RTO Insider

Your Eyes and Ears on the Organized Electric Markets

CAISO ▪ ERCOT ▪ ISO-NE ▪ MISO ▪ NYISO ▪ PJM ▪ SPP

ISSN 2377-8016 : Volume 2020/Issue 35

September 1, 2020

Exelon to Close Ill. Nukes as Gov. Touts Clean Energy Plan

By Michael Yoder

Exelon said Thursday that it will next year close two Illinois nuclear plants that face hundreds of millions of dollars of revenue shortfalls because of declining energy prices.

In a statement, Exelon said it must close the plants because of "market rules that allow fossil fuel plants to underbid clean resources in the PJM capacity auction, even though there is broad public support for sustaining and expanding clean energy resources to address the climate crisis."

The Byron nuclear plant is slated to close in September 2021, while the Dresden plant will shut down in November 2021, the company said.

"Today's unfortunate announcement comes after a long fight to keep these nuclear plants online," said Maria Korsnick, CEO of the Nuclear Energy Institute. "These closures not only will prevent Illinois from meeting its clean energy goals, but ultimately will keep our nation from reaching a carbon-free future by 2050."

Illinois Gov. J.B. Pritzker | *Gov. J.B. Pritzker*

News of the closure of the plants comes less than a week after Illinois Gov. J.B. Pritzker revealed he will pursue an alternative to legislation that seeks to pull the state out of PJM's capacity market in order to set up a fixed resource requirement (FRR).

Pritzker last week released a report outlining *eight principles* to guide Illinois to a clean energy economy, ranging from expanding consumer affordability protections to electrifying and decarbonizing the state's transportation sector.

Continued on page 33

MISO Enacts Rolling Blackouts in Laura Aftermath

Entergy trucks heading out in the aftermath of Hurricane Laura (p.22) | *Entergy*

Theories Abound over California Blackouts Cause

By Robert Mullin and Hudson Sangree

Observers last week cited dependence on uncontracted imports, underperformance of natural gas and wind, and market manipulation as possible causes of California's first rolling blackouts in nearly two decades, as a state regulator cautioned against drawing premature conclusions.

Edward Randolph, CPUC | *© RTO Insider*

"It is not helpful to speculate on the root cause until we have a chance to do a complete analysis on the factors leading to the outages," Edward Randolph, director of the California Public Utilities Commission's Energy Division, said Thursday during a commission meeting.

"Within weeks," the CPUC, CAISO and the California Energy Commission will release a joint initial report on causes, Randolph said. The report will focus on demand forecasts, the state's resource adequacy process, what resources were scheduled to meet demand during the emergency and whether those resources were actually available.

A second deeper dive will examine factors that will take more time and data to fully understand, he said.

"At this point, we know some basic facts about why there were outages on [Aug. 14 and 15], and why the grid was too close to the edge on [Aug. 17 and 18] than it ever should be," Randolph said. "The short of it is there was not enough available supply to meet demand. Based on our planning process, there should have been."

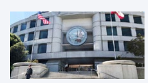
Randolph called out recent analyses and news reports that attempted to identify root causes of blackouts. Some relied on actual data, while

Continued on page 10

PGE Traders Burned by California Heat Wave
(p.7)

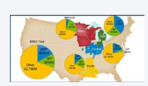
Also in this issue:

NRC OKs NuScale's Small Modular Reactor Design
(p.5)



CPUC Fires Executive Director for Improper Hiring
(p.14)

Montana Supreme Court Rebuffs PSC on PURPA Rules
(p.23)



MISO in Final Stretch of $4B MTEP 20
(p.27)

FERC Orders Tech Conference on MISO-SPP Congestion
(p.34)

10837 Deborah Drive ▪ Potomac, MD 20854 ▪ (301) 299-0375 ▪ info@rtoinsider.com

▪ www.rtoinsider.com ▪

RTO Insider

CAISO ERCOT ISO-NE MISO NYISO PJM SPP

RTO Insider LLC
10837 Deborah Drive
Potomac, MD 20854
(301) 299-0375

2020 Annual Subscription Rates:

Plan	Price
Newsletter PDF Only	$1,450
Newsletter PDF Plus Web	$2,000

See additional details and our Subscriber Agreement at rtoinsider.com.

In this week's issue

Stakeholder Soapbox
The Potential Impact of 'Perpetual Weekend' Load Profiles 3

FERC/Federal
NRC OKs NuScale's Small Modular Reactor Design 5

CAISO/West
Theories Abound over California Blackouts Cause 1
PGE Traders Burned by California Heat Wave 7
COVID Will Cut Electricity Demand in Calif., CEC Says 8
CAISO Finalizes ESDER Phase 4 Plan 9
CPUC OKs 1.2 GW of Storage by 2021, 38,000 EV Chargers 12
CPUC Fires Executive Director for Improper Hiring 14

ERCOT
Texas Escapes Disaster, PUC Ends COVID Program 16
ERCOT Technical Advisory Committee Briefs 17

ISO-NE
ISO-NE Planning Advisory Committee Briefs 19
FERC Defends Ruling on ISO-NE Winter Program Cost 21

MISO
MISO Enacts Rolling Blackouts for Entergy After Laura 22
Montana Supreme Court Rebuffs PSC on PURPA Rules 23
MISO, SPP Close to Ruling out Joint Projects Again 25
LS Power Again Seeks MISO Cost Allocation Change 26
MISO in Final Stretch of $4B MTEP 20 27

NYISO
NY Seeks Comment on Proposed Emissions Limits 28
NYISO Q2 Energy Prices, Load at 10-Year+ Lows 30
NYISO Management Committee Briefs 31

PJM
Exelon to Close Ill. Nukes as Gov. Touts Clean Energy Plan 1
FERC Partially Approves DP&L Tx Rate Incentives 32

SPP
FERC Orders Tech Conference on MISO-SPP Congestion 34
SPP Stakeholders Agree on WEIS Tariff Changes 35

Briefs
Company Briefs 36
Federal Briefs 37
State Briefs 38

Stakeholder Soapbox

The Potential Impact of 'Perpetual Weekend' Load Profiles

By Patrick McGarry

A few years ago, during my EMBA program at the University of Florida, I visited my Managerial Statistics professor one weekend. As I approached his office, I noticed a large sign taped to his door that declared:

"In God we trust. All others must bring data."

The message basically summed up the main point of our program, which is that critical thinking requires the objective analysis and evaluation of an issue devoid of gut feeling and cognitive biases. Utilizing reliable and accurate data offers the best option to understanding today in order to predict tomorrow.

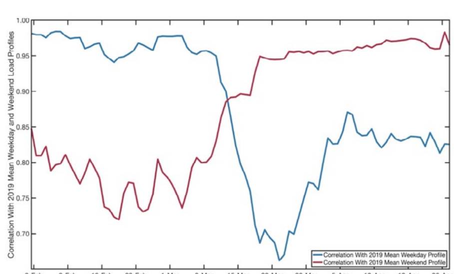
As I listen to all the futurists make COVID-19 pandemic impact predictions, I remind myself of that sign on the professor's door.

Behavior during market disruptions is historically a poor indicator of longer-term expectations. During the Great Recession, notable economists predicted the end of the age of overconsumption. The SUV would become a *relic of the past*, and $4/gallon gasoline would be a death knell. If you didn't understand that prediction, then you certainly would once gasoline reached $8/gallon.

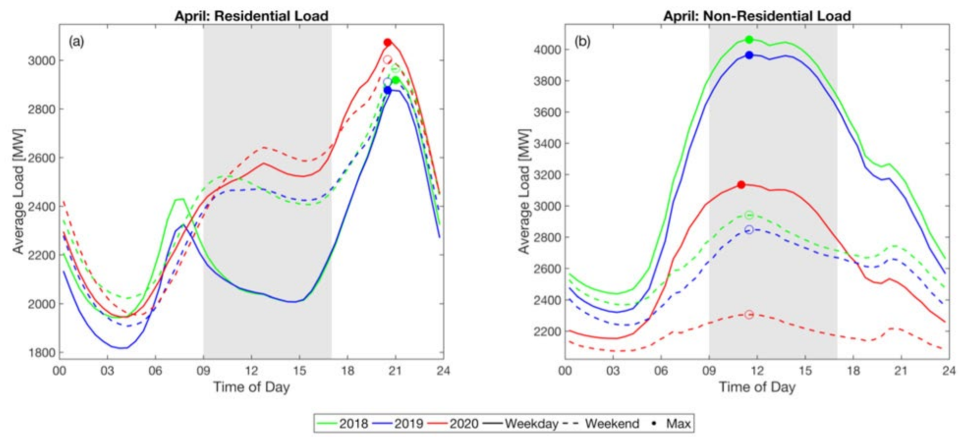
Of course, neither happened, and today, *SUVs comprise nearly half* of all the automobiles in the U.S., while the fracking revolution has flooded the global market in cheap and abundant oil.

People struggle to predict the future because disruptive events arise spontaneously, with little notice, and tend to be highly influential.

When Rosa Parks decided not to give up her seat on a Montgomery, Ala., school bus, how many people predicted the beginning of the civil rights movement?



Correlation between the residential load profile for a given day in 2020 and the mean weekday/weekend load profile from the same month in 2019 | *Pacific Northwest National Laboratory*



Mean weekday and weekend loads in April 2020 for residential and nonresidential customers. Diurnal maximum values indicated by circles. | *Pacific Northwest National Laboratory*

None.

The future is always more unforeseeable than it seems.

However, the recent COVID-19 shelter-in-place orders have provided utility data scientists with some reliable and accurate data to gain insight into changing residential and commercial load demand profiles. Predicting them as accurately as possible will be critical for planning the most economically efficient electricity grid operations and for designing rates.

What Do the Data Say?

The *Pacific Northwest National Laboratory* (PNNL) recently released a study assessing the first full month (April 2020) of COVID-19 impacts to residential and nonresidential load. *"Changes in Electricity Load Profiles Under COVID-19: Implications of 'The New Normal' for Electricity Demand"* examined two years of observed electricity consumption data from more than 3.8 million residential and nonresidential customers of Commonwealth Edison in Illinois.

In comparing load demand pre-COVID-19 to data following the national shelter-in-pace environment, the researchers discovered that the onset of the pandemic shifted weekday residential load profiles to closely resemble weekend profiles from previous years. (See Figures 1 and 2.)

PNNL observed that the April 2020 residential load profile demonstrated a correlation consistently over 0.95 with the 2019 Mean Weekend Profile.

The U.S. *Energy Information Administration* reported that residential electricity sales were 6% higher in April 2020 than in any April from the previous five years, while commercial and industrial sales decreased 9% and 10%, respectively.

While much more research will be needed this fall to determine a "new normal," we do know that weekday changes in residential loads have the potential to significantly change the total load profile.

The load data utilized in the PNNL study came from two extremely different environments: the pre-COVID-19 setting with rich data from many years, and the national emergency shelter-in-place order setting during April 2020.

PNNL's ComEd study data set covered customers that had deployed advanced metering infrastructure devices. Anonymous end-use electricity data are classified by class (four residential and 11 non-residential classes) and a zip code.

The main components of the PNNL study were:

- demonstrating how load profiles shifted as the U.S. transitioned to widespread shelter-in-place orders during March-April 2020 based on 30-minute aggregate loads for residential and nonresidential sectors; and
- a sensitivity analysis to explore how historical weekday total load profiles may have shifted if shelter-in-place conditions or widespread teleworking had occurred in prior months and years.

Stakeholder Soapbox

According to PNNL research scientist Casey Burleyson, "This paper was only possible because ComEd chose to make this unique data set available to the community. There is no shortage of eager scientists and engineers asking interesting questions. When you combine researchers with utilities willing to embrace the open-data movement, you enable real-time value-adding studies like we've done with this COVID-19 work."

What is the New Normal for Load Profiles?

We could talk forever about potential future impacts of COVID-19, but the topic of teleworking is of extreme interest to the energy industry. Up until the pandemic struck, most long-term planning discussions relative to the grid, generation and rate design did not really consider any evolution in how the U.S. workforce would be deployed. Now, however, those obvious changes will dramatically affect both residential and commercial load profiles.

While "gut feel" would indicate big changes ahead, we don't yet have all the data — or a vaccine — to help draw precise conclusions on the full impact of the pandemic. However, we do know they'll be felt differently in different parts of the U.S., which never has (nor ever will) have a one-size-fits-all load profile.

The unprecedented magnitude and length of pandemic-related disruptions raise the probability of lasting telework changes in our workforce. As a result, utilities need to be studying the current load patterns extremely closely in order to perform scenario planning.

With respect to shelter-in-place residential weekday load profiles, the PNNL study found:

- a more gradual morning ramp;
- higher mid-day loads; and
- smaller, less steep ramping during the evening peak.

Interestingly, PNNL's conclusions are consistent with the initial load profile observations from NYISO.

As mentioned earlier, PNNL used data historical load profiles versus a COVID-19 profile in analyzing different scenarios around increased teleworking along with reduced commercial loads. It determined that in the long term, increased teleworking could potentially lead to 5 to 7% higher spring and summertime peak hourly loads occurring up to 2.5 hours earlier.

It also found that the flattened daily load profile could potentially lower ramping needs, reduce oversupply risks and change market prices.

Rate Design and Budget Impacts

If some as-yet-unknown percentage of the workplace switches to teleworking for the longer term, one could logically deduce that residential power bills will go higher and that commercial/industrial bills will go lower. In an economy facing headwinds not seen since the Great Depression, this development could present significant rate design and budgetary challenges for utilities across the country.

Prior to the COVID-19 pandemic, the utility industry was beginning a discussion about reforming electric rate designs based in part on the fact that fixed costs are increasing. Grid modernization and investments to meet sustainability goals come at a significant capital cost, and utilities are struggling to cover these fixed costs, especially in the area of generation.

In a world in which some residential customers have the capacity to invest in distributed energy resources at home to potentially protect themselves from future, higher bills, others do not have that ability. Key questions in this area include:

- Will the consumer be able to shoulder higher power bills, and, if not, how badly will the economy be impacted?
- How will this impact "the electrification of everything"?
- Could COVID-19 workforce developments be the impetus for utilities to change from a single volumetric rate to a fix charged component with a set monthly fee?

While we can't yet fully answer these questions, we can assume that budgetary pressures will continue to be substantial while portfolio optimization dollars will become much more valuable.

Reliability and affordability will continue to be the two major challenges facing utilities in a post-COVID world. As always, operational effectiveness and efficiency will continue to be more important than ever.

Conclusion

Conjecture often makes a podcast interesting but does very little for the utility industry to predict the future. Fortunately, data scientists and research engineers utilize powerful, increasingly precise methodologies in forecasting realistic future scenarios.

There are things we know.

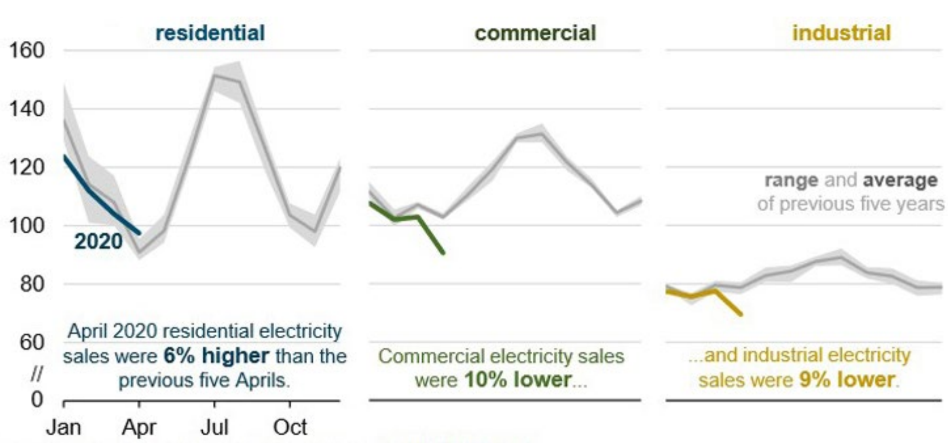
There are things we do not know.

There are things we do not know that we do not know.

COVID-19 is a "known unknown" and will clearly impact the future composition of residential and commercial load profiles, though the degree of the virus's influence is still coming into focus. Considering all the disruption now at hand in the energy industry, clearly understanding likely future loads will be a necessary and critical first step in scenario planning.

We have some of the data we need to begin this process. But during the next few months, one of the most important new normal planning tasks for individual utilities will be to collect, store and examine in fine detail their own meter data. ■

Patrick McGarry is senior director of Power Costs Inc.



U.S. monthly electricity sales by end-use sector, January 2015 to April 2020 (millions MWh) | *U.S. Energy Information Administration*

FERC/Federal News

NRC OKs NuScale's Small Modular Reactor Design

By Daniel Tyson and Rich Heidorn Jr.

Artist's conception of NuScale Power's small modular nuclear reactor plant. | *NuScale*

The Nuclear Regulatory Commission last week approved the final safety evaluation report for NuScale Power's small modular reactor (SMR) design, which proponents hope will revive the nation's nuclear power industry. Others are skeptical that this latest promise of a nuclear "renaissance" will come to pass given cheap natural gas and declining renewable and storage costs.

The commission greenlit the SMR design on Friday after completing its Phase 6 review of NuScale's design certification application (DCA), making the Portland, Ore.-based company the first and only SMR manufacturer to successfully complete a DCA review.

"This is a significant milestone not only for NuScale, but also for the entire U.S. nuclear sector and the other advanced nuclear technologies that will follow," company CEO John Hopkins said in a press release.

Two of the biggest threats to nuclear plants are the loss of water to keep their fuel from overheating and loss of power needed to operate pumps, valves and monitoring equipment.

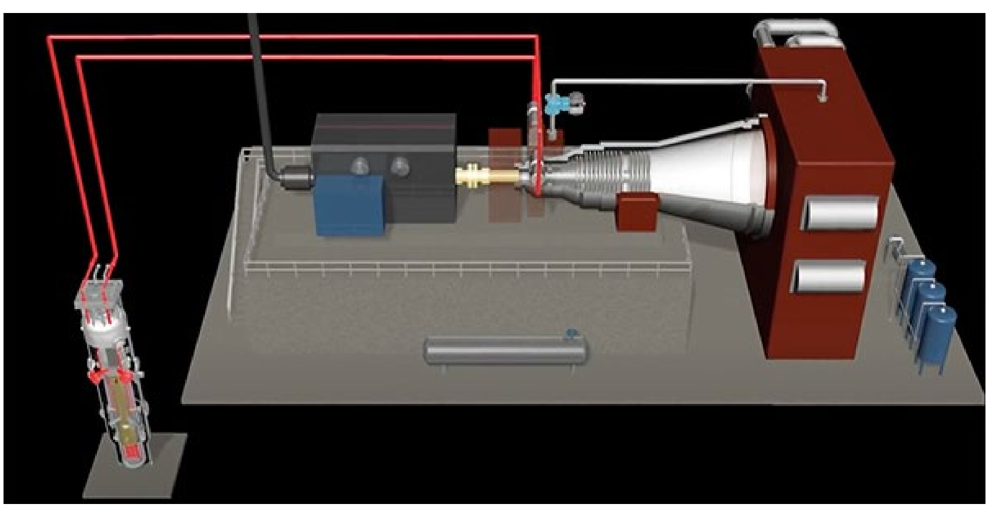
NuScale's pressurized light water reactor simplifies or eliminates systems used in earlier-generation plants and employs passive safety features that the company says will ensure the plant can shut down safely.

The passive design was instrumental in the approval process. "The NRC concludes the design's passive feature will ensure the nuclear power plant would shut down safely and remain safe under emergency conditions, if necessary," the commission said.

NuScale's SMR, called the NuScale Power Module, encompasses the reactor, steam generators and pressurizer, and the use of natural circulation eliminates the need for large primary piping and reactor coolant pumps, according to a company spokesperson. Each module has a generating capacity of 60 MW, and the design is scalable, allowing for combinations of up to 12 modules for a total of 720 MW.

By comparison, the smallest nuclear reactor in the U.S. is New York's R.E. Ginna Nuclear Power Plant, which has one reactor with a capacity of 582 MW. Arizona's Palo Verde nuclear power plant, the largest in the U.S. with three reactors, has a total capacity of 3,937 MW.

High construction costs and three reactor accidents still scar the industry: Three Mile Island's partial meltdown in March 1979; the April 1986 accident at Chernobyl; and the 2011 accident at the Fukushima Daiichi plant, in which three nuclear cores largely melted after the plant was swamped by a 45-foot tsunami that disabled the power supply and cooling.



The NuScale Power Module encompasses the reactor, steam generators, and pressurizer. | *NuScale*

NuScale says its plant can safely shut down and cool itself indefinitely without pumps, AC or DC power, or additional water.

As in traditional reactors, control rods are inserted to stop the fission reaction. But NuScale says its design allows the *decay heat removal system* and the steam generators to reduce the core thermal power to about 1.1 MWt (megawatt thermal) in one day. (The heat from 3 MWt is enough to generate 1 MW of electricity.)

After three days, core thermal power drops to about 0.8 MWt and reactor pool water begins to boil. For the next 30 days, the water level decreases as core thermal power falls to 0.4 MWt. After 30 days, the reactor pool is emptied, but the reactor remains cool indefinitely by transferring heat to the surrounding air via natural convection.

