-ties.

MISO said it has experienced escalating pseudo-tied generation with load farther from the seams in 2016. In the 2015/16 planning year, MISO-based generation pseudo-tied into PJM equaled only 155 MW; in the 2016/17 planning year, the amount is expected to reach about 2,000 MW. In the 2017/18 planning year, pseudo-ties are expected to creep toward 2,800 MW, with many of the deeper pseudo-ties sent to attaining balancing authorities with "very limited or no modeling-based visibility" of how their usage affects the larger MISO system.

Abell said MISO is contemplating new requirements for approving a pseudo-tie, including notification, pre-assessment and conditional approval steps. In addition, the RTO may set out requirements for an attaining balancing authority's network model for proposed pseudo-ties. Currently, MISO reviews and approves pseudo-tie requests, while balancing authorities are responsible for market-to-market redispatch.

MISO asked stakeholders for suggestions to improve its pseudo-tie congestion management before Aug. 26. The RTO also said it would meet with neighboring balancing authorities and RTOs and its Independent Market Monitor to discuss the issue. Abell said he would make another pseudo-tie presentation at the Aug. 16 Planning Subcommittee meeting.

MISO plans to revise its processes around congestion caused by pseudo-ties through November, in time to draft a work plan to implement the changes in December.

Smooth Operations in MISO Despite 'All-Time Hottest' July

MISO operations performed well in July despite several hot weather and severe weather alerts, said Steve Swan, MISO senior manager of dispatch and balance.

Swan said July 2016 was the "all-time hottest July" for multiple cities in the

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Proposed pseudo-tie process *Source: MISO*

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southern portion of the MISO footprint. It was also the driest month since MISO's creation for some southern MISO locations. Load peaked at 120.6 GW on July 21.

MISO reported that July 10, 12 and 20 fell outside of its unit commitment performance targets since forecasted load didn't materialize due to thunderstorm activity; units that were preemptively called up had to stay online to fulfill their minimum run times. MISO also had one maximum generation event in July.

July also marked the first month MISO was required to abide by NERC's balancing authority area control error limit (BAL-001-2) standards, which limit interconnection frequency errors to less than 30 minutes. Swan said MISO did not experience an error lasting longer than 15 minutes event in July.

RSC Chair Tony Jankowski commended MISO for its operations in the face of the hot weather. "We've had a pretty good summer so far, and MISO's gotten us through some hot weather we haven't seen in a while," Jankowski said.

> **"We've had a pretty good summer so far, and MISO's gotten us through some hot weather we haven't seen in a while."**
>
> **Tony Jankowski, We Energies**

Winter is Coming and Coordinated Seasonal Assessment is Scoped

With Labor Day looming, MISO is already thinking about winter. Its 2016/17 winter Coordinated Seasonal Assessment, which assesses risks and system capabilities will include four main analyses, said MISO's Katie Hulet:

- A steady-state AC analysis to study the effect of simple and complex contingencies;
- An analysis identifying large phase angle differences associated with reclosing a transmission line;
- A voltage stability analysis that will assess four critical interfaces for high transfers in combination with transmission and generator outages, which can cause stability issues; and
- A first contingent incremental transfer capability analysis to study the impact of high megawatt transfers and flowgate limitations. This analysis will examine six transfers in addition to wind transfer sensitivity.

MISO also will use only approved retirements and planned and forced transmission and generation outages lasting two months or more between December and February in its assessment.

Hulet said MISO would return to the RSC in November to provide the study's results.

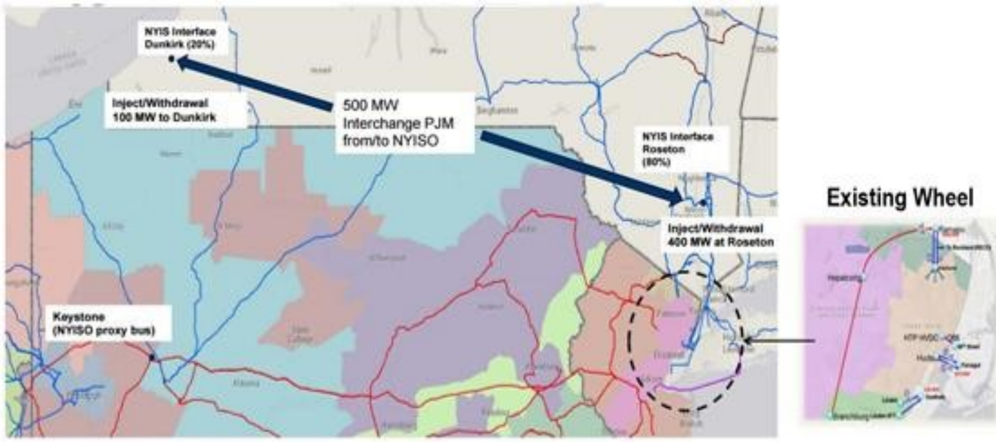
— Amanda Durish Cook

Real-time all hour unit commitment performance *Source: MISO*

NYISO NEWS

PJM, NYISO Seek Input on Replacing Con Ed-PSEG 'Wheel'

By Peter Kay and Rory D. Sweeney



PJM/NYISO wheel alternatives *Source: PJM*

VALLEY FORGE, Pa. — PJM and NYISO held a joint meeting on Monday to get stakeholder feedback on their effort to replace a decades-old power-flow protocol.

The RTOs must have a new protocol in place next May when Consolidated Edison terminates a "wheel" arrangement that allows it to move 1,000 MW from generators in upstate New York through Public Service Electric and Gas facilities in northern New Jersey to serve its load in New York City.

The main question is how to handle eight phase angle regulators (PARs) that currently govern the direction of flows on lines connecting the PJM and NYISO grids. There are one each on the A, B and C lines that flow the 1,000 MW from PSE&G into New York; three south of Waldwick on the J and K lines that flow the energy into PSE&G from upstate New York; and two on the Branchburg-Ramapo 5018 line.

At PJM, the situation is being overseen through the Planning, Market Implementation and Operating committees. During last week's Planning Committee meeting, PJM's Mark Sims explained that the PARs have more physical limitations than HVDC ties, which can be more specific in regulating flow. The PARs can be set to certain "tap positions" to "bias" the flow, but each of them has a limit of 20 adjustments per day and 400 per month.

At Monday's meeting, PJM and NYISO staffers gave presentations on the operational aspects and market impacts of the wheel replacement.

Phil D'Antonio, PJM's manager for reliability engineering, said the new protocol must protect reliability, manage congestion, preserve competitive market behavior and minimize the impacts to PJM and NYISO loads. It also must be able to be facilitated with the existing PAR technology and implemented in both grid operators' market models.

On the markets side, PJM and NYISO are proposing adding the J, K, A, B and C lines into the single PJM-NY AC Interface and implementing market-to-market coordination using the PARs on the lines' interfaces. The RTOs said the proposal uses existing market constructs in both their markets, increasing the likelihood it can be implemented by next May.

The review of the new protocol will include an N-1-1 analysis.

PJM and NYISO have agreed not to change their treatment of Rockland Electric Co.'s load, 80% of which is supplied by the 5018 line, with the remainder flowing over several western ties across the New York-Pennsylvania border.

One of the proposals being evaluated — the "natural flow" — would send about 500 MW from NYISO into PJM via the J and K lines and then into New York City via the A, B and C lines, Sims said. Stakeholders have questioned allowing this because it appears to provide similar service to the "wheel" without the same transmission payments. Completely curtailing that natural flow, or modeling 0 MW, threatens to "max out" the PARs' thermal and voltage limits, Sims said.

Among the "high-level" considerations that the grid operators are discussing are biasing the flows applied to the J, K, A, B and C lines by accounting for the natural flow, and then applying agreed-upon interchange percentages to each interface (5018 and ABC) to reduce congestion.

NYISO published a white paper on the process and will partner with PJM to publish another one that includes PJM's perspective, which will be released in conjunction with a meeting of NYISO stakeholders.

Stakeholders have asked PJM to create a contingency plan for extended outages of the PARs.

PJM NEWS

Monitor: PJM Markets Competitive, but Have Room for Improvement

By Suzanne Herel

	Jan – Jun, 2015	Jan – Jun, 2016	Percent Change
Load*	393,505 GWh	374,688 GWh	(4.8%)
Generation	398,280 GWh	380,923 GWh	(4.4%)
Net Actual Interchange	10,424 GWh	5,656 GWh	(46%)
Losses	8,820 GWh	7,223 GWh	(18.1%)
Regulation Requirement**	613 MW	613 MW	(0.0%)
RTO Primary Reserve Requirement	2,175 MW	2,175 MW	0.0%
Total Billing	$23.40 Billion	$18.29 Billion	(21.8%)
Peak	Fri, Feb 20	Mon, Jun 20	
Peak Load	143,115 MW	134,958 MW	(5.7%)
Load Factor	0.64	0.64	0.4%
Installed Capacity	As of 6/30/2015	As of 6/30/2016	
	176,741 MW	182,050 MW	3.0%

*The load reported in this table is the accounting load plus net withdrawals at generator buses.
**This is an hourly average stated in effective MW.

PJM market summary statistics, January through June, 2015 and 2016. *Source: Monitoring Analytics*

PJM's wholesale energy, capacity and regulation markets were competitive for the first half of the year, but there is room for improvement, according to the second quarter State of the Market Report by Monitoring Analytics. The Independent Market Monitor made new recommendations for the energy, capacity and ancillary services markets.

During periods of high demand, the market's performance "raised a number of concerns related to capacity market incentives, participant offer behavior in the energy market under tight market conditions, natural gas availability and pricing, demand response and interchange transactions," the report said.

The report also called efforts to subsidize uneconomic units a "threat" to PJM market design.

The report includes five new recommendations and one modified recommendation. Two are classified as high priority; the others are ranked medium.

One of the high priority items concerns the capacity market. The Independent Market Monitor said that the costs incurred by pseudo-tied units should be borne by the unit and included in its offers into the market.

The other, first reported in 2012, calls for the emergency load response program to be treated as an economic resource that does not only respond after an emergency has been called.

The medium recommendations were:

- Energy market: Clearly state the policy on the use of constraint relaxation and price-setting logic.
- Capacity market: Re-evaluate mitigation rules for offers by demand resource and energy efficiency resources.
- Capacity market: Eliminate the energy efficiency add-back mechanism so market clearing prices are not impacted.
- Ancillary services: Eliminate separate payments for reactive capability and have generators recover its cost in the capacity market.

Prices, Demand Down

Lower fuel prices and less demand caused energy market prices to drop significantly over the first half of last year, the report said.

The load-weighted average real-time LMP was $27.09/MWh, a 36% drop from $42.30/MWh in 2015.

Average real-time load dropped 5.3% year over year, from 90,586 MW to 85,800 MW.

