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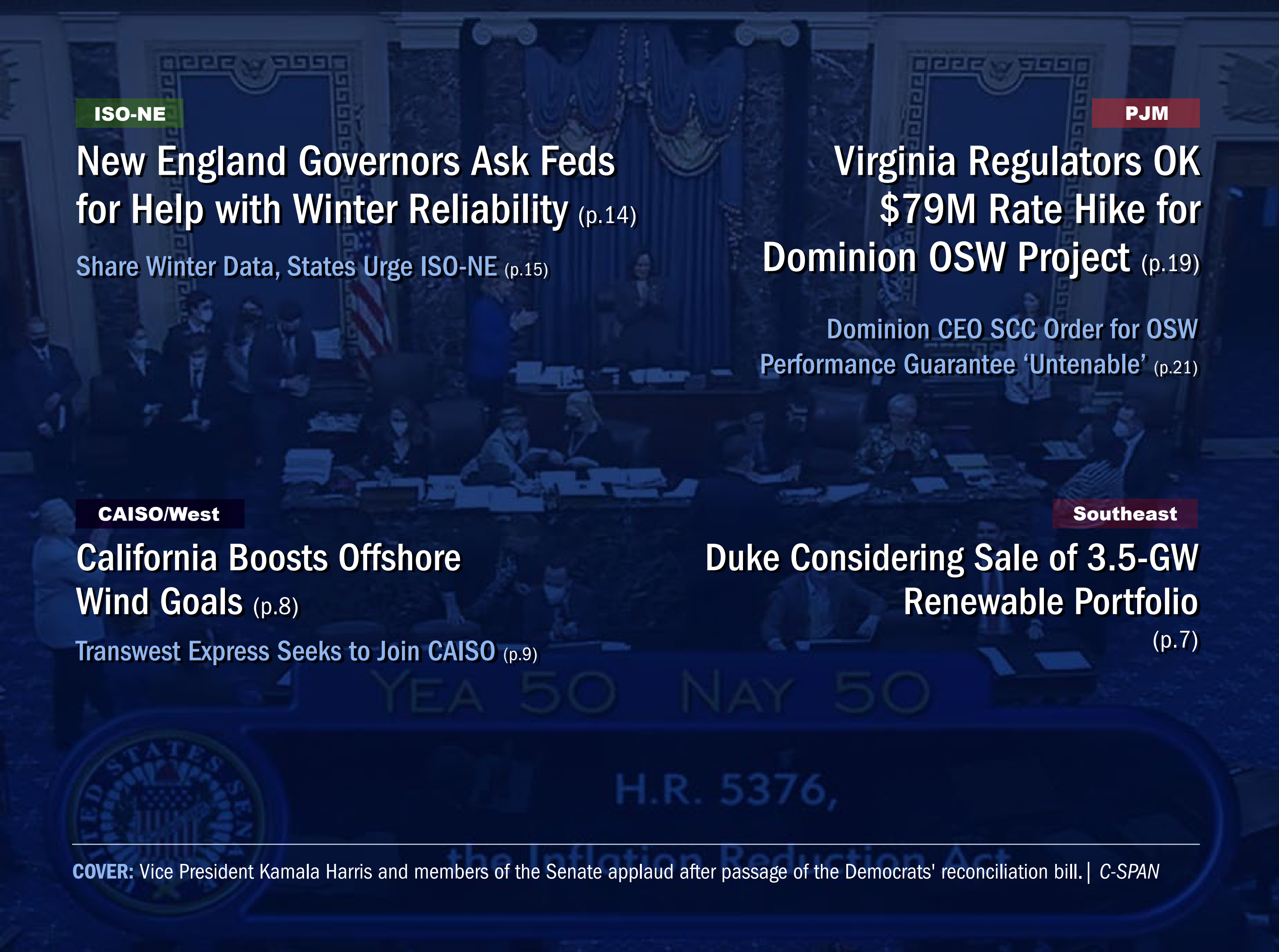

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In this week's issue

Counterflow

By Steve Huntoon

45Q: Money for Nothing

By Steve Huntoon

| International Energy Agency

Binge watching the earlier Star Trek series (highly recommended), there is this enigmatic, fantastically powerful entity, Q. Now it seems that the Manchin-Schumer package is going to create an enigmatic, fantastically powerful Q for the Internal Revenue Code.

Up until now this section 45Q has been a limited source of tax credits for carbon capture projects. BTW, 87% of the tax credit claims didn't comply with IRS requirements.[1] As for direct grant subsidies for carbon capture, GAO recently reported that DOE spent $684 million in taxpayer money for six carbon capture coal projects of which *zero* are operating.[2]

Under Manchin-Schumer the 45Q spigot will be opened wide with taxpayers on the hook for carbon capture at power plants and elsewhere at a cost of $85/ton, and for direct carbon capture at a cost of $180/ton.[3]

Why would taxpayers want to:

- pay twice the cost for one type of carbon capture versus another?[4]
- pay a multiple of the tax credit cost of emission reductions from wind and solar generation of about $32/ton?[5]
- pay many multiples the cost of carbon offset credits that range from $7-$22/ton?[6]
- pay an even bigger multiple of the cost of emission reductions from LED lighting of $5/ton?[7]

Money — both public and private — is inherently limited for any and all purposes. Not

Counterflow

By Steve Huntoon

spending efficiently inherently undermines the task at hand.[8]

The 45Q Cost Is Likely to Be Ginormous, Contrary to Congressional Claims

The Joint Committee on Taxation and the Congressional Research Service claim that new 45Q is going to cost U.S. taxpayers an average of $323 million per year over the next 10 years.[9]

That seems fanciful.

45Q supporters say they want to stop the massive shift from coal to natural gas and renewables,[10] the shift that is responsible for enormous reductions in carbon emissions.[11]

These supporters presumably know what they need, and they lobbied for the $85/ton level. And won. The Carbon Capture Coalition says: "The bill includes all of the Carbon Capture Coalition's top legislative priorities for the 117th Congress."[12]

This Coalition goes on to say that the bill could deliver 210-250 million tons of annual emission reductions.[13] So at $85/ton that would be about $20 billion per year.

Princeton's ZERO Lab projects this level of annual emission reductions is reached in 2031, increasing rapidly to 450 million tons by 2035,[14] when the annual cost would be about $40 billion per year.

So let's call it about $30 billion per year, and contrast that with the Joint Committee on Taxation/CRS claim of $323 million per year. Congress is understating taxpayers' cost of new 45Q by a factor of about 100. A mere bagatelle.

One More Thing

There's another problem with the credit to the extent it succeeds in heading off coal retirements that would otherwise occur. That's because coal plants *with* carbon capture still emit about as much carbon as new gas plants *without* carbon capture.[15] So in those instances taxpayers would be paying an enormous subsidy for nothing.

Of course new (and existing) gas plants could install carbon capture. But the incentive is relatively small because (ironically) there's so much less carbon to capture. New gas plants also will have to confront the prospect of low energy prices when so much other generation — wind, solar and now coal — will have low if not negative marginal costs.

My head hurts.

P.S. This discussion of 45Q isn't intended to imply that the bill overall isn't better than nothing, especially since the alternative might be nothing for a long time. But taxpayers deserve better when it comes to provisions like this one. ■

[1] https://www.menendez.senate.gov/imo/media/doc/TIGTA%20IRC%2045Q%20Response%20Letter%20FINAL%2004-15-2020.pdf.

[2] https://www.gao.gov/assets/gao-22-105111.pdf, Table 1 on page 7. This table shows the Petra Nova project as operating, but as reported by GAO it was suspended in May 2020 and has not resumed operations. So DOE funding is 0 for 6. The GAO report reveals shocking mismanagement of taxpayer dollars by DOE.

[3] https://carboncapturecoalition.org/inflation-reduction-act-of-2022-makes-monumental-enhancements-to-the-foundational-45q-tax-credit/

[4] The Carbon Capture Coalition advocated these levels based on the relative costs of the two carbon capture technologies, https://carboncapturecoalition.org/wp-content/uploads/2021/09/Proposed-AJP-and-Infrastructure-Investments-1.pdf. This doesn't make sense: Why pay twice as much to subsidize one technology just because it costs twice as much?

[5] https://www.catf.us/wp-content/uploads/2017/12/CATF_FactSheet_Cost_of_CO2_Avoided.pdf, adjusting the $48.76/ton value, based on a PTC of $23/MWh, for the current/future PTC of $15/MWh.

[6] https://www.projectfinance.law/publications/2022/february/carbon-offsets-as-a-potential-source-of-revenue/

[7] The average light bulb in the U.S. is on 1.6 hours per day averaging 47.7 watts, which is 27.86 kwh/year. https://www1.eere.energy.gov/buildings/publications/pdfs/ssl/2012_residential-lighting-study.pdf. LED bulbs use 84% less electricity, cost about $2.50 each, and last 25,000 hours or more, for a lifetime of 42.8 years at 1.6 hours/day. Incandescent bulbs over a collective lifetime of 42.8 years would use a total of 1,192 kwh, which reduced by 84% is a savings of 1,001 kwh, which is 1 MWh. Reduced electric use reduces carbon emissions at 0.47 tons/MWh, https://www.catf.us/wp-content/uploads/2017/12/CATF_FactSheet_Cost_of_CO2_Avoided.pdf, so reducing emissions by 1 MWh at a cost of $2.50/bulb costs $5.30/ton.

[8] One example I've discussed before is offshore v. onshore wind where the former takes 11 times the subsidy for a given MWh of generation, which means we can get on average 11 times more onshore wind from a given dollar of subsidy. https://energy-counsel.com/docs/Offshore-Wind-Edifice-Complex.pdf. Ditto rooftop v. grid solar.

[9] Joint Committee on Taxation, https://www.finance.senate.gov/imo/media/doc/7.29.22%20Estimate%20of%20Manchin%20Schumer%20agreement.pdf, Title I, Subtitle D, Part 1, line 4, the total for years 2022-2031 divided by 10; adopted by the Congressional Research Service, https://crsreports.congress.gov/product/pdf/R/R47202, Table 5.

[10] https://www.eenews.net/articles/big-payout-more-co2-greens-split-over-dems-ccs-plan/, quoting the head of the Wyoming Mining Association: "From the industry standpoint, we see it as necessary to keep coal viable going forward."

[11] Gas plants displacing coal plants are responsible for 90% of the carbon emission reductions in PJM. https://www.energy-counsel.com/docs/NRDC-Prescribes-More-Carbon-Emissions.pdf. Also, https://www.energy-counsel.com/docs/we-see-through-a-glass-darkly.pdf.

[12] https://carboncapturecoalition.org/inflation-reduction-act-of-2022-makes-monumental-enhancements-to-the-foundational-45q-tax-credit/

[13] Id.

[14] https://repeatproject.org/docs/REPEAT_IRA_Prelminary_Report_2022-08-04.pdf, slide 13.

[15] A study of Wyoming coal plants says that coal plant emissions after carbon capture would be 0.29 kg/kwh, https://pubs.acs.org/doi/pdf/10.1021/acs.est.1c08837, page 9876, which converts to 650 lbs/MWh. EPA data on new gas plants shows average carbon emissions of 777 lbs/MWh, https://www.epa.gov/system/files/documents/2022-01/egrid2020_data.xlsx, PLNT2016 tab, column PLCO2RTA, for sample plants Riviera Beach, Colorado Bend II and Cape Canaveral.

FERC/Federal News

Senate Passes Inflation Reduction Act

Republicans Win Tax and Health Changes, but Clean Energy Provisions Remain Intact

By K Kaufmann

Following a marathon overnight session of debate and amendments, the U.S. Senate on Sunday passed the Inflation Reduction Act with all of its $369.75 billion in clean energy spending intact.

Under special budget reconciliation rules that allowed passage with a simple majority, the bill was approved on a 50-50 party-line vote with Vice President Kamala Harris providing the tie-breaking vote that will now send the bill to the House of Representatives.

Speaking before the vote, Senate Majority Leader Chuck Schumer (D-N.Y.) called the bill "one of the defining legislative feats of the 21st century" and "the boldest climate package in U.S. history. This bill will kickstart the era of affordable clean energy in America. It's a game changer."

"Senate Democrats sided with American families over special interests," President Biden said in his statement hailing the IRA vote. "This bill … makes the largest investment ever in combating the existential crisis of climate change."

House Speaker Nancy Pelosi (D-Calif.) promised "the House will return and move swiftly to send this bill to the president's desk."

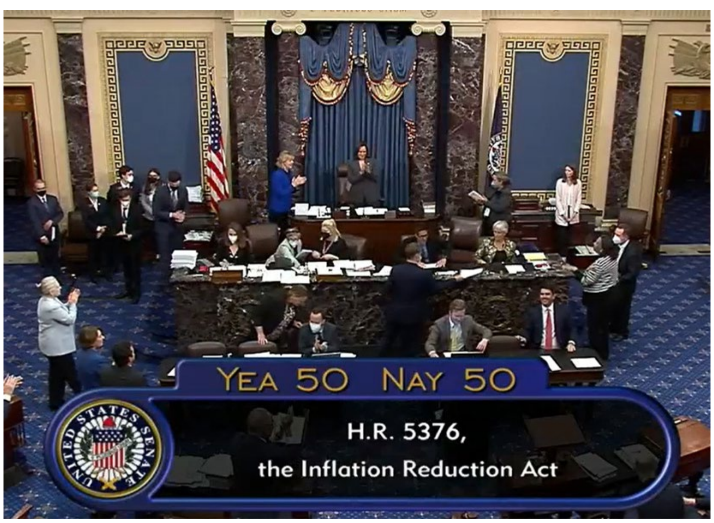
Getting to the Sunday afternoon vote has taken close to a year, beginning with Democrats' $2.2 trillion Build Back Better Act originally introduced in September 2021. Sen. Joe Manchin (D-W.Va.) walked away from negotiations on trimming the bill's price tag twice, once in December and again earlier in July.

But Schumer and Manchin hammered out the renamed IRA, with tax reform, health care and clean energy measures, behind closed doors last month, framing it as an inflation fighter that would reduce health care and energy costs for American families and cut the federal deficit by more than $300 billion. (See *Schumer, Manchin Reach Climate Deal*.)

In a Twitter thread following the vote, Manchin praised passage of the bill as the result of years of cross-aisle efforts to "determine the most effective way to increase domestic energy production, lower energy and health care costs, and pay down our national debt without raising costs for working Americans."

Still, with a 50-50 split in the Senate, Schumer and Manchin had to negotiate further concessions to ensure the critical vote of Sen. Krysten Sinema (D-Ariz.). Sinema was successful in removing language from the bill that would have closed a tax loophole on the profits of high-income hedge fund investors and asset managers.

Republicans also forced two last-minute changes to the bill during the 13-hour "vote-a-rama," that began late Saturday night and ended just after 3 p.m. Sunday. Part of the budget reconciliation process, the rules allow an unlimited number of amendments to be considered before a final vote on the bill.



Vice President Kamala Harris and members of the Senate applaud after passage of the Democrats' reconciliation bill | *C-SPAN*

The amendments offered by GOP senators during this time were often unrelated to the bill and were mostly voted down. However, the Republicans were able to remove a $35/month cap on insulin payments for consumers with private insurance, while retaining the cap for consumers on Medicare.

They also pushed through a further change on the bill's 15% corporate minimum income tax, exempting companies owned by private equity from the provision.

'An Arsenal of Clean Energy'

However, Republican attempts to change the bill's energy provisions were universally voted down.