The company said it is actively engaged with its manufacturing partners to ensure its SMR is ready for delivery to its first client in 2027. It says it has signed agreements with entities in the U.S., Canada, Romania, the Czech Republic and Jordan.

In addition, a 12-module, 720-MW NuScale plant is planned by the public power consortium Utah Associated Municipal Power Systems (UAMPS). The first module is expected to be operational by mid-2029, with the remaining 11 modules to come online for full plant operation by 2030, a company spokesperson told *RTO Insider*.

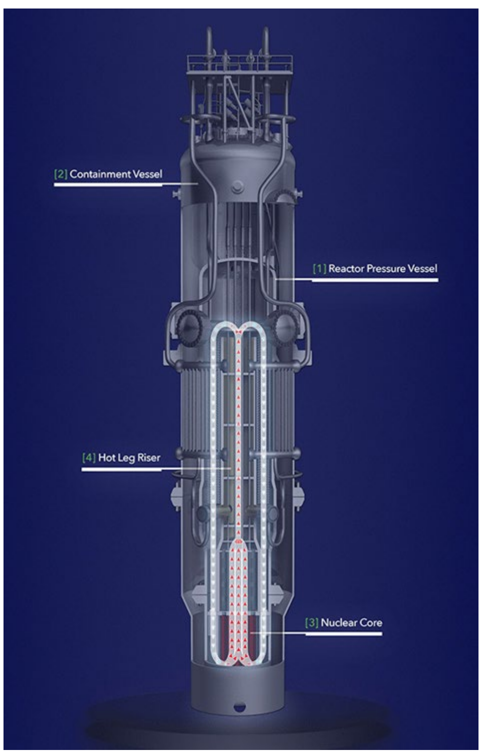
FERC/Federal News

To date, NuScale has invested close to $1 billion in the technology development and licensing, which includes more than $300 million in cost-shared funding from the U.S. Department of Energy. NuScale's majority investor is Fluor, a global engineering, procurement and construction corporation.

Marc Nichol, senior director of new reactors at the Nuclear Energy Institute, said SMRs could aid in bringing the U.S. closer to meeting its clean energy target and making electricity more accessible. "This milestone demonstrates the nuclear industry can meet the demands for reliable, safe and affordable carbon-free energy here in the U.S.," he said. Adding that clean energy is in demand globally, Nichol said there is a growing interest in SMR technology in Canada, Europe and the Middle East.

Neither NEI nor NuScale directly answered questions about the economic viability of SMRs and how they will compare to renewables and natural gas generation.

A paper published in February in the journal *Renewable and Sustainable Energy Reviews* found that a manufacturer would need to sell four 180-MW SMRs at $1.5 billion each to recover the cost of a $1 billion factory. It cited a base construction cost of $3,465.72/kW for the 12-module NuScale SMR.



NuScale's use of natural circulation eliminates the need for large primary piping and reactor coolant pumps. | *NuScale*

NuScale announced in 2018 that it had reduced the cost of a 12-module plant to $4,200/kWh. The company has set a goal of a $65/MWh levelized cost of electricity.

Lazard's latest levelized cost of energy puts onshore wind at $28 to $54/MWh, utility scale solar at $32 to $42/MWh, gas combined cycle plants at $44 to $68/MWh and conventional nuclear at $118 to $192/MWh.

'Big Grain of Salt'

Critics of nuclear power have expressed wariness over NRC's announcement last December that it is considering shrinking the emergency planning and evacuation zones around the smaller, new reactors from the current 10-mile radius.

"When you're talking about a reactor that's never been built or operated, you have to take with a big grain of salt the claims that it's actually safer or more secure," Edwin Lyman at Union of Concerned Scientists told NPR.

Lyman said weaker reactor containment shells and off-site operators at certain facilities are on the industry's wish list. UCS believes companies should follow current construct rules, even when building smaller reactors. "You have to work out the kinks of these new plants," he told NPR. "And then over time, you might be able to adjust your requirements accordingly. But you don't do that at the get-go."

DOE's National Nuclear Security Administration mirrored a few of Lyman's concerns in comments sent to NRC, saying the current rules provide "the last layer of a defense-in-depth for low-probability, high-consequence accidents."

A spokesperson for the commission declined to comment on the safety worries. "The NRC ensures nuclear power plants (and other civilian uses of radioactive material) are safe; questions about the relative benefits of reactors designs are best directed to the Department of Energy's Office of Nuclear Energy, or to the Nuclear Energy Institute." Neither responded to *RTO Insider's* questions.

Expansion Troubles

Nuclear supporters hope SMRs are the good news the beleaguered industry needs.

As recently as 2010, nuclear proponents talked excitedly of a "renaissance" in the U.S. NRC, which hadn't issued a construction permit for a nuclear reactor since 1978, streamlined its licensing process and hired hundreds of additional staff to process applications for 30 new generators received after 2007. Some environmentalists had begun to talk about nuclear power as part of the solution to climate change.

By the end of 2010, however, most of the applicants were having second thoughts because of falling natural gas prices, reduced demand projections as a result of the Great Recession and Congress' rejection of legislation to impose costs on carbon emissions.

While about a fifth of domestic electricity is produced by nuclear power, according to the Energy Information Administration, experts predict a decline in usage in the next few years. Just last week, Exelon announced it would shut down its Byron and Dresden nuclear plants in November 2021 if it fails to win subsidies. (See related story, *Exelon to Close Ill. Nukes as Gov. Touts Clean Energy Plan*.)

Not helping the industry are failed projects, delays and costly overruns common within new reactor construction.

Georgia Power's plans to expand Plant Vogtle ran into soaring construction costs, as had been warned by the project's critics.

Vogtle's AP1000 design also incorporates passive safety features not present at the Fukushima plants or the current U.S. fleet of reactors. A July 2011 Near-Term Task Force report on insights from the Fukushima accident said the AP1000's passive designs should keep the reactor core and spent-fuel pools from overheating for 72 hours without power or operator action.

Vogtle, currently the only commercial nuclear power plant expansion underway in the U.S., is billions of dollars over budget. The two reactors under construction were slated to begin commercial output in the spring of 2016 and 2017, but state officials said it is "highly unlikely" the reactors will be online soon.

A Georgia Power spokesperson said in June the company hopes to bring Vogtle Unit 3 online in November 2021 and Unit 4 in November 2022.

The Vogtle project lined up billions of dollars in federal loan guarantees and hundreds of millions of dollars in federal tax credits under both the Obama and Trump administrations.

In neighboring South Carolina, the V.C. Summer expansion by state-owned Santee Cooper experienced years of overruns and delays before the $9 billion project was canceled in July 2017 — dubbed by *The Post and Courier* as "one of the greatest business failures in state history." ■

CAISO/West News

PGE Traders Burned by California Heat Wave

By Robert Mullin

Portland General Electric said last week that it suffered $127 million in losses from wholesale electricity trades because of recent volatility in the California energy market — a figure that is almost certain to rise.

PGE estimates the losses could undercut its 2020 earnings by as much as 48%.

"Certain PGE personnel entered into a number of energy trades during 2020, with increasing volume accumulating late in the second quarter and into the third quarter, resulting in significant exposure to the company," CEO Maria Pope said in an email to employees included in a *filing* with the U.S. Securities and Exchange Commission. "Simply put, these trades were ill conceived."

PGE attributed the losses to trading positions that went sideways during the recent heat wave that roiled CAISO's market and caused supply shortages, driving up wholesale prices and creating constraints on regional transmission. The shortages prompted the ISO to order rolling blackouts in California for the first time since the energy crisis of 2000/01 and temporarily suspend its convergence bidding market. (See *CAISO Provides More Details on Blackouts*.)

"As a result of the convergence of these conditions, the company's energy portfolio, as of Aug. 24, 2020, has experienced realized losses of $104 million and unrealized, mark-to-market losses of $23 million," PGE said. "Total third-quarter losses in the portfolio are estimated to be up to $155 million subject to market conditions — although the ultimate amount of losses could exceed that amount."

PGE on Aug. 24 moved quickly to contain potential political damage from the incident, saying it had placed two unnamed staff members on administrative leave pending further review. It also assured customers that it would not seek to recover the losses through increased rates.

The utility also announced the formation of a special committee consisting of five independent board members to examine the events leading to the losses and review existing procedures and controls. The company has additionally engaged external consultants "to perform a full operational review of our energy supply risk management policies, procedures and personnel," Pope said.

She also said the company would not be adjusting its 2020 and 2021 capital and operational budgets and assured employees that "we do not anticipate any layoffs as a result of this situation."

PGE wind farm in Eastern Oregon | *Sherman County Government*

"This situation is not reflective of who we are at our core, and we will learn from the situation and make the necessary changes to ensure this will never happen again," Pope said.

Black Swan?

While PGE has not disclosed the exact cause of the losses, their sheer size — and the utility's response — suggests the trading activity leading to the losses fell outside expected norms.

"The way Pope worded it — 'ill-conceived' — makes me think it's something nonstandard," said a compliance analyst with another Northwest utility who asked not to be named.

The analyst also questioned how traders could build up such exposure under a standard protocol of daily trading and position limits.

"I know we have significant risk controls. But I don't really know what kind of trading led to the losses," the analyst said.

Portland-based energy economist Robert McCullough pointed to the potential impact of CAISO's convergence bidding market on PGE's trading woes.

"The nature of a relatively unregulated pure derivative — like the convergence market in California — has an enormously asymmetric risk profile. In English, this means that a prudent trade, on rare occasions, can lose 50 times the expected profit," McCullough said.

He said CAISO's suspension of convergence bidding during the heat wave — right after the declaration of a Stage 3 emergency — indicates that market losses were high at the time and that manipulation was a possible explanation.

"PGE is hardly a high-risk trading operation," McCullough said. "A regional utility with substantial assets, they traditionally 'trade around assets.' I would suspect that the natural asymmetry of a black swan caught them off guard."

Even CAISO officials seem aware of the potential for convergence bidding to produce a "black swan" trading event.

During a CAISO stakeholder call Aug. 21 to discuss the recent blackouts, ISO Director of Market Analysis and Forecasting Guillermo Bautista Alderete said convergence bidding can add confusion to the market in times of short supply because convergence bids and physical supply are cleared on the same basis.

When there's sufficient capacity and supply, "the positions taken in the day-ahead market can be supported. However, when the system is constrained … the position parties can take can result in chaos," he said. ■

COVID Will Cut Electricity Demand in Calif., CEC Says

Reduction in Commercial, Industrial Consumption Cited

By Hudson Sangree

The COVID-19 pandemic and accompanying recession will significantly reduce electricity demand in California through 2023 and slow consumption until the end of the decade, the state's Energy Commission predicted in a workshop Wednesday to update its long-term forecast.

"All of us know that massive changes have happened with COVID, with the economic contraction and all the trauma that our society is living through right now," said Commissioner Andrew McAllister, who is leading the forecast update.

Statewide electricity consumption will decline by 4 to 5% in the next two years, Cary Garcia, with the CEC's Demand Analysis Office, told the commissioners. Demand was already down 2% in 2019 — falling to about 278 TWh — compared with last year's forecast, he said. Energy consumption will decline at least another 2% through 2023, he said.

The commission uses data on economic performance, population growth and other factors to predict electricity demand in its 10-year forecasts. The current forecast runs through 2030. It adjusts its forecasts annually, but the changes usually aren't as significant as this year's updates, Garcia said. "Nobody was predicting 2020 to turn out this way."

Population growth has slowed. This year's update projects 1.2 million fewer residents in 2030 than the 2019 forecast predicted, he said. Household formation and income are also expected to decline, he said.

The biggest downturn will be in commercial employment and "floorspace," a measure of retail and business activity. Projected growth in commercial floorspace dropped 60% this year compared with last year's estimate, Garcia said. The pandemic has wreaked havoc on brick-and-mortar retailers and kept residents away from offices.

Manufacturing employment has been declining for decades in California and will continue falling through 2030, the CEC said last year. The update shows it dropping more steeply through 2023 and a larger long-term decline than previously anticipated.

"The big dip seems to be in the commercial and industrial sectors," Garcia said. "That's just [a] huge decline. There's nothing to really get away from massive amounts of people not working."

Dropping Demand

Taken together, the economic indicators suggest statewide electricity demand will be approximately 15 TWh lower in 2020/21 than the CEC predicted in its pre pandemic forecast. Consumption will remain at lower levels for years to come, the commission estimated in its preliminary analysis.

A caveat, Garcia said, is the analysis doesn't account for changes in demand driven by sales of electric vehicles. The commission still is working on those figures, he said.

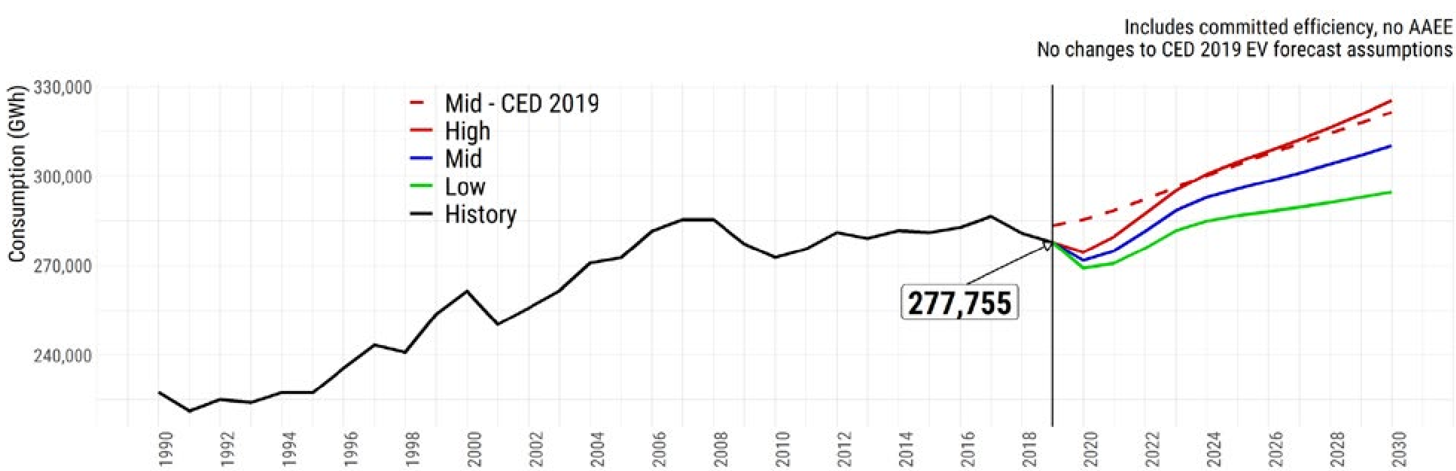
In addition, he said, the course of the pandemic and an economic recovery remain in question. Will vaccines and therapies trigger a swift return to work, restaurants and movie theaters? Or will medical help be slow in coming and lockdowns continue indefinitely?

To deal with those variables, the CEC forecasted low-, medium- and high-demand scenarios. The mid-case scenario shows a U-shaped dip in demand through 2023. It assumes the pandemic will ease and the economy will recover at a gradual but steady clip.

"In the COVID context … we have a recovery in the economy that is very similar to a natural disaster rather than a full recession," Garcia said. "In comparison to the Great Recession, you have a much quicker recovery. There's a rebound that occurs and then a slight lag and sort of a return to normal growth."

McAllister said the forecast update is intended to consider discrete factors, including the effects of the pandemic and EV adoption. The larger question of demand and resource adequacy, given the decision by CAISO to order rolling blackouts during shortfalls on Aug. 14-15, is not part of the agenda, he said. (See *CAISO Provides More Details on Blackouts*.)

"Obviously, they're very important … but those are not conversations that are happening today," he said on Wednesday. "Today, we're talking about specific elements of the 2020 forecast update." ■



The coronavirus pandemic will cause a significant dip in energy consumption in the next two years, the Energy Commission said. | *California Energy Commission*

CAISO Finalizes ESDER Phase 4 Plan

ISO Proposes Way to Predict Output of Demand Response Resources

By Hudson Sangree

CAISO on Thursday presented its final proposal in the fourth and last phase of its five-year effort to make it easier for energy storage and distributed energy resources (ESDER) to participate in its markets.

The ESDER initiative includes rooftop solar, energy storage, plug-in electric vehicles and demand response. (See *CAISO Eases Rules for Energy Storage, DERs*.)

DR is seen as an increasingly important part of California's resource adequacy programs and played a role in CAISO's efforts to reduce electricity use during rolling blackouts of Aug. 14-15 and the strained grid conditions of Aug. 17-18. (See *CAISO Provides More Details on Blackouts*.)

"As we move into the future, California will rely more heavily on variable and availability-limited resources as we move to decarbonize the grid," Lauren Carr, a CAISO infrastructure and regulatory policy specialist, said during Thursday's stakeholder call and *presentation*. "It's critical to assess the ability of preferred resources to displace both capacity and energy provided by traditional thermal [generation]."

The ESDER Phase 4 *final proposal* includes an informational section that discusses a new approach to predicting the capacity of variable-output DR resources. The ISO defines a variable-output DR resource as one "whose maximum output can vary over the course of a day, month or season due to production schedules, duty cycles, availability, seasonality, temperature, occupancy, etc."

"For instance, certain demand response resources' output may vary with weather, like an AC cycling demand response program that can reduce more load on a hot day, when air-conditioner use is high, versus on a moderate day, when air-conditioner use is low," the ISO said in its plan.

"When a variable-output demand response resource provides resource adequacy capacity in the year-ahead or month-ahead time frame, depending on conditions, the resource may be unable to deliver its full stated resource adequacy capacity in the day-ahead or real-time given its variable nature."

CAISO contracted with Energy and Environmental Economics to develop a way to evaluate the resource adequacy value of DR using effective load-carrying capability (ELCC), which evaluates reliability in each hour of a simulated year and compares a resource mix with limited resources against one with unlimited resources. A resource that contributes a significant level of capacity during high-risk hours will have a higher capacity value than a resource that delivers the same capacity only during low-risk hours.

The California Public Utilities Commission currently uses ELCC to determine the qualifying capacity of wind and solar resources, but it has not been used to assess variable-output DR. CAISO said the method could be used by local regulatory authorities to anticipate the true contributions of such resources.

In addition, the ESDER 4 final proposal addresses a state-of-charge biddable parameter for storage resources; streamlines market participation agreements for non-generator resources; applies market power mitigation to storage resources; and sets a maximum daily run time parameter for DR.

Updates to the final plan include details on the market application of the end-of-hour state-of-charge, clarifying when it is recognized within the short-term unit commitment process and how its use by a resource may impact its resource adequacy valuation.

Comments on the final proposal are due Sept. 10. It is scheduled for an advisory vote by the Western Energy Imbalance Market Governing Body on Sept. 16 and a vote by the CAISO Board of Governors on Sept. 30. FERC must then approve the ISO's Tariff changes.

CAISO said the initiative will apply to EIM participants by changing the non-generator resource and proxy demand resource model, but there are no changes specific to EIM balancing authority areas. ■

Banks of utility scale battery storage | *Southern California Edison*

CAISO/West News

Theories Abound over California Blackouts Cause

Continued from page 1

others were based on speculation that could be wrong, he said.

Contracted Imports Vital

A *report* from advisory firm ICF International leans heavily on available data. It cited CAISO's dependence on imported energy as a leading cause of the blackouts and calls on the ISO and state regulators to reduce the state's reliance on uncontracted imports for RA. CAISO and the commissions offered a similar view in an Aug. 19 letter to Gov. Gavin Newsom. (See *CAISO Provides More Details on Blackouts*.)

The report lays out discrepancies between CAISO's RA assessment for this summer and actual system performance Aug. 14-15, when the ISO declared Stage 3 emergencies prompting the blackouts.

The analysis shows that natural gas, wind and imports underperformed sharply both days from 6 to 8 p.m. — just as declining solar output and continuing high demand from air conditioning use during a triple-digit heat wave required sharp ramps to cover rising net load.

At 6 p.m. on Aug. 15, for example, natural gas generation came in at 4,369 MW — or 15% — short of the RA assessment, while wind lagged 661 MW, or 25%. At the same time, imports fell short of expectations by 5,672 MW, or 56%.

The authors of the ICF report noted that imports account for 10 to 12% of California's total RA procurement, and they applauded the move in July by the CPUC to require that non-resource-specific imports that count toward a load-serving entity's RA requirements be reinforced by contracts. The CPUC also required the imports to self-schedule into CAISO's day-ahead and real-time markets during availability assessment hours — the hours of greatest need on the system.

However, ICF said there is a mismatch between the CPUC's mandates and the figures used in reliability planning. The state continues "to include import resources that are not backed up by RA contracts (in addition to RA contracted imports) to meet its peak demand in its resource adequacy planning assessment," the report said.

"According to statistics released by CPUC, jurisdictional LSEs only have around 5.8 GW of contracted import RA capacity, [yet] … CAISO's 2020 summer assessment assumes availability of imports up to 9.5 GW during constrained hours," it said.