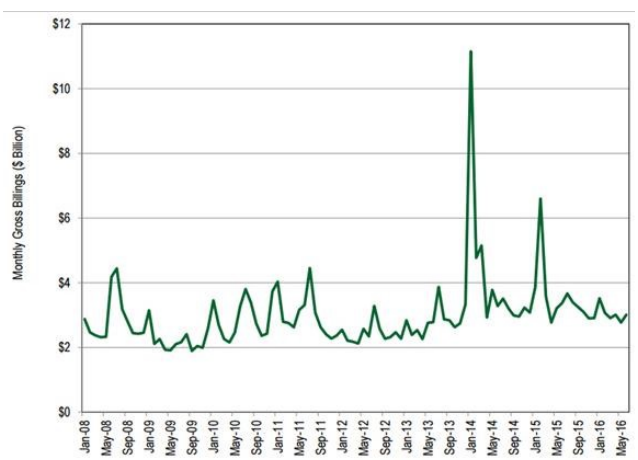
Net revenue, a measure of market performance and of the incentive to invest in new generation, decreased in the first six months of the year relative to 2015. Total net revenues, including both capacity and energy, dropped for a new combustion turbine (-50%), combined cycle (-41%), coal plant (-75%), diesel (-81%), nuclear plant (-46%), wind installation (-31%) and solar installation (-44%).

Combustion turbines (CTs) and combined cycle units (CCs) that entered the PJM markets in 2007 in three representative locations did not cover their total costs, including the return on and of capital. CTs and CCs that entered the PJM markets in 2012 did cover their total costs in the eastern PSEG and BGE zones but did not cover their costs in the western ComEd zone.

Mild winter weather, paired with low fuel prices and LMPs, enabled PJM to reduce uplift charges from $240.3 million to $63.9 million, a 73% cut.

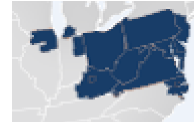
Congestion costs dropped from $918.6 million to $479.1 million, a 48% reduction.

The report also said that auction revenue rights were not an effective way to return revenue to load. Together with financial transmission rights, they offset 86.5% of total congestion costs for the 2015 to 2016 planning period.



PJM-reported monthly billings ($ billion), 2008 through June 2016
Source: Monitoring Analytics

PJM News



OC Briefs

PJM Considering Notification of Performance Assessment Hours

VALLEY FORGE, Pa. — PJM is considering providing generation operators an indicator to signal that the RTO has entered emergency conditions, which triggers a performance assessment hour under Capacity Performance rules.

The RTO will determine if there should be any delay in the notification process and, if so, for how long, PJM's Rebecca Stadelmeyer said. Stakeholders requested that PJM also ensure the signals don't create any type of market advantage.

Stadelmeyer also clarified that non-ramp-limited basepoints have no impact on calculating either performance bonuses or nonperformance charges during a PAH.

The question arose because generators had been asking for the basepoints to be sent via PJM's network, thinking they could help estimate units' expected performance, Stadelmeyer said.

Non-ramp-limited basepoints are theoretical expectations based entirely on the economics of the current LMP and regardless of the unit's actual capabilities. Ramp-limited basepoints, however, are developed from information about each unit submitted by operators into PJM's systems.

Nonperformance charges are imposed when a unit's output fails to meet its expected performance, and bonuses occur when actual output exceeds expected performance without exceeding PJM's dispatch instructions. Expected performance is calculated by multiplying a balancing factor by the amount of a unit's unforced capacity (UCAP) that clears as CP in a Base Residual Auction.

Balancing factors are hard to estimate, Stadelmeyer said, so she urged using the maximum 1.0 to identify the highest possible expectations.

PJM also clarified that the difference between UCAP and installed capacity (ICAP) is also available for bonuses as long as the RTO has dispatched the unit to that level.

In May, FERC rejected Tariff changes that would have exempted a capacity resource from nonperformance charges if it was following the RTO's dispatch instructions and operating at an acceptable ramp rate during periods of high load. The changes were designed as an interim solution to guard against generators self-scheduling prior to a performance assessment hour in order to avoid nonperformance charges. (See FERC Rejects Ramp Rate Exception in PJM Capacity Rules.)

Post-Polar Vortex Tools Enable PJM to Better Face Severe Weather

Date (2016)	Peak Load (MW)	Daily Average LMP ($)
7/21	139,892	28.23
7/22	143,953	31.98
7/23	143,625	28.91
7/24	139,008	25.95
7/25	151,882*	35.51
7/26	143,654	25.88
7/27	146,166	42.72

* 13th Highest on Record.

Daily load summary *Source: PJM*

Thanks in part to new forecasting, scheduling and reserve-checking tools implemented after the polar vortex of 2014, PJM was better able to weather a seven-day July heatwave, PJM's Chris Pilong told the Operating Committee last week.

The RTO recorded its 13th-highest peak load at 151,822 MW on July 25, a day that saw an average LMP of $35.51. During the hot spell, which ran July 21-27, the daily average LMP ranged from $25.88 on July 26, which recorded a peak load of 143,654 MW, to $42.72 on July 27, which saw a peak load of 146,166 MW.

Pilong said the experience was good news for PJM, which wanted to gauge the self-scheduling behavior of generators now that Capacity Performance is in effect. The RTO doesn't want generators to disregard its dispatch orders and self-schedule more capacity to avoid penalties when they believe they are approaching a performance assessment hour. (See "Ramp Rate Approach Would Excuse Nonperformance Penalties," PJM Markets & Reliability and Members Committees Briefs.)

"The day-ahead self-scheduled megawatts didn't change much from the past few summers," he said. "We're not seeing a big shift."

Day-ahead self-schedules for July 25 stood at 69,476 MW, compared with 68,649 MW a year ago, when load hit 143,633 MW. In real time, generators self-scheduled 73,177 MW, compared with 76,430 MW a year ago.

Self-scheduled units are price takers and cannot set marginal prices; they also are ineligible for operating reserve credits.

July 25 was the first time under the new market construct that PJM issued a maintenance outage recall. It canceled 11 planned outages, totaling 124 MW over 72 hours. Eight of them, a sum of 48 MW, were online by noon July 25; the remaining three, totaling 76 MW, did not return and were converted to forced outages.

An RTO-wide hot-weather alert was issued July 22-25. A heat advisory was issued July 21 in the ComEd zone and July 26-28 in Mid Atlantic and Dominion.

The grid experienced no transfer or interconnection reliability operating limits (IROL) issues during the hot weather, Pilong said.

However, two 765/345-kV transformers tripped in different parts of the system, causing local congestion. (See "Grid Remains Strong During Recent Heat Wave," PJM Markets and Reliability and Members Committees Briefs.)

PJM's new tools address two scheduling concerns leading into the polar vortex. Operators' ability to view the capacity position for the next several days was limited, as was their capacity to capture generator reserves in real time in order to validate their calculations.

In June 2014, PJM rolled out its "long lead" tool, which consolidates load forecasts, safety margins and generator data, and adopted a new procedure for scheduling generation that includes a seven-day look-ahead.

Last September the RTO developed an instantaneous reserve check, allowing it to validate unit reserves in real time.

Pilong said the new tools helped reduce balancing operating reserve (BOR) payments. BOR payments totaled $18.1 million from June through August 2015. That amount stood at $10.1 million through July 26, 2016.

Uplift payments for July 25 came to nearly $1.1 million, compared with $447,118 for the hottest day in 2015, which occurred on July 28.

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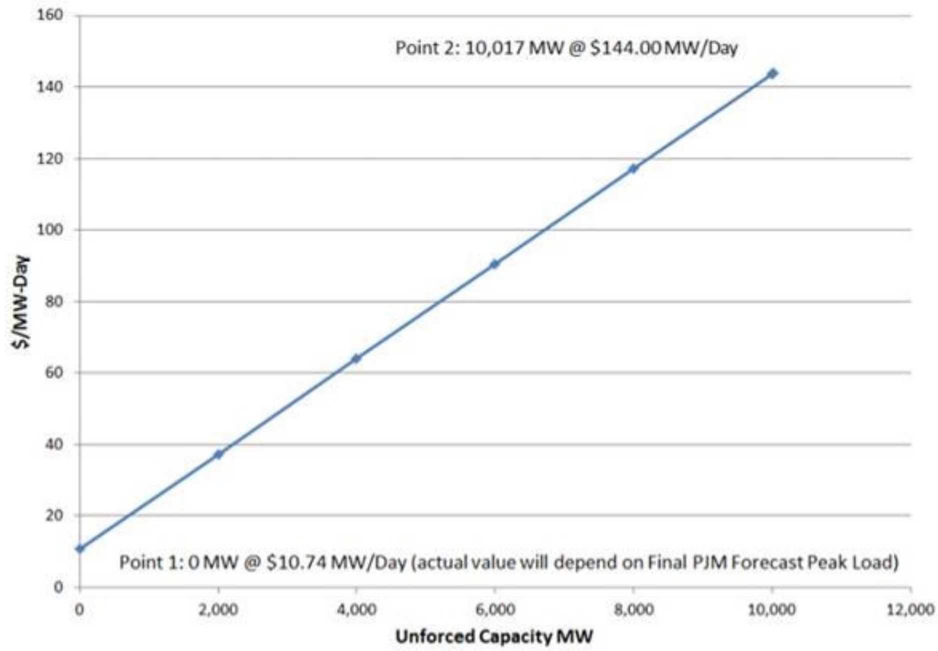
PJM NEWS

MIC Briefs

Proposal Would Set Higher Prices for Capacity Released in 3rd IA for 2017/18



Proposed sell-back price of new commitment megawatts *Source: PJM*

Excess capacity expected to be released in the third incremental auction for the 2017/18 delivery year in February would likely clear at $0 under current rules, PJM's Jeff Bastian told the Market Implementation Committee Wednesday.

To avoid that, PJM presented a proposal that would release excess capacity on an upward trajectory, ranging from 0 MW at $10.74/MW-day to all 10,017 MW being available at $144/MW-day or 1.2 times the Base Residual Auction clearing price.

That is, the RTO would retain more capacity at lower prices but be willing to release more at a higher price.

PJM must file its plans for releasing the capacity with FERC by November. Because of that time constraint, some members suggested advancing the PJM proposal to the Markets and Reliability Committee for a first read.

Among them were Jeff Whitehead of Direct Energy and Mike Borgatti, representing NextEra Energy. Both said they would be willing to forego their companies' alternate proposals to support PJM's solution.

At the July MIC meeting, Direct Energy had proposed using a sloped offer curve to create a price floor that would prevent supply resources from being able to cheaply buy out of their obligation at load's expense. NextEra proposed PJM's sell offer equal the transitional incremental auction adder that the RTO charges to load. (See "Members Debate Ways to Release Excess Capacity into Incremental Auction," *PJM Market Implementation Committee Briefs*.)