For example, Sen. John Barrasso (R-Wyo.), ranking member of the Senate Energy and Natural Resources Committee, offered an amendment that would have required the Department of Interior to hold additional sales of onshore oil and gas leases on public land by the end of 2022.

Similarly, an amendment from Sen. John Kennedy (R-La.) would have required the sale of offshore oil and gas leases, while Sen. Richard Shelby (R-Ala.) proposed requiring new coal leases.

"The Democrats' war on American energy continued today," Barrasso said in a statement following passage of the IRA. "While jamming through their reckless tax and spending spree, Democrats voted against common-sense Republican proposals."

Clean energy advocates were quick to applaud the bill's passage and its clean energy incentives, ranging from various tax credits to incentives for big transmission projects and for consumers purchasing electric vehicles.

"Rising inflation and global instability have put America's energy security in jeopardy," said Nat Kreamer, CEO of Advanced Energy Economy. "A federal clean energy investment of this magnitude is our best defense."

Key clean energy provisions in the bill include extensions of the solar investment tax credit and wind production tax credit, through the end of 2024, to be followed by technology-neutral clean-energy credits that will provide incentives for renewables, nuclear and green hydrogen.

Tax credits for electric vehicles, both new and used, are also part of the package, with EVs costing less than $55,000 eligible for a $7,500 credit and used EVs costing less than $25,000 getting a $4,000 credit. Incentives for transmission include $2 billion in direct loans for construction and modification of transmission deemed in the national interest and $760 million in grants for permitting and siting and for economic development in communities with transmission builds. ■

FERC/Federal News

DOE to Provide $26M for Renewable Energy Projects

Program to Demonstrate How New Tech Can Meet Admin's Carbon Targets

By Holden Mann

President Biden signs the bipartisan Infrastructure Investment and Jobs Act in Nov. 2021 | *C-SPAN*

The Biden administration announced last week that it will make $26 million available for projects to demonstrate that renewable energy and distributed energy resources can reliably power the U.S. electric grid.

The investment is part of the Department of Energy's Solar and Wind Grid Services and Reliability Demonstration Program, created under the bipartisan Infrastructure Investment and Jobs Act that President Biden signed into law last November. (See *Biden Signs $1.2 Trillion Infrastructure Bill*.)

According to a press release Aug. 2, the program is intended to "show how clean energy resources can address key reliability challenges facing the grid [with] tools and plant functions that allow the grid to stay online amid disturbances and restart if it goes down."

"Americans do not have to choose between a clean grid and a reliable one as we move forward towards our goals of a net-zero economy by 2050," Energy Secretary Jennifer Granholm said in the release. "Thanks to funding from [the] infrastructure law, DOE is proving that transitioning to solar, wind and other renewable energy sources can keep the lights on without service interruptions while creating good paying jobs."

Distribution of the funds will be handled by DOE's *Solar Energy Technologies Office (SETO)* and *Wind Energy Technologies Office (WETO)*, the department said in a *funding notice* Aug. 2.

The program will focus on two key areas.

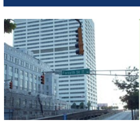
First is design, implementation and demonstration of wind and solar grid services, with $3 million to $6 million each earmarked for three to five recipients. For this category, the program will seek projects that produce at least 10 MW with solar, wind and storage and conduct long-duration demonstrations at existing facilities of their ability to provide grid services at scale. Organizers encouraged applicants to "develop centralized and/or autonomous local controls that demonstrate" the facilities' ability to react to "operational commands and schedules in the existing … grid."

The second topic is protection of bulk power systems with high contributions from inverter-based resources (IBR), planned for three or four projects at $2 million to $3 million each. This category is intended to promote large-scale studies of transmission protection systems with large amounts of IBRs, focusing on their response to faults. Recipients should be able to demonstrate protection modeling and simulation capabilities, along with technologies and strategies for maintaining reliability with "any level of inverter-based generation."

Applicants are expected to include a range of BPS stakeholders, such as utilities, laboratories, universities, vendors of hardware and software, and engineering firms, with preference given to applications from teams of multiple institutions rather than a single organization. The department also encouraged teams to cultivate diverse backgrounds, for instance by partnering with historically Black colleges and universities or other organizations focused on minorities. SETO and WETO will provide a forum for interested parties to connect with each other.

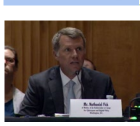
An informational webinar on the initiative is planned for Aug. 17. Concept papers are due by 5 p.m. ET on Sept. 1. ■

National/Federal news from our other channels



Biden Initiative Aims to Up Federal Use of Performance Contracts — NetZero Insider

States File Plans on Deadline for Federal EV Charging Funds — NetZero Insider



Cyber Ambassador Nominee Says US Leadership Needed — ERO Insider

RTO Insider subscribers have access to two stories each monthly from *NetZero* and *ERO Insider*.

Southeast

Duke Considering Sale of 3.5-GW Renewable Portfolio

Company Seeks Focus on Regulated Operations

By Rich Heidorn Jr.

Duke Energy put a "for sale" sign on its 3.5-GW commercial renewable business Thursday, saying it wants to focus its capital on regulated spending.

The company has about 5.1 GW of wind and solar in operation, with net ownership of 3.5 GW and a book value estimated at $4 billion. That puts Duke among the top 10 wind and solar operators in the U.S. and has helped it gain experience in renewable energy development and operations that it will rely on in the future.

But the unit represents less than 5% of the company's profits, generating $46 million in adjusted earnings for the second quarter.

Duke Energy's commercial renewables business owns a net 3.5 GW of generation, putting it among the top 10 wind and solar operators in the U.S. | *Duke Energy*

Competition for Capital

"As we look forward to the remainder of this decade and beyond, we have line of sight to significant renewable grid and other investment opportunities within our faster growing regulated operations," CEO Lynn Good said during the company's second-quarter earnings call. "We believe this is the right time to step back and really look at the strategic fit of the commercial business, because there's going to be competition for capital at Duke."

The company is projecting an adjusted per-share growth rate of 5 to 7% through 2026.

The renewable business includes a pipeline of 1 to 1.5 GW "that could be quite valuable in 2024-2025, in addition to what we had planned for 2023," Good said.

The company expects to conclude its review by the end of 2022 or early 2023. Sale proceeds would be used to avoid debt and postpone the need for raising equity, Good said.

NC Carbon Plan

The company will need capital, in part, to fund the new solar, battery storage, onshore wind and "hydrogen-capable" natural gas the company wants to add as part of the proposed *carbon plan* it filed with the North Carolina Utilities Commission on May 16. The plan also seeks permission to begin early development of long lead-time resources needed in the early 2030s, including offshore wind, pumped storage and small modular nuclear reactors (SMRs).

Good said Duke is working on SMRs "in an advisory capacity" by lending its operating expertise. The company operates the largest regulated nuclear fleet in the U.S., producing about half of its power in the Carolinas.

"We do not have an intention of being Version 1 of anything," she said. "We would like to see a broader adoption of the technologies, a broader understanding of not only operating characteristics, but the commercial attributes — a price — and the ability to construct them within a time frame that we're comfortable with. And so we see the decade of the 2020s as an important one to continue that work. And if it progresses, as we all hope it does, we would be in a position to potentially invest in one to come into service in the early 2030s."

Good indicated that neither supply chain problems in the solar industry nor rising natural gas prices have led the company to rethink its coal retirement plans. "Frankly … the logistics of getting coal from point A to point B are also a challenge," she said, citing labor shortages in railroads and mining companies.

Inflation Reduction Act, Load Trends

Good said the U.S. Senate's proposed Inflation Reduction Act would benefit the commercial renewables business and save customers money through the nuclear production tax credit. "We will be impacted by the [15%] corporate minimum tax, but we will also benefit from the credits which will pass to our customers," Good said.

Duke said it expects its 2022 load growth to be above its initial projection of 1.5%. But CFO Steve Young said the company is continuing to project minimal load growth over its five-year planning horizon as it balances the impact of electrification against energy efficiency.

Good said that while the company is basing its spending on assumptions of little additional load growth, migration trends in the Southeast give it "some tailwinds on growth that I think we'll enjoy for a period of time."

"But we continue to believe that flat to 0.5% is the best way to manage the business and always hope to be surprised to the upside," she added.

Q2 Results

Duke *reported* GAAP second-quarter earnings of $893 million ($1.14/share) versus $751 million ($0.96/share) in 2021. Adjusted earnings were identical to GAAP results for 2022, a drop from $898 million ($1.15/share) for 2021.

Lower 2022 adjusted earnings resulted from higher operations and maintenance expenses from plant outage timing, higher interest costs and the impact of Singapore-based GIC's 2021 *purchase* of 11.05% of Duke Energy Indiana. ■

CAISO/West News

California Boosts Offshore Wind Goals

By Hudson Sangree

The California Energy Commission released an updated draft report last week that would greatly increase the state's offshore wind goals to 25 GW by 2045, potentially doubling anticipated long-term capacity in response to urging by stakeholders and Gov. Gavin Newsom.

The *draft report* proposing the targets stemmed from last year's *Assembly Bill 525*, which required the CEC to "evaluate and quantify the maximum feasible capacity of offshore wind … [and to] establish megawatt offshore wind planning goals for 2030 and 2045." The effort is intended to contribute to the state's goal under Senate Bill 100 to supply all retail customers with 100% clean energy by 2045.

A prior draft of the report in May proposed goals of 3 GW by 2030 and 10 to 15 GW by 2045, but critics contended those goals were too conservative, and the CEC re-evaluated its estimates.

In its latest draft report, published Aug. 1, the commission considered stakeholder comments and a July 22 *letter* from Newsom to the chair of the California Air Resources Board in which he urged "bolder action" to address the urgency of climate change.

"In the letter, among other requested actions, the governor asks the CEC to establish an offshore wind planning goal of at least 20 GW by 2045 and to work with the state's federal partners to accelerate the deployment of offshore wind, noting that California is home to one of the best offshore wind resources in the world and that offshore wind can serve as a clean, domestic source of electricity that can play an important role in meeting the state's growing need for clean energy," the draft report said. "The Energy Commission factored this climate urgency and the call for at least a 20-GW goal into these proposed revisions."

Soon after the CEC released its first draft report in May, the federal Bureau of Ocean Energy Management issued a *proposed sale notice* for five lease areas off the California coast, a major step toward BOEM auctions expected this fall and the eventual development of the first offshore wind farms on the West Coast.

Two of the proposed lease areas in the proposed sale notice are in the Humboldt Wind Energy Area off the coast of Northern California, near the city of Eureka. Three are in the Morro Bay Wind Energy Area off Central California, about halfway between Los Angeles and San Francisco. Together, the wind energy areas (WEAs) cover 583 square miles and have the potential to generate at least 4.5 GW of electricity, enough to power 1.5 million homes.

In raising its 2030 offshore wind goals to 3 to 5 GW, the CEC said the "upper end of this range could come from a full build-out of the Morro Bay Wind Energy Area or a combination of a partial build-out of the Morro Bay WEA and Humboldt WEA," which will require development of a wind port in Humboldt Bay.

"The lower end of that range reflects an understanding that achieving a 2030 online date for any proposed offshore wind project will take a significant mobilization of effort and resources, and timely infrastructure investments, among other factors," it said. "The CEC will work with state and federal partners to identify process steps and milestones that could allow for a 2030 online date for California's first offshore wind projects."

The higher 2045 targets "are designed to be potentially achievable but aspirational and are established at levels that can contribute significantly to achieving California's climate goals," the report said.

"These preliminary planning goals may be refined as part of completing the strategic plan as more information becomes available from the analysis of suitable sea space and potential impacts on coastal resources, fisheries, Native American and Indigenous people, and national defense, as well as other strategic plan topics," it said.

The CEC is scheduled to vote on the revised goals in its business meeting Wednesday.

Proponents praised the higher targets.

"These goals set an ambitious course and show California is very serious about 'going big' on floating offshore wind to strengthen and diversify its clean power portfolio," Adam Stern, executive director of trade group Offshore Wind California, said in a statement. "We're determined as an industry to work closely with state and federal agencies and other stakeholders to ensure the high end of these goals becomes a reality." ■

Floating wind turbines off the California coast could surpass current installations in Europe, measuring up to 900 feet tall and generating 15 GW each. | *Principal Power*

CAISO/West News

TransWest Express Seeks to Join CAISO

New Transmission Owner Model, Fast Process Raise Concerns

By Hudson Sangree

The developers of a transmission line intended to carry Wyoming wind power to California have asked to join CAISO, a move that could extend the ISO's reach more than 700 miles across the West and help the state meet its 100% clean energy mandate by 2045.

But the ISO's plan to adopt a new participating transmission owner (PTO) model for the line and others like it has raised concerns.

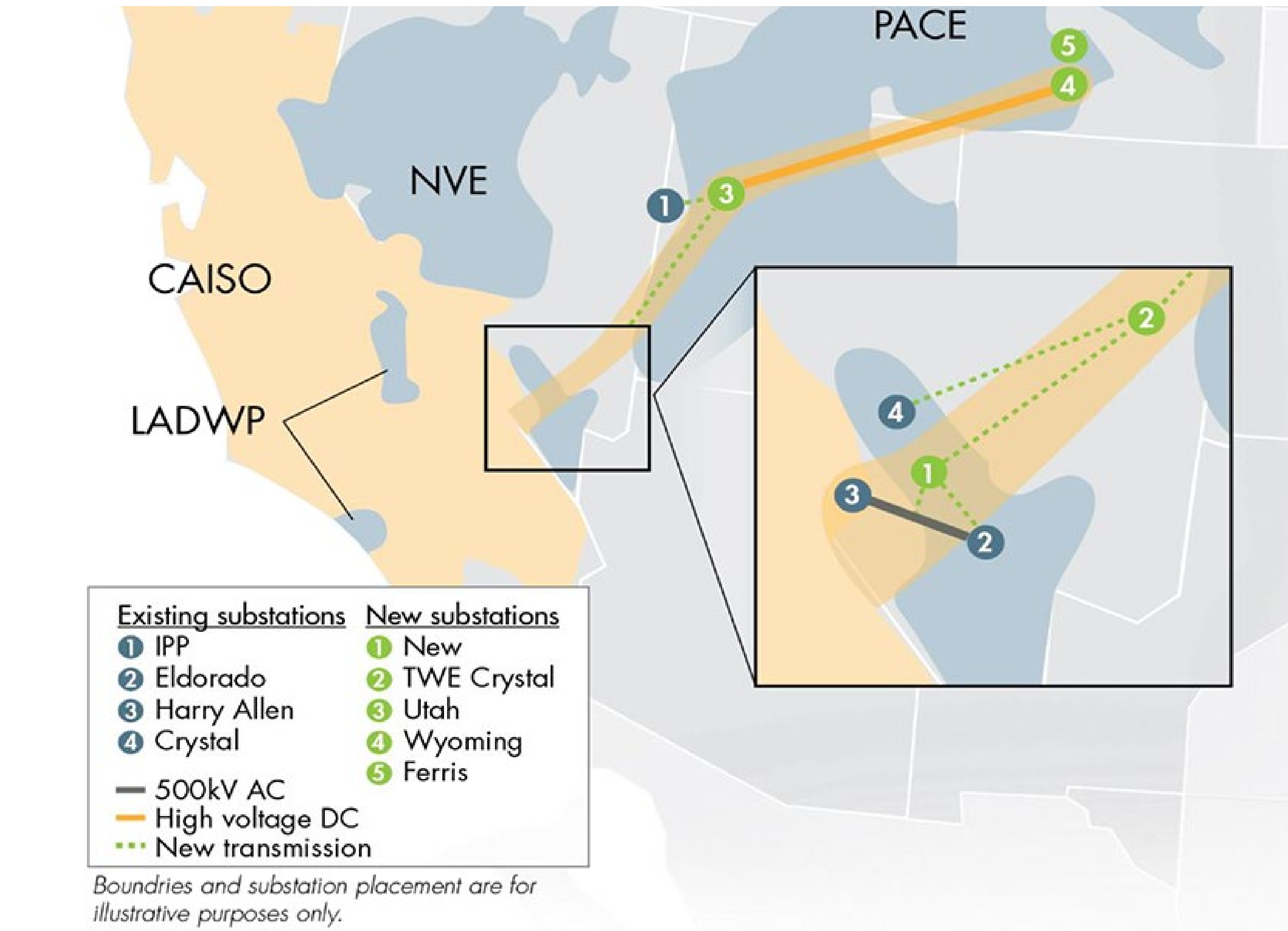
The planned TransWest Express line "intends to place under the CAISO's operational control all of [its] project transmission lines and associated facilities … that will connect to the existing bulk power system in Wyoming and Utah as well as directly to the [CAISO]-controlled grid in Nevada," the company said in its *application* to become a PTO.