The ICF report pointed out that CAISO's August RA assessment assumed 4.9 GW of uncontracted imports alone would be available during peak hours, but instead just 5 GW of total imports were delivered to CAISO during the 6 p.m. interval on Aug. 16, suggesting that most of the uncontracted supply didn't materialize. "The reliance on uncommitted import resources brings additional uncertainties to a grid with a large amount of intermittent internal resources and brings challenges to system operation under extreme events," the report said.

It also encouraged California to step up preparations for supply-driven system fluctuations as it brings on increasing volumes of variable renewable resources while retiring thermal units, a development that will reduce the margin for error in RA as demand also becomes more variable.

"California's RA procurement process should consider potential hourly variations in resource deliverability and prepare for stressful scenarios," ICF said.

It said it was encouraged by the latest revised straw *proposal* in CAISO's RA enhancements initiative, which proposed adopting an RA construct based on unforced capacity — the percentage of resource capacity available after outages are considered. The proposal also considers increasing LSE planning reserve margins from the current level of 15% to 20% or higher.

"The proposal, if implemented, will be helpful in pushing the LSEs to secure additional resources to prepare for emergency conditions," ICF contended.

Time		Market Performance (MW)			CAISO RA Assessment for 2020 (MW)			Delta (MW)				Delta (%)			
Date	Hour	Natural Gas	Wind	Imports	Natural Gas	Wind	Imports	Natural Gas	Wind	Imports	Total	Natural Gas	Wind	Imports	Total
8/14/20	18	24,962	810	5,855	28,689	2,694	10,193	(3,727)	(1,884)	(4,338)	(9,949)	-13%	-70%	-43%	-24%
8/14/20	19	25,278	1,045	6,887	28,689	2,876	10,193	(3,411)	(1,831)	(3,306)	(8,548)	-12%	-64%	-32%	-20%
8/14/20	20	25,220	1,025	7,217	28,689	2,828	10,193	(3,469)	(1,803)	(2,976)	(8,248)	-12%	-64%	-29%	-20%
8/15/20	18	24,320	2,033	4,521	28,689	2,694	10,193	(4,369)	(661)	(5,672)	(10,701)	-15%	-25%	-56%	-26%
8/15/20	19	25,781	1,436	5,480	28,689	2,876	10,193	(2,908)	(1,440)	(4,714)	(9,062)	-10%	-50%	-46%	-22%
8/15/20	20	25,880	2,114	5,751	28,689	2,828	10,193	(2,809)	(714)	(4,442)	(7,964)	-10%	-25%	-44%	-19%

This chart shows the wide discrepancy between CAISO's RA assessment for August and the actual performance during key periods of the system emergency. | *ICF*

CAISO/West News

Contrary Take

Energy economist Robert McCullough offered a contrarian view on the blackouts. He raised the possibility that CAISO's flawed market design or even market manipulation caused the outages.

A longtime observer of California's electricity sector, McCullough pointed to CAISO's highly complex convergence bidding market, a mechanism that allows market participants to hedge their physical positions and limit exposure to day-ahead and real-time price differentials.

The bid is a purely financial one, implying no obligation to take or deliver electricity. Instead, a market participant buys or sells "virtual" energy in the day-ahead market, a position required to be automatically liquidated in the opposite direction in real time. The objective is to make day-ahead and real-time prices converge as much as possible.

As California's recent emergency episode unfolded, CAISO announced it would temporarily suspend day-ahead convergence bidding beginning Aug. 17 because the practice was "detrimentally affecting the ISO's ability to maintain reliable grid operations." CAISO later pointed to the difficulty of distinguishing how much actual supply was available on the system with physical and virtual bids mingling.

McCullough suggested there might have been a connection between convergence bidding and generation outages during the system emergencies. The ISO had initially explained the crisis as a demand-driven outcome of the heat wave, he said.

"As we now know, the wave of [resource] outages was probably a more important factor. This does suggest market manipulation."

California's 2000/01 energy crisis "ended abruptly" when FERC finally imposed price controls, he noted.

"On the day the controls went in place, forced outages ended and prices never reached the price cap," McCullough said.

"The nature of convergence bidding rewards a similar exploit," he said. "If you own a unit at a sensitive location, you can schedule an outage and create a price spike. Of course, revenues from that plant would be zero. However, convergence bids are purely financial. This means that the plant owner could both reduce output and make a profit in the convergence market."

McCullough has previously told *RTO Insider* that convergence bidding doesn't even require manipulation to enrich some market participants at the expense of other participants, "just a willingness to gamble on the ISO's computer systems."

"Past experience has tended to make this less of a gamble than you might think, since critical information is often learned by specific market participants and then used to advantage," he said. (See *CAISO Blames Blackouts on Inadequate Resources, CPUC*.)

Oregon utility Portland General Electric has yet to disclose the precise cause of its staggering trading losses related to recent market volatility in California, but McCullough speculates that convergence bidding could have played a role by creating a "black swan" trading event that left PGE heavily exposed. (See related story, *PGE Traders Burned by California Heat Wave*.)

McCullough said he hopes Gov. Newsom or Attorney General Xavier Becerra will investigate alternative possibilities behind the blackouts before moving to increase the state's 15% reserve margin, as ICF and others have urged.

"Collecting ratepayer dollars to offset possible mismanagement and market manipulation is a bad idea, especially since these dollars are needed for system hardening," he said.

Convergence Breakdown

A question about CAISO's decision to suspend convergence bidding arose during a biweekly market update call Thursday.

Seth Cochran, manager of market affairs and origination at trading firm DC Energy, said it was still unclear why the ISO suspended bidding when it could have used its day-ahead residual unit commitment (RUC) process to count available units, examine their schedules and make curtailments.

CAISO's RUC process is designed to procure additional generation needed when the day-ahead market fails to clear enough resources to meet forecasts.

"I wasn't sure why that process couldn't be used, and why you had to resort to suspending convergence bidding," Cochran said. "I would note that the markets didn't look well converged, and that seems to be a market dysfunction, not something that should impede reliability necessarily."

CAISO Director of Market Analysis and Forecasting Guillermo Bautista Alderete responded that when the system has sufficient available supply, operators can dip into the RUC market to cover load and back up convergence bids with physical supply.

"The problem is when you don't have enough physical supply to cover the demand," Bautista Alderete said. "In this case, the convergence bids are going to be backing up potential exports and load that later on we know won't be supported and then we have to start curtailing those in the real-time.

"This is a problem. We have to have physical supply enough to cover physical demand and the exports," he said.

During the same call, Rahul Kalaskar, the ISO's manager of market validation and analysis, provided an operational rundown of the emergency events.

High demand during the heat wave created congestion on the transmission lines comprising the SP-26 path between Northern and Southern California, creating price separation between the two regions, Kalaskar said. Higher demand in Southern California drove up prices, a situation exacerbated by a shortage of imports because of correspondingly higher demand in neighboring states, he said.

The heat wave also created a scarcity of ancillary services, particularly non-spinning reserves, Kalaskar said. A CAISO *market notice* issued Friday showed consistently high levels of ancillary service scarcity during the 7 and 8 p.m. delivery periods over Aug. 14-18, with non-spinning reserve shortages peaking around 1,000 MW — or 75% of requirements — on Aug. 18.

"The non-spin reserves scarcity was essentially because of the fact that some of the resources that received a non-spin award in the day-ahead market were committed in real time to provide energy," Kalaskar explained.

Kalaskar noted the calm after the storm.

"For the period of Aug. 17 and 18, we were facing higher loads in the real-time, or somewhere around 50,000 MW, but the loads came in much lower on these days, so that's why the real-time events were much milder [compared] to what we saw on Aug. 14 and 15," Kalaskar said.

During Thursday's CPUC meeting, Director Randolph said CAISO came close to calling for more outages over Aug. 17-18 but didn't have to thanks to conservation encouragement and efforts by the governor's office, state agencies, utilities, community choice aggregators, large and small customers, and customers using backup batteries and generation to support the grid.

"Thanks to massive efforts … California was able to dramatically reduce overall demand and bring more generation into the mix to avoid more outages," he said. ■

CPUC OKs 1.2 GW of Storage by 2021, 38,000 EV Chargers

Approves $1.5B for Research and Development via EPIC Program

By Hudson Sangree

The California Public Utilities Committee on Thursday greenlit a major expansion of the largest utility-run electric vehicle charging program in the nation and approved contracts signed by investor-owned utilities to procure 1.2 GW of battery storage.

The contracts were signed in response to a CPUC procurement order in 2019 intended to head off projected shortfalls starting in the summer of 2021, but the shortage conditions arrived a year earlier than expected. A weeklong August heat wave across the West strained grid conditions and led to the rolling blackouts of Aug. 14-15.

CAISO recently estimated California needs 12 GW of battery storage to adequately store solar and wind power for when it's needed most; California has about 200 MW of battery storage currently. (See *CAISO Blames Blackouts on Inadequate Resources, CPUC*.)

The CPUC also renewed the state's Electric Program Investment Charge (EPIC) program for another 10 years, providing nearly $1.5 billion for research and development during that time. Grants from the ratepayer-funded program are distributed by the California Energy Commission to finance cutting-edge clean energy, storage and EV projects, among others.

"Developing new technologies and solutions that are laser-focused on improving reliability, safety and affordability attracts investment to California and keeps our clean economy growing," Commissioner Martha Guzman Aceves said in a statement. "Several EPIC-funded microgrids even supported the grid during the recent grid crisis, demonstrating real-time value to ratepayers."

1.2 GW of Battery Storage

In 2018, the CPUC and CAISO identified potential capacity shortfalls starting in the summer of 2021 and extending for at least several years, caused by the state's shift to solar and wind power and away from fossil fuel plants.

The projected shortfalls, like the rolling blackouts of mid-August, could be triggered by peak summer demand shifting to later in the day, as the sun sets and solar power wanes. Continuing high demand during the "net-peak" hour can strain available supply.

To ensure resource adequacy, the CPUC in November 2019 ordered the utilities under its authority to collectively procure 3,300 MW on a *pro rata* basis. (CAISO had asked for 4,700 MW and blamed the CPUC for coming up short, following the rotating outages.) The procurement contracts the CPUC approved Thursday were the first tranche of resources under the reliability effort.

SCE's Charge Ready program installs chargers at multiunit dwellings. | *Southern California Edison*

The commission ordered Pacific Gas and Electric, the state's largest utility, to procure 717 MW of new resources by 2023. At least half that amount must come online by Aug. 1, 2021, it said. (See *California PUC Votes to Keep Old Gas Plants Operating*.)

PG&E submitted seven contracts to the CPUC for 423 MW of lithium-ion battery storage, all of which the regulatory agency *approved* Thursday. PG&E said the storage projects all will come online by next July.

Under the agreements, Dynegy Marketing and Trading will operate a 100-MW battery storage facility at its Moss Landing natural gas plant on Monterey Bay; Coso Operating Co. will provide 60 MW of battery storage at its 145-MW geothermal project at the U.S. Naval Weapons Center in Inyo County; and NextEra Energy Resources Development will operate a 63-MW storage facility at its 225-MW Blythe Solar Energy Center in Riverside County.

PG&E contracted with Diablo Energy Storage for three battery projects totaling 150 MW in the San Francisco Bay Area and with LS Power Group's Gateway Energy Storage for a 50-MW standalone project in San Diego.

The CPUC approved seven contracts signed by Southern California Edison for 770 MW of battery storage. In its 2019 order, the CPUC required SCE to procure nearly 1.2 GW of new resources by 2023, with at least half operational by August 2021.

SCE contracted with NextEra for approximately 230 MW of storage at the Blythe facility and for 230 MW at its McCoy Solar Energy Center in Riverside County; with Gateway for 100 MW of storage in San Diego County; with Southern Power, a subsidiary of Southern Co., for 150 MW of storage at its solar arrays in Fresno and Kern counties; and with Terra-Gen for 50 MW at its Sanborn facility in Kern County.

The CPUC approved all seven SCE *contracts*, some of which are tolling agreements or RA-only contracts.

"California recently experienced reliability challenges not seen in decades, and we are working to identify the root causes," Commissioner Genevieve Shiroma said. "Our decisions today continue to build the foundation of our resource adequacy program by securing additional contingency resources for use when needed."

Largest EV Charging Program

Also on Thursday, the CPUC *authorized* $437 million to fund the installation of 38,000 charging ports for EVs via SCE's Charge Ready 2 infrastructure program, the largest single-utility EV charging program in the U.S., according to the commission.

SCE originally asked for $760 million, but the

CAISO/West News

CPUC said its decision reduces ratepayer costs by 40% while reducing the number of charging ports by just 20%, partly by lowering the estimated cost per port to $15,000 from SCE's requested $19,000.

The Charge Ready program started in 2016 with a pilot program of 1,500 charging ports and began expanding in 2018. The program prioritizes low-income communities and apartment buildings "because they face barriers to transportation electrification," the CPUC said in a statement.

The program includes infrastructure upgrades to support EV chargers, including higher-voltage electric panels, conduit and wiring. A construction rebate offsets installation and charger costs for new multiunit dwellings that exceed state or local building codes.

Program participants must sign up for demand response programs and accept time-of-use pricing to align charging incentives with grid conditions, the CPUC said.

PG&E contracted with NextEra Energy Resources for storage at its Blythe Solar Energy Center. | *NextEra*

"This decision furthers California's ambitious goals to increase [zero-emission vehicles to 5 million by 2030] and end harmful tailpipe pollution by filling gaps in the state's EV infrastructure," Commissioner Cliff Rechtschaffen said in a statement. ■

CPUC Fires Executive Director for Improper Hiring

Alice Stebbins Says she was Targeted as Whistleblower

By Hudson Sangree

Alice Stebbins, CPUC | *CPUC*

An ugly feud between the members of the California Public Utilities Commission and its executive director, Alice Stebbins, played out in public Monday during an online hearing in which the commissioners unanimously voted to fire her.

"A vote was taken to dismiss the executive director … effective Sept. 4," CPUC President Marybel Batjer said after the commissioners deliberated in closed session for more than three hours. She did not elaborate and quickly ended the video call.

Both sides hurled accusations Monday morning during arguments Stebbins had requested remain public, an unusual move in a personnel matter.

CPUC President Marybel Batjer | *CPUC*

Batjer outlined the results of a state investigation that found Stebbins hired poorly qualified former colleagues for key positions, including a deputy executive director. The CPUC president said Stebbins' behavior had been "abhorrent" after the accusations came out, as she immediately went to the media and leveled her own accusations of wrongdoing at the commission.

Stebbins argued she was being targeted as a whistleblower because she reported the CPUC had failed to collect $200 million in fees from regulated utilities.

"I and my staff blew the whistle on that, and that's why I'm being fired," Stebbins said.

Her lawyer told the commissioners they had violated the state's open meeting laws by texting about Stebbins' case and deciding her fate well in advance of Monday's hearing.

'Appalling and Disgraceful'

The case began in July when the State Personnel Board (SPB) issued a *report* to the CPUC concluding Stebbins had improperly hired former colleagues who lacked job qualifications. The report was made public Aug. 6.

CPUC headquarters in San Francisco | © *RTO Insider*

In particular, the SPB said Stebbins had "preselected" Bernard Azevedo, her longtime coworker at the state Air Resources Control Board and Water Resources Control Board, as the deputy executive director of the CPUC's Administrative Services Division, which manages facilities, budgets and contracts.

"'Preselected' means you had already made up your mind to hire this person before the recruitment process occurred," Batjer said. State law requires civil servants to be hired based on merit, she noted.

Azevedo was less qualified than other applicants, the report said. He had no college degree, and his experience was limited to accounting. The job description called for someone with significant experience in administration and budgeting who could represent the CPUC before the State Legislature.

Other candidates had post-graduate degrees and had managed fiscal affairs at executive levels, it said. CPUC employees who rated the candidates said they felt pressured to hire Azevedo because Stebbins made it clear whom she preferred, it said.

Four months after Azevedo was hired, Stebbins added new duties to his role and increased his six-figure salary by 49%. She then took away some of the duties, "thereby removing the justification for the higher salary," Batjer said, citing the report. Asked about the situation, Stebbins falsely claimed Azevedo was still performing the duties, Batjer said.

CAISO/West News

"It is appalling and disgraceful to engineer the hiring of a marginally qualified former colleague over more qualified candidates, to spike the person's pay and then make false statements to justify the compensation," Batjer said.

Other CPUC appointments and transactions under Stebbins were of "highly questionable legitimacy," the SPB found.

After the board's report was sent to the CPUC, the commission undertook its own investigation. Stebbins was removed from her usual personnel duties but continued to make hiring decisions against clear orders, Batjer said.

She criticized Stebbins for failing to show concern for her employees or to take responsibility.

"Instead, you repeatedly suggested that the commissioners should use our political influence to, in your words, 'make the SPB report go away,'" Batjer said. "Your suggestion was abhorrent."

Stebbins' claim that the CPUC was owed $200 million is false, Batjer said. The commission had $50 million in uncollected fees at the end of 2019, including a $20 million fine of a bankrupt, defunct telecommunications company, she said. It had repeatedly tried to collect that fine, including by going to court, she said.

'A Chilling Message'

Stebbins was given 45 minutes to make her argument. Her attorney Karl Olson began by telling the commissioners that the "firing of Ms. Stebbins would be a clear case of retaliation against a whistleblower."

On May 15, Azevedo filed a detailed report about the $200 million in uncollected revenue, Olson said. It showed the CPUC collected only $21 million in fiscal year 2018-19 and, as of June 30, 2019, was owed $200 million, he said.

"This contradicts what the commission … said today about how the $200 million was an exaggeration," he said.

Olson also said the commissioners had repeatedly spoken in text messages about firing Stebbins, reaching a consensus long before Monday's hearing.

"You all agreed in serial private meetings to fire Ms. Stebbins," the lawyer said. One commissioner texted, "I can't imagine her remaining," according to Olson. Another texted, "It's not tenable for her to stay," he said.

"Wrong. What's not tenable is to violate the state constitution," which requires open meetings, he said. "You made the decision in secret texting sessions.

"You probably know the law, and you consciously and brazenly defied it," Olson added.

Two commissioners spoke with Stebbins by telephone the night of Aug. 3 and told her they had decided to fire her, he said. He contended Stebbins should have been given a second chance.

"There was and is no reason to fire Ms. Stebbins, because the SPB report was contrived and unfounded and did not detract from the fact that she had done an excellent job," he said. "She hired 800 people and was moving the PUC in the right direction. The SPB raised unfounded questions about five people who were doing an excellent job including Mr. Azevedo.

"If you go ahead with this firing, this kangaroo court, in which President Batjer seems to be serving as prosecutor, judge and jury, you will send a chilling message to whistleblowers in state service: People who report illegal and improper activity will be fired," Olson said. ■

ERCOT News

Texas Escapes Disaster, PUC Ends COVID Program

By Tom Kleckner

PUC Chair DeAnn Walker calls the open meeting to order. | *Texas PUC*

Texas regulators last week approved a timeline for winding down its pandemic relief program as the state apparently escaped significant damage from Hurricane Laura.

The Public Utility Commission met briefly in an open session Thursday, the morning after the hurricane swept through the Texas-Louisiana border area.

The storm left 125,000 Texas customers without power, in PUC Chair DeAnn Walker's estimation. "For this level of a storm, that's astounding," she said.

By Saturday morning, Entergy Texas was reporting more than 73,000 outages, mostly in southeast Texas.

The commission approved an *order* that formally winds down the state's *Electricity Relief Program* (ERP), which has been providing customer protection from disconnection for nonpayment because of the COVID-19 pandemic since late March (*50664*). (See *Texas PUC to End COVID Relief Program*.)

The ERP was designed to prevent disconnections of those who lost jobs because of the pandemic. More than 595,000 households are currently participating in the program, which has provided more than $30 million in bill payment assistance.

Under the order, the program was scheduled to stop taking enrollments yesterday. Disconnections for ERP enrollees may resume on Oct. 1, provided they have received at least 10 days advance notice, but not more than 30 days.

"This has been an unusually tough time for our state, and I am proud of our team for managing the details of a program that has protected so many Texans during a difficult time," Walker said. "I hope we never encounter a similar challenge in the future."

Texas has reported 622,496 COVID-19 cases and 12,526 deaths as of Friday.

SPS Rate Request Halved to $73.2M

The commission signed off on an unopposed settlement between Southwestern Public Service and other parties that allows the Xcel Energy subsidiary to raise its base rate by $73.2 million a year (*49831*).

PUC Commissioner Shelly Botkin | *Texas PUC*

The parties agreed to a "black-box settlement" — with a revenue total but no specific return on equity — of $88 million in base-rate revenues for SPS' Texas retail jurisdiction. They also agreed to setting the utility's transmission cost recovery factor to zero, resulting in the net impact of $73.2 million, effective Sept. 12, 2019.

SPS originally asked for an overall increase of $141.3 million/year in its request filed last year. It later reduced that amount to $129.7 million/year.

Parties to the agreement with SPS included PUC staff, the U.S. Department of Energy, Texas Industrial Energy Consumers, the Office of Public Utility Counsel, the International Brotherhood of Electrical Workers Local Union 602 and the Alliance of Xcel Municipalities.