Bastian said all three approaches are intended to preserve value for load.

"If the clearing price is zero, then you are releasing capacity commitments with no benefit going back to load," he said.

The PJM proposal contains three parts. The first retains the status quo for how PJM determines the quantity and price at which it procures or releases MW in an incremental auction due to changes in load forecast or reliability requirements.

The second part, however, would release

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OC Briefs

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Metering Task Force Presents Proposal to Improve Clarity

PJM presented the first read of an 11-point proposal for manual and Tariff changes to close the gap between PJM's metering requirements and members' understanding of the rules.

The proposal was outlined by Nancy Huang of the Metering Task Force, which was formed by a problem statement approved Sept. 8. (See "Metering Requirements to Receive Overhaul," *PJM Operating Committee Briefs*.)

The group also recommended two topics for further study: minimum metering requirements for location and density to ensure system observability, and metering requirements for distributed generation.

The revisions aim to reduce the risk of non-compliance, provide clarity around the specifications and design of new equipment, improve the energy management system's state estimation solution and maintain operation reliability and market fairness.

The proposal is set to go before the Members Committee on Sept. 29, with a FERC filing expected in October.

Systems Information Committee Heads into the Sunset

Members approved sunsetting the Systems Information Committee.

Topics related to the energy management system will be assigned to the Data Management Subcommittee (DMS), which will meet next on Aug. 25. Remaining topics will be transitioned to the new Tech Change Forum, which will hold its first meetings Sept. 27-28.

To accommodate the changes, the Operating Committee also approved modifying the DMS charter.

The DMS will now function as a joint subcommittee, with generator and transmission owners addressing pertinent issues and TOs considering topics applying only to them.

— Suzanne Herel and Rory D. Sweeney

PJM NEWS

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the 10,017 MW separately, according to the upward-sloping price curve.

Lastly, any of those separately released MW that did not clear would not be included in the determination of excess commitment credits.

"We would exclude this uncleared quantity from the quantity included in the first bullet," Bastian explained.

Katie Guerry of EnerNOC said she was surprised by PJM's new proposal, given that in July it had presented a plan to release capacity into the 2017/18 year using the same method FERC had approved for the 2016/17 delivery year, which yielded $4.79/MW-day.

"To hear PJM changing [its] position after the conclusion of that second incremental auction, after what we've been hearing from PJM for months now, is a little confusing," Guerry said, adding that she was not comfortable with the issue being advanced yet to the MRC.

"PJM's thinking has evolved," Bastian said. "I wouldn't say we had a position here. When we brought this forward again, we brought it forward as a discussion item. Our intent at this point would be to release it. We could go forward using the same method as last time. But if we use the same method, we're likely to clear at zero, and that didn't seem to make sense."

Whitehead said PJM's new proposal should not be a surprise, as the committee has been debating different approaches for several months.

"I feel this has been vetted here. I understand that you may not be happy with the outcome, but the opportunity for dialogue certainly occurred," Whitehead said to Guerry.

"There's a reliability tradeoff for these sales," he said. "It is critical to recognize that we have the potential to sell back 10,000 MW of capacity. To do that and to know there's a distinct possibility that most of those MW could clear close to zero … it's counter-intuitive that in one auction we're valuing capacity at $150, and, in the next instance, we're valuing it at zero. The reduction in load's cost is 1%, while giving up 5% of reliability — that should be concerning.

"It's a lot of capacity, and my company's position is we need to make sure we are putting the right value on those sales," said Whitehead.

Independent Market Monitor Joe Bowring repeated his position that PJM should not buy more capacity than it needs and should not sell it back for less than it paid. But, he said, the PJM proposal goes in the right direction.

Still, Bowring said, "There's no cap. There is no limit. There's no reason not to hold onto that capacity, which was purchased for a higher price."

In the end, committee Chair Chantal Hendrzak declared the item an official first read for the group.

Order 825 Progress

PJM staff announced their preliminary plans for implementing five-minute interval data for load, generation and shortage pricing.

For generation, PJM would use existing estimated or telemetry data and create five-minute profiles that correspond to hourly revenue-quality meter data already submitted. The five-minute telemetry data would be average and combined with a scaling factor for each five-minute interval profile associated with five-minute LMPs. The total of the 12 intervals would equal the hourly revenue-quality data. This is a protocol other ISOs are using, PJM's Adam Keech said.

Order 825 doesn't require load to provide five-minute data, so PJM plans to use flat profiling over the 12 intervals in an hour and associate that with five-minute pricing to determine load pricing. Demand response is also submitted hourly, so PJM would prorate such resources by interval for curtailments of less than an hour. PJM doesn't have the granularity to use state estimator data for discrete DR, Keech said.

PJM wants to continue using megawatt-hour values and augment them with five-minute LMPs for pricing. The plan hasn't yet been discussed with other RTOs, though, and stakeholders expressed concern that differences in each RTO's plan might impact their interaction.

For shortage pricing, PJM introduced a problem statement to develop new curves that are complementary with the rules of Order 825.

While the order allows more time for initiating shortage pricing, PJM wants to implement it jointly with the load and generator changes because of concern that five-minute pricing could distort hourly prices, Keech said. PJM has been discussing this with other RTOs, particularly ISO-NE, and have come up with similar solutions.

Currently, PJM's four curves are very similar and all have the same $850 penalty factor. The RTO currently addresses transient shortages — those expected to last a very short time — by easing reserve requirements slightly until expected supply arrives. Order 825 prohibits PJM from doing this, so the RTO wants to develop new demand curves that complement the requirements of the order.

Members Hear First Read on Plan to 'Un-Nest' Operating Parameters

The MIC will be asked at its September meeting to endorse one of two proposals on whether and how to "un-nest" operating parameter definitions to separate soak time from start time (see table below).

The definitions are contained in Manuals 11, 15 and 28. (See "Members OK Operating Parameters but Urge Refinements," *PJM Markets and Reliability and Members Committees Briefs*.)

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Combined Cycle Parameters	Package A	Package B
Start Time	To steam turbine generator breaker closure.	To CT generator breaker closure.
Minimum Run Time	From CT generator breaker closure to last breaker opening.	From dispatchable to PJM release.
Soak Time	From steam turbine generator breaker close to dispatchable.	From CT generator breaker close to dispatchable.
Ramp Down Time	From Econ Min to last breaker opening.	From function of unit output to last breaker opening.

Proposals for 'un-nesting' combined cycle operating parameters *Source: PJM*

PJM NEWS

Generators Balk at PJM Proposal on Fuel Cost Policies

By Rory D. Sweeney

Stakeholders continue to react coolly to PJM's proposed rules for generator fuel-cost policies, spending two and a half hours expressing their concerns at last week's Market Implementation Committee meeting.

PJM has held three meetings in the past three weeks to explain the policy to stakeholders, several of whom said last week that the rules are more punitive than incentivizing. The RTO is due to make an interim compliance filing on the issue Aug. 16.

The rules have been revised so that sellers without approved fuel-cost policies are not required to submit cost-based offers. They can, however, submit negative price offers and are subject to the greater of their capacity resource's deficiency charges or nonperformance charges — such as those from a performance hour assessment.

A seller would have 30 days to revise a rejected policy, during which time the seller would revert back to using a previously approved policy.

A seller deemed by PJM and the Independent Market Monitor to have violated its approved policy would be subject to a separate penalty. The amount would be calculated via a formula based on the unit's capacity and the LMP at its bus. The penalties would begin five days after the seller is notified about the noncompliance.

The proposal has "significant problems and needs substantial rethinking," said Monitor Joe Bowring, who distributed his own proposal that requires CP units that don't

Natural gas plants in PJM's energy market, such as Duke Energy's 620-MW Buck Combined Cycle Station in Rowan County, N.C., would be subject to the RTO's rules on fuel-cost policies. *Source: Duke*

have approved policies to make offers, but penalizes them in a way similar to the unit capacity/LMP formula.

"It sounds like one bad rule offset by another bad rule," Bowring said of PJM's proposal. "They all have unintended consequences. What that means is that the units aren't going to offer in, which isn't what you want. You want units to offer in."

"Unless we're just trying to find another way to penalize a generator, can we please rethink this?" asked Jason Cox of Dynegy. Instead, the lost opportunity created by holding sellers to a $0 offer "seems like a pretty efficient way to get them to get a policy done," he said.

Stakeholders felt the policy lacked clarity. Bob O'Connell of Main Line Electricity Market Consultants said that it has no way to maintain compliance, no procedure for making necessary revisions while maintaining compliance and no timeline for that process.

Ed Tatum of American Municipal Power said stakeholders have expressed "grave concerns" that "this penalty is overly punitive, goes beyond the scope of the order and is generally bad market design."

Under the proposal, if the Monitor disagreed with a PJM-approved policy, it could refer it to FERC's Office of Enforcement.

That, said Tatum, is "unacceptable."

The purpose of the policy is twofold, Bowring explained: to ensure compliance with all requirements to participate in the PJM market and that offers are consistent with competitive offers. Sellers need to document a verifiable and systematic method for calculating cost-based offers, he said.

"There has to be recognition that we're changing the paradigm about fuel-cost policies; it makes sense to give everyone enough time to get there, but there have to be incentives to get there so people are not simply wasting time [and] everyone's working toward that same objective," he said.

Stakeholders questioned how the policies would be reviewed and whether the process or the result was the real focus.

"I'm just hopeful that in the final language, that we're talking about the reasonableness of the process, not the reasonableness of the result and that that's really clearly articulated to everybody," said Mike Borgatti of Gabel Associates.

The proposal is scheduled to be brought to votes by the MIC, along with the Markets and Reliability and Members committees next month, with board approval targeted for October before a filing with FERC.

MIC Briefs

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NYISO to be Consulted on Changing Spot-in Service Allocation Methods

Joe Wadsworth of Vitol presented further discussion on how to improve the process of allocating spot-in transmission for energy imports from NYISO.

In April, the committee approved a problem statement and issue charge on the subject. (See "Allocating Spot-in Service for NYISO Imports to be Studied," *PJM Market Implementation Committee Briefs*.)

Currently, the free but limited service is allocated on a first-come, first-served basis with no priority for participants who have cleared the NYISO market.

Wadsworth proposed removing PJM's limit on requests for spot-in service and relying on NYISO's real-time economic evaluation to determine which importers get spot-in service. He also proposed modifying some rules and timelines for the NYISO/PJM interface.

Wadsworth said talks are planned with NYISO and he would present their feedback at the next meeting.

Although no similar concerns have been expressed regarding the MISO seam, Bowring suggested the committee consider expanding the proposal to apply to all of the neighboring RTOs.

— Suzanne Herel and Rory D. Sweeney

PJM NEWS

PC/TEAC Briefs

Reliability Analyses Show Few Issues with Closing Exelon, FirstEnergy Plants

VALLEY FORGE, Pa. — A reliability analysis identified no adverse impacts on the PJM system from closing the 1,819-MW Quad Cities nuclear plant, which Exelon plans to deactivate on June 1, 2018.