TransWest would consist of 732 miles of transmission lines in three linked segments: a 405-mile, 3,000-MW HVDC system between Wyoming and Utah; a 278-mile, 1,500-MW HVAC line between Utah and Nevada; and a 49-mile, 1,500-MW HVAC transmission line in Nevada. It will connect in Utah to lines serving the Los Angeles Department of Water and Power (LADWP) and in Nevada to CAISO's grid and balancing authority area.

The project is an "advanced stage of development, focused on pre-construction matters including tower design and testing; interconnections; contracting with engineering, procurement and construction contractors; and financing," the application says. "All major permits have been acquired, and 100% of the easements/authorizations to build on private lands have been secured." Major parts of the project could be in service by 2026, it says.

Subscriber Model

TransWest would be CAISO's first subscriber participating transmission owner (SPTO), a new model that would give the ISO operational control of the lines without increasing its transmission access charge (TAC), currently more than $16/MWh.



Adding Transwest Express as a transmission owner would expand CAISO's balancing authority area 600 miles across the West. | *CAISO*

CAISO/West News

Last year, TransWest conducted a FERC-approved open-solicitation process that offered firm, long-term transmission service to California via Utah and Nevada. It decided to allocate 100% of its capacity to Power Company of Wyoming, owner of a 3,000-MW wind farm in the south-central part of the state. FERC approved the arrangement in February.

Both TransWest and Power Company are wholly owned affiliates of The Anschutz Corp., a privately held company based in Denver controlled by billionaire Phillip Anschutz, a conservative who made much of his fortune from oil and natural gas. Anschutz has sought to profit from California's clean-energy mandate under Senate Bill 100.

To meet the 2045 goal, the state will need to import as much as 10 GW of out-of-state wind by 2040, at least half of it from Wyoming, according to projections by the California Public Utilities Commission and the California Energy Commission.

CAISO's recent 20-year transmission outlook examined new transmission needed for the undertaking, predicting overall costs of $30 billion that includes $12 billion to carry wind from the Great Plains and Rocky Mountain states. (See *CAISO Sees $30B Need for Tx Development*.)

Stakeholder Meeting

In an Aug. 1 presentation and stakeholder question-and-answer *session*, Deb Le Vine, CAISO director of infrastructure contracts and management, described the TransWest project and how the new SPTO model would work.

"In trying to implement a new type of participating TO, there are a number of things to consider," Le Vine said. "The intent was to go ahead and come up with a model that allows a remote transmission facility to become part of the ISO grid but to have subscribers that would pay for the transmission."

Most of the transmission capacity for TransWest is subscribed in at least one direction and would not rely on ISO for funding, Le Vine said in her *presentation*.

Subscriber rights to the line will be treated as encumbrances, similar to existing contracts on transmission lines joining CAISO, she said. An SPTO could recover incremental charges from CAISO market participants using the lines, for instance, if non-subscribers send capacity from south to north on TransWest, she said.

"We're looking to go ahead and support this concept by an amendment to [CAISO's] Transmission Control Agreement" (TCA) without tariff changes, she said.

Need More Info?

Some stakeholders felt CAISO needed to provide more information that spells out the details of how the new subscriber model would work and to engage in a stakeholder process, making tariff changes.

Chris Devon, director of market intelligence in the West for advisory firm Customized Energy Solutions and a former CAISO senior policy developer, asked De Vine if the subscriber model would be detailed in a paper or only through slide decks like the one that she used in her presentation.

De Vine said it would be presented through slide decks because the new model does not require changes to CAISO's tariff, only to its TCA.

Devon said he thought the changes should be vetted in a stakeholder process and made through tariff changes, not through the TCA. He expressed concern with CAISO using an abbreviated process to adopt a complex, untested TO model that diverges from current market practices.

The subscriber model resembles processes being discussed in the ISO's transmission service and market scheduling priorities stakeholder initiative, Devon said. That *initiative* is meant to develop a "long-term, holistic framework for establishing scheduling priorities," the ISO says.

The new model could impact the CAISO market and stakeholders, Devon said. "It just seems to me like this is actually creating a new type of policy as opposed to just being something that should be done through this change to the TCA, so I think it should be stakeholder-ed."

The subscriber model's potential costs to ratepayers remains unclear.

Asked to comment, the CPUC, which has been trying to control rising ratepayer bills for the state's increasingly expensive electric system, said in an email that it is "actively participating on behalf of ratepayers in the CAISO's stakeholder processes related to the newly proposed subscriber participating transmission owner model concept related to TransWest Express."

"As such, we are unable to provide a specific comment on the TransWest Express transmission line at this time as we continue to develop our analysis."

Comments on the Aug. 1 presentation are due Aug. 15. Stakeholders have until Sept. 19 to comment on the TransWest application. ■

West news from our other channels

Judge Rejects BLM Coal Plans for Omitting Health Impacts

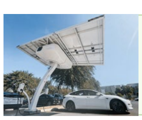
NetZero Insider

CPUC Adopts Submetering for EV Charging

NetZero Insider

Opening of Wash. Green Hydrogen Plant Delayed to Mid-2023

NetZero Insider



West Coast NEVI Plans to Charge Up I-5 … and Beyond

NetZero Insider

RTO Insider subscribers have access to two stories each monthly from *NetZero* and *ERO Insider*.

ERCOT News

CenterPoint Takes the Heat, Raises Earning Guidance

Texas Utility's Performance During Summer Boosts Execs' Confidence

Texas' record-breaking heat through June boosted CenterPoint Energy's second-quarter earnings and led its management to again raise its earning guidance.

The Houston-based utility *reported* quarterly earnings of $179 million ($0.28/diluted share) as compared to $221 million ($0.37/diluted share) in the same quarter last year, driven primarily by favorable weather and continued customer growth in its Houston Electric footprint.

CEO David Lesar said the performance of its transmission and distribution company gave CenterPoint the confidence to raise its 2022 earnings guidance from $1.37/share to $1.39, a 9% increase and the fifth time in two years his team has done so.

"We are setting a new and higher baseline for future earnings growth," he said in a statement.

Lesar told financial analysts that Houston Electric accounts for only about 2.5% of ERCOT's service territory but about 20% of its delivered energy. CenterPoint continues to see about 2% organic customer growth in Houston, which will be important as electric vehicle ownership and electrification increase.

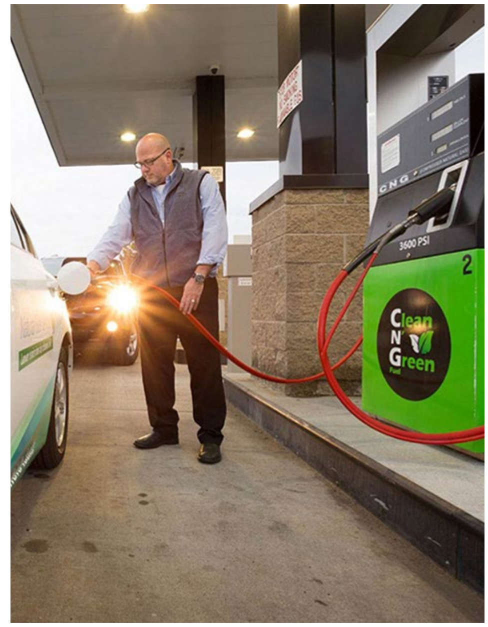
"Consistently hot" temperatures that have reached as high as 105 degrees Fahrenheit in the nation's fourth largest city have stressed the grid, but it has "held up well," Lesar said.

CFO Jason Wells said CenterPoint will recover about 80% of its $1.1 billion in incremental gas costs from the February 2021 winter storm when the state's securitization process begins to distribute funds.

The company's non-GAAP earnings came in at 31 cents/share, up 11% from the comparable quarter in 2021. That beat Zacks' consensus estimate of 31 cents/share.

CenterPoint shares were trading at $31.70 in the after-hours market, up 7 cents for the day. ■

— Tom Kleckner



CenterPoint's tailwinds include EVs and electrification in Houston. | *© RTO Insider LLC*

ERCOT Briefs

Grid Operator has Set 38 Records this Summer — so Far

Records are meant to be broken, as the saying goes.

Just ask the folks at ERCOT, which has set 38 peak-demand records since May for all-time, monthly and weekend highs. The grid operator's all-time peak has been broken 11 times, and it has exceeded the previous 74.8-GW record that dated back to 2019 on 33 days since June 12, as 100-degree Fahrenheit temperatures in Texas have become the norm.

ERCOT's all-time record for average hourly demand now stands at 79.8 GW. The grid operator predicted in May that demand would peak at 77.3 GW during August. The Texas Interconnection has held up so far even as temperatures approach those set during the state's record-breaking summer of 2011.

Interim ERCOT CEO Brad Jones said Wednesday in an interview with NBC News that his team is preparing for the possibility that this summer's extreme heat could top 2011's, the hottest on record.

"We are approaching a 2011 summer, and the grid is holding together, and I have high confidence that it will continue to do so throughout the summer," Jones said last month.

Staff have continued to maintain their conservative operations posture, setting aside several thousand megawatts every day in operating reserves. ERCOT has issued eight operating condition notices, its lowest-level market communication. The most recent one expired last Thursday.

Clayton Greer with his name tent in its usual position.| *© RTO Insider LLC*

Staff have also deployed non-spinning reserves once this summer and asked for voluntary conservation measures three times. "We want to be respectful of Texans, so we will only call for conservation if we need it," they said in an email to *RTO Insider*.

ERCOT's *weather forecast* calls for increased rain chances and cloud cover this week as unsettled weather patterns take shape over the state. The forecast predicts highs of 100 or more are still likely over the next week, but "105+ degree highs will be much harder to come by."

There's still plenty of summer left, however, and with it, the chance for more records.

Greer Steps down from TAC

The Technical Advisory Committee has lost one of its more vocal and experienced members with last week's announcement by Morgan Stanley's Clayton Greer that he is leaving his firm to pursue an outside opportunity.

"For the amusement of some and the relief of many — and mainly because I have to — I will be stepping down from [TAC] after almost 20 years of faithful service," Greer said in an email to the committee.

Greer praised those he sat alongside for nearly two decades ("You are some of the most professional individuals I've had the pleasure of working with.") and hinted at the work that lies ahead for TAC and its relationships with ERCOT's new Board of Directors and a revamped Public Utility Commission.

"The [stakeholder] process actually works to create a market that has, until recently, operated in an extraordinarily efficient manner to maintain reliability and save money for ratepayers," he said. "I firmly believe it will get back there someday, but there will obviously be some bumps and bruises along the way. I have always been amazed at how we can be beating each other up over policy one minute and then enjoying lunch together the next.

"I'm confident that the wisdom and talent in TAC is more than up to facing the challenges coming quickly upon the market as crypto loads, storage, distributed load and generation resources, and renewable resources continue to be added to the grid at a rapid pace," he continued. "My wish for all of you is that you have the chance to experience some of the stakeholder processes provided in the other markets. I think if you did, you would be amazed at how well our process here works for the benefit of all involved."

"Clayton's contributions to the ERCOT market and the stakeholder process have been invaluable over the years," said TAC Chair Clif Lange, of South Texas Electric Cooperative. "His candor and depth of expertise are unmatched and will be greatly missed. When others were unable or unwilling to comment on controversial items, Clayton was never afraid to point out when the emperor had no clothes."

Greer was an outspoken critic of emergency response service (ERS). He regularly voted against revision requests related to the market, which he and others see as a capacity market for a subset of market participants. During the July TAC meeting, he cast the lone opposing vote against a measure that raised ERCOT's ERS budget to $75 million, saying, as he has before, that the grid operator was paying to dispatch a service participants had already deployed.

"I am most thankful that I was able to vote 'no' on an ERS [revision request] one last time," he wrote in a postscript to his email. "That made my year."

Peakers Return to Seasonal Ops

Garland Power & Light has notified ERCOT that it plans to suspend year-round operations at two gas-fired peaker units and return them to seasonal status.

According to the utility's notification of suspension of operations (NSO) to the grid operator, the two Spencer Road Generating Station units will operate from March 1 to Nov. 30.

Spencer 4 has a maximum summer sustainable rating of 57 MW, and Spencer 5 has a 61-MW rating. The units date back to 1966 and 1973, respectively.

ERCOT is conducting a reliability analysis to determine whether the units are still needed for system operations.

The grid operator also recently approved Greenville Electric Utility System's NSO to return a steam unit to seasonal operations. GEUS 1 will operate from June 1 until Sept. 30. (See "Steam Unit Goes Seasonal," *ERCOT Briefs: Week of July 4, 2022*.)

The unit has a summer seasonal net max sustainable rating of 17.5 MW. It went into operation in 2010. ■

— Tom Kleckner

ERCOT News

Abbott Fills out Texas PUC with 5th Member

Texas Gov. Greg Abbott on Friday *appointed* long-time ExxonMobil employee Kathleen Jackson to the Public Utility Commission, bringing the agency that regulates the state's electricity industry to its full five-person membership.

Jackson's term expires in September 2027. She previously served on the Texas Water Development Board, where she was first appointed in 2014. She is a registered professional engineer and has a diverse background representing agricultural, environmental, industrial and wholesale-supply interests.

She has been a public affairs spokesperson since 1997 for an ExxonMobil refinery in Beaumont, where she lives. Jackson joined the company in 1977 after receiving a degree in chemical engineering from North Carolina State University.

Legislation last year expanded the PUC's seats from three to five. All three previous commissioners left the PUC in the aftermath of the February 2021 winter storm that almost collapsed the ERCOT grid. ■

— Tom Kleckner

Kathleen Jackson, Texas Water Development Board | *Texas Water Development Board*

ISO-NE News

New England Governors Ask Feds for Help with Winter Reliability

By Sam Mintz


An LNG facility in Everett, Mass. | *Constellation Energy*

Staring down the possibility of fuel shortages this winter, New England's governors are asking the Biden administration for help, including a possible waiver of the Jones Act for LNG deliveries to the region.

In a letter to Energy Secretary Jennifer Granholm dated July 27, the six governors in the region warned that price volatility because of the war in Ukraine will have "have significant implications for our region's electric and natural gas customers and raises reliability concerns if the region suffers a severe winter."

New England relies on LNG for both electricity generation and heating in the winter, as domestic natural gas capacity is constrained.