In other actions, the PUC:

- approved a *settlement agreement* that allows Southwestern Electric Power Co. to recover $5.4 million in 2018 rate-case expenses through a rider (*47141*); and

- slapped retail electric provider Our Energy with a $30,000 administrative fee for not responding to informal customer complaints in a timely fashion (*50983*). The commission has now assessed more than $3 million in penalties during its financial year, which ended yesterday. ■

ERCOT Technical Advisory Committee Briefs

Members Discuss but Table Action on 2% Shift Factor Rule

ERCOT stakeholders last week debated an artifact from the old zonal market, eventually tabling action without a revision request to act on.

Staff brought forward to the Technical Advisory Committee discussion of the "2% rule," which directs that generating units with shift factors of less than 2% will not be dispatched by the real-time market to respond to transmission overloads. A desk procedure in 2011, shortly after the nodal market went live, clarified the use of the 2% shift factor cutoff in real time.

Under the rule, if a transmission constraint exists for which there are no generator shift factors of at least 2%, operators must verify a mitigation plan or temporary outage action plan exists for the contingency and they are to review the plans with the affected transmission owner. If no plans exist, then the operators are to develop a mitigation plan with ERCOT's operations support engineer. If no plans have been developed within 30 minutes, the operations desk issues a transmission watch, a step down from an emergency.

ERCOT has conducted several recent analyses on the effects of activating low shift-factor constraints in the economic dispatch engine. Staff found that the effect of activating the constraints is dependent on the system's topology near the constraint and observed no oscillation in the resource's output level.

The Congestion Management Working Group has been unable to reach a consensus on whether to eliminate the rule, despite working on the issue since last year.

"It feels like we've been talking about it forever," said CPS Energy's David Kee, who chairs the Wholesale Market Subcommittee, to which the working group reports.

ERCOT's Independent Market Monitor, however, believes the 2% rule should be eliminated, with all congestion priced in real time, regardless of generation's effect.

"Prices matter. The whole market is predicated on that," said Monitor Director Carrie Bivens in arguing against out-of-market actions. "Whether or not an existing resource can move to resolve the constraint is not relevant to whether it should be priced. We don't need to define in advance what the response will be. The magic of the market is that it can and does respond to those market signals."

Bivens said incorporating a price signal for what would be an out-of-market action on hidden congestion would incentivize the market to resolve the issue.

She noted that ERCOT only activates contingency constraints if three thresholds are met: the system is loaded at 98% of the emergency limit; a resource shift factor of 2% or more exists; and a similar constraint is not already activated.

Other markets have lower constraint thresholds, are lowering them or don't have them at all, Bivens said. MISO's Independent Market Monitor is urging the RTO to remove its 1.5% threshold; PJM just removed its threshold; and CAISO is discussing a change to its 2% rule, she said.

With an efficient congestion revenue rights (CRR) market, she said, the overall cost to load does not increase. "If the real-time congestion rent goes up, the day-ahead market's congestion rent will rise and the CRR revenue goes up," Bivens said.

"This is a pretty significant issue for the market. It's in the ERCOT procedure manual, but this needs to be documented in a guide procedure," Morgan Stanley's Clayton Greer said. "In my view, we're going to see [the] effective elimination of the 2% rule anyway with all the distributed generation going out on the system. I'd rather just rip the Band-Aid off, let the market see the change and everyone adapt to the change [at the same time]."

Kenan Ögelman, ERCOT's vice president of commercial operations, said the Monitor "brought up a worthy issue for consideration," but because the 2% rule doesn't reside in the protocols or another binding document, options are limited.

"This is something that needs to be resolved to move the issue forward, one way or another," Ögelman said.

"Maybe it would be cleaner if there was an NPRR [Nodal Protocol revision request]," said Eric Goff, a residential representative in the Consumer segment.

TAC Chair Bob Helton, of ENGIE, said he will discuss the matter offline with Ögelman and TAC Vice Chair Clif Lange, of South Texas Electric Cooperative, and work on a document that stakeholders can vote on.

Clayton Greer, Morgan Stanley | © *RTO Insider*

On that, members were able to reach consensus.

PRS Prioritizes List of Approved RRs

The Protocol Revision Subcommittee (PRS) and ERCOT staff have spent the past few months prioritizing work on approved revision requests to balance resource availability with the flood of changes.

ERCOT's Troy Anderson said 40 items on the priority list, "an unusual amount," have yet to be started. That doesn't take into account RRs from stakeholder groups working on real-time co-optimization, energy storage and distributed generation.

"We'll be starting on real-time co-optimization, the [Battery Energy Storage Task Force] and [distributed generation] in the very near future," Anderson said. "We have to be careful not to put those items at risk. This doesn't mean the remaining items won't get done. We will seek opportunities for those items when the resources become available or we have the opportunities to work on them."

Anderson shared with the TAC a graphic that listed more than 70 RRs or other initiatives currently underway or waiting in the wings. ERCOT has a limited number of resources available to work on the backlog.

"We want to ensure we have prioritized the right items to be worked on soonest," Anderson said.

Committee Passes 3 Change Requests

The TAC approved three revision requests in two roll-call votes.

ERCOT News

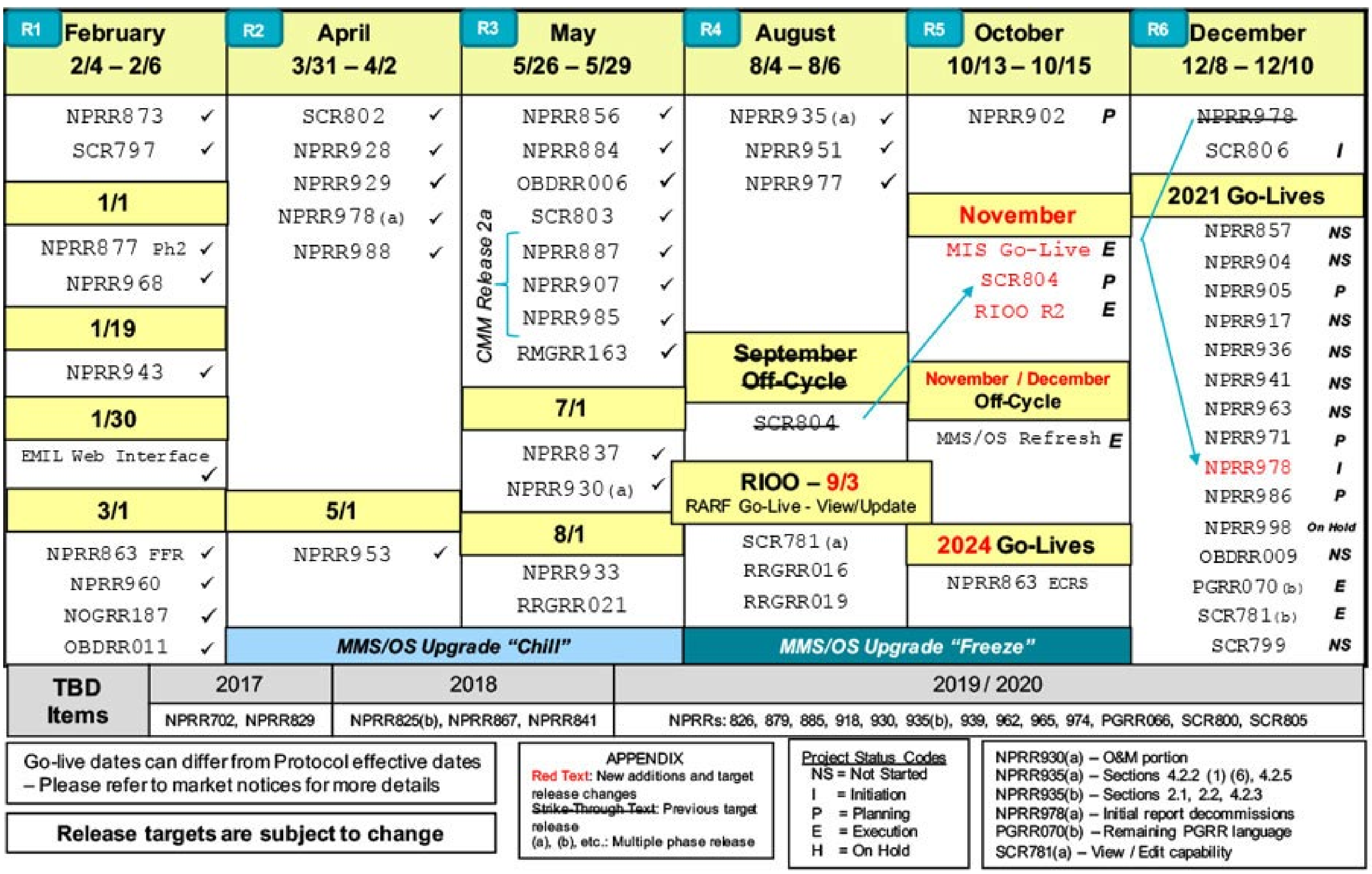
The first vote paired an NPRR (*NPRR984*) with an accompanying Other Binding Document request (*OBDRR023*), both related to emergency response service (ERS) in what Helton dubbed "the Clayton ballot." Greer, the ballot's namesake, said during July's TAC meeting that he would vote against anything related to ERS. True to form, he cast the lone vote against the measures on behalf of Morgan Stanley, but he did side with the majority on behalf of his proxy, EDF Trading's Kevin Bunch.

NPRR984 changes the number of ERS standard contract terms from three to four per program year to align the terms with typical seasonal conditions and improve ERS' procurement. OBDRR023 changes ERS' procurement methodology to match NPRR984's protocol changes.

Troy Anderson, ERCOT | *ERCOT*

In addition, the committee unanimously approved *NPRR1027*, which removes gray-boxed language from the protocols related to *NPRR702* (Flexible Accounts, Payment of Invoices, and Disposition of Interest on Cash Collateral) following the elimination of prepay accounts. ■

— Tom Kleckner



ERCOT's 2020 release targets for the more than 70 approved revision requests | *ERCOT*

ISO-NE Planning Advisory Committee Briefs

Pandemic has Mixed Impact on New England Emissions

Economy-wide carbon dioxide emissions in New England fell by 28 to 34% between March and June versus a year earlier, driven by a big cut in transportation because of stay-at-home orders issued in response to the COVID-19 pandemic.

But carbon emissions from the region's electric generation increased 1.4% in the first half of 2020 because the retirement of Entergy's 680-MW Pilgrim nuclear plant in Plymouth, Mass., caused an increase in natural gas generation, ISO-NE's Patricio Silva *told* the ISO-NE Planning Advisory Committee on Thursday.

The U.S. saw a 7% cut in electric generation in April versus a year earlier and a 16% reduction in emissions. The Energy Information Administration is projecting that U.S. energy-related carbon emissions for 2020 will be 11% lower than in 2019.

The pandemic caused significant reductions in electric demand during the spring, but load has rebounded with the hot, humid weather of July and August, ISO-NE's Jon Black said.

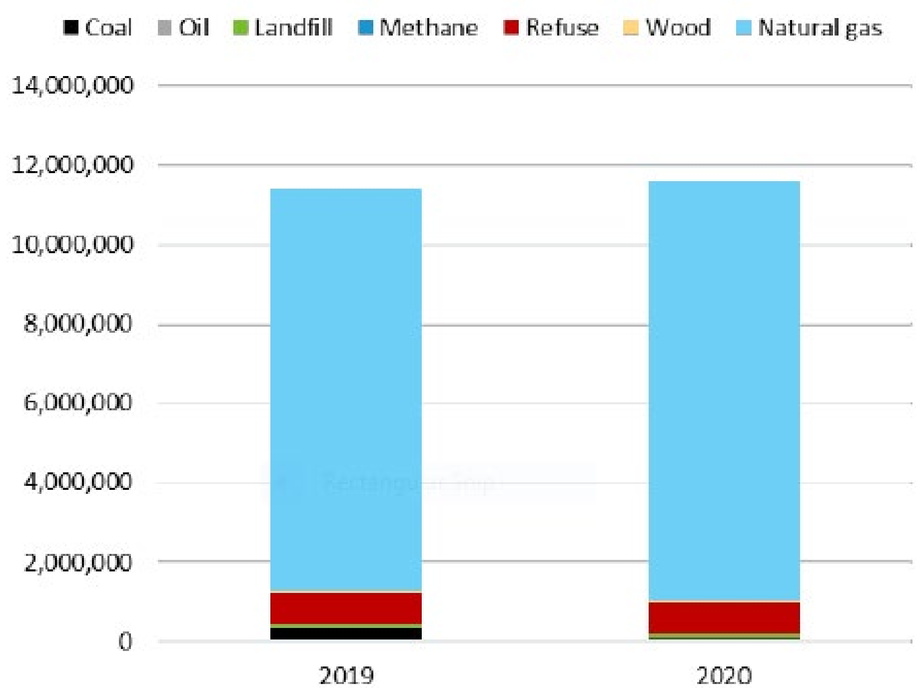
Black provided the PAC a *briefing* on Moody's Analytics' updated macroeconomic forecast and performance of the peak load forecast model in preparation for the 2021 Capacity, Energy, Loads and Transmission (CELT) forecast.

Because of the pandemic, Moody's June 2020 forecast predicts real gross state product (RGSP) for the region to be 7% lower in 2021 than projected in its October 2019 forecast used in the 2020 CELT, recovering somewhat to 1.4% lower by 2024. Black said that translated to a baseline summer demand forecast for 2021 that is about 113 MW lower in 2021 and 24 MW lower in 2024.

The baseline assumes that new COVID-19 infections peaked in April and there is no second wave that causes states to shut down again, with a 6% confirmed case fatality rate and a 10% hospitalization rate.

Moody's said there is a 4% chance that the RGSP will be as much as 14.3% lower in 2021, rebounding to 8.5% lower by 2024. That would result in a 232-MW reduction in summer 2021, with a 147-MW reduction in 2024. It is based on a 12% confirmed case fatality rate and 17.5% hospitalization rate with a much higher than expected incidence of new infections and deaths in late 2020.

ISO-NE plans to use Moody's October 2020 macroeconomic outlook to develop CELT 2021.



2019 and 2020 year-to-date carbon dioxide emissions by fuel type (metric tons) | *ISO-NE, using Moody's Analytics data*

Comments due on Boston Tx Project

ISO-NE will open a 15-day comment window on its selection of the $48.6 million Eversource Energy-National Grid project to reinforce the Boston-area transmission grid in response to the retirement of Mystic Units 8 and 9.

The RTO announced the companies' Boston Area Optimized Solution (BAOS) as the winner of its first competitive transmission procurement on July 17. (See *ISO-NE Chooses Incumbent as Boston RFP Winner*.)

ISO-NE's Andrew Kniska, who *briefed* the PAC on the project, said the comment period will begin once the RTO posts the draft solutions study report.

The BAOS was the cheapest of 36 projects submitted in response to the RTO's solicitation, which called for addressing an N-1 115-kV line overload and three N-1-1 345-kV line overloads. It also sought a dynamic reactive device (DRD) to aid in system restoration.

The utilities will install one 11.9-ohm, 345-kV series reactor on each of the two 345-kV Woburn-to-North Cambridge cables at the North Cambridge substation. A normally closed bypass breaker will be installed in parallel with each series reactor and opened only when there is a need to switch in one or both of the reactors.

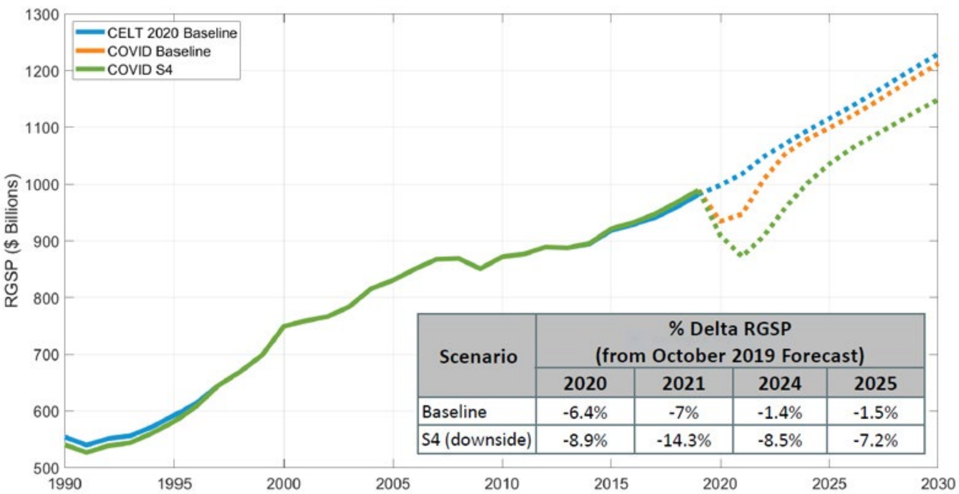
They also will install a direct transfer trip scheme on the 394 line in response to the contingency causing the 115-kV K 163 line overload and install a +/-167-MVAR static synchronous compensator at the 345-kV Tewksbury substation.

Kniska said the RTO's steady-state analysis found the BAOS solved the thermal needs and did not introduce any new thermal or voltage violations. The short-circuit analysis found all area circuit breaker duties were within their limits, and the DRD was found to meet the needs for reactive injections.

"The reactors have a bypass breaker to allow operators the flexibility to open and close them … as they see [is needed] for either operational flexibility or maintenance," Kniska said.

One stakeholder asked about the rules for the operator to determine the need for deploying the breakers. "Are we in an N-1 condition and you open the breaker because you're afraid of

ISO-NE News



Scenario	% Delta RGSP (from October 2019 Forecast)			
	2020	2021	2024	2025
Baseline	-6.4%	-7%	-1.4%	-1.5%
S4 (downside)	-8.9%	-14.3%	-8.5%	-7.2%

Moody's Analytics expects real gross state product (RGSP) for New England to be 7% lower in 2021 than projected in its October 2019 forecast because of the COVID-19 pandemic. There is a 4% chance that the RGSP will be as much as 14.3% lower in 2021. | *ISO-NE, using Moody's Analytics data*

an N-1-1 occurring?"

"I don't have the details on … how the operators will use them," Kniska responded. "Obviously, from our needs assessment, this is for N-1-1. If you have the first contingency out, they will need to be in to protect the second contingency."

Kniska said the proposed plan application study will include a transfer analysis "to determine if there's any adverse impact on any of the operating conditions, including the interface import capability into Boston."

Eversource and National Grid told the PAC in June they would reduce their return on equity by 25 basis points if they exceed the $48.6 million cost cap by more than 5%, with additional 25-point reductions for each incremental 5% overrun.

The project is expected to be in service in October 2023.

3 Tx Projects Canceled in Revised SEMA/RI 2029 Needs Assessment

ISO-NE will *cancel* three transmission projects because of reduced load expectations in the revised Southeast Massachusetts/Rhode Island (SEMA/RI) 2029 Needs Assessment.

The RTO's Kaushal Kumar said the needs assessment was revised to determine if projects that have not started construction are still needed in light of the decrease in forecasted loads and other changes in study assumptions since the SEMA/RI 2026 Solutions Study.

Of the 15 projects from the SEMA/RI 2026 Solutions Study that have not started construction, 11 were confirmed as still needed and will be retained.

Canceled are:

- Project 1733: Separate the 325/344 double-circuit tower lines, from West Medway to West Walpole (Estimated project cost: $17.9 million; spending to date: $1.1 million).
- Project 1719: Install a 45-MVAR capacitor bank at the Berry Street substation ($5.0 million; $1.5 million).
- Project 1723: Reconductor the L14 and M13 lines from the Bell Rock substation to Bates Tap ($38.7 million; $2.6 million).

A project to replace the 345/115-kV Kent County T3 transformer (Project 1724) also was determined to no longer be needed, but "the decision was made [that] this project will move forward," Kumar said, because of the age of the current transformer and because $3 million of the $5.9 million cost has already been spent.

The existing transformer, which was installed in 1971, is the last remaining 345-kV transformer of its kind in National Grid's fleet and has a higher-than-normal potential for failure, Kumar said.

Kumar said short-circuit levels have increased to 40 kA on the 115-kV system at the Kent County station, largely because of two new autotransformers. Similar units have failed in recent years because of short-circuit events outside of the transformer protection scheme, he added.

National Grid had put the project on hold late last year. Its new in-service date is March 2022.

Comments on the revised study will be accepted until Sept. 11.

Eversource Outlines $38M Line Rebuild

Eversource will spend $38 million to replace conductors and wood poles on its 10.3-mile 115-kV line between Harwinton and Watertown, Conn. (Line 1191).

Constructed in 1933 as two parallel 27.6-kV lines, the span was bundled and reconfigured to a single 115-kV line in 1957.

Eversource's Christopher Soderman *said* the utility will reconductor the line and replace 96 wood H-frames and one lattice tower with new single-circuit weathering steel monopole structures. Four structures will be removed to optimize the line, Soderman said.

Soderman said the existing 2/0 copper conductor and 3/8-inch Copperweld shield wires are obsolete and prone to failure because of thermal rating degradation and degradation from environmental factors.

He said 2/0 copper conductor is no longer used for transmission, and hardware for it is not readily available, requiring "non-traditional" repair methods.

In addition, about 30% of the existing poles show evidence of woodpecker damage, rot, decay, splits or cracked arms, he said.

The in-service date is the second quarter of 2022. ■

— Rich Heidorn Jr.