Exelon announced the closure in June after failing to convince Illinois legislators to act on a bill that would help subsidize its money-losing stations. (See *Exelon to Close Quad Cities, Clinton Nuclear Plants*.)

It also plans to shutter the 1,065-MW Clinton station next June 1.

Meanwhile, PJM is wrapping up analyses on FirstEnergy's plans to close its W.H. Sammis and Bay Shore plants — a combined 856 MW — in Ohio.

Those studies did indicate some issues, said Paul McGlynn, senior director of planning, but they are in areas where PJM already has identified needs for baseline Regional Transmission Expansion Plan (RTEP) upgrades.

"We're just making sure those previously approved upgrades will meet the needs," he said.

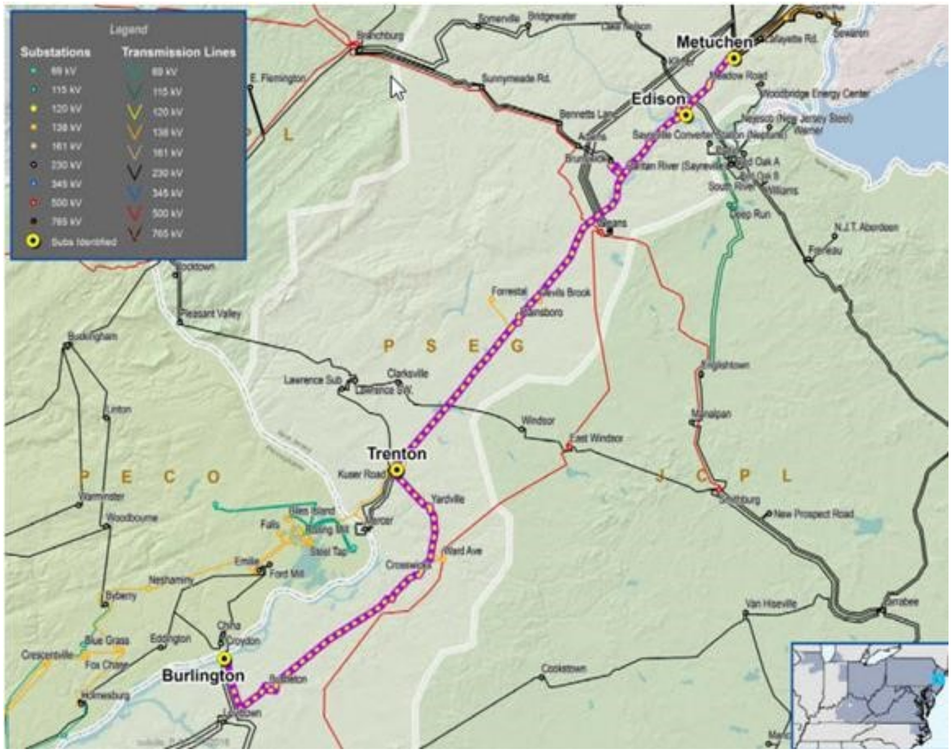
In July, FirstEnergy announced the retirement of Sammis, its largest coal-fired plant in Ohio. At the time, it said it would deactivate or sell its Bay Shore plant by 2020. (See *FirstEnergy Closing Largest Coal Plant in Ohio, Bay Shore also in Peril*.)

Third RTEP Window of 2016 Set to Open in September

PJM expects to open the third RTEP window of the year in mid- to late September, McGlynn told the Transmission Expansion Advisory Committee (TEAC) on Thursday. Its scope will be short circuits and 2021 winter and light load reliability.

McGlynn also provided an update on the second proposal window, which closed July 29. (See "PJM to Open FERC Order 1000 Proposal Window in Late June," *PJM Planning Committee and TEAC Briefs*.)

PJM received 87 proposals from 13 entities in a dozen transmission zones to address N-1 and N-1-1 thermal and voltage issues and



PSE&G transmission line to be replaced *Source: PJM*

load and generation deliverability problems.

Of those, 46 involve greenfield projects, ranging in cost from $5 million to $224 million; 41 were transmission owner upgrades estimated at $30,000 to $125 million.

PJM said it cannot provide details on the projects until after cost analyses are submitted. They were due Aug. 15.

PSE&G End-of-Life Price Tag: $1.15B

McGlynn presented $1.15 billion in proposed solutions to end-of-life issues involving Public Service Electric and Gas equipment. (See "PJM Concerned PSE&G Equipment at the End of its Life," *PJM Planning Committee and TEAC Briefs*.)

Planners are considering replacing the double 138-kV circuits on the Metuchen-Edison-Trenton-Burlington corridor with 230-kV lines in three sections: Metuchen-Brunswick ($125 million), Brunswick-Trenton ($327 million) and Trenton-Burlington ($349 million).

The 30-mile Metuchen-Trenton span is about 86 years old; structures in the 22-mile Trenton-Burlington section average 75 years old. About 81% of the towers are at 95 to 100% of their load-carrying capacity and as much as 30% of the structures require extensive foundation rehabilitation or replacement.

"We don't have time to put [the projects] through a [competitive] window," McGlynn said.

An alternative would be to rebuild the corridor with the existing double-circuit 138-kV configuration, an option that would be about 20% cheaper, McGlynn said.

PJM staff also recommend the existing Newark switch station be demolished and a new one constructed adjacent to that site at a cost of $353 million.

PJM Creates System Planning Modeling and Support Group

PJM has created a new planning department called the System Planning Modeling and Support Group.

The reorganization, which will take effect next month, is intended to streamline case-building, PJM's Jason Connell explained. The effort is time-consuming, and PJM is seeing an increase in required cases, he said.

The unit will report to McGlynn, along with Interconnection Analysis, headed by Aaron

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PJM NEWS

PJM OKs $636M in Tx Projects, Including its Largest Market Efficiency Proposal

By Suzanne Herel

The PJM Board of Managers has approved more than $636 million in transmission investments, including a $320 million market efficiency project — its largest ever — designed to ease congestion at the AP South interface.

That project alone is predicted to save customers $622 million over 15 years, PJM said.

Project 9A (without capacitors) is expected to alleviate congestion across Pennsylvania's border with Maryland and is set to go online in 2020.

The plan, which evolved from the Order 1000 competitive process for transmission improvements, involves substation upgrades, two new substations, two new transmission lines and improvements to current lines.

"This is PJM's largest-ever market efficiency project, and we expect it will resolve a significant amount of the remaining transmission congestion in the eastern portion of PJM," said CEO Andy Ott.

The principal developers are FirstEnergy's Allegheny Power, Exelon's Baltimore Gas and Electric and Transource Energy, an American Electric Power affiliate.

At the same meeting at which it approved AP South, the board halted another Order 1000 project, the stability fix for New Jersey's Artificial Island. (See *PJM Board Halts Artificial Island Project, Orders Staff Analysis*.)

The board also approved $316.3 million in other new or amended projects to maintain reliability.

PJM's selection of the AP South project was criticized by some stakeholders who argued that planners should further study competing proposals ranging from $72 million to $253 million. (See "Planners to Recommend $340.6M Solution to Congestion in AP South," *PJM Planning Committee and TEAC Briefs*.)

Among the detractors was Linden VFT, which wrote a July 29 letter to the board saying, "Despite similar benefits per dollar of cost, PJM has chosen the larger project which purports to produce higher benefits on an absolute basis because of its size. However, PJM gave no indication that it had considered in its recommendation the value of the cost-cap guarantee proposed by" LS Power's Northeast Transmission Development.

It warned that if cost containment is not valued, it will cease being offered.

"Linden VFT agrees that determining the relative importance of a cost cap over other factors will require PJM to make value judgments, but PJM's role in project selection requires it to either consider all of the issues in a deliberate fashion (not just those which are easiest to compute) or punt, and effectuate the same value judgments, but by default, without thoughtful consideration."

The board also received a letter from AEP and Transource lauding the selection process.

Since the Regional Transmission Expansion Plan began in 2000, PJM has greenlit $29 billion in new development and upgrades.

PC/TEAC Briefs

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Berner, and Transmission Planning, led by Mark Sims.

Planners are reaching out to transmission owners about the change, Connell said.

PJM Poised to Exempt TO Upgrades from Order 1000 Process

PJM is waiting until FERC accepts its deficiency filing related to exempting low-voltage facilities from the Order 1000 process before it files a similar request involving transmission-owner upgrades.

PJM's Mark Sims said the commission is expected to act by Aug. 26, and the Planning Committee likely will be asked to endorse the proposal at its September meeting. If approved, the exemption would go into effect for the 2017 RTEP cycle.

The proposal would exclude typical transmission substation equipment upgrades from competitive windows unless there's an indication that the problem could yield a greenfield project. (See "PJM Beefing up Details of TO Upgrade Exemption Proposal," *PJM Planning Committee and TEAC Briefs*.)

Such upgrades would include short-circuit violations and fixes to substation terminal equipment such as wave traps, current transformers and capacitors.

In February, members approved revisions to the Operating Agreement exempting transmission reliability projects of less than 200 kV from the competitive proposal windows. (See "Low-Voltage Projects to be Exempted from Competitive Window Process," *Markets and Reliability and Members Committees Briefs*.)

FERC responded by ordering PJM to make a compliance filing addressing concerns such as how stakeholders would comment on exempted projects (ER16-1335).

PJM Staff Continues to Scrutinize Planning Process

PJM staff is continuing to review the RTEP planning cycles and the TEAC's communications and processes, Fran Barrett told the Planning Committee.

Preliminary discussions are being held internally, but Barrett assured members that no action would be taken without being vetted by the stakeholder process.

Cross-departmental teams are mapping out current processes and identifying areas for improvement.

"We want to take a picture of today, project it to the future and you tell us what's right about that picture and what needs to change," said Barrett.

For example, he said, while some stakeholders do business within PJM only, others are involved in transmission planning projects in other RTOs as well. One idea: provide members an ESPN SportsCenter-like "highlights reel" from various RTOs' planning committees.

"We're trying to improve workflow and do it more efficiently," said Barrett. (See "PJM Starts Process of Redesigning TEAC," *PJM Planning Committee and TEAC Briefs*.)

— Suzanne Herel

SPP News

Briefs

New Gas-Day Nom Process on Track for Oct. 1 Go-Live

SPP says it is on track to go live as scheduled with the new gas-day timeline in October and enhanced combined cycle (ECC) software in March.

Testing on SPP's gas-day system began Aug. 1 and concludes Aug. 29.

The first operating day will be Oct. 1, when participants must submit bids and offers by 9:30 a.m. instead of 11 a.m. SPP requested a one-day extension of the first operating day from Sept. 30, which FERC granted last week (ER16-2258).