The new letter follows increasingly vocal warnings from ISO-NE and a back-and-forth between it and the states over how to prepare for the possibility of extreme cold that could strain the electric grid.

Despite its alerts about the precarious state of the grid in winter, ISO-NE recently determined that no out-of-market solutions to make sure that generators stockpile fuel would be appropriate for this winter because of their cost and unclear benefits. (See *ISO-NE Says No Extra Winter Programs Make Sense this Year*.)

The states are turning to the federal government with three distinct asks.

First, they request that the administration begin "to explore the conditions under which it might be appropriate to suspend the Jones Act for the delivery of LNG for a portion or all of the winter of 2022-2023."

The letter notes that the law, which requires that ships hauling cargo between U.S. ports be built in the U.S., "effectively precludes all U.S.-exported LNG from being delivered into New England."

The governors also asked that the Biden administration consider utilizing the Northeast Home Heating Oil Reserve and consider developing a "new or modernized strategic energy reserve to protect against low-probability weather events to ensure energy system reliability."

And third, the letter asks that the federal government and the states "commence coordinating immediately to monitor the developments as winter approaches."

The issues facing New England's system aren't likely to disappear overnight, the states acknowledged.

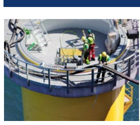
"While our immediate focus is on this upcoming winter, the ramifications of Russia's invasion and the realignment of natural gas supplies will have long-term global consequences and could have adverse impacts in New England," the letter says, calling for an expanded energy strategy and construction of new critical infrastructure.

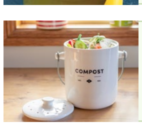
"It's really important that we have active and direct collaboration and communication going on among all of the entities that have a role to play in ensuring our grid is reliable for consumers in New England," Katie Dykes, commissioner of Connecticut's Department of Energy and Environmental Protection, told *RTO Insider* on Wednesday.

"We're in a really unprecedented time with the war in Ukraine and supply chain disruptions and volatile commodity prices falling out of the pandemic," Dykes said. "We know how this is affecting consumers already in terms of energy costs, and we're keenly aware of the unique vulnerability of the New England electric grid."

FERC is holding a forum in Vermont in September to examine the challenges facing New England's grid reliability in winter. ■

Northeast news from our other channels


$36M Allocated to East Coast OSW Workforce Training Initiatives — NetZero Insider



NH Takes Comments on Climate-centered Waste Management Plan — NetZero Insider

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ISO-NE News

Share Winter Data, States Urge ISO-NE

The New England states are asking ISO-NE to share confidential data to help prepare for winter. | © *RTO Insider LLC*

New England state energy officials are urging ISO-NE to share confidential data about fuel supply and grid reliability with FERC ahead of the upcoming winter.

In a *letter* to ISO-NE last week, the New England States Committee on Electricity (NESCOE) said it would accept the RTO's decision not to move forward with a winter reliability or inventoried energy program this year. (See *ISO-NE Says No Extra Winter Programs Make Sense this Year*.)

But the group said that it is "very concerned that the long-known, significant structural issues contributing to winter reliability challenges remain unresolved."

To that end, it urged ISO-NE to share with FERC the confidential data that drove the decision not to create a winter program this year before the commission holds a *forum* in Vermont next month to discuss reliability issues in New England. That could include information about "fuel supplies, resource availability, historical resource performance and overall system conditions" to which the public does not have access.

"We understand that your recommendation for this winter rests in part on your confidence in your assumptions about oil and LNG availability over the coming months, which are based on both economic expectations grounded in historical actions and information not available to us or other stakeholders," the letter says. "Sharing your analysis and the confidential information behind your fuel supply assumptions and recommendation with FERC would be helpful and appropriate given FERC's regulatory role, ability to receive and protect confidential information, and expressed interest in discussing New England's winter 2022/2023 outlook."

The letter comes a few days after the states' governors wrote to the Biden administration urging it to consider several actions before this winter, including a waiver of the Jones Act for LNG deliveries to the region. (See *New England Governors Ask Feds for Help with Winter Reliability*.) ■

— Sam Mintz

MISO News

Entergy Beats Expectations with Q2 Earnings

Company Reaches Settlement over Grand Gulf with Mississippi PSC

By Tom Kleckner

Entergy easily beat analysts' expectations with its second-quarter results Wednesday, thanks to better-than-expected retail sales during the early-summer heat.

The company *reported* earnings of $160 million ($0.78/share) for the quarter. A year ago, the company disclosed a loss of $6 million ($0.03/share).

The New Orleans-based company's adjusted earnings of $364 million ($1.78/share) far exceeded Zacks Investment Research's consensus estimate of $1.42/share.

"We had a productive second quarter," CEO Leo Denault said in a statement.

Denault said Entergy had reached a settlement valued at $300 million with the Mississippi Public Service Commission over performance and accounting issues at its 1.43-GW Grand Gulf nuclear plant in the state. The agreement was designed as a global settlement to resolve all disputes between FERC and Entergy subsidiary System Energy Resources Inc., the plant's majority owner. (See *Entergy Offers Regulators $588M to End Grand Gulf Complaints*.)

Arkansas regulators and the New Orleans City Council *rejected* or *opted out* of similar settlements last week. The Arkansas Public Service Commission said Entergy's "low-ball" offer did not include a cash refund for Entergy Arkansas' customers, as did the Mississippi settlement.

| *Shutterstock*

Denault told financial analysts during the company's earnings call Wednesday that the Mississippi commission "recognized the opportunity to deliver meaningful value to customers today, rather than wait for an uncertain outcome potentially years down the road."

A FERC decision is expected later this fall.

Grand Gulf sells most of the output at wholesale to Entergy's Arkansas, Louisiana, Mississippi and New Orleans operating companies, but it has been the subject of complaints for overcharges because of poor plant operations and incentive pay to company executives. The plant has been offline for several weeks to repair mechanical issues, Entergy said.

Denault said completing the sale of Michigan's Palisades Nuclear Plant in May to Holtec Decommissioning International represented the "last major milestone" in exiting the merchant nuclear power segment. (See *Federal Aid Likely Too Late to Save Palisades, Diablo Canyon Nukes*.)

Entergy's share price closed Wednesday at $117.38, up $2.27 (1.97%) from the previous closed. ■

MISO News

DC Circuit Upholds FERC Rejection of Midwestern Co-op Contract

Mobile-Sierra Presumption not Appropriate, Court Rules

By Rich Heidorn Jr.

FERC acted reasonably in rejecting a Wabash Valley Power Association power contract and denying it a *Mobile-Sierra* presumption, the D.C. Circuit Court of Appeals ruled Aug. 2 (*20-1286*).

The court upheld FERC's April 2020 ruling over how to determine the reasonableness of rates for the sale of electricity from an energy cooperative to its individual member utilities (*ER20-1101*).

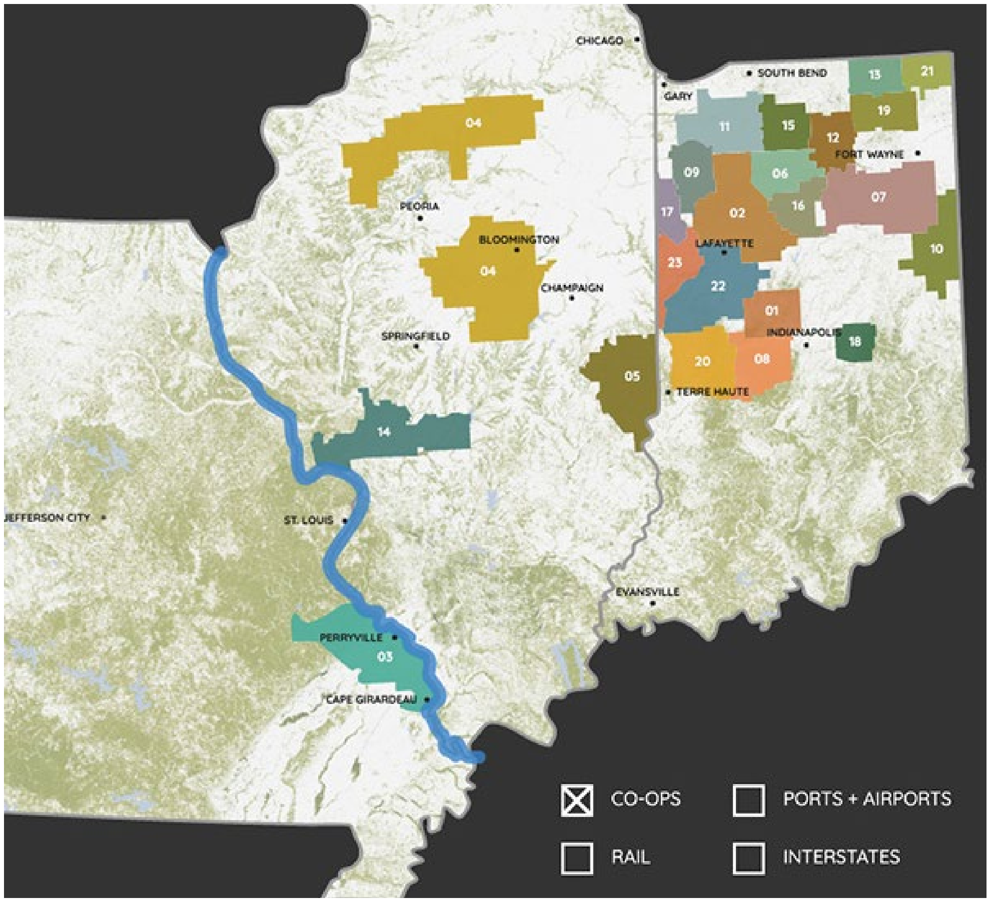
Indiana-based Wabash Valley generates and transmits electricity to 25 members in Indiana, Illinois and Missouri. Wabash's bylaws give each member one seat on its board of directors, which acts by majority vote.

In 2020, Wabash executed new contracts with all but two of its 23 retail-serving members. The new contracts continued the prior practice of requiring members to pay the formulary rate tariff and empowering Wabash's board to raise the rate to produce sufficient revenue to meet the co-op's costs. But it also added a new provision asserting that any changes to the formulary rate tariff were entitled to the *Mobile-Sierra* presumption of justness and reasonableness, which can only be overcome only if FERC concludes that the contract seriously harms the public interest.

Tipmont Rural Electric Membership Cooperative, one of the two member utilities that did not sign the new contracts, protested to FERC that the *Mobile-Sierra* presumption should not apply to changes to the formulary rate tariff. The commission agreed, ruling that the tariff is a "generally applicable rate" rather than a contract rate, making the new language "an unlawful attempt to apply the public interest presumption to proposed changes to Wabash's tariffs."

In denying rehearing, FERC said the rate "is generally applicable to all Wabash members and is not negotiated between Wabash and its executing members on an individualized basis. Rather, the Wabash board of directors determines the rates." In determining whether a unilaterally set tariff rate is just and reasonable, FERC must balance the interest of the investor and the consumer.

In its appeal, Wabash challenged FERC's refusal to apply the *Mobile-Sierra* doctrine.



Wabash Valley Power provides power to 331,000 homes, schools, farms and businesses in Illinois, Indiana and Missouri. | *Wabash Valley Power*

The D.C. Circuit agreed with FERC, saying a "contract requiring the purchaser to pay a utility's 'going rate' on file with FERC, without more, does not eliminate review under the ordinary just-and-reasonable standard."

The court noted that Wabash's contracts with individual members are virtually identical, suggesting that "individual members face a 'binary,' take-it-or-leave-it choice" — not the "presumptively equal bargaining power" required under *Mobile-Sierra*.

Wabash contended its rate changes are not unilateral because member utilities control the board. But the court noted that each individual member controls only 4% of the board's votes.

While individual members collectively own the cooperative and benefit from higher prices charged by Wabash and passed on to retail customers, the individual utilities "lack the same incentive as a buyer negotiating with an unrelated seller for the lowest possible prices," the court said. "In other words, the utilities are effectively on both sides of the transaction. And the *Mobile-Sierra* presumption applies only to rates that are 'the product of adversarial negotiations between sophisticated parties pursuing independent interests.'"

The court declined to rule on FERC's assertion on rehearing that a contract must contain individualized terms to enjoy the *Mobile-Sierra* presumption.

"We do not read FERC's decision as resting on a *per se* rule that the presumption can never apply to form contracts, and we do not opine on such a sweeping rule. We simply conclude that, in this case, the small bargaining power of any individual member relative to the cooperative plus the highly standardized nature of the governing contracts supports FERC's conclusion that the contracts impose a unilateral tariff rate as opposed to a freely negotiated bilateral contract rate," it said. ■

MISO News

DC Circuit Backs Kentucky Munis on Tx Rate ‘Pancaking’

By Rich Heidorn Jr.

FERC failed to consider the impact of potential rate increases when it allowed Louisville Gas and Electric (LG&E) and Kentucky Utilities (KU) to partially exit market power mitigation measures, the D.C. Circuit Court of Appeals ruled Friday (*19-1236*).

The court vacated parts of a March 2019 order and rehearing orders in September 2019 and September 2020 (*ER19-2396, ER19-2397*). (See *FERC Again Rejects LG&E-KU Mitigation Exit*.)

The commission imposed rate de-pancaking provisions to resolve horizontal market power concerns after LG&E and KU merged in 1998 and left MISO in 2006. The utility was *acquired* by PPL in 2010.

As a condition for allowing the utility to leave MISO, FERC required it to agree not to charge its wholesale power customers duplicative “pancaked” transmission rates for power shipped to or from MISO, so long as the RTO did the same.

In March 2019, the commission agreed the de-pancaking provisions — spelled out in the utility’s Schedule 402 — could be removed because loads located in its market would have access to enough competitive suppliers.

But the commission sought to protect customers that had made business decisions based on the de-pancaking provisions by requiring LG&E and KU not to end de-pancaking during a transition period. It set the transition at 10 years for the cities of Paducah and Princeton, Ky. (P&P), which had invested in the Prairie State coal-fired generator connected to the MISO grid.

The D.C. Circuit said that while “the commission reasonably found that sufficient competition would survive the return of pancaking, it was arbitrary and capricious for the agency to ignore the effect pancaking would have on rates.” It also said FERC failed to adequately explain two aspects of its transition requirements.

While there were no more than seven competitive wholesale energy suppliers for the grid when FERC approved the LG&E-KU merger, by 2018, more than 100 suppliers could competitively sell to the grid, the commission said.

LG&E and KU’s “neighbors include some of the largest independent grids on the continent — MISO and PJM Interconnection LLC — giving those customers ready access to independent power suppliers,” the court said.

But the court said FERC erred in “backhanding the effect that pancaking would have on rates.” It quoted an expert for municipal utilities protected by Schedule 402 who estimated that the end of de-pancaking would raise municipalities’ rates by at least 15%, with one customer’s rates rising 47%.

“Importantly, this rate analysis goes beyond just looking at competition because, as the commission has recognized, markets do not always function perfectly,” the court said. “Yet here, the commission expressly refused to even consider the effect ending de-pancaking would have on electricity rates. The commission held, instead, that because de-pancaking was imposed to protect competition, that was the only factor it needed to consider in ending the program.