Eversource Energy will spend $38 million to replace conductors and wood poles on its 10.3-mile, 115-kV line between Harwinton and Watertown, Conn. | *Eversource Energy*

ISO-NE News

FERC Defends Ruling on ISO-NE Winter Program Cost

By Michael Kuser

FERC on Thursday defended its April ruling approving bidding results in ISO-NE's 2013/14 Winter Reliability Program as just and reasonable, expanding on its reasoning in response to a rehearing request (*ER13-2266-005*).

TransCanada Power Marketing's request was automatically rejected when the commission failed to act on it within 30 days. FERC's April order was prompted by a D.C. Circuit Court of Appeals ruling in December 2015 that directed the commission to provide additional justification for approving the rates. (See *FERC Reaffirms ISO-NE Winter Program Cost*.)

TransCanada had argued that ISO-NE's pay-as-bid auction resulted in excessive costs because resources were incented to raise their bid prices knowing they would probably be accepted, but the commission ruled that the RTO's Internal Market Monitor's cost-based supply curve and a 25% adder used in the analysis were reasonable.

ISO-NE's program procured reliability service from resources providing demand response and generators able to run on oil — a response to limited natural gas supplies that can leave gas-fired generators without fuel during peak winter heating demand.

In requesting rehearing, TransCanada claimed that the "only support" for the 25% upward adjustment was that the suppliers were "likely to adjust their bid prices upward to compensate" for their lack of knowledge regarding how other suppliers would bid in the market.

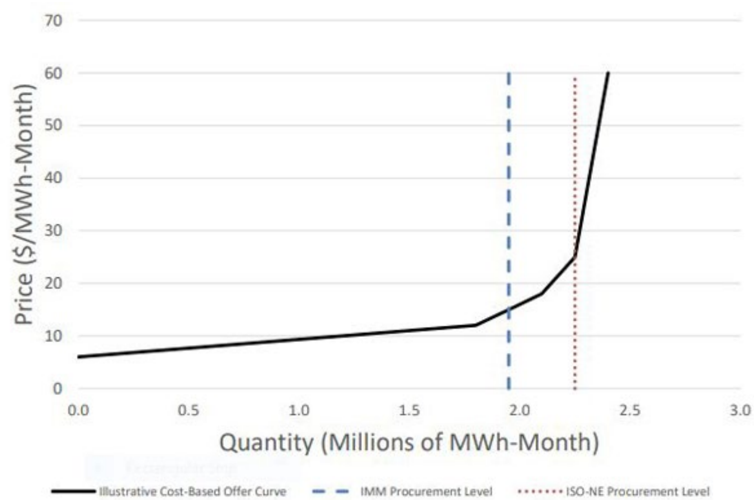
"This is incorrect," the commission responded, saying it also considered analysis submitted by ISO-NE and its Monitor that included a cost-based offer curve (i.e., supply curve) that intersected with an expected procurement of 2.25 million MWh at a price of $24.86/MWh-month. "This adjustment revealed an expected clearing price of $31.08/MWh per month. Given that no accepted bids from the auction exceeded that price, the commission concluded that the accepted bids were reasonable."

TransCanada also asserted that ISO-NE did not seek commission approval to administer the program as a competitive "oil inventory services" market, and that the commission failed to make an *ex ante* finding of the absence of market power.

"TransCanada's attempt to invoke the commission's market-based rate regulations in the instant proceeding is unavailing because the Winter Reliability Program does not fall within the rubric of the commission's market-based rate program, and, contrary to TransCanada's arguments, our use of a market-based paradigm to review the bids did not convert the bids and awards into transactions under our market-based rate program," FERC said.

This case instead involved FERC's analysis of the RTO's bid and auction results from a one-time process created for the purpose of maintaining reliability during the 2013-2014 winter season, the commission said.

"Finally, we continue to find that a market-based analysis of the auction results is appropriate and is not indicative of any '*post hoc* rationalization,' as TransCanada alleges," the commission said. ■



ISO-NE and its Internal Market Monitor calculated different expected marginal bids for the Winter Reliability Program because the RTO assumed procurement of 2.25 million MWh and the Monitor assumed the purchase of only 1.95 million MWh. | *FERC*

MISO News

MISO Enacts Rolling Blackouts for Entergy After Laura

By Amanda Durish Cook

Entergy trucks heading out in the aftermath of Hurricane Laura | *Entergy*

Hurricane Laura's lashing of south Louisiana and southeast Texas on Thursday led MISO to implement last-resort rolling power outages in an Entergy load pocket during restoration efforts.

MISO said its southern member companies are reporting widespread destruction following the storm. Citing transmission system damage and generation outages, MISO *directed* Entergy to begin periodic power outages just before noon ET in the Atchafalaya Basin load pocket straddling Texas and Louisiana.

It's unclear how many customers were affected. MISO also cited Laura's "unpredictable load patterns" as another reason for the load shedding. Entergy was asked to report its load-shed activities through the nonpublic MISO Communications System.

"MISO has implemented emergency operating procedures to address reliability in a load pocket of the region that experienced significant damage from the hurricane," System Operations Executive Director Renuka Chatterjee said in a *statement*. "While we continue to support our members' restoration efforts in the South Region, we maintain our focus on ensuring grid reliability across the entire footprint."

The RTO said it "escalated to the most severe step in its emergency actions in order to avoid a larger power outage on the bulk electric system in the affected areas." Periodic load shedding to stymie a more severe blackout was in effect for about 12 hours; the maximum generation emergency was lifted around 10:55 p.m. ET.

MISO has never shed firm load because of a capacity emergency since it began running its market in the new millennium, though it has shed local load during transmission outages. This appears to be the first time that MISO has shed load because of a capacity shortfall and transmission outages. The grid operator called it a "highly unusual action."

During the blackouts, energy was priced at MISO's $3,500/MWh value of lost load. The grid operator has been in discussions with its stakeholders to raise the current price limit, saying it could be undervaluing involuntary load sheds. (See *MISO Revisits Scarcity Pricing Rethink*.)

Entergy appealed to its Texas customers that they pare down their electricity usage.

"The unusual circumstance is the result of extensive damage to Entergy's transmission system caused by Hurricane Laura in east Texas and west Louisiana and the anticipated high demand for electricity due to high temperatures. Hurricane Laura damaged conductors [and] wooden and steel towers in key transmission lines needed to bring electrical power from the east," the utility said.

Entergy on Thursday *reported* more than 540,000 customers without power in its service territory. The utility said it convened a 16,750-strong restoration crew, more than double what it originally pledged before the storm. By Monday, the utility said it restored power to about 115,000 Louisiana customers.

In the height of the storm's wake, nearly 1 million total customers were without power, according to the Edison Electric Institute. Restoration crews were able to half that number over the weekend, with more than 29,000 workers from at least 29 states, D.C. and Canada assisting the region in restoration efforts, the nonprofit *reported*.

Entergy *said* its hardest-hit areas are the Lake Charles, Calcasieu and Cameron parishes, which collectively account for 5,648 poles in need of repairs, 10,037 spans of inoperable wire and 2,484 mangled transformers.

While MISO as a rule doesn't reveal what member assets are offline from outages, Montgomery County, Texas, County Judge Mark Keough said on Facebook late Thursday that Entergy Texas successfully re-energized its 500-kV Hartburg line.

"Please watch energy consumption for the next few days to ensure we are not putting pressure on the grid as they have to balance the load," Keough said in his *post*.

Keough also said Entergy was restoring power to a generator on Thursday and continued to make transmission repairs. He said Entergy was "confident" that its restoration work will avoid the need for further load shed.

MISO extended by a day on Thursday a conservative operations declaration issued ahead of the storm. (See *Gulf Grid Operators, Utilities Shore up for Laura*.) The RTO also said additional declarations and alerts may be issued in the aftermath.

Compounding matters, MISO said it also experienced "challenging capacity availability" in its North and Central regions Thursday because of a heat wave. The bleak capacity picture led the RTO to *issue* a hot-weather alert for the two regions while control room operators contended with a ravaged MISO South.

"We continue to work with our member companies and partner RTOs like SPP and ERCOT toward a speedy recovery," South Region Executive Director Daryl Brown said. "Mutual assistance and collaboration before and during the storm as well as throughout restoration are necessary to maintain our focus during times of crisis." ■

MISO News

Montana Supreme Court Rebuffs PSC on PURPA Rules

FERC's Revised PURPA Regulations Challenged

By Rich Heidorn Jr.

The Montana Public Service Commission "arbitrarily and unlawfully" reduced solar generators' payments and contract lengths under the Public Utility Regulatory Policies Act, the state Supreme Court ruled last week.

Upholding a 2019 lower court order, the high court said the PSC improperly reduced solar qualifying facility standard-offer rates by excluding carbon dioxide emissions costs and other costs from NorthWestern Energy's avoided-cost rate. It also said the regulators acted improperly in calculating solar QFs' capacity contributions and reducing contracts to a maximum of 15 years.

The *ruling* Aug. 24 remanded the case back to the PSC for reconsideration of Orders 7500c and 7500d, which reduced standard-offer contract rates and maximum contract lengths for solar QFs of 3 MW or less under NorthWestern's QF-1 tariff rate. The court acted on a challenge by Vote Solar, the Montana Environmental Information Center and Cypress Creek Renewables.

In 2017, citing remarks by Commissioner Bob Lake caught on a hot mic, the *Billings Gazette* *reported* that the rules rejected by the court last week "might have been knowingly set to discourage development."

The ruling came days after the Solar Energy Industries Association and other intervenors asked FERC to rehear its July rulemaking giving state regulators more flexibility in how they establish avoided-cost rates and the ability to require those rates to vary over the span of a QF's contract.

NorthWestern Energy and Bozeman Solar Array | *OnSite Energy*

'Gold Rush' Feared

PURPA and the Montana PSC's regulations require that avoided-cost rates and contract lengths be sufficient to "enhance the economic feasibility of" QFs. NorthWestern historically signed QF contracts for at least 25-year terms.

The dispute began in May 2016, when NorthWestern asked the PSC to reduce standard-offer rates for small solar and wind QFs from $66/MWh to between $34 and $44/MWh. (See *Montana PSC Racks up 2nd Lawsuit over PURPA Rates*.)

The utility said the reduction was needed for solar QFs because the $66 rate exceeded its avoided costs and threatened to cause a "gold rush" of developers seeking new QF-1 projects. At the time, NorthWestern had executed five power purchase agreements with small solar QFs, and had 43 active interconnection requests for 3-MW facilities under study and another 75 requests in preapplication phases.

NorthWestern also sought to abandon use of the "proxy" method of calculating avoided-cost rates, which is based on the projected capacity and energy costs of the utility's next planned resource additions.

The utility asked regulators to adopt the "peaker" method, separating its avoided-cost rate into separate energy and capacity elements. It also proposed that avoided-capacity costs be based on the levelized cost of internal combustion engines it planned to bring online in 2019.

In October 2016, the commission asked for comment on whether 25-year maximum-length contracts were unduly risky for ratepayers and whether a shorter length would be reasonable — issues not raised by Northwestern or any of the intervenors in the case.

In July 2017, the PSC issued Order 7500c, reducing the maximum contract length to 10 years and cutting standard-offer rates for QFs by more than half — lower even than proposed by NorthWestern.

The PSC continued to use the proxy methodology, but it declined to use as its proxy resource the internal combustion engine identified as the next resource to be added under NorthWestern's 2015 resource procurement plan. Instead, regulators chose to use a combined cycle combustion turbine as its proxy unit.

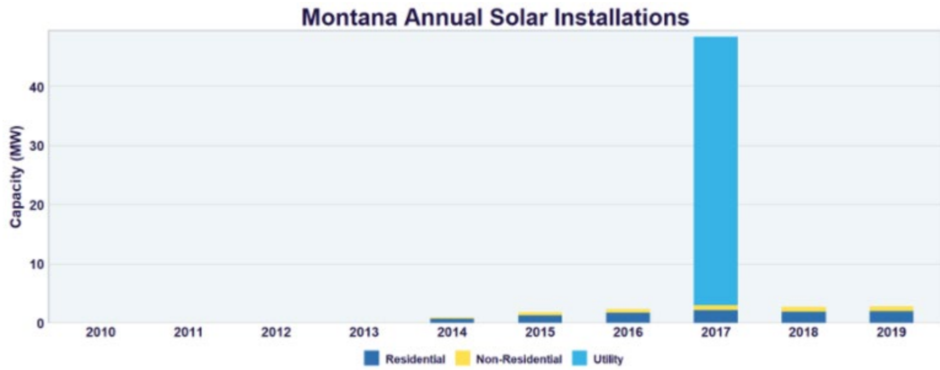
It adopted what the court called SPP's "novel" method for calculating QFs' capacity contributions. Under the new methodology, NorthWestern and the PSC concluded that solar QFs contributed only 6.1% of nameplate capacity, well below the 38% capacity contribution value then used in QF-1 rates.

The PSC also declined to use a carbon emission adjustment in its avoided-cost calculations, saying "the political forces that once indicated environmental regulatory action at the federal level was likely in the reasonably foreseeable future has diminished and, accordingly, the likelihood of carbon emissions regulation has decreased" — a reference to the election of President Trump.

The commission said a 10-year contract would provide sufficient encouragement for QF development while mitigating forecast risk for customers, citing decisions by Idaho and North Carolina regulators, which reduced QF contracts to between two and 15 years.

In November 2017, however, the commission revised the contract length to 15 years in response to requests for reconsideration (Order 7500d).

MISO News



Montana ranks 44th among U.S. states in installed solar generation. Solar supplies only 0.21% of its electricity. | *SEIA*

Reversal

In April 2019, Montana's 8th Judicial District Court vacated and modified Orders 7500c and 7500d. The state Supreme Court stayed the district court's ruling pending the appeal.

In its ruling last week, the Supreme Court concluded it was discriminatory to exclude carbon costs from solar QFs while permitting them for hydro and wind QFs, saying "mere speculation based on political forecasting hardly constitutes technical or scientific knowledge worthy of deference."

The court also slammed the PSC's reduced contract length, saying it "was based almost entirely on a 2014 North Carolina Utilities Commission decision. However, the PSC lacks any intimate knowledge regarding QF development policies in North Carolina or other states. Indeed, we find the PSC's justification especially dubious given its wholesale rejection of out-of-state decisions as a consideration when setting the avoided-cost rate."

"To be sure, 15-year contracts, standing alone, are not *per se* unreasonable," the court added. "But because the PSC failed to consider shortened contract lengths in conjunction with greatly reduced standard-offer QF-1 rates, 15-year contracts cannot be considered sufficient to encourage and enhance QF development."

The court said the PSC also acted arbitrarily in its distinction between avoided capacity and energy costs. It agreed with the district court's rejection of the 6.1% capacity factor, which concluded the commission had discounted NorthWestern's summertime capacity needs and disregarded regional peak demand data. The court said the PSC "focused only on a handful of peak demand hours — 220 hours over a 10-year period — that reflect primarily infrequent wintertime spikes while overlooking evidence that NorthWestern lacks sufficient capacity to meet peak customer demand in both summer and winter."

The court said the PSC also "misapplied" SPP's methodology "by acting contrary to the plain language of the SPP criteria and did not articulate a satisfactory explanation for its actions."

It rejected the argument of the Montana Consumer Counsel that the most critical factor of avoided-cost analysis is protecting the ratepayer.

"Were that the case, there would be no purpose to PURPA, which is to preclude discrimination in the marketplace for sources of energy that provide an alternative to fossil fuel development," the court said.

It added that NorthWestern's "frequently uttered trope that the requirements of PURPA and thus approval of solar sources of energy will wildly increase the rates charged to consumers finds little basis of support in this record."

Rehearing Sought on FERC Rule

The Montana ruling came a week after several groups, including SEIA and the *Electric Power Supply Association*, asked for rehearing of FERC's July 16 final rule revising its PURPA regulations (AD16-16, RM19-15). (See *FERC Issues Final Rule to 'Modernize' PURPA*.)

SEIA *said* FERC's rulemaking violates PURPA and discourages the development of QFs by terminating their ability to select a long-term energy rate under long-term supply contracts. It also challenged the commission's revision of the "1-mile" rule for preventing gaming.

"The commission erred in revoking a qualifying facility's longstanding right to elect to be paid a long-term energy rate in contract for long-term energy delivery without citing to any evidence in the record that financing is generally available for projects using as available energy rates and fixed capacity rates," SEIA said. ■

MISO News

MISO, SPP Close to Ruling out Joint Projects Again

By Amanda Durish Cook

MISO and SPP appear to have come up empty once again after a fourth interregional study failed to detect a joint transmission project that could pass the RTOs' benefit criteria.

After wrapping a coordinated system plan (CSP) study that began in March, the seam neighbors concluded no projects would pass the requisite 1.25:1 benefit-to-cost ratio. The two used transmission owners' planning-level cost estimates to evaluate project candidates.

This is MISO and SPP's fourth CSP in six years, all of which have failed to spot a beneficial project. (See *MISO, SPP Empty-handed After 3rd Project Study*.) Their joint operating agreement requires a CSP study be conducted at least every other year; the grid operators last performed one in 2019.

Speaking during a special MISO conference call Wednesday, economic planner Gavin Christenson said the RTOs evaluated about 200 stakeholder-submitted needs that focused on 10 flowgates in Minnesota, Iowa, Nebraska, Kansas, Missouri, Oklahoma and Arkansas. He said that while MISO is still verifying some planning-level cost estimates with TOs, he doesn't expect the decision against an interregional project to change.

SPP Director of System Planning Casey Cathey has been optimistic about finding a joint project this year. He noted staff still need to assess cost estimates for projects and that the RTOs' seam includes a "number of transmission opportunities."

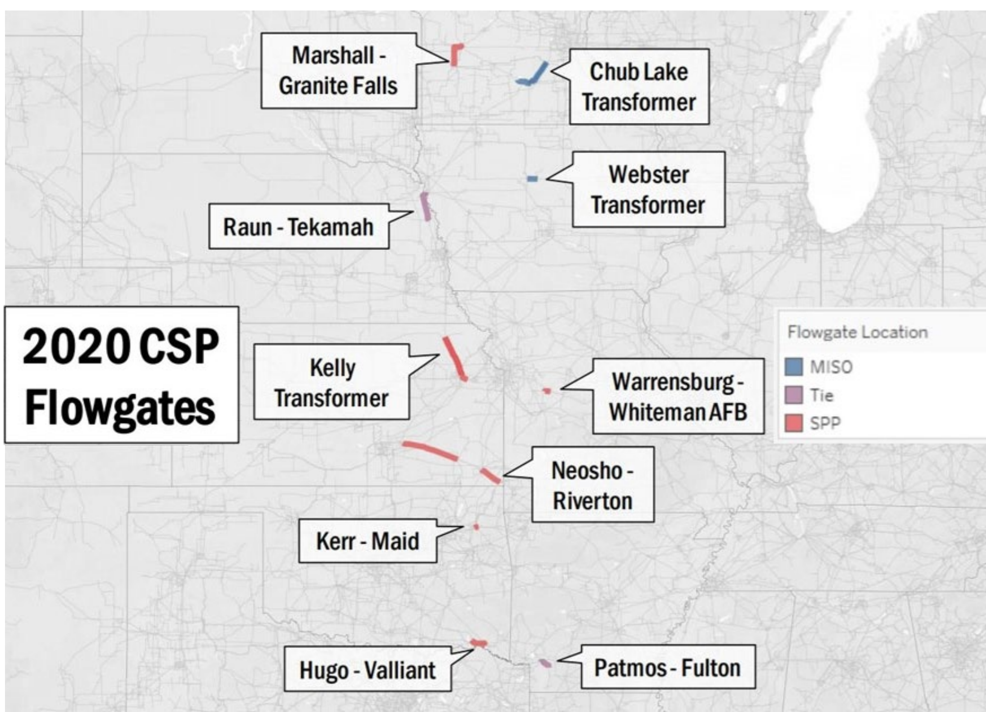
"We will continue to look at those opportunities with the next coordinated planning study with MISO," Cathey said.

The RTOs will present final CSP *results* during their Interregional Planning Stakeholder Advisory Committee (IPSAC) meeting this month, Christenson said.

A plan to use a transformer providing a parallel path for the Marshall-Granite Falls flowgate in Minnesota proved to be one of the study's better-performing projects. However, the $13 million line could only show a 1.08 B/C, despite eliminating the flowgate's congestion.

Another promising project would have eased congestion on the 161-kV Raun-Tekamah flowgate on the wind-rich Iowa-Nebraska border. A new $356 million, 345-kV line would have run parallel to the flowgate and eliminated nearly all its congestion, but it would have had a 0.69 B/C.

The study also included the chronically congested 161-kV Neosho-Riverton flowgate on the eastern Kansas-Nebraska border. The flowgate is a repeat visitor on the RTOs' joint planning studies and has accrued $32.6 million in market-to-market settlements in SPP's favor, more than four times the next nearest flowgate.



MISO and SPP's 10 flowgates studied under the 2020 coordinated system plan | *MISO*

MISO said potential projects tested for the area "saw low or negative benefits to MISO despite clearing congestion." SPP, however, appeared to benefit considerably "for almost all projects studied on this flowgate," MISO said.

Several project candidates along the seam showed negative benefits to SPP, where MISO would shift some of its congestion to its neighbor.