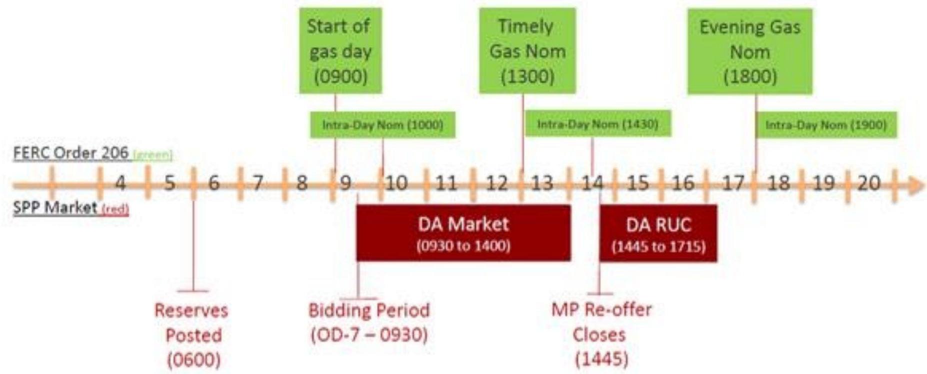
"There's no real system changes for members," Jodi Woods, SPP's day-ahead market manager, told the Gas Electric Coordination Task Force last week. "We're using this opportunity to go through the processes and make sure they can meet their deadlines."

The gas-day timeline changes are a result of FERC Order 809, which moved the RTO's timely nomination cycle deadline for gas supplies to 1 p.m. CT from 11:30 a.m. and added a third intraday nomination cycle.

Last July, SPP's Board of Directors approved timeline changes that post day-ahead market results at 2 p.m. CT, up from 4 p.m., and shorten the reoffer period to 45 minutes, with reliability unit commitment offers due at 2:45 p.m. and results posted by 5:15 p.m. (See "Board Approves Gas-Electric Timeline Change," *SPP BoD/Members Committee Briefs*.)

Enhanced Combined Cycle Project

Testing the enhanced combined cycle (ECC) project's software, which involves more than a dozen systems and interfaces, is scheduled to begin in December, with a projected March 1, 2017 go-live date. The project is expected to provide more sophisticated modeling to capture combined-cycle plants' flexibility.



SPP gas day timeline *Source: SPP*

The two projects have an estimated implementation cost of $7.7 million, the bulk of which is related to the more complicated ECC software.

Task Force Suggests Minimum Threshold for Competitive Projects

The Competitive Transmission Process Task Force last week made official its support for a minimum threshold for competitive projects under FERC's Order 1000. However, the group rejected the idea of instituting a $2.5 million threshold, asking staff to return with additional analysis before its next meeting Wednesday.

The threshold was one of five issues the task force was assigned to study by the Strategic Planning Committee.

The SPC directed the group to base any process improvements on lowering costs for the end customer — rather than simplifying the process for staff — and to report back with recommendations in October.

MISO currently has a $5 million threshold for market-efficiency projects and a $20 million hurdle for its multi-value projects. An SPP staff review of more than 300 highway/byway high-priority projects dating from 2010 found that only 34 projects receiving notices-to-construct (NTC) had costs under $10 million, with 18 under $5 million.

The task force is also considering whether to: seat the industry panel evaluating competitive bids earlier in the solicitation process; develop a region-wide formula rate; report proposal costs as an incremental cost or as an average for each respondent; and move from the current competitive model to a sponsorship model.

The task force also approved developing Tariff language that allows for the re-study of approved competitive projects before an NTC is issued. The action was a result of last month's cancellation of SPP's first competitive project under Order 1000. (See *SPP Cancels First Competitive Tx Project, Citing Falling Demand Projections*.)

> **"We're using this opportunity to go through the processes and make sure they can meet their deadlines."**
>
> **Jodi Woods, SPP**

MOPC Fills Out Z2 Task Force

On Friday, the Markets and Operations Policy Committee (MOPC) closed its solicitation for members interested in participating on a task force to address unresolved issues concerning the Z2 crediting process.

The Board of Directors created the task force last month to address complaints of members being charged for costs that were not identified in service agreements after declining to address the members' waiver requests. (See *Board Approves Z2 Timeline Extension, Creates Task Force for Further Study*.)

Bruce Rew, SPP's vice president of operations, told members the task force would review the waiver requests, with the intention of "expeditiously" conducting a study and finding an "acceptable solution" before the October MOPC and board meetings. Rew said the full scope of work is still being developed, but the group may also be asked to work on improving the Z2 payment process.

The task force is expected to be "highly engaged" for at least six months, Rew said.

— Tom Kleckner

COMPANY NEWS

NRG Continues to Pare Down Businesses, Affirms Guidance

By Tom Kleckner

NRG Energy continues to retrench after a dismal 2015, announcing last week it will sell its stake in the California Valley Solar Ranch and restructure its GenOn unit, whose acquisition in 2012 nearly doubled NRG's generation portfolio.

New Jersey-based NRG also said it had sold two Illinois gas plants for $425 million, helping the corporation deliver $779 million in adjusted earnings before interest, taxes, depreciation and amortization (EBITDA) for the quarter. NRG has generated almost $1.6 billion in adjusted EBITDA — or cash flow — this year, putting it in the upper range as it reaffirmed its guidance for 2016 ($3 billion to $3.2 billion).

"We have a lot of the summer ahead of us. I think it's just prudent to keep our guidance the way we had it," interim CEO Mauricio Gutierrez said during a conference call with analysts. "We're very comfortable with the positon we have. We still have August and September, which can be really hot in Texas."

NRG said it has reached agreement to sell its 51% stake in the 250-MW California Valley solar project for $78.5 million in cash plus assumed debt to NRG Yield. NRG Yield is a separate, publicly traded company that has 4,438 MW of renewable and conventional generation under contract; NRG

El Segundo gas plant in California
Source: NRG Energy

Energy owns 55.1% of the yieldco's outstanding common stock.

The company also said GenOn has appointed two independent directors and retained restructuring advisors "to help navigate the [restructuring] process efficiently and judiciously" in a bid to reduce its "excessive" leverage ratio.

GenOn, which has $2.6 billion in debt, is expected to generate only $335 million in EBITDA in 2016 — a leverage ratio of 7.7, far above the 4.2 ratio for the company as a whole and the 4.0 ratio the company is seeking to reach by the end of the year.

NRG's $1.7 billion acquisition of GenOn boosted the company to 47 GW of generating capacity, making it the largest competitive generator in the U.S. But the 22.7 GW acquired from GenOn — coal, natural gas and oil — have not fared well due to the entry of increasingly competitive renewables and more efficient plants burning cheap shale gas.

NRG said its second quarter net loss of $276 million ($0.61/share) — worse than its $9 million loss a year ago — resulted from $198 million in impairments and losses on asset sales and an $80 million loss related to extinguishing debt.

Excluding one-time charges, the company's loss was $0.04/share, below Zacks Investment Research's consensus expectations of a $0.03/share profit. NRG reported $2.64 billion in quarterly revenues, well below Zacks' consensus projection of $3.45 billion.

The company had a net loss of $229 million ($0.37/share) for the first six months of this year, after recording a $6.44 billion loss in the fourth quarter of 2015, which ended with the resignation of CEO David Crane.

NRG shares were down 5.6% in the two days following the Aug. 9 earnings announcement, closing off 75 cents at $12.76 Wednesday.

NRG serves more than 3 million residential customers throughout the country, primarily in Texas and the Northeast.

COMPANY BRIEFS

EFH Files 3rd Amended Reorg Plan With Delaware Bankruptcy Court

Energy Future Holdings last week filed a third amended joint reorganization plan and related disclosure statement with the U.S. Bankruptcy Court in Delaware.

EFH is set to begin its latest attempt to exit bankruptcy this month after the deal at the center of a prior plan fell apart after it had been confirmed by Bankruptcy Court Judge Christopher S. Sontchi.

Energy Future, the largest power company in Texas, filed for Chapter 11 in April 2014 after it failed to meet its debt obligations as electricity prices weakened. The bankruptcy is one of the largest ever in the United States.

More: *Bankrupt Company News*

Troubled Kemper Needs Another Month, $43 Million

The controversial, multi-billion-dollar Kemper Power Plant, which began making synthetic gas from coal July 14, will take an additional month to finish and cost an extra $43 million, Mississippi Power Co. announced last week.

The oft-delayed coal gasification plant, whose costs have increased to $6.8 billion, is now planned for a Halloween completion. The most recent cost overruns prompted Mississippi Power Co. to write off $81 million in losses in its second quarter.

Mississippi Power parent Southern Company said it needs the additional month to achieve "sustainable operations" by adjusting the two gasifiers that transform soft lignite coal into synthetic gas and to complete testing on the technology that removes carbon dioxide from the gas.

More: *Jackson Free Press*

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COMPANY BRIEFS

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Black Hills Energy Starts $54 Million Tx Project

Black Hills Energy started construction on a $54 million, 147-mile transmission line running from eastern Wyoming to western South Dakota. Planning for the project took 10 years, and construction crews started cleaning land on the route last week.

Most of the land is owned by the state or federal governments, but agreements were reached with 24 property owners to allow access to their land. A company spokesman said it would be completed by mid-2017.

More: *Rapid City Journal*

Chesapeake Gives Up Barnett Assets to Private Group

Chesapeake Energy Corp. said it has agreed to hand over its Barnett Shale holdings to a private-equity-backed operator. The move allows Chesapeake to avoid almost $2 billion in pipeline contracts.

Chesapeake issued a statement saying it will give its interests in the North Texas Barnett region, estimated to be worth as much as $1 billion, to First Reserve Corp.-backed Saddle Operating LLC. The move will cut Chesapeake's shipping and processing costs by $715 million between now and the end of 2017 and will eliminate $1.9 billion in long-term pipeline agreements.

The Barnett Shale, once at the forefront of the U.S. shale boom, lost its competitive advantage when gas prices collapsed and it was eclipsed by lower-cost production areas closer to Eastern markets. The Barnett is Chesapeake's second-smallest production region, accounting for 10% of the company's output.

More: *Bloomberg*

Duke Issuing $3.75 Billion In Debt to Finance Piedmont

Duke Energy will issue three series of unsecured bonds, totaling $3.75 billion, to help finance its $4.9 billion purchase of Piedmont Natural Gas. The first series, with an interest rate of 1.8%, will be due in 2021; the second series, at 2.65%, will be due in 10 years. A third series, carrying the highest interest rate of 3.75%, will be due in 30 years.

The company said it expects the purchase to close by the end of this year, but it could come as soon as the North Carolina Utilities Commission approves the merger. Hearings on the purchase concluded last month, and briefs are due at the end of this month.