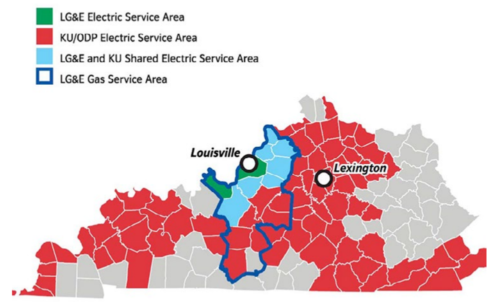
“By refusing to consider the material effects of its order on customer rates — a factor that its own regulations identify as a key component of the public interest, the commission engaged in ‘unreasoned, arbitrary and capricious decision-making,’” the court concluded.

The court said that although vacating the commission’s action may cause some disruption, “that disruption seems unlikely to be severe, as our decision implicates in large part the same type of rates that are required to be de-pancaked in the short term under the transition mechanism. We therefore vacate the commission’s decision to permit [LG&E and KU] to end de-pancaking under Schedule 402 and remand for the agency to reconsider its decision in light of the direct and indirect effects ending de-pancaking would have on customers’ rates.”

Win for LG&E/KU

LG&E and KU claimed one victory in the appeal, convincing the court that FERC acted arbitrarily in extending the de-pancaking of P&P’s rates related to their investment in a hydroelectric project until their power agreements expire in 2057.

“That reasoning cannot be reconciled with the commission’s determination that the transition mechanism was meant to extend de-pancaking only for a ‘limited period of time.’ The commission had just said that 10 years of mitigation was enough to protect P&P’s similar long-term investment in Prairie State. Yet here, the commission concluded that mitigation must continue for an additional 38 years — simply because the hydropower agreements contained a concrete end date of 2057.



LG&E and KU service territory | *Kentucky PSC*

“That makes no sense. If 10 years of protection suffices for an ownership interest that continues ‘indefinitely,’ something in the neighborhood of 10 years would seem the relevant time frame to protect another exceptionally long investment,” the court said. “The commission failed to explain why the fact that an agreement will terminate by a date certain justified extending the mitigation term for nearly four decades.

“Should the commission conclude on remand that the public interest supports ending de-pancaking under Schedule 402, it must either better explain this aspect of the transition mechanism or take a fresh approach to the question,” the court said.

‘Inexplicable’ Rejection

The court also said FERC’s reasoning for declining to protect the entirety of the Kentucky Municipal Energy Agency’s eight-year transmission reservation with MISO was “inexplicable.”

“The commission’s holding that transmission reservations are not ‘separate financial commitment[s]’ meriting independent protection was conclusory and inconsistent with the plain criteria of the transition mechanism,” the court said. “The commission’s competition finding does nothing to justify reaching a different result for transmission reservations than it did for power purchase agreements. The commission’s claim that de-pancaking Energy Agency’s entire transmission reservation would unduly extend its remedy to future power agreements was also baseless. ...

“If the commission chooses again to end Schedule 402 de-pancaking on remand, it must come forward with a logical explanation for its decision here that is consistent with the purpose and scope of the transition mechanism, or it must extend de-pancaking on reasoned terms to Energy Agency’s transmission contract,” the court said. ■

Virginia Regulators OK $79M Rate Hike for Dominion OSW Project

Legislature Urged to Consider Supplemental Funding to Lighten $21.5B Ratepayer Impact

By Rich Heidorn Jr.

Virginia regulators warily approved a $78.7 million rate hike for Dominion Energy's 2.6-GW Coastal Virginia Offshore Wind (*CVOW*) project Friday, warning that the legislature had left ratepayers facing "unprecedented risks" of cost overruns and delays on the massive $21.5 billion project.

With a projected capital cost of $9.8 billion, the project "will likely be the largest capital investment, and single largest project" in the utility's history, the State Corporation Commission (SCC) said in its 45-page order, which also approved the interconnection and transmission facilities to connect the project to the PJM grid (*PUR-2021-00142*). "The project will also likely be the costliest project being undertaken by any regulated utility in the United States, with the exception of Southern Co.'s ongoing Vogtle nuclear project, and will likely be the most expensive on a dollars-per-kilowatt of firm capacity basis."

Total project costs, including financing costs minus investment tax credits, are estimated at $21.5 billion, including a $7.22 billion return on equity based on Dominion's 9.35% ROE rate.

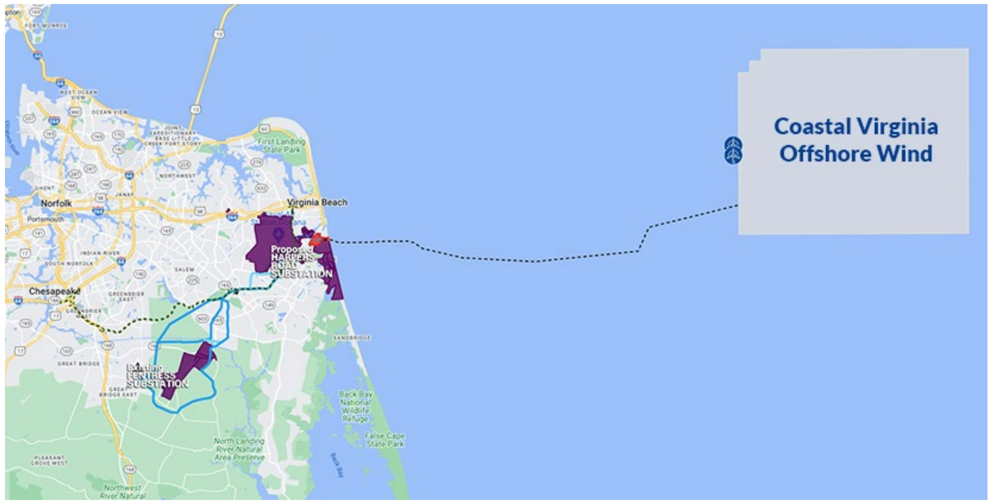
The new rate adjustment clause (Rider OSW) will cost a residential customer using 1,000 kWh/month an average monthly bill increase of $4.72 over the projected 35-year lifetime of the project, with a peak increase of $14.22 in 2027, the commission said.

Ratepayers at Risk

"While neither staff nor any respondent opposed approval of CVOW, significant concerns were raised throughout this proceeding regarding affordability and the financial risk to ratepayers," the commission noted. "The project is truly distinctive in numerous respects, encompassing cost, size, technology, complexity, ownership and risk. … No other utility or independent developer has attempted to construct and operate an offshore wind project of this size in the United States."

Unlike other East Coast states backing offshore wind, Virginia did not choose procurement models to mitigate the risk to ratepayers.

Instead, Dominion will construct, own and operate the project, with its costs presumed prudent under the 2020 Virginia Clean Economy Act (VCEA) as long as the total levelized cost of energy — including tax credits and the costs of transmission and distribution facilities — does not exceed 1.4 times the cost per megawatt-hour of a simple cycle combustion turbine.



| Dominion Energy

"Every other state that is pursuing large-scale offshore wind is utilizing power purchase agreements or offshore renewable energy certificate contracts, which limits the risks to customers by shifting construction, operational and market risks from customers to the project's owner," the SCC noted.

Cost-control Protections

Acknowledging concerns raised by the Office of the Attorney General's Division of Consumer Counsel, the state Department of Energy, Walmart, Clean Virginia and Appalachian Voices, the commission ordered Dominion to:

- file a notice with the SCC within 30 calendar days if it determines that total project costs are expected to exceed the current estimate, or if the final turbine installation is expected to be delayed beyond Feb. 4, 2027. The company currently projects an in-service date by the end of 2026;
- include any material changes to the project in each annual Rider OSW update application it files before the project's commercial operation, and a written explanation for any cost overruns; and
- hold ratepayers harmless for the cost of replacement power if CVOW's energy production fails to meet its projected 42% annual net capacity factor, as measured on a three-year rolling average.

Dominion contended "it would be inappropriate for the company to be put at risk if it fails to meet the capacity factor upon which it has justified and supported this project," the SCC said. "We disagree. This particular risk for this particular project should not fall on the company's customers."

Dominion did not immediately respond to a request for comment on the SCC's concerns. In a *press release*, Dominion CEO Robert Blue said the company was happy with the commission's approval and is "reviewing the specifics of the order, particularly the performance requirement."

The commission acknowledged that its 42% performance standard will not protect customers from cost overruns or abandonment costs, the latter of which "would not be inconsequential," the commission warned. "Even if the project is abandoned at the end of 2023, Dominion still estimates it would have prudently incurred approximately $3.7 billion of costs to be recovered from customers."

The commission warned rising commodity prices and supply chain problems could result in construction delays and cost overruns.

"As a first-mover project, there is no developed supply chain, including equipment suppliers, specialized installation vessels, and infrastructure to handle the transportation and installation of the equipment," the SCC said. It noted that turbine supplier Siemens Gamesa has

PJM News

suffered supply chain disruptions and that the company has two installations ahead of CVOW that will be receiving the same turbines.

No EPC Contractor

The commission also said the designs for the turbines, monopiles, transition structures and other components have not been finalized and questioned whether Dominion's 3% contingency estimate ($300 million) was sufficient "for a project of this size and risk."

"Dominion has also opted not to use an engineering, procurement and construction (EPC) contractor on the project, which the record shows is a departure from how it has managed construction of prior generation facilities. In prior cases, the use of an EPC contractor enabled the company to shift materials, labor and schedule risk away from the company and its customers, as well as risk of construction delays and cost overruns," the commission said. "In this case, however, Dominion is instead managing the project in-house using multiple interrelated contractors."

The VCEA declared "in the public interest" the construction or purchase by a public utility up to 5,200 MW of offshore wind. Dominion's choice of "a construction and ownership model that places most of the risks on customers … is one of the reasons why Clean Virginia seeks an independent assessment of whether the utility-owned model for this project should not be used for the next 2,600 MW tranche of offshore wind," the SCC said.

Effective Sept. 1, Rider OSW will recover financing costs on $661.7 million in capital expenditures during the rate year, as well as allowance for funds used during construction accrued on Dominion's books.

Like all VCEA-related costs, Rider OSW will be a non-bypassable charge generally paid by all Dominion retail customers — even those who purchase power from competitive service providers — with limited exceptions. "Prior to the VCEA, shopping customers would generally not be responsible for the costs of Dominion generation facilities to the extent they procure for their own energy and capacity from someone other than Dominion. The VCEA now directs that shopping customers pay for VCEA-related costs, with limited exceptions."

Transmission

The project — 176 14.7-MW wind turbines that Dominion says will produce enough carbon-free power for up to 660,000 homes — will be located 27 miles off the coast of Virginia Beach.

The capital cost includes a projected $1.15 billion for the onshore Virginia facilities, including $774.3 million for transmission-related work and approximately $374.2 million for substation-related work (2021 dollars).

The SCC order approved Dominion's route for the offshore export circuits and the route for the 4.4-mile underground route for its onshore export circuits from the cable landing to a new Harpers Switching Station. Also approved was an overhead route from Harpers to the existing Fentress Substation.

Transmission upgrades are estimated to be about $215 million. The final costs of transmission network upgrades are unknown because ongoing study work in the PJM generation queue was placed on hold to clear the current backlog.

"The transmission interconnection facilities are a significant component of this project, and [Dominion] has experienced delays and cost overruns on recent transmission projects," the SCC said.

Jagdmann Suggests Legislative Action

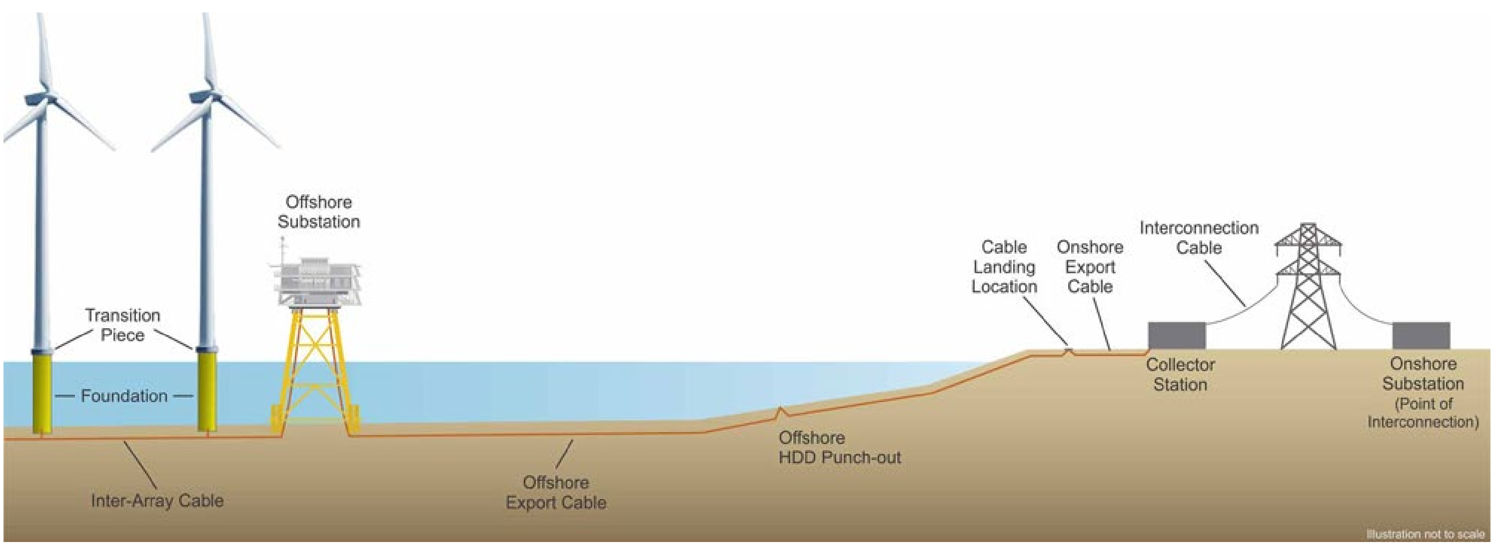
SCC Commissioner Judith Jagdmann | *NARUC*

In a concurrence, SCC Commissioner Judith Jagdmann observed that CVOW "is a legislatively favored project. If the elements of [the VCEA] are met, the costs of the project are presumed 'reasonable and prudent' — which means, in effect, 'ratepayers pay,'" Jagdmann wrote.

But she said the General Assembly could reduce the impact on ratepayers by making general fund appropriations or authorizing the use of auction proceeds from the Regional Greenhouse Gas Initiative. "Such action may be appropriate given the public policy support for and economic development aspects of this project," she wrote.

She said the legislature's requirement for yearly cost recovery proceedings provide "in theory, the opportunity in upcoming sessions to determine if additional steps are warranted to reduce the economic burden that will be placed on Dominion's customers as the project proceeds."

"Timing may be of the essence," she added. "In less than 18 months from now, Dominion plans to have spent close to $4 billion of capital costs on the project." ■



| *Dominion Energy*

PJM News

Dominion CEO: SCC Order for OSW Performance Guarantee 'Untenable'

Data Center Interconnections in Northern Va. on Hold for Potential Tx Constraints

By K Kaufmann

Three days after the Virginia State Corporation Commission approved Dominion Energy's 2.6-GW Coastal Virginia Offshore Wind (CVOW) project, the utility's CEO, Robert Blue, said the 42% capacity performance guarantee in the decision is "extremely disappointing" and "untenable."

The guarantee "would require DEV [Dominion Energy Virginia] to financially guarantee the weather, among other factors beyond its control, for the life of the project," Blue said during Dominion's second-quarter earnings call on Monday.