Some stakeholders sounded deflated that the RTOs would spend another year without an interregional project on the horizon and asked for more details around the evaluation process.

WPPI Energy's Steve Leovy found it odd that so many new projects showed negative benefits.

"Benefits can get a little bit hairy when you have a project between two pools. It's not unlikely that [the modeling software] would sacrifice the benefits on one pool to optimize overall system benefits," Christenson said.

He added that the RTOs will have more details on the study methodology during the IPSAC call. They each conduct the study using different models and adjusted production costs savings calculations.

Clean Grid Alliance's Natalie McIntire asked if some of the more promising projects could be restudied using the RTOs' soon-to-be-updated transmission planning futures.

"Do we need to go through the same process next year to argue for another CSP, or is it possible that MISO and SPP could have an automatic redo on some of the projects that show stronger benefits?" she said.

MISO staff said they would have to discuss and coordinate with SPP before they could commit to any restudies.

"We really like to look at the full gamut of issues. That's pretty much the first step of the study," MISO Economic and Policy Planning Adviser Ben Stearney said.

"It just seems like we should take another look if these issues aren't going away," McIntire responded. ■

MISO News

LS Power Again Seeks MISO Cost Allocation Change

By Amanda Durish Cook

Competitive transmission developer LS Power on Thursday made a three-pronged attack on MISO's cost-allocation structure with a trio of FERC filings against the rules.

Two of LS Power's requests for rehearing pushed back against MISO's contention that sub-230-kV projects do not demonstrate enough benefits to share costs regionally, while a third decries the RTO's local allocation for baseline reliability projects.

LS Power said MISO's use of an "arbitrary" 230-kV threshold for its market efficiency project (MEP) category, a class of projects that enjoy regionwide allocation, is wrong. The RTO gained FERC approval to use the 230-kV cut-off in late July; the commission's acceptance also denied LS Power's entreaty for a 100-kV threshold for MEPs (ER20-1723). (See *MISO Cost Allocation Plan Wins OK on 3rd Round*.)

The company sought rehearing on both its 100-kV petition and FERC's cost-allocation order. It said relegating economically beneficial sub-230-kV projects to allocation only at the transmission-pricing-zone level does "real harm" and argued that projects as low as 100 kV have proven regional benefits.

"The evidence presented in the proceeding leaves no doubt that a 230-kV minimum voltage threshold for market efficiency projects will preclude from regional consideration sub-230-kV projects that have consumer and regional benefits," LS Power said. "The commission's acceptance of the limited expansion of the MEP category seems to conclude that lowering the voltage threshold to 230 kV would be 'good enough' and shirked its obligation under [Federal Power Act] Section 205 to fully evaluate whether a 230-kV minimum voltage threshold actually results in a just and reasonable rate in every case."

The company said FERC dismissed its request for a 100-kV threshold "in the face of substantial evidence" that lines under 230 kV deliver economic advantages.

"[FERC's] decision ignored evidence that MISO currently identifies the regional benefits of economic projects operating between 100 kV and 230 kV," LS Power said.

The company also argued for a second time that MISO should devise a better allocation for its baseline reliability projects that identifies beneficiaries beyond transmission pricing zones.

Early this year, LS Power signed on to a complaint against MISO's current location-based, cost-allocation methodology for baseline reliability projects (BRPs), saying it doesn't comport with the commission's principle that transmission projects' beneficiaries should pay for them (EL20-19). FERC said the complaint failed to show that MISO's current approach was unfair and said any spillover benefits were modest. (See *FERC Upholds Cost Allocation on MISO BRPs*.)

MISO allocates BRP costs only to local transmission zones where project facilities are physically located; costs are recovered by the transmission owners developing the projects.

LS Power said FERC was "presented with unrebutted evidence" that the current allocation methodology can result in unjust and unreasonable rates, and chose to ignore it.

"The commission's complaint denial order appears to be based on the unsupported premise that the commission's obligation to ensure just and reasonable rates is a 'most of the time' standard. There is no precedent to support such a *laissez-faire* approach to the commission's obligations under the Federal Power Act," LS Power wrote.

The company said FERC, in making its decision, instead "reverted to statistics that suggest that the current location-based, nonquantitative methodology gets cost allocation mostly right, most of the time, and therefore meets the commission's statutory standard of establishing just and reasonable rates."

LS Power said far from modest spillover benefits, BRPs passed benefits to outside zones 28 to 100% of the time. It again pressed for an allocation based on a line-outage distribution factor methodology. ■

| *LS Power*

MISO News

MISO in Final Stretch of $4B MTEP 20

By Amanda Durish Cook

MISO is putting the final touches on its most expensive annual transmission investment package yet after a final round of subregional planning meetings last week.

The RTO's 2020 Transmission Expansion Plan (MTEP 20) now contains 519 new projects costing slightly more than $4 billion. Last year's 480-project portfolio was just shy of $4 billion.

The Planning Advisory Committee will vote on the package during its Sept. 23 meeting. If approved, the Board of Directors' System Planning Committee will then vote on it during an Oct. 26 meeting, with the full board deciding on final approval during its December meeting.

MISO Executive Director of System Planning Aubrey Johnson in July said MTEP 20 investment closely resembles that of MTEP 19.

The grid operator said the majority of MTEP 20 projects are line and substation work and will go into service within four years. Assuming the portfolio's approval, MISO members will spend $684 million in baseline reliability projects (BRPs) and another $538 million on generator interconnection projects. Ameren alone proposed 156 new projects costing $1.6 billion for reliability and interconnection reasons in Illinois and Missouri and to replace aging equipment and accommodate load growth. Ameren has embarked on a $7.6 billion, five-year grid modernization plan in Missouri.

MTEP 20 doesn't yet contain any market efficiency projects.

Speaking during a West subregional planning teleconference Thursday, Senior Expansion Planning Engineer James Slegers said MISO tested four BRPs that were rated 230 kV and higher and cost at least $5 million. The projects — in central Illinois, southeast Michigan, eastern Missouri and eastern Louisiana — didn't show enough economic benefits, Slegers said.

Project investment in MISO South will be less this year than in 2019. The region will pick up $530 million worth of 46 new projects. Most of the investment — $309 million — is to accommodate load growth. Last year, MISO South was on the receiving end of 71 new projects costing about $811 million.

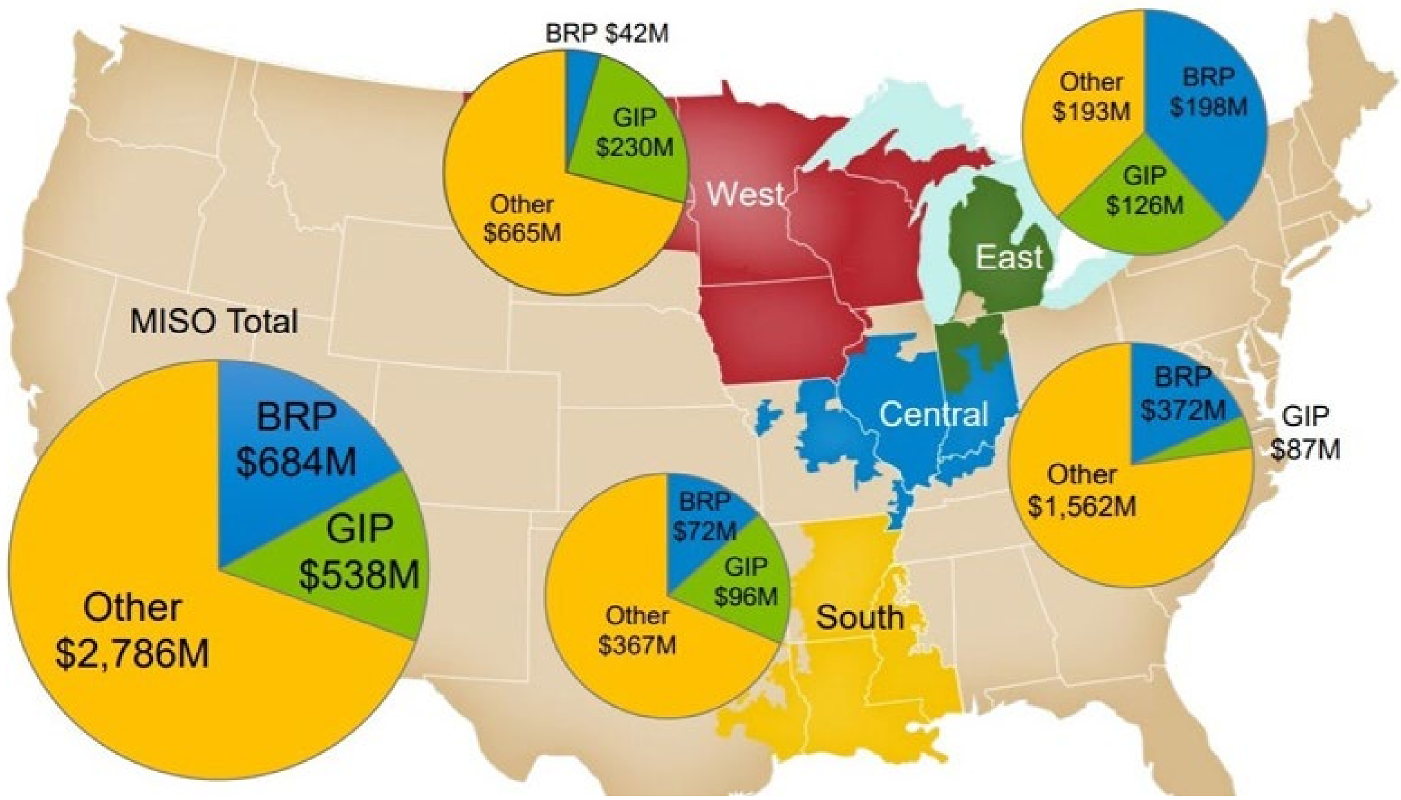
Entergy Cancels MTEP 16 Project

Entergy Louisiana, meanwhile, will withdraw a major project near New Orleans originally approved in MTEP 16. The utility announced that the nearly $74 million, 27-mile, 230-kV Waterford-to-Churchill transmission line no longer demonstrates the benefits it once did. Over four years, the benefit-cost ratio dropped from 2.3 to about 0.2, according to the company.

The line has not entered the construction phase. It was originally estimated to be in service by early 2022.

Entergy has since built new projects in the area that have eased congestion and eroded the original project's benefits, MISO Senior Manager of Expansion Planning Edin Habibovic said during an Aug. 25 South subregional planning meeting. He also said Entergy found cost increases after more detailed project scoping.

"We are OK with removing this project from the economic point of view, the reliability point of view [and] the impact of any other processes," Habibovic said. "If the load didn't materialize, then obviously there's no need for this project." ■



MISO and SPP seams | *Organization of MISO States*

NYISO News

NY Seeks Comment on Proposed Emissions Limits

Baseline Emissions Estimate up 70% Under New Methodology

By Michael Kuser

New York officials last week discussed recently *proposed* statewide greenhouse gas limits of 60% and 15% of 1990 emissions for 2030 and 2050, respectively.

The new methodology for estimating the emissions in 1990, as set out by the Climate Leadership and Community Protection Act, include upstream emissions in the calculation, meaning the baseline increased by 70%, Jared Snyder, deputy commissioner of the Department of Environmental Conservation (DEC), told the New York State Climate Action Council (CAC).

"It increases the starting point for calculating those 40% and 85% emission reductions," Snyder said. Statewide GHG emissions in 1990 totaled 401.38 MMT of carbon dioxide equivalent, which under the proposed rule translates into 240.83 MMT allowed a decade from now, and 60.21 MMT at midcentury.

The CLCPA directs the DEC to set greenhouse gases on a common scale using the CO_{2e} metric and the 20-year global warming potential of each gas, as *derived* from the U.N.'s Intergovernmental Panel on Climate Change. In calculating the proposed limits, the DEC interpreted the statute as focusing on gross emissions, Snyder said.

Administrative Law Judge Molly T. McBride will conduct two public comment hearing *webinars* for the proposed rule on Oct. 20, and public comments will be accepted by the *DEC* until Oct. 27.

The NY State Climate Action Council met via webinar Aug. 24. | *NY DPS*

CAC's Role

CAC member Robert Howarth, Cornell University professor of ecology and environmental biology, brought up the question of the council's role in drafting the proposed emissions limits.

"My reading of the CLCPA says that the DEC and the New York State Energy Research and Development Authority, in consultation with the Climate Action Council, will develop these guidelines," Howarth said. "I appreciate that I as an individual have been able to talk to you [Snyder] and staff, and I will certainly give written comment in the hearing, but so far I haven't seen any real role for the CAC here other than the fact that we are getting these briefings."

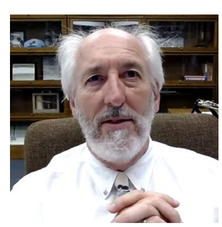
On the quantification of methane emissions, Howarth said he had just recently published a peer-reviewed paper on the topic. He said he believed the DEC team did a better job in some parts, but that he did better on others, and that there should be a way to reconcile those differences.

"Specifically, I very strongly believe that we should use a top-down approach when we can ... for the 1990 baseline," Howarth said. "What is the role for the council here? What does it mean for these numbers to be developed in consultation with the council?"

Snyder replied that the DEC consults with council members and considers their input, but that any rulemaking decision has to be based on the record. He encouraged anyone interested to submit written comments.

Sector	CO_2	CH_4	N_2O	PFCs	HFCs	SF_6	Total
Energy	254.43	70.12	1.31	--	--	4.00	329.87
IPPU	1.67	0.00	0.00	0.90	0.02	0.01	2.60
AFOLU	0.05	13.07	4.01	--	--	--	17.13
Waste	3.03	48.25	0.50	--	--	--	51.78
Total	259.18	131.45	5.83	0.90	0.02	4.01	401.38

Total NY greenhouse gas emissions in 1990 by sector and gas, in MMT CO_{2e}, as estimated by the New York DEC. | *NY DPS*


Paul Shepson, Stony Brook University | *NY DPS*

"Our understanding of the actual emissions, particularly for methane, is a rapidly developing field in the scientific community, and my concern is whether we are effectively carving in stone the emissions limits at the end of October ... so the opportunity for input is relatively urgent," said Paul Shepson, dean of the College of Ma-

NYISO News

rine and Atmospheric Sciences at Stony Brook University.

He asked, for example, how the DEC would respond if at some point in the future the scientific community's understanding of 1990 emissions changes dramatically.

"The limits we establish now are not necessarily written in stone forever," Snyder said. "If there are further developments that cause us to question the accuracy of those emission limits, there is nothing to prevent us from undertaking another rulemaking to amend them."

Just Representation

Meeting for the second time this summer, the CAC also approved member rosters for a Just Transition Working Group and six advisory panels that will collectively prepare a scoping plan by next fall for the council's mission to help the state achieve its clean energy and climate agenda. (See *NY Climate Action Council Looks at Deep Decarbonization*.)

The panels include representatives from public, private, academic, environmental and community groups and cover six different economic sectors: agriculture and forestry; energy-intensive and trade-exposed industries; housing and energy efficiency; land use and local government; power generation; and transportation.

"Two of the most controversial and important issues with renewables are connected with agriculture and community acceptance and support of renewables," said Anne Reynolds, executive director of the Alliance for Clean Energy New York. "I would just plant the seed that if it's decided that the agriculture and forestry panel is going to tackle the issue of solar interacting with ag-land, then there should be a representative of the solar industry in that group, and the same with land use and local government."

Anne Reynolds, ACE NY | *NY DPS*

Gavin Donohue, president and CEO of the Independent Power Producers of New York, said he was surprised and disappointed that the power generation panel had no utility representatives, as the statute says the panel should include regulated industries.

"You can't generate electricity and not have a utility deliver it to its customers," Donohue said. "And while I see someone from National Grid on the energy-intensive and trade-exposed industries panel ... it's an oversight that the generators are not on that panel."

Several members of the 22-member CAC emphasized the importance to all its proceedings of public comment, especially from environmental justice communities.

Peter Iwanowicz, executive director of Environmental Advocates of New York, said he was pleased to see representatives of the environmental justice community included on panels. "They fought pretty hard to make sure that the offset program is fairly constrained in [power generation], and I think they're going to have valuable input."

Council co-Chair Doreen Harris, acting CEO of NYSERDA, agreed, saying that environmental justice representation throughout the panels is not only important, but significant.

Doreen Harris, NYSERDA | *NY DPS*

"We want to make sure that the advisory panels' primary work is to identify recommendations for our consideration through the spring of next year, and then we as a council will integrate the input and consider it as part of the statewide strategy we will be advancing," Harris said.

Raya Salter, CAC | *NY DPS*

Clean energy advocate Raya Salter lauded the representation of environmental justice groups but questioned the lack of local elected officials on a proposed working group to estimate waste management emissions.

"I'm concerned because solid waste management seems a key area for direct stakeholder representation," Salter said.

Basil Seggos, NY DEC | *NY DPS*

Co-Chair and DEC Commissioner Basil Seggos said that the council "would certainly entertain" proposals to structure the working group to ensure full public input. ■

NYISO News

NYISO Q2 Energy Prices, Load at 10-Year+ Lows

Pandemic Reduced NYC Load by 11%

By Michael Kuser

NYISO energy markets performed competitively in the second quarter of 2020, with the economic shutdown caused by the COVID-19 pandemic leading to the lowest load levels and average fuel prices seen in more than a decade, according to the Market Monitoring Unit.

"Demand was extremely low, and fuel prices were extremely low," Pallas LeeVanSchaick of MMU Potomac Economics told the ISO's Installed Capacity/Market Issues Working Group last week in presenting its quarterly *report* on the markets.

"All-in prices ranged from $15 to $61/MWh, down 9 to 31% from 2019 in all regions except New York City, which saw an increase of 12% because of the higher capacity prices we saw there," LeeVanSchaick said.

For the first time in more than a decade, capacity costs constituted the majority of the city's all-in prices (71%), compared to the usual third or so, because of an increased locational minimum installed capacity requirement (LCR) and very low energy prices, he said.

Energy consultancy ICF International in June 2018 highlighted the possibility of increasing capacity prices in New York City, *citing* NYISO's revised assumptions and references for its buyer-side mitigation analysis that forecasted the LCR for the city at 2.5 to 4.5% above its then-current level of 80.5% in the 2020/2021, 2021/2022 and 2022/2023 capability years, saying the "higher LCRs are equivalent to approximately 320 MW of demand in 2020 and 550 MW in 2021 and 2022."

The report said the actual LCR rose from 82.8% to 86.6% in New York City. Capacity costs fell by 5% on Long Island and 40% in the Lower Hudson Valley but rose by 64% in the city and doubled in the Rest-of-State regions, both from changes in demand and supply.

"In ROS, Kintigh retired at the end of March, and both Cayuga units retired in June, marking the end of the coal era in NYISO," he said.

Natural gas prices continued to fall, with quarterly averages being the lowest witnessed over the last decade, regardless of season: $1.43/MMBtu at the Transco Z6 hub, down from $2.25/MMBtu in the same quarter a year ago.

Swing Low and Loose

The 5% average load reduction was a decrease against what had previously been the lowest second-quarter load in more than a decade, although peak load levels were consistent with last year because of a heat wave in June that drove energy demand higher.

The pandemic had a significant reductive impact on loads, reducing New York City's load by 11%, based on weather-normalized values. The pandemic drove most of the load reduction from 2019, continuing the trend seen in the first quarter. (See *NYISO Q1 Energy Prices Hit 11-Year Low*.)

Generation patterns and capacity supply changed with the retirement of the Indian Point 2 nuclear unit, as well as the last two coal plants in the state, and some of those impacts were offset by the new entry of the Cricket Valley Energy Center, LeeVanSchaick said.

Lower load levels and gas prices led to lower transmission congestion and uplift.

Mapping Congestion

The report featured a new system congestion map, which LeeVanSchaick said offers a truer representation of congestion patterns.

"Where there's a generator, it shows you what the pricing of that generator location is, but all of the load zones are shown according to the average price of the load zone on the other chart; but on this one, it's on a gray background, and that's helpful to distinguish between areas where there's not a lot of generation versus areas where there may be a concentration," he said.

Day-ahead congestion revenues totaled $62 million, down 46% from a year ago, primarily because of lower gas prices and load levels. Day-ahead congestion fell across the system, with most of the decrease occurring on the Central-East interface and in the West Zone.

New York City constraints accounted for only about 5% of congestion, which fell by nearly 80% in the city from the previous year.

Unlike most other transmission corridors, congestion from the North Zone to central New York rose by more than 100% from a year ago, and 90% of this congestion occurred on the 230-kV Moses-Adirondack MA1 line when the parallel MA2 line was out of service in most of May and June.