More: *Charlotte Business Journal*

SolarCity Panel Plant Start Date Moved Up

SolarCity plans to make solar panels in its Buffalo factory by the end of next June, several months earlier than its previous estimate.

Improvements in the equipment the factory will use, and a more efficient plant layout, should allow the factory to make more solar panels than would have been possible under its original design. The plant's capacity was pegged initially at 1 GW, and company officials would not say how much extra capacity it will add.

SolarCity initially had planned to start making solar panels this year, but slower growth and financial constraints delayed some investment, pushing the production timetable until late 2017.

More: *The Buffalo News*

Exelon Outlines Growth Strategy, Continues to Push Reforms

At Exelon's Analyst Day last week in Philadelphia, the company outlined a growth strategy that includes investing in its six electric and gas utilities and adopting innovative technology.

Exelon plans to invest $25 billion in infrastructure and smart grid technology over the next five years.

The company also said it will continue to push policy and market reforms to preserve nuclear plants that face economic challenges.

More: *Business Wire*

Fire at Four Corners Plant in NM During Decommissioning Work

A chemical fire broke out during the decommissioning of three units at the Four Corners Power Plant in northwestern New Mexico Aug. 11, forcing the plant's evacuation. The fire was reported at 10:54 a.m. and was extinguished shortly after 1 p.m.

A spokesman for Arizona Public Service Co., which operates the plant, said the fire erupted as crews were working to dismantle a crystalline brine concentrating tower used to purify water for cooling equipment.

APS does not expect the incident to impair its plans to close the units by the end of the year. The remaining two units were offline for maintenance and not affected by the fire.

More: *Farmington Daily Times*

DTE Plant in St. Clair Burns for 12 Hours

A fire at DTE Energy's St. Clair County coal-fired power plant burned for 12 hours Thursday night into Friday morning before firefighters were able to extinguish the blaze. There were no injuries at the plant, which is located on the St. Clair River in East China Township.

The fire was reported about 6:30 p.m. Thursday, and all employees were evacuated after shutting down all remaining units. Company and state officials continued to work to determine the cause of the blaze.

The plant is among three slated for retirement by 2023.

More: *The Detroit News*

Federal Briefs

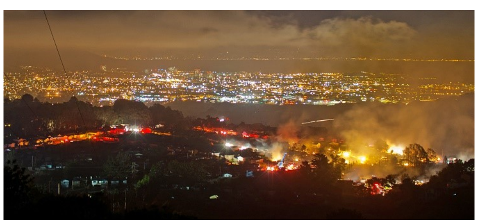
Natural Gas Generation Sets Record in July

The amount of electricity generated by natural gas in July eclipsed its own record, set in July of last year, according to the Energy Information Administration. The trend, caused in part by coal plant retirements and a boost in temperatures, spurred the agency to predict natural gas and coal will be used to generate 34% and 30%, respectively, of the nation's electricity in 2016. This compares with slightly less than 33% for natural gas, and a bit more than 33% for coal, last year.

The increase in the use of natural gas to generate electricity led to a rare drawdown of natural gas stocks in a month when pipeline operators typically are injecting natural gas into storage for winter use, rather than sending it out. Gas inventories declined by 6 billion cubic feet for the week ending July 29. The last time a net withdrawal was recorded in July was in 2006.

More: *EIA*; *PennEnergy*

Jury Convicts PG&E in San Bruno Blast Trial



A federal jury last week convicted Pacific Gas & Electric on six charges of violating gas pipeline safety laws and obstructing the federal investigation into the 2010 pipeline explosion that killed eight people and destroyed 38 homes in San Bruno, Calif.

PG&E faces a maximum penalty of $3 million after it was found guilty on five felony counts of wittingly failing to inspect its gas network, as well as the felony obstruction count.

Prosecutors initially sought $562 million in penalties before the presiding judge ruled the company could not be held to newer safety standards that would have led to higher fines for illegal cost-cutting. The penalty will be paid by company shareholders, but ratepayers will have to cover the costs for pipeline upgrades. No company executives were convicted in the case.

More: *San Francisco Chronicle*

NRC Names David Nelson As New Chief Info Officer

Nelson

The former chief information officer at the Centers for Medicare and Medicaid Services (CMS) will be the next CIO for the Nuclear Regulatory Commission.

David Nelson, an Air Force veteran and developer of two broadband companies, has worked for the federal government since 2004, including several positions at CMS, where he was director of the Office of Information Services, director of the Office of Enterprise Management and director of the Data Analytics and Control Group at the Center for Program Integrity.

One of his high-profile jobs was to help rescue the problem-plagued HealthCare.gov site.

More: *FCW*

NM Spent-Fuel Facility Seeking NRC Approval

Intrepid Potash has relinquished a mineral rights lease in eastern New Mexico, clearing the way for construction of an interim storage facility for spent nuclear fuel by a partnership between Holtec International and the Eddy Lea Energy Alliance.

The HI-STORE Consolidated Interim Storage project is expected to cost more than $1 billion and provide around 200 construction and operations jobs. Initially, the facility will be built to house 200 to 500 spent fuel casks, but it can be expanded to store 4,000. Holtec will present its application to the Nuclear Regulatory Commission in March, with the approval process taking two to three years.

Intrepid Potash idled its West Mine near Carlsbad in May, eliminating around 300 jobs. The New Mexico Land Office will now retain the rights to the minerals.

More: *Carlsbad Current-Argus*

Regulator Calls for Companies to Put up Collateral for Cleanups

The head of the federal Office of Surface Mining and Reclamation Enforcement said states should demand that coal companies put up collateral to cover the cost of mine cleanups.

Pizarchik

Joe Pizarchik said that coal companies are edging toward bankruptcy in a climate of low demand and cheap natural gas prices, leaving behind a potential legacy of environmental waste.

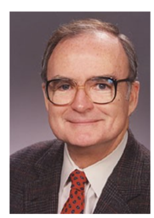
He pointed at the bankruptcies of Peabody Energy, Arch Coal and Alpha Natural Resources in the past year. Those bankruptcy plans call for the companies to use federal subsidies to fund cleanup efforts, at the expense of taxpayers.

More: *Reuters*

Two Former EPA Chiefs Backing Hillary Clinton

Reilley

Two former EPA administrators who served under Republican presidents said they are endorsing Hillary Clinton over Donald Trump for the U.S. presidency. William D. Ruckelshaus, the first EPA administrator under President Richard Nixon, who also served under President Ronald Reagan, and William K. Reilley, who served under President George H.W. Bush, issued a joint statement of endorsement.



Ruckelshaus

The Republicans said Trump "threatens to destroy that legacy of respect for the environment and protection of public health" and went on to decry Trump's unwillingness to accept the prevailing consensus on climate change.

"That Trump would call climate change a hoax — the singular health and environmental threat to the world today — flies in the face of overwhelming international science," they said.

More: *CNN*

GE Exec Calls for Fed Support of New Tech

The head of GE Hitachi Nuclear Energy issued a call for federal support of research and adoption of advanced nuclear reactor

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FEDERAL BRIEFS

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technology during an Aspen Institute appearance.

GE Hitachi Nuclear Energy President and CEO Jay Wileman called nuclear generation the nation's largest source of clean energy and said it was an important part of attaining clean air goals set by the government.

Wileman

"We are seeing significant global opportunities for our PRISM advanced reactor technology, but in order for us to move forward, we must gain the support of the federal government on specific developmental milestone projects," Wileman said.

More: *GE Hitachi Nuclear Energy*

In 5 Years, Army's Energy-Saving Investments Exceed $1B

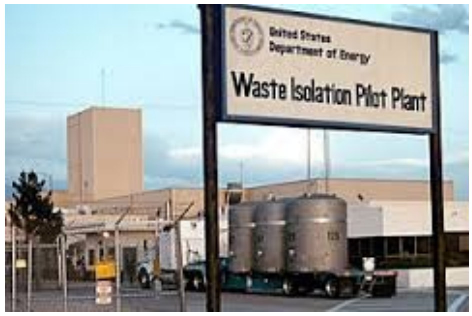
In response to a 2011 challenge by President Obama, the Army has entered into 127 energy-saving projects with the private sector worth more than $1 billion.

Under the Energy Savings and Performance-Based Contracting Investments Initiative, Obama asked federal agencies to engage in $4 billion of power-saving projects by the end of this year.

The Army's projects are spread among 52 installations.

More: *U.S. Army*

DOE 80% Certain Waste Facility Will Reopen by December



A Government Accountability Office audit released last week revealed that the Department of Energy knew it had only a 1% chance of meeting a March 2016 deadline to clean up and safely reopen the Waste Isolation Pilot Plant nuclear-waste facility near Carlsbad, N.M. A truck fire and a leaking drum of radioactive waste shut down the nation's only underground nuclear waste facility in February 2014.

In 2015, the agency admitted that it couldn't safely reopen the Waste Isolation Pilot Plant until at least December 2016 and that the project would be over budget. Now auditors say even the revised cost estimate was flawed. The result of missteps in the process of reopening the facility, according to auditors, was a nine-month delay and a price tag $64 million higher than the original $242 million estimate for cleanup and an additional $77 million to $309 million to install a critical new ventilation system.

The department now says it is 80% confident that it will meet the December 2016 deadline to reopen on a limited basis.

More: *Santa Fe New Mexican*

Scientists Conclude Fracking Report 'Lacking' in Areas

Most of the advisory group behind EPA's draft report on fracking announced last week that, as a group, it has concluded that the report was "comprehensive but lacking in several critical areas."

The panel said 26 of the 30 members reached the decision that the report be updated to include "quantitative analysis that supports its conclusion." The draft report concluded that the analysis "did not find evidence that these mechanisms [fracking] have led to widespread, systemic impacts on drinking water" in the U.S.

The oil and natural gas industry praised the preliminary report, while environmentalists criticized it. The report has been five years in the making so far.

More: *The Washington Post*

Interior Department to Open NC Shore to Wind

The Department of the Interior announced Friday that it would be opening 144,000 acres off the coast of North Carolina to leases for offshore wind projects. The site, to be called the Kitty Hawk Wind Energy Area, starts about 24 miles offshore and extends another 26 miles to the southeast.

The department's Bureau of Ocean Energy Management will hold September seminars on the auction rules in Raleigh and in Kitty Hawk.

More: *The Charlotte Observer*

STATE BRIEFS

REGIONAL

Report Advocates a More Aggressive RGGI

A new Acadia Center report suggests the Regional Greenhouse Gas Initiative (RGGI) should adopt more aggressive emissions targets aligning it more closely with those of some member states. The climate-change advocacy organization also recommends extending the RGGI caps to 2031 to coincide with the proposed federal Clean Power Plan.

"RGGI continues to prove itself as an effective means of reducing carbon emissions and supporting economic growth," said Daniel L. Sosland, Acadia Center president. "Now, Northeast and Mid-Atlantic states have an opportunity to build on RGGI's success and lead the country by taking the steps necessary to meet state and federal climate requirements."