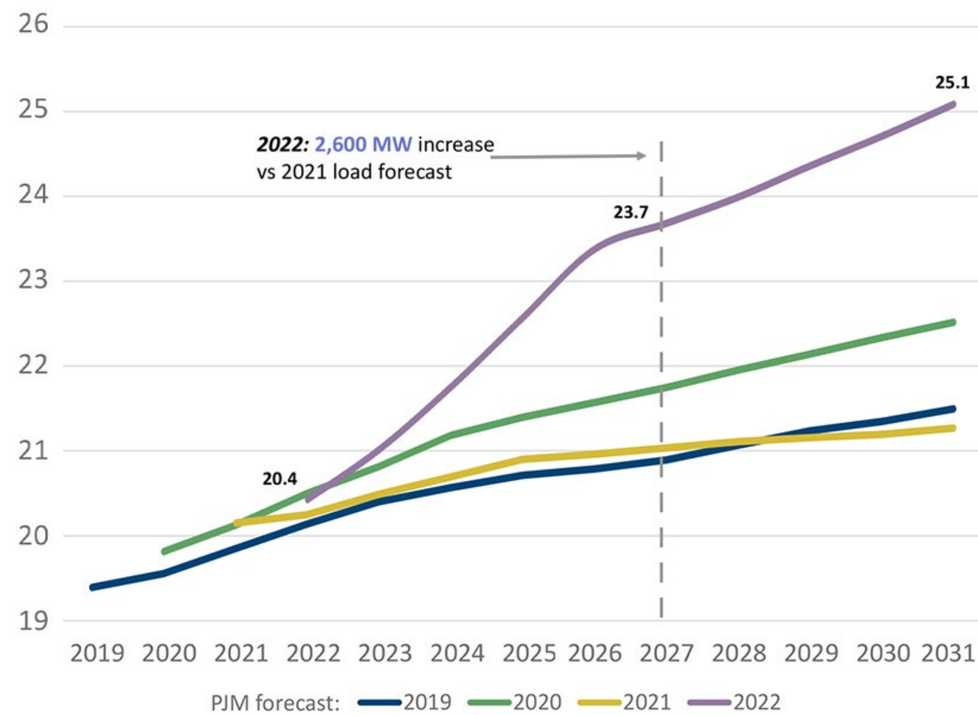
"Given a project of this magnitude, however, the commission's performance guarantee creates an unprecedented layer of financial one-way risk to DEV and is inconsistent with the utility risk profile expected by our investors," he said. "We plan to actively engage with stakeholders on the unintended consequences of that provision and are reviewing all public policy options including reconsideration or an appeal."

The performance guarantee was part of the SCC decision approving a $78.7 million rate hike for the project while warning that the state legislature left ratepayers facing "unprecedented risks" of cost overruns and delays on the $21.5 billion project. (See related story, *Virginia Regulators OK $79M Rate Hike for Dominion OSW Project*.)

The performance guarantee was one of several measures the SCC put in place with the goal of controlling costs and protecting ratepayers. However, the commission acknowledged that the guarantee would not protect customers from cost overruns or abandonment costs.

Dominion is, in fact, projecting a lifetime capacity of 42% for CVOW over 30 years. But, Blue said, "there are obviously factors that can affect the output of any generation facility notwithstanding a reasonable and prudent action [of] the operator, including natural disasters, acts of war or terrorism, changes in law or policy, regional transmission constraints, or a host of other uncontrollable circumstances."

He also noted that the SCC did not impose a performance guarantee when approving Dominion's previous solar energy projects in 2021, saying they were not required for projects developed to comply with the 2020 Virginia Clean Economy Act. "The same outcome should be made here," he said.



PJM is now predicting a 2,600 MW increase in peak demand in Virginia over the next five years, due to the explosion of data centers in Loudon County. | *PJM*

While the performance guarantee was clearly top of mind for Blue, the call also covered the potential impact for Dominion of the Inflation Reduction Act and its 15% minimum corporate tax, the utility's upcoming plan to invest $1.5 billion in new solar, and the explosion of data centers and power demand in Northern Virginia.

Data Center Alley

Dominion has connected 70 data centers in its Virginia service territory since 2019, with more than 2,600 MW of capacity, Blue said. Now dubbed Data Center Alley, eastern Loudon County is the center of that growth, with more than 25 million square feet of data centers now online and another 4 million square feet in development, according to the county's Department of Economic Development.

Data centers now represent 20% of Dominion's electricity sales, and on top of that growth, Blue says the peak demand of individual data centers in the region is also growing. Further, once a new data center is online, he said, it is ramping up to full demand more quickly than previously.

"A single data center typically has demand of 30 MW," he said. "However, we're now receiving individual requests for demand of 60 MW or greater."

PJM has predicted a 2,600-MW jump in peak demand from Dominion's system by 2027 — a 12% increase from its load predictions a year ago and the same capacity as the CVOW project, which is scheduled to be completed in late 2026, Blue said.

In response, Dominion is planning to accelerate its plans for two new 500-kV transmission lines in the area, but the utility is facing potential transmission constraints in the future and has put a "pause on new data center connections while we work on solutions to alleviate the constraints as quickly as possible," Blue said.

The utility is "reviewing the current capacity constraint analysis, including performing additional in-depth analysis substation by substation; engaging further with customers and other stakeholders ... to pace new connections' ramp-up schedules, and reviewing a variety of technical alternatives to address areas of concentrated load," Blue said.

Dominion recently submitted plans for the first 500-kV line to PJM and expects to file for approval from the SCC "in the coming weeks," Blue said. The utility also expects "to resume new connections in the near term, but how much and how quickly is still be determined," he said.

But Buddy Rizer, executive director of economic development for Loudon County, said officials there are "still trying to figure out what it means. We don't know how many of the 4 million square feet [in development] will have power."

"Dominion surprised everyone" with the pause, which was announced late in July, he said. The pause is also causing uncertainty for additional projects in the early stages of development, he said.

Blue provided no information on how many projects might be affected by the pause in interconnections, but he said any slowdown is not expected to hurt electricity sales or revenue. The pause is also not affecting any data centers outside Loudon County, he said.

"We expect to overcome any headwinds by the acceleration of needed new-build transmission projects from later in the long-term plan to earlier," which will increase capital investment and recovery in the utility's five-year capital growth plan, he said.

Inflation Reduction Act

Responding to analyst questions about the IRA, Blue called the bill, passed by the Senate on Sunday, "still a moving target" as the House of Representatives prepares to consider the bill later this week, with a possible vote coming as soon as Friday. (See related story, *Senate Passes Inflation Reduction Act*.)

While additional amendments could still pop up, Blue rated the bill on a "really high level" as "pretty good — really positive from a decarbonization incentive perspective; really positive from a utility, customer perspective." For example, Dominion and its customers stand to benefit from the IRA's extension of the wind production tax credit and its nuclear and clean energy tax credits, he said.

Blue also predicted that the IRA's 15% corporate minimum tax rate could have a negligible impact for the utility, which is already a "cash taxpayer" but is "shielded by our inventory of tax credits," which have kept the company's tax rate around 5.25%.

Applying the company's tax credits to the 15% minimum tax rate could cut that figure even further to 3.75%, he said.

Nuclear and Solar

The SCC has also approved Dominion's application to recover costs of close to $4 billion for extending the licenses of its North Anna and Surry nuclear plants. The two units at North Anna generate about 1.9 GW, and Surry's two units 1.6 GW. Together, they provide about 30% of Virginia's power, according to Dominion.

The utility is also preparing its next clean energy filing in the coming weeks, which will include about a dozen solar and energy storage projects. "The filing will represent at least $1.5 billion of utility-owned and [recovery] eligible investment, further de-risking our growth capital plan," Blue said.

Earnings

The company announced a GAAP net loss of $453 million ($0.58/share) for the second quarter, compared with net income of $285 million ($0.33/share) for the same period in 2021.

Non-GAAP operating earnings for the second quarter were $658 million ($0.77/share), compared to $628 million ($0.76/share) for the same period in 2021.

According to CFO James Chapman, the difference between GAAP and operating earnings reflect the impact of economic hedging activities, gains and losses on nuclear decommissioning trust funds, charges associated with the sale of Kewaunee nuclear power station in Wisconsin, regulated asset retirements and other adjustments. ■

PJM News

PSEG Eyes Democrats' Climate Bill for Nuclear Plant Support

Utility Optimistic on Bill Passage; Seeks Stable Subsidy

By Hugh R. Morley

Public Service Enterprise Group's departing CEO Ralph Izzo said Aug. 2 he is optimistic that the Democrats' proposed climate bill will pass Congress and provide stable, long-term support for the utility's three nuclear plants, now subsidized by New Jersey ratepayers to the tune of $300 million a year.

As proposed, the federal subsidy, which would run for six years from 2024, includes the Nuclear Production Tax Credit that "we have advocated for over the last two years," Izzo said during the company's second quarter earnings call.

He also cited several other recent green energy developments that will put the company in a strong position for the future. They include the New Jersey Board of Public Utilities' (BPU) June 29 approval of the company's $511 million Infrastructure Advancement Program, spending largely intended to upgrade the "last mile" of the company's distribution system, he said. The company, through its environmental, social and governance strategy, is also finalizing company-wide emissions reduction goals to be submitted to the U.N. by September 2023 for validation that they meet the requirements of the Paris climate agreement, he said.

Izzo, who steps down as CEO on Sept. 1 after 30 years at the company, will be succeeded by current COO Ralph LaRossa. Izzo will continue as executive chair of the board until his retirement on Dec. 31.

He told the conference call that the company sees a growing recognition that nuclear plants are necessary to cut carbon emissions.

"We continue to observe a positive shift in public sentiment in support of preserving these nuclear plants," he said. "This pricing floor for nuclear generation squarely addresses our need for a longer-term framework within which we can continue to own and operate our fleet with extended revenue visibility beyond the current three-year zero-emission certificate cycle."

Solid Cash Flow

The enactment of the Democrats' Inflation Reduction Act (*HR 5376*), is far from certain. (See *What's in the Inflation Reduction Act, Part 2*.) But its passage and the delivery of a federal nuclear subsidy would relieve PSEG of the pressure to secure state nuclear subsidies, at least for a while. The BPU in 2019 and 2021 awarded the company three-year subsidy packages of $300 million a year under the zero-emission certificate program. The state created ZECs to support nuclear plants that otherwise could be forced to close because they are financially unviable, undermining the state's effort to meet its clean energy goals. The PSEG subsidies stoked criticism, however, that the company did not need a $10/MWh rate, the maximum allowed under New Jersey's law creating the subsidies, to remain open.

According to *an analysis* by Taxpayers for Common Sense, the maximum subsidy awarded under the IRA would be $15/MWh, which the nuclear operator could only receive if it paid prevailing wage levels and met apprenticeship requirements.

Izzo said he is "very encouraged" by the bill, adding that based on his talks with legislators the "odds are looking quite good" that it could be passed. If that happens, and all goes to plan, he said, the nuclear plant will provide a "very predictable earnings stream with a very solid cash flow generation that I think serves the state of New Jersey very well, serves the company very well, serves the planet very well."

PSEG officials said the company would no longer receive the state subsidy if it was getting the federal tax credit. Izzo said that talks continue with New Jersey legislators over future nuclear subsidies, should they be needed.

Those "policy level" talks with legislators include discussions with state legislators about "a longer duration alternative to the current zero-emission certificate framework for nuclear should the price levels contained in the [federal] reconciliation bill prove elusive," he said.

OSW Investment or Sale

Izzo's departure comes as the company faces a rapidly changing environment, which includes the sale earlier this year of the last of its 6,750-MW portfolio of 13 fossil generating units. The company owns 25% of 1,100-MW Ocean Wind 1, the first New Jersey offshore wind project to be developed, which is co-owned with Danish developer Ørsted.

And the company is awaiting the BPU's decision on whether to adopt any of the 80 proposals for grid upgrades that would tie future offshore wind projects to the grid, among them several submitted by PSEG. Izzo has said in the past that the company's proposals could be worth $1 billion to $3 billion.

PSEG's Hope Creek and Salem nuclear plants | *Public Service Enterprise Group*

Izzo said its part-ownership of the offshore project will have no bearing on whether the BPU adopts any of the utility's projects to upgrade the grid. He added that "as related to the opportunity to co-invest with Ørsted, we continue to have conversations on a variety of fronts."

Under questioning from an analyst, he elaborated, saying the company would evaluate whether it should sell its share of the offshore project.

"It should be obvious to everyone, New Jersey is going to build seven and a half gigawatts of offshore wind. I think half a dozen states are going to build 30 gigawatts of offshore wind," he said. "That's going to have a significant impact on power markets," he said, adding that it would present "opportunities to grow earnings per share for companies. So it's something that we want to make sure we are taking the long view in terms of the role we should or shouldn't play in that."

PSEG *reported net income* of $131 million ($0.26/share) in the second quarter, compared with a net loss of $177 million ($0.35/share) a year earlier. Non-GAAP operating earnings for the second quarter of 2022 were $320 million ($0.64/share) compared to non-GAAP operating earnings of $356 million ($0.70/share) in 2021. ■

PJM News

Exelon, PPL Differ on Impact of 15% Corporate Minimum Tax

Both Welcome Incentives for Renewables

By Rich Heidorn Jr.

Exelon said Wednesday that the proposed 15% minimum corporate income tax included in the Democrats' energy and climate bill could impinge its cash flow and slow infrastructure investments, while PPL said the change would not affect it significantly.

The companies commented on the proposed Inflation Reduction Act of 2022 during their respective second-quarter earnings calls.

Exelon CEO Chris Crane praised the bill's extended tax benefits for solar and wind and its new ones for nuclear and hydrogen, as well as its measures to support energy efficiency and electrification.

But he said the incentives could be undermined by the new minimum tax and "slow the investment needed to make this [low-carbon] transformation."

"As currently drafted, we could see an impact of … approximately $300 million per year starting in 2023. Higher taxes would ultimately limit our ability to invest in infrastructure needed to accommodate the clean energy our customers want," Crane said, adding that the company and its trade group, the Edison Electric Institute, is lobbying for "language that better aligns incentives to achieve" decarbonization.

CFO Joseph Nigro declined to say whether the alternative minimum tax (AMT) would increase the company's equity needs, saying the company would determine a response during its end-of-year planning. "It's unclear at this point how these taxes will flow through to our customers," Nigro said.

The company reiterated its previously announced plans to raise $1 billion in equity by 2025, half of it this year, in part to pay down short-term debt from the Feb. 2 spinoff of Constellation Energy, its former generation unit.

Crane said the company could resort to cost cutting and adjusting project schedules to maintain its capital spending plans and earnings metrics despite the tax.

"There's a few balls in the air that we'll have to … juggle. But we'd rather have the fix to the bill so we're not having to juggle this," Crane said. "We'll see how we prevail as an industry as we go forward."

No Unity

The industry does not appear united on the minimum tax, however.

At PPL's earnings call later Wednesday, company officials said they did not expect the AMT to have a material impact.

"As you know, we are now a federal cash taxpayer," CEO Vincent Sorgi said in response to an analyst's question. "So, we're not anticipating the 15% AMT provision to have a significant impact on our business. … No real headwind there."

CFO Joe Bergstein said the company's effective tax rate is currently about 15%.

Sorgi said the IRA is a net positive for PPL, particularly as it looks to replace 1,000 MW of coal-fired generation in Kentucky by 2028 and meet Rhode Island's newly enacted 2033 target for 100% renewable energy. In a solicitation that closes in mid-August, PPL's Kentucky utilities said they would consider replacing the coal generation with renewables, battery storage, and peaking or baseload natural gas. PPL completed the acquisition of Rhode Island Energy in May.