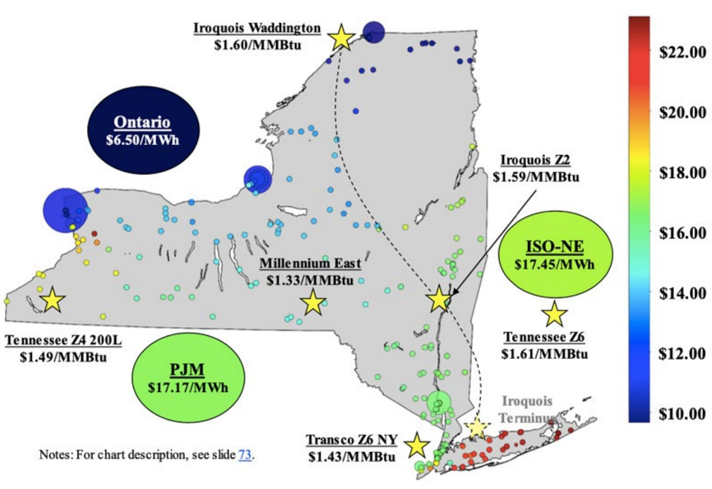
"We also saw wind curtailments about 8% of the time because of unusually high congestion from the north," he said.

Day-ahead Congestion Revenues

The report included a graph of day-ahead congestion revenue shortfalls, identified by transmission corridor, with the majority coming on the West Zone lines.

To the extent that the congestion revenue shortfalls weren't associated with Lake Erie circulation, they were generally related to outages at the Niagara plant of transformers 1, 2 and 4, as well as the Niagara-Rochester line, LeeVanSchaick said.

"Those outages will reduce how much can flow through there, so you see where that resulted in significant uplift," he said. "We also saw in May and June very significant amounts of shortfalls coming down from northern New York, and those were associated with the outages of those Moses-Adirondack lines related to the [New York Power Authority] Smart Path Reliability *Project*." ■



System congestion real-time price map at generator nodes | *NYISO*

NYISO Management Committee Briefs

Remote Working to Continue All Year

NYISO management has decided to remain in remote work mode for the rest of the year, Executive Vice President Emilie Nelson told the Management Committee on Wednesday.

Nelson thanked stakeholders for their continued engagement and said the virtual meetings seem to be productive. Given the decision to continue meeting remotely, she said it makes sense to welcome any additional input, and she encouraged people to contact *Mark Seibert*, manager of member relations, and his team with any suggestions for improvements.

Committee OKs Additional SENY Reserves

The MC approved NYISO's Reserves for Resource Flexibility *project* to increase the portion of the total statewide reserve requirement for Southeast New York (SENY, zones G-K) during certain hours from 1,300 MW to 1,550 or 1,800 MW, depending on the hour. Stakeholders in July had delayed a vote on the proposal pending additional cost analysis. The ISO will seek to implement the new project in 2021.

"These additional reserves will help to bring transmission assets in SENY back to normal transfer criteria after suffering a contingency," said Ethan Avallone, the ISO's technical specialist in energy market design. "The 2,620-MW reserve requirement will remain as is [for all of the New York Control Area], and this proposal only contemplates shifting an additional portion of these reserves into SENY."

As part of its Grid in Transition initiative, the ISO is seeking to assess and develop a variety of energy and ancillary services market design changes in response to the ongoing transition of the resource fleet in New York. (See *NYISO Moves Forward on EAS Projects*.)

New Siting Law Milestones for Class Year Study

The MC also approved a new regulatory milestone in its Class Year Study for any large generator that is required or eligible and elects to undergo the new siting process for major renewable energy facilities under a new state law.

The Accelerated Renewable Energy Growth and Community Benefit Act, enacted April 3, streamlines the siting of new renewable energy generation projects through a new Office of Renewable Energy Siting, supplanting determination by the Public Service Commission under Article 10 for any "Major Renewable Energy Facility."

Thinh Nguyen, NYISO's senior manager for interconnection projects, *said* the revision fills a gap in NYISO's existing regulatory milestone requirements by creating a specific milestone for large generators meeting the definition of "Major Renewable Energy Facility" to demonstrate that their applications are deemed complete comparable to an Article 10 application.

If approved by the Board of Directors this month, the ISO will make a filing under Federal Power Act Section 205 with FERC. ■

— Michael Kuser

PJM News

FERC Partially Approves DP&L Tx Rate Incentives

By Michael Yoder

FERC last month partially accepted Dayton Power and Light's transmission rate incentives request, requiring more information on its petition for an RTO participation adder for its continued membership in PJM (*ER20-1068*).

DP&L submitted a request for approval on Feb. 25 of incentives for investment in transmission projects it asserted are needed for reliability, including:

- a 50-basis-point adder to reflect its continued PJM membership;
- inclusion of 100% of construction work in progress (CWIP) for the projects;
- and 100% recovery of all "prudently incurred transmission-related development and construction costs" if one or more transmission expansion plan projects are canceled or abandoned because of factors beyond the company's control.

In its petition for the PJM participation adder, DP&L argued that the commission has a "longstanding policy" to provide a 50-basis-point adder to the base return on equity of a transmission owner's entire rate base as a way to encourage utilities to join an RTO. The company said it has not had a rate case to seek the incentive since joining PJM in 2004.

FERC on Aug. 17 accepted the adder proposal but suspended it for a five-month period subject to the outcome of a paper hearing "exploring whether Dayton has shown that its participation in PJM or another RTO is voluntary, as required for it to be entitled to the adder, or if such participation is mandated by Ohio law."

The Public Utilities Commission of Ohio and the Ohio Consumers' Counsel objected to the adder, arguing that, under state law, all TOs with facilities in the state are required to be members of an RTO. The OCC also contended that if DP&L were not a member of an RTO, the utility would be forbidden to own or control transmission facilities in Ohio.

Commissioner Richard Glick dissented in part to the RTO participation adder decision. He said the record made clear that Ohio law requires DP&L to be a member of an RTO. As a result, Glick said, there was nothing for the commission to incentivize by awarding an additional adder for the utility's PJM membership.

"Where the law is as clear as it is here, I see no reason to give Dayton a second bite at the apple after it has already failed to adequately prove an essential element of its case for the requested incentive," Glick said. "Under those circumstances, our role is to answer the legal questions presented to us, not to punt those questions to another day."

Expansion Plans

FERC granted DP&L's requests for the CWIP and abandoned plant incentives for Category 1 and Category 2 projects. Category 1 projects include baseline upgrades identified and selected by PJM through the Regional Transmission Expansion Plan (RTEP) process to resolve NERC reliability violations, while Category 2 projects are identified as supplemental projects operating at or above 125 kV and are required under Ohio law to be approved by the Ohio Power Siting Board.

DP&L's abandoned plant incentive requests for two of its Category 2 projects are effective May 3, including the Buckeye Haas Delivery Point in Bethel Township and the 138-kV Gebhart Substation. Three other Category 2 project requests are effective upon approval from the state siting board: the 345-kV South Charleston Substation, the 345/69-kV Clinton transformer and the Fort recovery line, transformer and capacity bank.

But the incentives were denied for Category 3 projects, which are supplemental projects that DP&L said are "required to enhance reliable operations but, because they operate at voltage levels below 125 kV, are not subject to approval from either the PJM RTEP or the Ohio Siting Board."

"Dayton indicates that Category 3 includes projects that primarily improve segments of its 69-kV transmission system and states that the majority of these projects will improve reliability by reducing outages and line overloading," the commission said. "However, we note that the PJM Board [of Managers] does not approve or select supplemental projects in the RTEP. Further, Dayton provides no congestion analysis nor any third-party analyses of reliability benefits."

DP&L said its transmission expansion plan projects are estimated to cost approximately $170 million, which is projected to increase its gross transmission plant in service by approximately 40% over the next four years and its net transmission investment by 90%. It said almost all the projects will be placed into service by the summer of 2023. ■

Dayton Power and Light building

Exelon to Close Ill. Nukes as Gov. Touts Clean Energy Plan

Continued from page 1

Publication of the principles comes after a tumultuous summer in which Exelon's Commonwealth Edison agreed to pay a $200 million fine to settle allegations that it bribed Illinois House Speaker Michael Madigan to back legislation that increased the company's earnings and bailed out its money-losing nuclear plants. (See *ComEd to Pay $200 Million in Bribery Scheme* and *How ComEd Got its Way with Ill. Legislature*.)

"With these principles as a starting point, we will ensure any legislation on energy includes robust consumer protections as we work to increase transparency and restore the public's faith in this process," Pritzker said. "I will be an advocate for ratepayers, so they know they will finally have a seat at the table."

Pritzker called the principles "guideposts for crafting a legislative proposal that puts consumers and climate first."

Of the principles, it was the FRR alternative that drew the most attention from renewable energy companies and advocates. The proposal calls for implementation of a market-based program separate from the FRR proposal set out in legislation, which the report said "does not seem to accomplish" the goals of reducing emissions. (See *Illinois: End PJM Capacity Market?*)

The report said the proposed FRR has been a "centerpiece" in energy discussions in the legislature, but it includes annual payments to each of Exelon's nuclear plants at an amount "equal to three times the current taxpayer subsidy that [they] already receive without any strings attached and without Exelon showing us their math as to why this is necessary."

"Existing legislative proposals both tacitly assume all of Exelon's existing nuclear plants, including Quad Cities, need a large amount of money to remain open (and the same amount of money for each plant)," the report said. "Exelon has refused to show their math to explain why this is the case — they are asking us to take their word for it without providing the relevant financial statements for each plant."

The report went on to say nuclear plants are "integral" to Illinois achieving its clean energy goals and for the economies of the communities where the plants are located. It also said "taxpayer and ratepayer financial support for these plants cannot be a blank check" and that "alleged cost reductions for consumers that might result from current FRR proposals may actually result in cost increases for consumers."

The report also cites concerns about the FRR raised by PJM's Independent Market Monitor, who has argued that Exelon "would be compensated at the functional equivalent of giving contracts for [zero-emission credits] to all of the Exelon nuclear plants in Illinois."

"We cannot afford to increase costs to consumers in the wake of COVID-19," the report said.

Solutions

The FRR construct in current legislative proposals does not provide the same benefits as a market construct, the report argues, and could bring problems with Exelon's market power concentration while not guaranteeing the environmental generation mix the state seeks.

Instead of the FRR option, Pritzker gave his support to establishing a market-based program incorporating the social cost of carbon into generation costs.

"Implementing a carbon price makes dirty energy less competitive, reduces emissions, creates room for renewable energy development and raises revenue for the state," the report said. "Several states participate in the Regional Greenhouse Gas Initiative or some form of cap-and-trade. Illinois can lead the Midwest by pricing the dirty energy that we plan to phase out."

Pritzker also called for incorporating "equity provisions" into the carbon price that "accelerates closures" of coal-fired plants in communities while redirecting revenue to other clean energy pursuits. The proposal also calls for directing revenue to communities that will experience plant closures. ■

SPP News

FERC Orders Tech Conference on MISO-SPP Congestion

By Amanda Durish Cook

FERC last week ordered a technical conference to investigate overlapping congestion charges imposed on pseudo-tie transactions between MISO and SPP.

The commission said it was displeased with MISO's and SPP's first round of briefs in the matter (EL17-89, EL19-60). Commission staff will set a date for the technical conference.

FERC last September said it would investigate the possibility of overlapping congestion charges between the grid operators after American Electric Power subsidiary Southwestern Electric Power Co. and the city of Prescott, Ark., complained. (See FERC Sets Briefings on MISO, SPP Congestion Fees.)

The RTOs have argued in briefs that though duplicative congestion charges are possible for their pseudo-tie transactions, mechanisms such as virtual transactions, financial transmission rights and firm-flow entitlements (FFE) counteract double charging. MISO has maintained that congestion charges on pseudo-tied generation with SPP do not require special Tariff remedies similar to those it took correcting double-charging with PJM, which it said, are less than those with SPP.

MISO-SPP pseudo-tied generation has "minimal impacts" on reciprocally coordinated flowgates, and generators can also pursue FFE allocations, MISO said. The RTO also said it models pseudo-tied loads in aggregate with the load at its commercial pricing nodes, "which prevents discretely quantifying the individual impact on pricing, settlement and congestion associated with the pseudo-tied load."

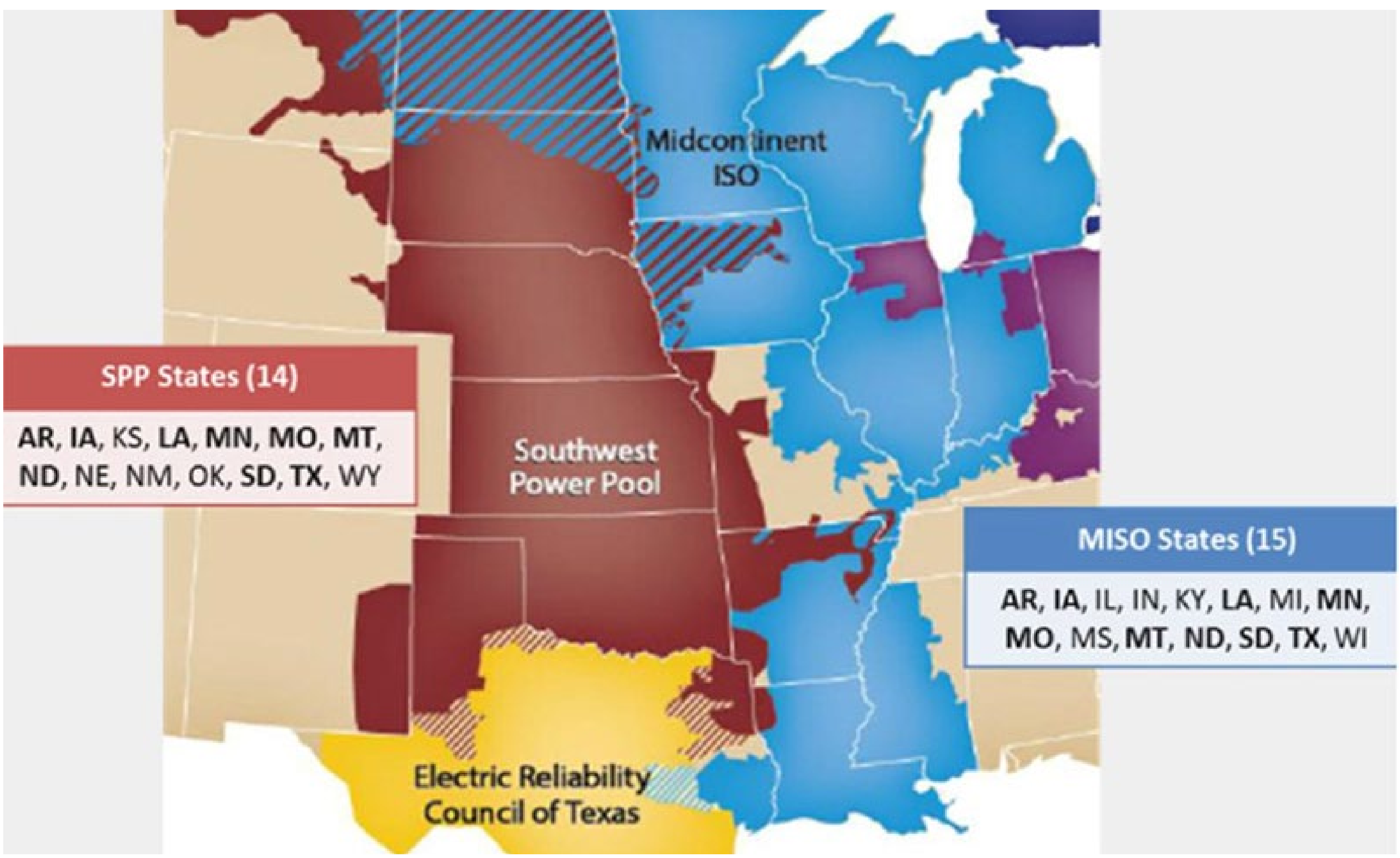
SPP also said it doesn't think it needs changes to its Tariff or its joint operating agreement with MISO, and said such changes would disturb FERC's longstanding position that RTOs and utilities "are not required to offer special terms and conditions to accommodate pseudo-tie requests."

The commission wasn't satisfied with those characterizations.

"We find that the current record, after the briefing, is still not adequate for us to either (1) confirm that the mechanisms available to market participants are sufficient to remedy any potential for overlapping congestion charges, or (2) find that MISO and/or SPP must make changes to their JOA and/or individual tariffs," FERC wrote.

The commission said the RTOs failed to answer when and how many times pseudo-tied generation imposed duplicative congestion charges and their total cost. It ordered another round of briefs and posed additional questions, including how the RTOs handle charges under the simultaneous binding of flowgates, MISO's aggregation methods and a more detailed description of the grid operators' FFE process and other existing offsetting mechanisms.

FERC also asked the RTOs to explore a grandfathered treatment of pseudo-tied loads, as SWEPCO suggested. ■



MISO and SPP seams | *Organization of MISO States*

SPP News

SPP Stakeholders Agree on WEIS Tariff Changes

By Tom Kleckner

Stakeholders in SPP's Western Energy Imbalance Service (WEIS) market last week approved three revision requests (WRRs) in response to FERC's recent rejection of the RTO's proposed Tariff.

The Western Markets Working Group and Western Markets Executive Committee held two joint web meetings to expedite protocol changes necessary to help SPP meet an early September schedule for refiling its WEIS Tariff.

FERC in July rejected SPP's first attempt, saying the grid operator failed to respect nonparticipants' transmission rights and could improperly burden reliability coordinators. The commission also cited shortcomings on supply adequacy, market power protections and line-loss calculations (*ER20-1059, ER20-1060*). (See *FERC Rejects SPP's WEIS Tariff*.)

While the groups easily passed three WRRs, it was unable to hold a vote on nonparticipant transmission. After nearly four hours of discussion and one minor editing change Friday afternoon, stakeholders agreed to postpone action until a yet-to-be-scheduled third joint meeting can be held this week.

In its order, FERC said any future WEIS market proposal "should include the mechanisms or agreements that will ensure that the SPP WEIS market respects the transmission capacity of nonparticipating entities with appropriate constraints in the [security-constrained economic dispatch]."

The commission said if SPP is unable to reach an arrangement with nonparticipating entities for their transmission capacity, it "must include constraints in its market model to appropriately respect the transmission rights of nonparticipating entities when calculating the market solution."

Colorado utilities Xcel Energy-Colorado, Colorado Springs Utilities, Platte River Power Authority and Black Hills Energy, all of which plan to join CAISO's Western Energy Imbalance Market, protested the first WEIS filing. They contended that an existing and neighboring joint dispatch agreement could be impaired by the WEIS market dispatch and that its market flows may harm the Western Interconnection Unscheduled Flow Mitigation Plan, which mitigates real-time flows on certain transmission paths to reliable levels.

WRR6 provides that SPP will include constraints in SCED to use the combined transmission capability made available by market participants (MPs) and participating balancing authorities on transmission facilities within a participating BA area or on transmission facilities used to transfer energy between participating BAs.

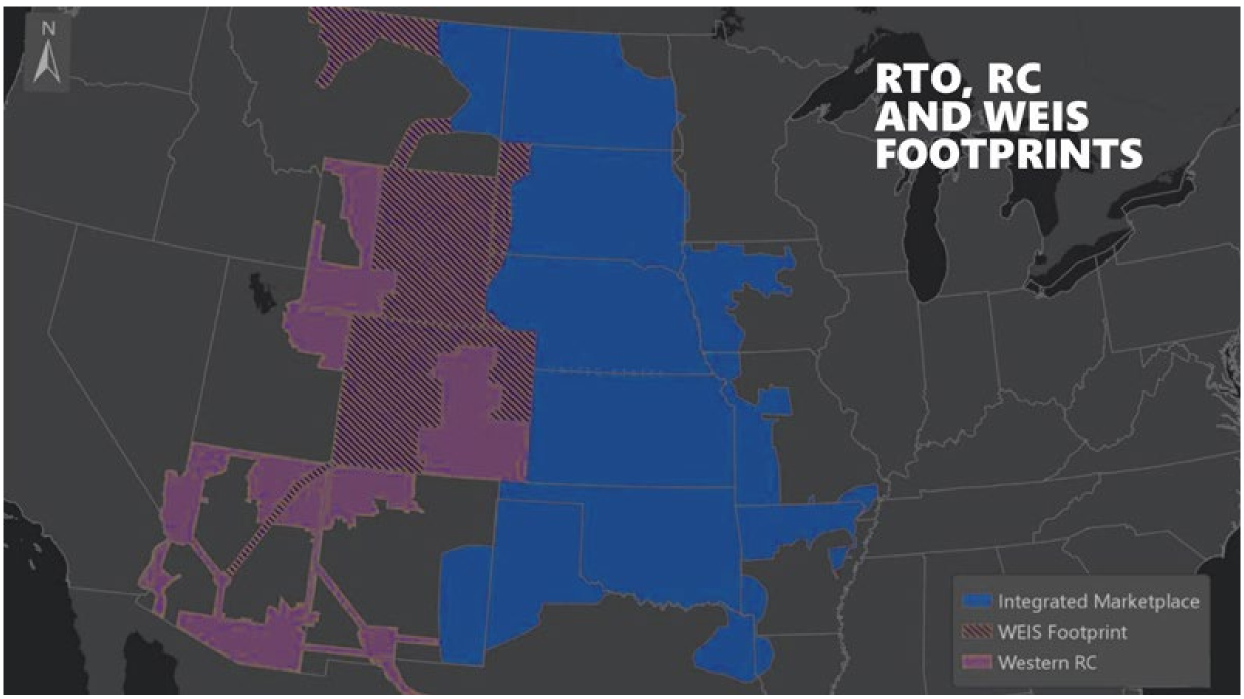
SPP staff also added a new section to the WEIS protocols that lists the responsibilities to communicate transmission capacity by SPP, MPs, BAs and the joint dispatch transmission service provider. The addition came following comments by Xcel and Black Hills.