RGGI states have committed to reducing emissions by about 40% across their economies by 2030. In addition, eight of the nine participating states have established 2050 requirements for 80% reductions.

More: *Acadia Center*

Del. Officials Say W.Va. Plant is Polluting Their Air

Delaware officials are asking federal regulators to take action against a coal-fired West Virginia plant they say is contributing

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STATE BRIEFS

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to pollution in the First State.

The Department of Natural Resources and Environmental Control says emissions from the Harrison Power Station near Haywood exceed federal standards. The plant is 245 miles west of the Delaware border.

The move is the latest effort by state officials to battle emissions produced in Maryland, Pennsylvania and other states that they say are making it impossible for Delaware to meet EPA air quality standards.

More: *Delaware Online*

CALIFORNIA

Watchdog Says Energy Companies Influenced California Democrats

A public interest group said Gov. Jerry Brown and California Democrats have received more than $9.8 million in campaign contributions from energy companies during the past eight years.

In a report titled "Brown's Dirty Hands," Consumer Watchdog alleges that the donations coincided with the companies' winning political favors — including a deal between Southern California Edison and the state's Public Utilities Commission that allowed the utility to charge ratepayers with most of the cost of shutting down the San Onofre nuclear generating station.

"The report really paints a troubling picture," said Jamie Court, the group's president. A spokesman for the governor called the report "cuckoo."

More: *Pasadena Star-News*

Pilot Program to Generate Power from California Highways

The California Energy Commission is initiating a series of pilot programs next year that will attempt to generate electricity from sensors in the roadway triggered by cars driving along the state's freeways.

The project will rely on piezoelectric technology, which involves installing tiny sensors beneath the road surface to capture energy produced by vibrations of passing cars. Gov. Jerry Brown vetoed a bill, introduced by Assemblyman Mike Gatto, to fund the project, but the commission expressed interest in the technology shortly after.

"As an engineer, I could just see that vision of all these people driving down the roads and all that energy that's sitting there and goes nowhere," said Michael Gravely, a commission deputy division chief.

More: *KCRA*

DISTRICT OF COLUMBIA

OPC Takes Exelon Merger to Appeals Court

The Office of the People's Counsel (OPC) is asking the D.C. Court of Appeals to examine the Public Service Commission's order approving the Pepco/Exelon merger. (See *Exelon Closes Pepco Merger Following OK from DC PSC*.)

"Judicial review is critical not only because the decision impacts this case but all cases going forward in terms of the process and procedures the commission uses in making its decisions," said Sandra Mattavous-Frye of the OPC. "It concerns the amount of process, or lack thereof, afforded to all parties, and the manner in which settlements are decided."

Mattavous-Frye said the OPC also is opposing Pepco's $85 million rate increase request.

More: *Office of People's Counsel*

ILLINOIS

Lawmakers Urged to Follow NY's Lead

A group of pro-nuclear Illinois mayors and community leaders have urged Illinois lawmakers to follow the lead of New York State policymakers, who arranged a nuclear bailout, expediting Exelon's decision to buy and operate Entergy's James A. FitzPatrick nuclear station.

In a letter sent to Gov. Bruce Rauner and lawmakers, the local leaders praised New York's Clean Energy Standard, which includes subsidies for nuclear stations. "New York's Clean Energy Standard is a road map for effective policy in Illinois," said Tim Followell, city administrator of Clinton, Ill., which is home to one of the two nuclear stations Exelon says it will be closing because it is losing money due to low wholesale prices.

Followell and others have been pushing for passage of an Illinois version of a bill that would provide credits for nuclear stations. Critics have tagged that proposal, called the Next Generation Plan, a bailout.

More: *Quad-City Times*

AG Settles Case With Ethical Electric

Madigan

Attorney General Lisa Madigan has reached a settlement with competitive retail energy supplier Ethical Electric requiring the company to refund up to $3 million for misleading customers.

Ethical Electric touted its power as being generated exclusively by renewable energy sources, when, in fact, it was sourced from a variety of generators paired with renewable energy certificates.

It also falsely promoted its fees as comparable with Commonwealth Edison's rates, when they were more expensive.

More: *Energy Manager Today*

IOWA

Landowners File Yet Another Motion Against Dakota Access

A group of 14 landowners has filed a motion in Polk County District Court seeking to halt construction of the $3.8 billion Dakota Access Pipeline, asking the court to review the Iowa Utilities Board (IUB) ruling that the pipeline could use eminent domain.

"The landowners believe that Dakota Access is not a public utility and should not have the ability to use eminent domain to forcibly access Iowa landowners' property to build a private pipeline," Bill Hanigan, an attorney for the property owners, argued in a motion. He said the IUB misinterpreted Iowa law in calling the pipeline a public utility.

The 1,168-mile pipeline, parts of which are already under construction, will carry Bakken crude oil from North Dakota to terminals in Illinois.

More: *The Gazette*

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STATE BRIEFS

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KANSAS

Regulators Outline Standards For Upcoming Acquisition Dockets

The Corporation Commission said last week its members will consider whether Great Plains Energy's proposed acquisition of Westar Energy will "promote the public interest" when it votes on the deal next year. Commissioners adopted merger standards for the Westar/Great Plains union and two other unrelated mergers to ensure the KCC takes a "consistent approach."

The criteria the commission will consider include the merger's effects on consumers, the environment and state and local economies and to the utilities' communities.

The KCC is expected to hear the Westar Energy and Great Plains acquisition docket sometime between Jan. 3 and March 30. The two other acquisitions in front of the KCC are the purchase of Empire District Electric Co., of Joplin, Mo., by Liberty Utilities (Central) Co., a subsidiary of Algonquin Power & Utilities Corp., and a proposal for ITC Holdings to become an indirect, majority-owned subsidiary of FortisUS with minority ownership by GIC Ventures.

More: *The Topeka Capital-Journal (Kan.)*

KENTUCKY

LG&E Awarded Customer Charge for Clean Up

The Kentucky Public Service Commission has approved a request by Louisville Gas & Electric Co. (LG&E) to assess a new monthly charge for customers to pay for the cleanup of coal ash ponds. The commission approved the charge of 30 cents a month for this year for the typical residential customer, which will increase to $2.08 a month in 2024.

The commission approved a similar charge for LG&E's sister company, Kentucky Utilities (KU), which was set at 30 cents per month and will later increase to $3.12 a month. The charges were approved after the two companies requested $994 million to meet new federal coal-ash cleanup rules. LG&E said it will spend more than $300 million in cleanup efforts. KU said it will spend about $675 million.

More: *Louisville Courier-Journal*

MICHIGAN

State Preps for Higher Rates In Face of Supply Shortage

Some consumers in the state are expecting electricity price increases in the coming years because of DTE Energy's decision earlier this year to shut down seven coal-fired plants.

The Public Service Commission's five-year outlook anticipates electric supply shortfalls through summers 2017 and 2020. The Lower Peninsula is expected to see a 270-MW shortage next year, an improvement over the 520-MW shortage that the PSC previously predicted. MISO's Midwest region is predicted to fall short of the reserve margin requirement by 2018.

Tim Arends, executive director of Traverse City Light & Power, said the municipal utility's annual power prices nearly doubled to $850,000 this year. The utility recovers the cost through a user fee.

More: *Traverse City Record-Eagle*

Consumers Installing More Safety Buoys Near Hydroelectric Dams

Consumers Energy in installing more safety buoys across rivers below its Michigan hydroelectric dams to warn swimmers and boaters of the dangers of swirling water released from impoundments.

The utility is working with the Michigan Department of Natural Resources to keep swimmers and boaters out of "potentially unsafe areas immediately downstream of hydroelectric dams." Consumers will place buoys at 10 dams on five rivers statewide during the year.

Last year, Consumers installed buoys at three dams on two northern Michigan rivers.

More: *Post-Bulletin*

MISSOURI

PSC Could Quash Westar-KCP&L Merger

The Public Service Commission's claims of jurisdiction over the $12.2 billion acquisition of a Kansas utility by Great Plains Energy could have significant impact on the deal. Commission staff says job cuts and possible outsourcing spurred by the proposed acquisition could harm existing customers of Great Plains' subsidiary, Kansas City Power & Light.

The staff claims Great Plains violated a 2001 agreement with the Missouri commission, in which it agreed not to acquire any public utilities without commission approval.

Great Plains argues that combining Westar and KCP&L would benefit customers on both sides of the state line. Moreover, it says the commission's complaint is a moot point because Westar isn't a public utility under state law, and, therefore, Great Plains doesn't need the state's approval to buy Westar.

More: *The Wichita Eagle (Kan.)*

NEW MEXICO

Regulatory Examiner Recommends 67% Slash to PNM Rate Increase

A state hearing examiner has recommended a 67% reduction to Public Service Company of New Mexico's (PNM) rate increase request, from $123.5 million a year to $41.3 million a year. The recommendation would result in a 6.4% increase for the average customer, compared to 14.4% under PNM's request.

The hearing examiner rejected the $152.8 million PNM spent to purchase power from the Palo Verde Nuclear Generating Station in Arizona, which was disputed in a separate commission matter. The examiner also disallowed a $52 million investment in pollution controls at the San Juan Generation Station, which PNM did at the behest of the EPA, but some felt it was unnecessary. The examiner also reduced PNM's requested rate of return from 10.5% to 9.575%.

PNM can file exceptions to the examiner's findings, after which the regulatory commission's general counsel will present a draft order to the Public Regulation Commission (PRC). According to the current schedule, the PRC must make a final ruling in the case by Aug. 31.

More: *Albuquerque Journal (N.M.)*

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NEW YORK

Storage Provider Demand Energy Wins Load Relief Auction

Demand Energy was a successful bidder in Consolidated Edison's first-ever auction to provide load relief on peak power days in New York City.

Demand Energy will soon begin installing several megawatts of energy storage in Brooklyn and Queens, controlled by the company's Distributed Energy Network Optimization System (DEN.OS) intelligent software. The project is part of Con Ed's Brooklyn-Queens Demand Management program.

The energy storage project, which will come online in 2017, will delay the need for a new $1.2 billion substation. The program will use demand-side resources such as energy storage, energy efficiency and demand response. The project is a prototype for New York State's Reforming the Energy Vision initiative to encourage the use of more distributed resources.

More: Demand Energy

NORTH DAKOTA

Tribe Blocks Access to Dakota Access Crews

Members of Standing Rock Sioux Tribe blocked crews working on the $3.8 billion Dakota Access pipeline that is to carry crude oil from North Dakota to terminals in Illinois.

Although the pipeline developers have received the necessary permits from state and regulatory agencies, they face continuing legal and political challenges. One was by the Standing Rock Sioux Tribe, which sued federal regulators in July, claiming the pipeline runs too close to sacred land and the tribe's drinking water supplies. Tribe members blocked a road near their 2.3-million-acre reservation, backing up a line of 45 construction vehicles.