"The ability to elect the production tax credit instead of the [investment tax credit] for solar will improve the economics of our self-build options as we look at renewables as a potential source of replacement generation in Kentucky," Sorgi said. "In addition, the extension of the renewable tax credits should lower the cost of renewables overall. …

"The transferability provisions around tax credits also makes it more likely that renewables will be built," he added. "And that'll also be good in general for the industry and for accelerating our clean energy transition. It simplifies the structure of the deals significantly."

EEI told ***RTO Insider*** on Wednesday that it welcomed the bill's "robust clean energy tax package."

But Eric Grey, EEI's vice president of government relations, did not directly respond when asked whether the group was seeking changes to the AMT.

"As always, EEI continues to be a resource for policymakers seeking feedback on how provisions in this legislation would impact electric companies and their customers during implementation," Grey said in a statement.

Exelon CEO Chris Crane | *© RTO Insider LLC*

PPL said EPA's proposed "*good neighbor" rule*, expected to take effect late 2022 or early 2023, could require shifting the retirement of an additional 500 MW of coal generation from a planned 2034 shutdown to the "2026 to 2028 time frame."

The rule would require EPA and states to address interstate transport of air pollution that affects downwind states' ability to attain National Ambient Air Quality Standards. Based on the final rule, PPL will determine whether to retire the plant or invest in "back-end technology" to keep it operating until 2034, Sorgi said.

Earnings Results

Exelon *reported* GAAP net income from continuing operations of $962 million ($0.47/share) for the second quarter, up from $808 million ($0.33/share) a year earlier. Adjusted (non-GAAP) operating earnings were $935 million ($0.44/share), up from $842 million ($0.36/share).

Nigro said 2021's second quarter reflects a 9-cents/share impact for corporate overhead costs that were previously allocated to the company's generation segment and were required by accounting rules to be presented as part of Exelon's continuing operations. "These costs were paid for by generation and are not indicative of our corporate overhead post-separation," he said.

PPL's second-quarter GAAP *earnings* were $119 million ($0.16/share) versus $19 million ($0.03/share) in 2021. Non-GAAP earnings from continuing operations were $222 million ($0.30/share), compared with $147 million ($0.19/share) the year before. ■

PJM News

FERC Orders 'Paper' Hearing on PJM FTR Collateral Dispute

By Rich Heidorn Jr.

FERC ordered a "paper" hearing last week to determine whether it should require a 99% confidence level in setting collateral requirements for financial transmission rights traders or the 97% level that PJM and most of its stakeholders have sought.

The commission accepted and suspended PJM's proposed tariff revisions subject to refund. It issued an eight-page list of questions to be answered, saying that the evidence provided thus far failed to address its concerns that PJM's requirements may be insufficient to protect stakeholders against losses (ER22-2029, EL22-32).

On Feb. 28, FERC rejected PJM's proposal to modify the FTR credit requirement with an initial margin calculation from a historical simulation model (HSIM) using the 97% confidence interval, saying the RTO failed to support its proposal because its independent auditors validated the model at a 99% confidence interval. It directed PJM to make a filing within 60 days to show cause why its existing FTR credit requirement remains just and reasonable or explain what tariff changes will remedy the commission's concerns (ER22-703). (See *FERC Rejects PJM's FTR Credit Requirement Proposal*.)

At the Members Committee meeting March 23, stakeholders endorsed a motion for PJM to refile the original proposal "accompanied by some new supporting rationale." The motion received a sector-weighted vote of 3.9 out of 5 (78%). (See *Stakeholders Encourage PJM to Defend FTR Filing*.)

Supporters of the filing said PJM credit revisions had demonstrated a significant drop in the failure rate of FTR portfolios and a reduction in potential collateral shortfalls.

But the Organization of PJM States Inc. (OPSI) and the Independent Market Monitor said the 97% confidence interval was unsupported. The IMM said PJM failed to justify why it selected 97% when the International Swaps and Derivatives Association uses a 99% confidence interval in its HSIM.

Among the questions asked by the commission was whether, compared to the 99% confidence interval, 97% causes the PJM market and its customers to subsidize collateral for FTR market participants and exposes the entire PJM membership to potential default costs.

It also asked how structural differences between the PJM FTR market and exchanges regulated by the Commodity Futures Trading Commission might justify the use of a lower confidence interval.

In compliance with the order, PJM told stakeholders it would implement the new FTR credit requirement effective Wednesday, coinciding with the close of the 2023/26 FTR long-term auction bidding window that opened last Monday.

The RTO said it would make any collateral calls required by the revised credit requirement last Thursday, after the bidding window closes. ■

	CLEARED REQUIREMENT				
Confidence Interval	Status Quo Total Requirement ($B)	IM-H Total Requirement ($B)	Change	Failure Rate	Winter Failure Rate
99%	$1.345	$1.703	27%	0.45%	0.90%
97%	$1.345	$1.125	-16%	1.65%	2.72%
95%	$1.345	$0.948	-30%	2.98%	4.89%

Estimated confidence intervals for total FTR collateral | *PJM*

SPP News

SPP Monitor: Impacts of WEIS in Year 1 'Limited'

MMU also Releases Latest SotM; SPP Issues VRL Analysis

By Tom Kleckner

SPP's Western Energy Imbalance Service (WEIS) market saw "very limited growth" in its first 13 months, SPP's Market Monitoring Unit said in its first *annual report* on the market.

Unlocking renewable resources in the market's region — which spans six states in the West, from Montana south to Arizona — has been cited as one of the market's key benefits. But the footprint's nameplate capacity increased by only 207 MW, all of it wind. Coal generation produced more than 62% of the market's total generation. Hydro was second at 22% and wind third at 9%.

The market continues to struggle with limited capacity and ramp constraints and is often unable to procure sufficient power in real time to balance, the MMU said. It has urged the market to address ramping issues, through either a minimum requirement per participant or a fully developed ramp capability product, and supply adequacy.

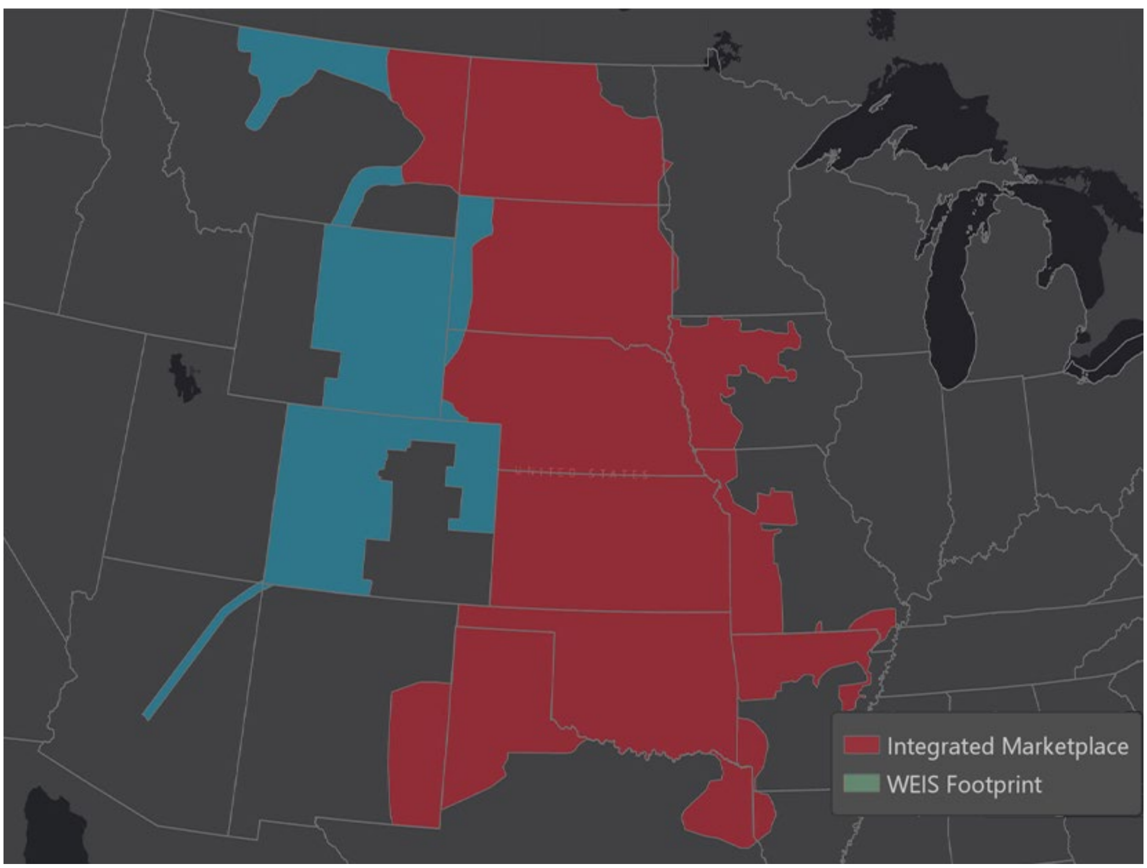
WEIS has been a net exporter of energy since its inception, with an hourly average of 800 MWh of net exports. The addition of Colorado Springs Utility this month and three more participants next April will essentially double the amount of generation and load within the market.

The market began service Feb. 1, 2021, just prior to the historic winter storm that month. Prices that month averaged $90/MWh, but the storm's impact was limited because of the generation mix and a limited ability to export to the east. The MMU found that market prices averaged around $36/MWh for the first 13 months, but that drops to just over $31/MWh when February 2021 is removed.

The MMU also recently released its spring Quarterly State of the Market *report*, which found that day-ahead prices were $31.66/MWh during the quarter (March through May), double last year's average of $15.97/MWh. Average real-time prices also more than doubled, up 112% to $29.37/MWh.

Wind generation accounted for 48% of total generation, up from 45% for the same period a year ago. Coal generation remained flat at 28%, and combined cycle and simple cycle gas generation fell from 18% to 14%.

Average gas prices at the Panhandle Eastern hub were more than double from where they were last spring, up 146% to $6.02/MMBtu this year from $2.45/MMBtu. Gas prices peaked at $7.59/MMBtu in May, an all-time high if not for the winter storm in February 2021.



SPP's Integrated Marketplace and WEIS footprints | *SPP*

SPP Releases VRL Analyses

SPP last week released its annual analysis of violation relaxation limits (VRLs) for the *Integrated Marketplace* and the *WEIS*.

The grid operator is recommending changes to the operating constraint VRL blocks and increasing the spinning reserve constraint VRL to $250 from $200. Its analysis showed the slight increase reduces the number of scarcity intervals and product shortage with only a slight increase to cost.

SPP did not recommend any changes to the WEIS VRL block, penalties or VRL related to resource capacity.

The RTO says that its market clearing engine (MCE) attempts to enforce all constraints when generating a solution. When this results in solutions that are not feasible, SPP will apply VRLs in the MCE solution. The VRLs and their associated values attempt to achieve a reasonable balance between honoring operating requirements and constraints while mitigating large price excursions or other extreme prices.

The security-constrained economic dispatch (SCED) for day-ahead and real-time balancing markets optimizes constraints to determine the most efficient and reliable solution, SPP said. When system limitations cause a constraint's shadow price to exceed a defined VRL, the constraint's limit is relaxed and the shadow price is replaced with the VRL penalty, allowing SCED to solve more economically. ■

SPP News

OGE Benefits from Enable Midstream's Sale

By Tom Kleckner

OGE Energy's exit from a midstream gas joint venture continues to pay dividends for the Oklahoma City-based utility.

CEO Sean Trauschke said Thursday that OGE has shed 77% of its limited partner units in Enable Midstream Partners for an $813 million return at an average price of $11.09/unit. Trauschke said that's a 33% premium from where the units were when OGE and CenterPoint Energy completed Enable's $7.2 billion sale to Energy Transfer Partners in December. (See *OGE, CenterPoint Complete Enable's Disposal*.)

"Interestingly, we've already received more net proceeds than the value of our investment when the transaction closed," Trauschke told financial analysts during the company's quarterly earnings call. "We're pleased with the pace of our progress and the value that we've captured for our shareholders."

OGE also received $750 million worth of securitization bonds in July stemming from the February 2021 winter storm. The company has also filed a request with Arkansas regulators to recover $80 million in storm costs over 10 years.

CFO Bryan Buckler said the revenues will be deployed so that OGE will not have to issue equity with its five-year, $475 billion capital investment plan. Much of that plan is customer-focused transmission and distribution assets.

OGE *reported* earnings of $73.1 million ($0.36/diluted share) during the quarter, as compared to $112.9 million ($0.56/diluted share) for the same period a year ago. It said earnings were primarily driven by more favorable weather and recovery of capital investments.

A partial reversal of a first-quarter interim period consolidating tax benefit related to mark-to-market activity and the gain from Energy Transfer unit sales resulted in a 5-cents/diluted share hit.

Trauschke said its Oklahoma Gas & Electric subsidiary's grid has performed well during the summer, which has seen 18 days above 100 degrees Fahrenheit since June 1.

"The grid has not been strained; we've not cautioned the public about potential blackouts or asked for conservation," he said. "I'm proud of the performance of our system and employees."

OGE's share price lost 54 cents during a down day for the Dow Jones Industrial Average, closing at $40.13. ■

OGE CEO Sean Trauschke (right) during a recent media interview. | *OGE Energy*

SPP News

SPP MOPC Approves Change Addressing Fuel Limitations

Committee also Holds Email Vote on Temporary RAS

By Tom Kleckner

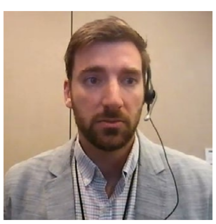
Coal limitations a concern for SPP's market participants. | *Shutterstock*

SPP stakeholders Friday unanimously approved an urgent revision request that expands the ability of market participants facing fuel limitations to include opportunity costs in their mitigated offers.

The Market Monitoring Unit (MMU) drafted the revision request (*RR452*) over concerns that a *potential rail strike* and other coal-delivery issues could create difficulties in meeting system demand in late summer and this winter.

The measure creates a new circumstance for fuel limitations caused by abnormal fuel supply, transportation or market limitations not rising to the level of ***force majeure***. Documentation must be provided to the MMU for its determination of eligibility on case-by-case basis. Current rail limitations fall under the new language.

The Markets and Operations Policy Committee passed the measure 56-0, with nine abstentions, during a special conference call. The change was added to the Integrated Marketplace's protocols before the work week ended. The Market and Regional Tariff Working Groups also approved it.



MMU supervisor Raleigh Mohr | *SPP*

Raleigh Mohr, an MMU supervisor, said the Monitor saw a need for a transparent market mechanism to conserve scarce fuel when conditions do not rise to *force majeure*. He said the change is both a market benefit and a reliability benefit.

"Coal deliveries are falling short of nominated demand from our market participants," Mohr said. "The market benefit is that the opportunity cost of the scarce fuel is transparent in the market price. The reliability benefit is that that this change would slow down or alleviate some of the issues being seen immediately with the coal transportation constraints … by assigning an opportunity cost to it."

Oklahoma Gas & Electric's Usha Turner spoke for several MOPC members concerned about RR452's unintended consequences and its lack of parameters. She said that based on her reading of the protocols, "*force majeure* very clearly includes labor disputes, labor material shortages [and] restrictions imposed by lawfully established civilian authorities."