"After some internal deliberation, we thought we could make the roles and responsibilities of communicating information clearer," said David Kelley, SPP's director of seams and market design.

The WEIS stakeholder groups approved three other revision requests addressing the commission's order:

- *WRR7*: Incorporates a pricing mechanism for MPs in BAs that experience supply-adequacy shortfalls. The mechanism responds to FERC guidance that its next Tariff proposal should ensure MPs are incentivized to maintain supply adequacy. Black Hills argued that the change doesn't address the FERC order, saying it was concerned there still remains opportunities for deficient MPs to cause a BA to be deficient.
- *WRR8*: Adds a marginal loss component to the LMP calculation, meeting FERC's request that SPP include marginal losses in dispatch and LMPs to minimize imbalance costs, provide prices that accurately reflect marginal costs and preserve resources' incentives to follow dispatch.
- *WRR9*: Clarifies that demand response resources will be compensated at the LMP, as are other MPs offering resources in the market.

SPP hopes to launch the WEIS in February. The market will include eight members and cover the Western Area Power Administration's Colorado Missouri and Upper Great Plains West areas. ■



| SPP

Company Briefs

ComEd Appeals Radford's Run Ruling

Commonwealth Edison has asked the D.C. Circuit Court of Appeals to overturn FERC's April 16 order directing PJM to recalculate an Illinois wind farm's incremental capacity transfer rights (ICTRs) to the Commonwealth Edison locational deliverability area (LDA).

FERC ordered PJM to recalculate the ICTRs for Radford's Run Wind Farm, agreeing with facility owner E.ON Climate & Renewables N.A. that the analysis should have used the base case for the 2015 Base Residual Auction, entitling it to 279 MW of ICTRs. PJM said in May it would pay Radford's Run at least $10 million for the nearly completed 2019/20 delivery year, clawing back payments from other LSEs in the ComEd LDA. (See *PJM Announces $10M Resettlement in ComEd LDA*.)

More: *EL18-183*

Duane Arnold Nuclear Plant Decommissioning Early After Derecho

The Duane Arnold nuclear plant, which was set to close at the end of October, is beginning its decommissioning process early after the cooling towers sustained damage from an Aug. 10 derecho.

"After conducting a complete assessment of the damage caused by recent severe weather, NextEra Energy Resources has made the decision not to restart the reactor at Duane Arnold Energy Center. The strong storms that hit the area on Aug. 10 caused extensive damage to Duane Arnold's cooling towers, and our evaluation found that replacing those towers before the site's previously scheduled decommissioning on Oct. 30, 2020, was not feasible," NextEra Energy Resources said in a statement.

More: *KGAN*

FERC OKs Reactive NRG Settlement

FERC on Aug. 24 approved an uncontested settlement on reactive power revenue requirements for NRG Energy's Louisiana Generating, Bayou Cove Peaking Power and Big Cajun I Peaking Power generating plants.

The settlement was supported by FERC trial staff, which noted that it reduces the Louisiana Generating annual revenue requirement (ARR) for reactive service from $3.1 million to $2.7 million; the Bayou Cove ARR from $600,00 $485,000; and the Cajun I ARR from almost $547,000 to $483,00.

More: *ER14-2080-002*

FERC Threatens to Revoke Market-based Rates over EQR Failures

FERC on Aug. 24 threatened to revoke the market-based rate authority (MBRA) for six companies for their failure to file electric quarterly reports summarizing contractual and transaction information related to their market-based power sales.

The commission said it would revoke the MBRA authority for ResCom Energy; PowerOne; Capital Energy; HIC Energy; Veritas Energy Group; and Iridium Energy unless they file all delinquent reports with the commission within 15 days.

More: *ER20-2001-020*

Invenergy to Expand Wind Power Availability in Missouri, Kansas

Invenergy last week said it plans to increase the delivery capacity of its Grain Belt Express transmission line in Missouri and Kansas to 2,500 MW, which is nearly two-thirds of the line's planned total of 4 GW. The company had previously announced that only 500 MW would go to Missouri.

The line would run from the plains of Kansas across Missouri and Illinois to Indiana. After previously being rejected in Missouri, the project won regulatory approval in both Missouri and Kansas in 2019. The line still needs regulatory approval in Illinois.

More: *The Associated Press*

NWPP Selects New COO

Northwest Power Pool (NWPP) last week announced it has selected Gregg Carrington to be its new chief operating officer.

As COO, Carrington will support regional program development activities, including NWPP's development of a regional resource adequacy program. He will also help in day-to-day functions, such as system operations and the implementation of contingency reserve and western frequency reserve sharing programs.

More: *Northwest Power Pool*

Talen Energy Assessing Fire Damage at Turbine Building

Talen Energy officials last week began assessing how a fire in the turbine building of the company's Martins Creek power plant in Lower Mount Bethel Township, Pa., will affect operations.

Sandt's Eddy Fire Department Chief Jeff Larrison Sr. said the belief is that leaking lubricant caused the fire, which ignited around 9 p.m. on Aug. 23 at the top of the 13-story facility. The leaking oil then came in contact with machinery with temperatures of about 1,800 degrees.

Larrison said the building was badly damaged, with areas of the roof buckling and burned through. Not all the equipment in the building was affected, but a true tally of what was destroyed remained unclear as of last week.

More: *The Morning Call*

Vistra Joins Effort to Repeal Nuclear Bailout

Vistra Energy, the owner of two Cincinnati-area coal-fired power plants, has joined the Coalition to Restore Public Trust to repeal Ohio House Bill 6. The law provided a $1 billion bailout for nuclear power plants that sparked the federal indictment of former Ohio House Speaker Larry Householder and other political insiders.

"We the believe in competitive markets. We oppose subsidies, especially subsidies baked into a corrupt law that harms the competitive market, our customers and our employees," Vistra Media Relations Director Meranda Cohn said.

The coalition will launch a digital ad campaign costing more than $1 million as a part of its repeal effort.

More: *Cincinnati Business Courier*

Walmart Cuts 230 Million Tons of Emissions

Walmart last week said it has cut 230 million metric tons of greenhouse gases out of its supply chain in the past three years as it aims to reduce its cumulative carbon footprint by 1 billion tons by 2030. It has reduced its own emissions by 7.7% between 2015 and 2018, which doesn't include supplier cuts.

The company is putting pressure on its suppliers to keep the emission cuts coming by using more clean energy and shifting toward environmentally friendly product design and packaging. About 95% of Walmart's emissions stem from its supply chain.

About 29% of Walmart's electricity comes from renewable sources, and the company expects that figure to hit 35% by the end of the year. However, it still has a way to go to reach its goals of 50% by 2025 and 100% by 2030.

More: *Transport Topics*

Federal Briefs

Consultant to Review TVA CEO Pay

The Tennessee Valley Authority last week announced it has hired independent consultant Erin Bass-Goldberg of FW Cook to look into its executive compensation after President Trump recently said CEO Jeff Lyash is "ridiculously overpaid."

The TVA Act already requires hiring an independent consultant to review executive compensation, but the utility is switching firms to provide a "new set of eyes on the problem."

In his first six months on the job, Lyash's earned $8.1 million, making him the highest paid federal employee. Lyash said he supports the review.

More: *The Associated Press*

FERC Grants Columbia Gas Tx More Time to Build Pipeline

FERC last week granted Columbia Gas Transmission until July 18, 2023, to complete its natural gas pipeline near Hancock, Md.

Opponents of the pipeline argued that Columbia did not demonstrate good cause to justify the extension and that circumstances have changed since FERC issued its approval two years ago, including intended shipper Mountaineer Gas pursuing alternative sources of supply because of the delay. FERC rejected the arguments, saying that its "finding that the project is required by the public convenience and necessity remains unchanged."

The pipeline would go under the Chesapeake and Ohio Canal Historical Park, which is owned by the National Park Service, and the Western Maryland Rail Trail, which is owned by the state.

More: *The Herald-Mail*

Mountain Valley Asks FERC for More Time to Complete Pipeline

Mountain Valley Pipeline last week asked FERC to extend a key approval, which will otherwise expire in October, for its interstate natural gas pipeline by two years.

FERC determined on Oct. 13, 2017, there was a public need for the natural gas and granted Mountain Valley a three-year certificate for a project the company said would only take a year to build. However, multiple legal challenges led courts to set aside three sets of federal permits.

Matthew Eggerding, assistant general counsel for Mountain Valley, said in an Aug. 25 letter to FERC that "due to the uncertainty regarding the timing of these permits and the outcome of any subsequent legal challenge, Mountain Valley asserts that a two-year extension is necessary and proper." Company spokeswoman Natalie Cox said Mountain Valley still expects to complete the work on schedule but requested the extension "out of an abundance of caution."

More: *The Roanoke Times*

NRC Extends Seabrook's License with Conditions

The Nuclear Regulatory Commission's Atomic Safety and Licensing Board on Aug. 21 accepted the Seabrook nuclear plant's concrete monitoring program after months of deadline extensions. The board is treating its ruling as nonpublic to allow parties an opportunity to review it and propose any redactions. A public version of the ruling will be issued by Sept. 11.

The board's decision was to be issued within 90 days of a Sept. 24, 2019, hearing about concrete degradation but was extended multiple times. Concrete degradation was discovered at the plant in 2010.

The board has accepted NextEra Energy's concrete testing program but did so with "several important conditions that will ensure the health and safety of the public." Some conditions include conducting more frequent and detailed monitoring and engineering evaluations and increasing the frequency of testing from the proposed five to 10 years up to six-month intervals.

More: *Gloucester Daily Times*

NRC Fines TVA over Employee Discrimination Violations

The Nuclear Regulatory Commission last week fined the Tennessee Valley Authority $606,942 for employee discrimination violations and cited two former managers for their roles in the incidents.

NRC investigations revealed that two former TVA employees were subject to "adverse actions" after raising concerns about a "chilled work environment" where employees were less likely to report safety violations because of fears of retaliation. The commission singled out former Vice President of Regulatory Affairs Joseph Shea and former Director of Corporate Nuclear Licensing Erin Henderson for violating employee-protection rules and engaging in deliberate misconduct.

TVA has 30 days to appeal the ruling.

More: *WAFF*

Puerto Rico Regulators Affirm Solar-centric Grid Overhaul

The Puerto Rico Electric Power Authority (PREPA) last week presented a modified integrated resource plan that included a higher proportion of renewables than it did in its IRP last year, with the territory shooting for at least 3,500 MW of solar and more than 1,300 MW of storage by 2025.

In its IRP filed in 2019, PREPA presented a plan that included 1,800 MW of solar and 920 MW of storage additions in the next five years, plus eight minigrids that could power sections of the island if the grid is disrupted, though regulators rejected the $5.9 billion plan for the minigrid system.

The proposal will cost about $13.8 billion, which is less than the $14.4 billion for PREPA's preferred plan.

More: *GreenTech Media*

Solar, Wind Output up 16% in H1

Between January and June of this year, solar-generated electricity expanded by 22% year-on-year and provided nearly 3.4% of the nation's total. Meanwhile, wind grew by 14.5% and accounted for more than 9.1% of total generation, according to the Energy Information Administration.

Combined, net generation from wind and solar was 16.4% greater than a year ago and provided a bit more than 12.5% of the total U.S. electrical production during the first six months of 2020.

More: *Renewables Now*

State Briefs

CALIFORNIA

Dems Scrap Wildfire Utility Fee Plan

State lawmakers last week scrapped a last-minute bill to extend fees for utility customers and instead plan to call for $500 million in emergency fire response and mitigation efforts. The decision to abandon the bill came five days after it was introduced.

The legislation's reliance on a 10-year extension of fees on utility bills — at a cost of more than $3 billion to customers — to pay for wildfire mitigation and climate projects drew criticism from ratepayer advocates and utilities. The new plan would instead tap into proceeds from the state's cap-and-trade program, as well as general fund revenues and a 2018 bond measure.

The new proposal would require Gov. Gavin Newsom to waive a state law that prevents legislators from amending bills in the final hours before the Legislature adjourns for the year. A spokesman for Newsom declined comment on the new proposal or whether he would waive the 72-hour rule.

More: *Los Angeles Times*

LA Natural Gas Plant has Leaked Methane for Years

The Los Angeles-area Valley natural gas plant has been leaking large amounts of methane for years, and the city has been aware since at least March but has not scheduled repairs until later this year, according to a recording made public last week.

Faulty compressors at the 690-MW plant have been leaking more than 10,000 cubic feet of methane per hour "for the last couple years," said Norm Cahill, the city's Department of Water and Power's director of power supply operations.

The leak was reported to the utility by NASA's Jet Propulsion Laboratory, which uses airborne sensors to observe methane sources. However, the utility was made aware of the leak in March following a study by the Electric Power Research Institute, Cahill said. New equipment is scheduled to be installed in November.

More: *Reuters*

COLORADO

Xcel Proposes Lower Rates for New, Expanding Businesses

Xcel Energy last week submitted a proposal to the Public Utilities Commission that would lower rates to new and expanding businesses for up to 10 years. The incentive would hopefully encourage new commercial and industrial customers to come to the state and help it rebound from the pandemic-driven economic downturn.

Xcel spokeswoman Michelle Aguayo said the base rate discounts for a 10-year contract would be 40% in the first three years; 30% in years four and five; 20% for years six and seven; and 10% for the remainder of the contract. A 2018 law allows the PUC to approve lower rates as an economic incentive for businesses to expand their operations or move to the state.

More: *The Denver Post*

ILLINOIS

Study Cautions Chicago not to Cut Ties with ComEd

Cutting ties with Commonwealth Edison would cost the city of Chicago $8.8 billion and not lower customer costs in the process, a study by NewGen Strategies and Solutions announced last week. The city has been considering leaving the utility to run its own.

The study figured the cost of operating a city-run utility would be around $338 million each year, but the debt service for the next 30 years would be around $708 million annually. The study instead recommended officials push for renewable energy such as community solar and an electric vehicle fleet in a new franchise agreement with ComEd.

"Now that municipalization by the city appears to not be feasible, we can focus on getting the best deal for our residents and ratepayers through a transparent process as we negotiate the future of our franchise agreement," Mayor Lori Lightfoot said.

More: *WBEZ*

MINNESOTA

PCA to Expand EV Charging Network

The Pollution Control Agency last week announced it will fund the installation of 38 electric vehicle fast-charging stations. The additional chargers will extend the existing EV corridor network by more than 2,500 miles. The $2.6 million grant opportunity leverages funds from the national Volkswagen settlement.

The chargers will be placed 30 to 70 miles apart along seven proposed corridors.

More: *WCCO*

NEVADA

PUC Grants Investigation into Supply Adequacy Issues

The Public Utilities Commission last week unanimously approved a formal investigation into electric supply adequacy issues in the state, a week after NV Energy issued a request for customers to voluntarily reduce power consumption amid grid strain during a record-breaking heat wave.

The filing of an investigation gives the PUC a more direct and immediate way to look into supply issues and take action if necessary. It can also retroactively fine or take action against the utility if it determines the company took actions that were not "reasonable and prudent."

Commission Chair Hayley Williamson said the step was necessary to "ensure the commission is doing everything in its power to ensure Nevada's resource adequacy and supply of energy is sufficient." However, she did acknowledge the heat wave may have played a role in the supply issues and capacity planning.

More: *The Nevada Independent*

PENNSYLVANIA

Federal Court Rejects Smog Regulations

The 3rd U.S. Circuit Court of Appeals last week ruled that EPA's approval of a weak air pollution standard was "arbitrary and capricious" and directed the federal and state environmental agencies to come up with tougher, enforceable regulations.

The court stated EPA was "simply rubber-stamping an average of current pollution output as its supposed new gold standard," and a state allowance of low-temperature coal combustion could increase pollution emissions fivefold. The Sierra Club and Earthjustice originally brought the appeal to the court on May 21, saying EPA's approval of coal-fired power plant pollution standards wrongly claimed the regulations would reduce emissions of nitrogen oxides.

The ruling vacated EPA's approval on three provisions of the state implementation plan and directed it to either approve a revised, compliant SIP within two years or formulate new standards. The agency is reviewing the decision.

More: *Pittsburgh Post-Gazette*

PUC Leaves Shutoff Moratorium in Place

The Public Utility Commission last week effectively extended a moratorium preventing utilities from terminating service to nonpaying customers for three more weeks.

The four-member panel of two Democrats and two Republicans postponed a vote until Sept. 17 after deadlocking twice on motions to lift the moratorium over the summer.

In letters to the PUC, Gov. Tom Wolf, Attorney General Josh Shapiro and Philadelphia Mayor Jim Kenney asked the commission to keep the moratorium in place. The Energy Association of Pennsylvania asked the commission to end the moratorium this month, as its member utilities reported that residential customers owed $404 million through June 30.

More: *The Associated Press*

UTAH

Logan Opts out of Planned Nuclear Power Project

The city of Logan last week withdrew from the "next-generation" nuclear power plant planned at the Idaho National Laboratory over cost concerns. Fellow city Lehi agreed to do the same later in the week.

A change in funding by the U.S. Department of Energy for the Carbon Free Power Project caused Logan Finance Director Richard Anderson and Light and Power Director Mark Montgomery concern. It prompted both to recommend Logan withdraw its participation from the project. The city had already invested $400,000 and was due to commit another $654,000 by Sept. 14. Instead it chose to bow out.

Critics say the proposed 720-MW plant is too risky and ratepayers should not be footing the bill for technology they say is not yet proven.

More: *Deseret News*; *Daily Herald*

VIRGINIA

Fredericksburg Eyeing Cheaper Rooftop Solar

The Climate, Environment and Resiliency (CLEAR) group last week announced it is partnering with the Virginia Local Energy Alliance Program to conduct a "Solarize" community bulk-purchasing campaign for rooftop solar panels and installation through mid-October.

Anne Little, founder and executive director of Tree Fredericksburg, said the campaign doesn't have prices yet but expects the average will be $2,500 to $2,600/kW and the payback will take nine to 12 years.

CLEAR has put out a request for proposal for solar contractors. The one chosen for the campaign will do energy efficiency audits and upgrades before installing solar panels on participants' roofs.

More: *The Free Lance-Star*

SCC Renews Disconnection Ban

The State Corporation Commission last week announced it will extend the state's existing moratorium on utility disconnections through Sept. 15. However, the SCC said it does not intend to extend the moratorium any further unless ordered to do so by the General Assembly.

"This period of time has been sufficient to provide an opportunity for the General Assembly to choose whether to address legislatively the effects of the COVID-19 crisis on utility customers and utilities," the commission said.

Democrats in both chambers of the statehouse have proposed a law that would require all utilities to develop an "Emergency Debt Repayment Plan" for residential customers to ensure that user costs remain "sustainable and affordable." The proposal would allow customers up to 24 months to make repayments and cap minimum monthly debt payments at either $45.50 or 4% of household income.

More: *Virginia Mercury*

WEST VIRGINIA

Justice Questions Need for New Power Plant

Gov. **Jim Justice** last week questioned the need for the proposed 830-MW Brooke County ESC natural gas plant and said the Department of Commerce still needed some questions answered.

Some of the other questions Justice had were about the plant's loan guarantee request, where the gas would come from and how many jobs the plant would create.

According to the company's application with the Public Service Commission, it expects 75% of the construction jobs to come from state workers.

More: *The Weirton Daily Times*

WYOMING

Lawmakers Resurrect Renewables Tax Discussion

Lawmakers last week restarted a conversation centered around an increased electricity tax levied on companies that generate renewable energy. There is no specific proposal or bill on the table. Members of the Legislature's Joint Revenue Committee last week conversed with Montana lawmakers in a comparative study of the neighboring state's electricity taxes. They also listened to extensive public comment from industry representatives and Wyoming residents.

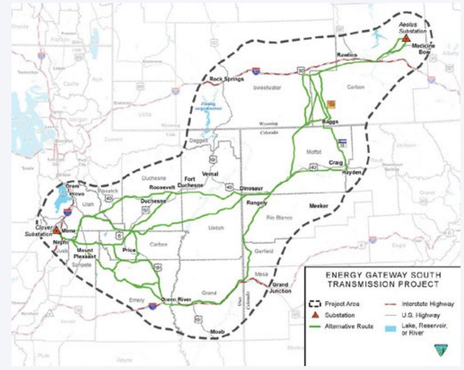
Lawmakers instituted the state's $1/MWh wind generation tax in 2012. Since then, the committee has repeatedly brought up the possibility of boosting the tax, but none of the attempts have been successful.

More: *Casper Star-Tribune*

Rocky Mountain Power Moves Ahead with Gateway South

Rocky Mountain Power last week said it submitted an application for approval with the Public Service Commission for a 142-mile segment of the Gateway South transmission line. It also applied to rebuild and expand about 120 miles of its Gateway West transmission line.

RMP's latest integrated resource plan, pub-



lished in October 2019, announced plans to invest heavily in expanding transmission lines.

The goal is to launch into construction by Aug. 1, 2021, and finish the projects by Dec. 31, 2023.

More: *Casper Star-Tribune*