Work has already started on the 1,168-mile pipeline in other places in North Dakota, South Dakota and Illinois.

More: Associated Press

OKLAHOMA

Drop in Number of Earthquakes Could be Result of Regulation

Oklahoma has experienced a decline in earthquakes compared to last year, and some geophysicists believe that more stringent regulation of underground injection of wastewater from oil and gas drilling operations may deserve some of the credit.

According to the U.S. Geological Survey (USGS), Oklahoma experienced 448 magnitude 3.0 or greater earthquakes as of Aug. 10, compared to 558 for the same period last year. Robert Williams, with USGS, said the increased restrictions on wastewater injection and disposal could be one reason for the decrease, as well as the drop in oil and natural gas exploration.

More: USA Today

City Tests Smart Meters Before Making the Switch

City of Edmond officials in Oklahoma are conducting a pilot program to help determine whether the city should install smart meters for all 35,000 electric customers and 32,000 water customers. The pilot program could last from six months to a year before a decision is made.

In a 2011 feasibility study, consultants told city officials a total system, with all the possible extras, could cost $36 million over 15 years.

About 1.7 million smart meters were installed across Oklahoma in 2014.

More: The Oklahoman

PENNSYLVANIA

PUC Reliability Report Dings Penelec

Penelec
A FirstEnergy Company

A report by the Public Utility Commission says Penelec customers saw more power failures last year compared with consumers of electricity from other large companies in the state.

The report relies on data from quarterly and annual reliability reports submitted by electric distribution companies and details four benchmarks.

Penelec failed to meet any of the bench-marks but expects to improve reliability by 2018.

More: The Bradford Era

NC Health Official Resigns in Dispute with Gov. over Duke Energy Coal Ash

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dogged by the Duke coal ash issue since February 2014, when a dike at a retired Duke plant burst, releasing 39,000 tons of toxin-laden coal ash and 27 million gallons of contaminated water into the Dan River.

The dispute became public this month after a judge released portions of a deposition Rudo gave in a lawsuit by the Sierra Club, the Southern Environmental Law Center and other environmental groups over Duke's coal ash storage sites. The suit alleges that toxins from coal ash stored on Duke sites are contaminating rivers and other waterways and groundwater. It calls on Duke to safely remove the coal ash and ensure residents living near the plants have clean water.

By the end of the week, Democrats in the state legislature were calling for a probe into the whole affair.

Meeting with the Governor

In his deposition, Rudo testified his office sent a warning to about 400 homeowners near Duke plants in late 2014, telling them their well water wasn't safe to drink because of pollution from Duke's coal ash.

Rudo said groundwater samples showed increased levels of hexavalent chromium and vanadium, both cancer-causing agents. As a result, while the issue was still being debated by Duke and other state environ-mental and health officials, Duke began supplying some of the homeowners with bottled water.

Rudo said that in early 2015, he was called in to a discussion with Reeder and other higher-ups about the wording of the letters. "They wanted language put on there that

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stated, in essence, we were overreacting in telling people not to drink their water," Rudo said in the deposition. He said he objected to the wording and told them to take his name off the letter.

"You know, I can't stand behind that," he said. "It is just not right. It is going to confuse people. People are not going to really know whether they should drink the water or not," Rudo testified.

The dispute came to a head, he said, when he was called to another meeting with a McCrory aide in March 2015 in which McCrory briefly took part by phone. "I have never talked to a governor in all of the years I have been here, so I was a little … intimidated," he said.

Rudo said McCrory and the aide raised concerns about the department warning people not to drink the water.

The language on the letters was changed, and the revised letter was sent out while he was on vacation. "And it was just amazingly misleading and dishonest language," Rudo said.

In May 2015, EPA fined Duke $102 million for federal Clean Water Act violations; North Carolina added a $6.6 million penalty.

Following public outcry, North Carolina legislators passed legislation calling for Duke to clean up all of its coal ash dumps in the state.

McCrory, who had worked for Duke for almost three decades before becoming governor, vetoed the bill in June 2016. Last month, he signed a compromise bill calling for Duke to begin cleaning up half of its coal storage sites immediately while monitoring the rest.

Deposition Becomes Public

The dispute became public last week after the Southern Environmental Law Center filed Rudo's redacted deposition in the group's lawsuit.

The McCrory administration fired back. "We don't know why Ken Rudo lied under oath, but the governor absolutely did not take part in or request this call or meeting, as he suggests," said McCrory's chief of staff during a rare, late-night press conference.

When Rudo stood by his testimony, the administration issued a scathing statement Aug. 9.

"Rudo's unprofessional approach to this important matter does a disservice to public health and environmental protection in North Carolina," Reeder and Williams wrote. "It doesn't help that political special interest groups perpetuate his exaggerations and fuel alarm among citizens for their own purposes."

The statement was the last straw for Davies, who issued a letter resigning from the Division of Public Health (DPH) on Wednesday night. Davies defended Rudo and claimed her superiors in DPH and the Department of Health and Human Services (DHHS) were fully involved in all decisions.

"The [statement] signed by Randall Williams and Tom Reeder presents a false narrative of a lone scientist … acting independently to set health screening levels and make water use recommendations to well owners," she wrote. "In fact, and as I briefed you in August 2015, NCDHHS followed a process that engaged DPH and DHHS leadership in all decisions.

"Upon reading the open editorial yesterday evening, I can only conclude that the department's leadership is fully aware that this document misinforms the public," she wrote. "I cannot work for a department and an administration that deliberately [mislead] the public."

McCrory addressed the dispute again while at a ribbon cutting ceremony on Thursday.

"We basically have a disagreement among scientists," McCrory said, according to WRAL. "One group of scientists, which I support, believe the public ought to get all the information about the water, not limited information and one opinion."

State Democrats, in their continued feud with McCrory and his administration, are calling for an investigation. "There is at least an appearance of pay-to-play politics, and, unlike other incidents of McCrory rewarding his friends and donors with political favors, this insider dealing puts lives at risk," North Carolina Democratic Party spokesman Dave Miranda told reporters.

It is unclear who would lead such an investigation. The state attorney general, Roy Cooper, is running against McCrory for governor in November.

Energy Wildcatter Hopes to Make His Mark in Emerging Mexican Market

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anybody to put up the guarantee," Cummins said. "That would have required about $2 million, which I ain't got."

Cummins was riding in a Mexico City taxi as he spoke, on his way to a meeting with a fourth-level executive in the country's energy department to discuss timetable issues. The man he was going to meet "is the guy that turns the crank," the person who implements policy directives, Cummins said.

In order to place financial guarantees for the September auction, Cummins needs an interconnection, which requires a bond guaranteeing that upgrade costs will be paid, and a generation permit from Mexico's Energy Regulatory Commission. And he must be ready to turn in reams of paper.

"Coordinating calendars for other permits … makes it tricky," Cummins said. He planned to complete the paperwork by Aug. 29. "The [first official] deadline is Sept. 1. That's a slim margin for error."

It may not matter. Cummins said in a subsequent email exchange that an "unexpected change" in the auction's evaluation criteria "most likely knock[s] us out as contenders in this auction as well."

Growing Pains

Growing pains are to be expected in any immature market, but those pains have been amplified by Mexico's emergence from a state-run monopoly. Vertically integrated CFE has long been the country's only electric utility, much as Pemex controls the country's oil industry. It is only now being restructured into generation, transmission and distribution firms.

"The market is open, and it has a single participant … CFE, which was the single participant before it opened," Barbara Clemenhagen, Customized Energy Solutions' vice president of market intelligence, explained at an Infocast conference in March. "If the statements for the initial 48 days are indicative, there' s not much transparency and liquidity in the market."

Clemenhagen said CFE is participating as both a buyer and a seller in the clean-energy auctions, covering the demand of its regulated clients and load centers. The

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utility was the only buyer for capacity, energy and clean-energy certificates in the last two auctions but was not allowed to sell because its generation companies do not exist yet.

El Centro Nacional de Control de Energía (CENACE), the grid operator, was an operating division of CFE, the vertically integrated national electric utility. CENACE became an independent system operator in August 2015.

CFE is also being restructured into different generation, transmission and distribution firms.

"The same guys who are on the CFE payroll in the morning are with CENACE in the afternoon," Cummins said. "The independent part needs some time to set, since most CENACE folks were transitioned from similar posts in CFE."

Grupo Fenix, which works with rural communities in Nicaragua to promote renewable energy, reforestation and sustainable development, also qualified as a market participant but has chosen not to participate.

"They pulled this thing together so fast, all the loose ends aren't tied up," Cummins said. "How long did it take ERCOT to get [its competitive market] going? The Senate bill passed in 1999 and it took 10 years to decide what was up.

"Wildcatter guys like us, we don't mind navigating in an uncertain environment. But when you start putting hundreds of millions of dollars down, you better have everything locked up pretty good."

Tres Mesas *Source: Mannti Cummins*

Cummins said he would like to see more clarity in the market's interconnection rules, the source of many of his current headaches.

"There needs to be coordination between the auction process and the interconnection process," he said. "In ERCOT, you file your study and ERCOT comes in with theirs. There's a date certain your study has to be done. Not in Mexico. That process and the auction timetables sometimes just don't line up."

The wildcatter would also like to see clean-energy generators create bilateral contracts outside the auction process with consumers, who will be required by Mexican law to buy 5% of their load from clean-energy sources in 2018.

"The rules in that market are uncertain and not definable for the amount of risk [involved]," Cummins said. "Those rules have not been ironed out."

Compounding the problem, Cummins said, is the lack of a mechanism to balance load with generation and the requirement that private-generation companies purchase clean-energy certificates — even though clean-energy projects have yet to be built.

Clemenhagen said even when the rules are finalized, a lack of transparency makes it difficult to know who changed the rules and why. As of this spring, only 13 of 30 expected operating procedures and manuals had been released, and only one (the long-term auctions market) had been finalized.

"She's not the only one [who feels that way]," Cummins said. "There are inconsistencies in the rules, gaps in the rules, downright confusion in the rules. The sheer volume of the rules … you have to have a person, or two or three, just to read the darn documents on a daily basis.

"It's a haul, especially in a market like Mexico's, where you have plenty of unknown unknowns," he said.

Still, Cummins is making a go of it. His 148.5-MW Tres Mesas wind farm in the state of Tamaulipas, owned and operated by Oak Creek de México, is scheduled to be operational by the end of the year.

He also has four other projects in development in four states, Baja California Sur, Jalisco, Sonora and Zacatecas. That includes a 50-MW wind farm in Baja Sur, an island grid where all generation is supplied by fuel oil.

"We're in so deep now," Cummins said, "we don't have a choice but to accomplish the goal."