"I'm not sure why the agreement of an opportunity cost adder isn't already within the MMU's authority," Turner said. "It seems to me that the language is already there. So, the question is kind of, 'Why do we need this language?' We're not adding something entirely new. That isn't a declared ***force majeure*** or biofuel supplier or a permit limit by EPA or something specific. It is unbounded."

To ease concerns, the MMU said it would update MOPC during its October meeting on the measure's implementation and potential bounds to limit the scope of opportunity costs.

"There are tariff elements we have to work with. We want to see if this tool is effective," MMU Director Keith Collins said.

Email Vote Held on Temporary RAS

MOPC declined to act on a last-minute agenda addition requesting endorsement of modification to a temporary remedial action scheme (RAS). However, members did agree to conduct an email vote that will close Friday.

The Transmission Working Group approved the temporary RAS early last week, revising its operation to not last more than two years. Invenergy's Arash Ghodsian noted that the minor modification was the only change to a previously approved RAS.

Invenergy proposed the temporary scheme so that its Thunderhead Wind Farm can operate at its full nameplate capacity (300 MW) when it becomes operational later this fall. The facility, located in northeast Nebraska, was to interconnect with Nebraska Public Power District's R-Line, a proposed 220-mile 345-kV line put on hold in 2020 when a U.S. district court *revoked a federal permit* because it would disturb the endangered American burying beetle during construction.

Without the R-Line, Thunderhead is limited to 195 MW. The RAS would detect when a nearby 345-kV line is open and trigger a direct trip of circuit breakers at Thunderhead.

The Operating Reliability Working Group and the System Protection and Control Advisory Group have joined the TWG in endorsing the proposal. ■

Company News

Vistra Stays the Course Despite Q2 Loss

By Tom Kleckner

Vistra CEO Jim Burke | *Vistra*

During his first earnings conference call as CEO of Vistra, Jim Burke said Friday that he continues to remain confident in the company's value proposition, even as it turned in a major second-quarter loss.

The Texas-based company *reported* a loss of nearly $1.4 billion in net income for the second quarter, driven by an increase in forward power prices requiring it to record mark-to-market hedging losses for GAAP purposes. The company had a $35 million profit for the same period a year ago.

Adjusted EBITDA from ongoing operations came in at $761 million during the quarter, down from $854 million a year ago. Vistra uses adjusted EBITDA as a performance measure, saying it believes that outside analysis of its business is improved by visibility into both net income prepared in accordance with GAAP and adjusted EBITDA.

"I continue to remain confident … because we intend to remain focused on the four key strategic priorities we initially defined in" 2021, Burke told financial analysts.

Vistra management said then it intends to "unlock … earnings power" through:

- its integrated business model of generation and retail that provides stability in volatile commodity markets;
- managing liquidity needs by supporting its hedging strategy;
- focusing on shareholder returns through an "upsized" $3.25 billion share repurchase program; and
- executing on its zero-carbon Vistra Zero initiative.

Burke said Vistra had bought back $1.6 billion of its shares, representing about 14.6% of outstanding shares as of last November, and that the board of directors has authorized buying back an additional $1.65 billion in shares before the year ends.

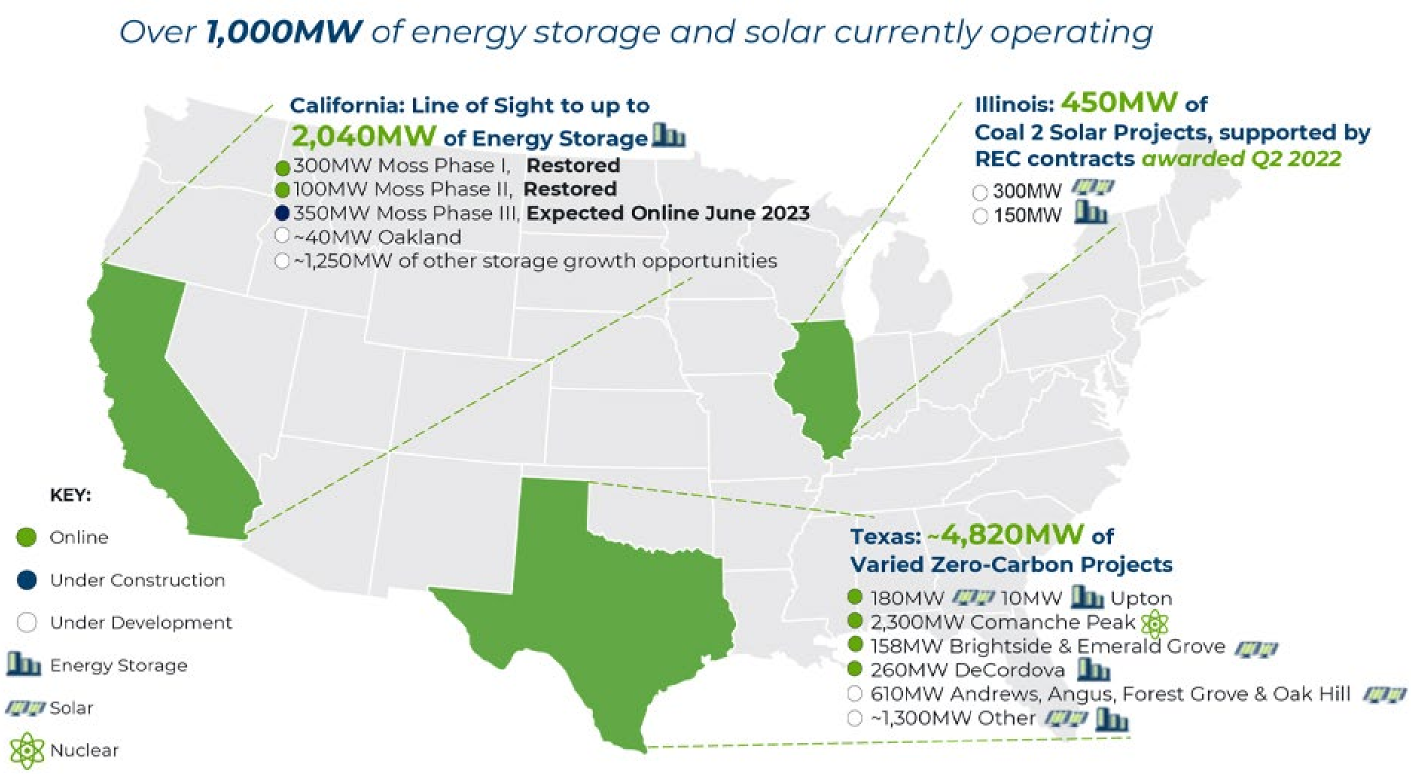
"Our confidence in our outlook is reinforced by the upsizing of the share repurchase program," said Burke, who was named in March to succeed the retired Curt Morgan as CEO, effective Aug. 1. (See *Burke to Succeed Morgan as Vistra's CEO*.)

Vistra said it had brought online an additional 418 MW of capacity as part of its *Vistra Zero* program: the 260-MW DeCordova Energy Storage Facility, the 50-MW Brightside Solar Facility and the 108-MW Emerald Grove Solar Facility. Along with the 2,425-MW Comanche Peak nuclear plant, the projects bring Vistra Zero's portfolio to nearly 3.3 GW, with plans to grow that to 7.3 GW by 2026.

Burke said Vistra is tracking ahead of its 60% greenhouse gas emissions-reduction target by 2030. "We anticipate Vistra Zero will more than replace the earnings of the retiring coal units," he said.

The company also restored 98% of its 400-MW Moss Landing Energy Storage Facility in California, which has been shut down several times after *battery overheating incidents*. Burke said Vistra will eventually restore the world's largest storage facility to full capacity.

Vistra shares dropped nearly 4% on Friday, closing down $1 at $24.62. Its stock closed at $24.74 on Monday. ■



Vistra has more than 1 GW of energy storage and solar resources currently online. | *Vistra*

Company Briefs

Oncor Reports $60M Boost in Profits from Texas Heat Wave

Oncor, Texas' largest regulated utility, reported a profit boost of $60 million for the three-month period that ended June 30.

Oncor's quarterly profit soared to $229 million — up from $169 million during the same months last year — as sweltering temperatures drove electricity demand. The results didn't include July, which was one of the region's hottest months on record.

More: *The Dallas Morning News*

GM Prepaying Livent for Guaranteed Lithium Supply

General Motors last week announced it will prepay Livent $198 million for a guaranteed six-year supply of lithium.

The deal ensures that GM will have sufficient raw materials to meet its goal of producing 1 million EVs annually in North America by 2025.

Livent, which also supplies BMW, expects to receive the GM prepayment later this year and will start supplying GM in 2025 at a contractual price per ton.

More: *Reuters*

Duke Energy Announces New Leadership Appointments

Duke Energy last week announced executive appointments for its chief financial officer and chief commercial officer positions, effective Sept. 1.

Brian Savoy and Steve Young will essentially switch roles: Savoy will become executive vice president and CFO; Young will become executive vice president and chief commercial officer.

The company also announced that Kodwo Ghartey-Tagoe will add the administrative services organization to his current responsibilities, while Harry Sideris will broaden his responsibilities to include the supply chain organization.

More: *Duke Energy*

Federal Briefs

NRC Approves Fuel Load at Vogtle Unit 3

The Nuclear Regulatory Commission last week authorized Southern Nuclear Operating Co. to begin fuel loading and operation at Vogtle Unit 3 in Georgia.

On July 29, Southern Nuclear told the NRC it had completed all inspections, tests, analyses and acceptance criteria needed to show the unit was ready for operation.

The unit is the first reactor to reach this stage under the NRC's combined license process. The decision moves the 1,117 MW AP1000 generating unit out of NRC construction monitoring and into the regulatory body's operating reactor oversight process.

More: *Power Engineering*

TVA Moves Forward with Smaller Nukes to Achieve Carbon-free Goal

The Tennessee Valley Authority last week said it has an agreement with nuclear manufacturer GE-Hitachi to pursue a small modular reactor design at the Clinch River reactor and will spend the next year preparing a possible construction permit to build a few of the 300-MW reactors.

TVA President Jeff Lyash said smaller nuclear reactors such as the GE-Hitachi BWRX-300 can be built more cost effectively and offer more flexibility than the previous generation of nuclear plants. Lyash said while TVA is pursuing a range of energy options for the future, he thinks the small reactors will be needed to help the utility achieve its long-term goal of being carbon-free by 2050.

TVA has pledged to shutter the last of the 59 coal units it once operated by 2035.

More: *Chattanooga Times Free Press*

State Briefs

REGIONAL

Illinois, Indiana, Wisconsin Join Lake Michigan EV Charging Circuit

The states of Illinois, Indiana and Wisconsin last week signed an agreement with Michigan to add charging stations and boost electric vehicle use around Lake Michigan.

The memorandum says the four states would "work together with a united effort to design, facilitate the development, maintenance and marketing of a scenic route with

reliable light-duty vehicle charging options along the Lake Michigan coastline."

More: *Detroit Free Press*

ARKANSAS

PSC Opens Inquiry into Solar Array Delays

The Public Service Commission opened a formal investigation on July 15 into "the alleged unauthorized net-metering practices of electric distribution cooperatives in

Arkansas," according to the new docket.

Seventeen cooperatives and the Arkansas Advanced Energy Association are parties to the docket, which asks the utilities to respond to questions by Aug. 5 in direct testimony before the commission. One question asks whether the co-ops require application fees, insurance minimums and other encumbrances on net metering. Another question asks about areas deemed as "saturated" with solar systems — a rationale at least one cooperative has used to deny solar interconnection.

The General Assembly made renewable energy development a priority with the Renewable Energy Development Act of 2001 and reinforced the promotion of solar power as a native fuel with the Solar Access Act of 2019.

More: *Arkansas Business*

PSC Rejects Entergy Settlement Plan

The Public Service Commission last week said $142 million isn't enough for the state to settle with Entergy in a dispute related to cost overruns at its Grand Gulf nuclear-power facility in Mississippi, with the commission condemning the offer for not including a cash refund for customers.

The PSC also called on FERC to hold a hearing to examine the "continued imprudent mismanagement" of the plant.

Last month, the Mississippi Public Service Commission accepted a $235 million settlement, which Entergy valued at $300 million because the company agreed to hold off rate increases that were planned for 2023.

More: *Arkansas Democrat Gazette*

FLORIDA

Escambia County Approves FPL Solar Farm

The Escambia County Development Review Committee last week approved Florida Power & Light's 75-MW Sparkleberry Solar Energy Center in North Escambia.

The farm will include 200,000 solar panels on 553 acres.

FPL must still obtain construction permits; the development order remains valid for at least 18 months.

More: *NorthEscambia.com*

ILLINOIS

EPA Approves EmberClear Gas Plant

The state EPA last week approved EmberClear's plan to build an 1,100-MW natural gas plant south of Springfield despite the objections of environmental groups.

Although the $1.5 billion Lincoln Land Energy Center runs counter to the state's increased development of clean energy projects, the company insisted it will be compliant ahead of the state's goal of eliminating power-plant carbon emissions by 2045.

The plant, which will run on methane, is expected to be operational by 2025.

More: *State Journal-Register*

INDIANA

Duke Energy Requests 7.2% Rate Hike

Duke Energy last month applied for a 7.2% rate increase with the Utility Regulatory Commission.

The utility cites rising fuel costs as the reason for the increase.

If approved, it would add to a 16% increase the URC approved in June.

More: *WRTV*

PENNSYLVANIA

Energy Transfer Held Criminally Responsible for Damage from Pipeline

The state attorney general says Texas-based pipeline builder Energy Transfer is "accepting criminal responsibility" for dozens of charges related to construction of its Mariner East pipeline project and the 2018 explosion of the Revolution pipeline in Beaver County.

Attorney General Josh Shapiro announced the company pleaded no contest to the charges, meaning the company will have a permanent criminal record for causing damage to drinking water, wetlands and waterways across the state during five years of construction on the LNG pipeline system.

"Every time Energy Transfer bids for a new project here in the commonwealth of Pennsylvania or somewhere across this country their criminal conduct will stick with them forever," Shapiro said at a news conference announcing the plea.

More: *StateImpact Pennsylvania*

TENNESSEE

DEC Awards $5.2M for EV Charging Network

The Department of Environment and Conservation last week announced the awarding of $5.2 million in grants to install direct current fast chargers for electric vehicles along interstates and major highways.

The grants will fund 32 chargers at 13 sites as part of a partnership with the Tennessee Valley Authority to develop a fast-charging network along major travel corridors. TVA is contributing $15 million.

The grants are funded from a settlement with Volkswagen over software that allowed it to cheat on emissions tests.

More: *The Associated Press*

VIRGINIA

Records Show Regulator Lobbied for Gas Project

Records obtained by the Energy and Policy Institute through a Freedom of Information Act request to officials in Petersburg show that Marine Resources Commissioner James Minor lobbied elected city officials to support a proposed natural gas pipeline expansion now before the commission, as well as FERC.

The records show that Minor sent draft support letters to the Petersburg City Council that would be sent on behalf of a pipeline expansion project from TC Energy and its subsidiary, Columbia Gas Transmission, to FERC. Minor also sent the Petersburg mayor a draft op-ed and asked him to put his name on it and emailed some city council members with TC Energy talking points in support of the project.

Minor declined to say how he came to promote a fossil fuel project that's headed to him for consideration. He said he didn't work for the company but wouldn't say if he was paid by the company or a subsidiary, or if someone approached him to do the work. "When it comes to the [project], then I'm going to have to recuse myself from it. That's all," he said in a phone interview.

More: *Richmond Times Dispatch*