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Commodity Insights

PLATTS MEGAWATT DAILY

Volume 27 / Issue 215 / November 8, 2022

NEWS HEADLINES

US POWER TRACKER: Nuclear fleet outage drives up coal, gas usage, power prices

- Without nuclear, gas reaches near 13-month high
- Nuclear outages occur the same season every four years
- Power forwards trended near or below year-ago packages

Another cyclone threatens Florida power grid, still rebuilding after Hurricane Ian

- Nicole forecast to land as hurricane
- Duke, FPL preparing to restore service
- Power, gas price, power demand effects likely

US to see surge of offshore wind lease sales in coming years along all coasts

- US to have 8 GW of floating offshore wind by 2027
- Offshore wind workforce needs to be developed

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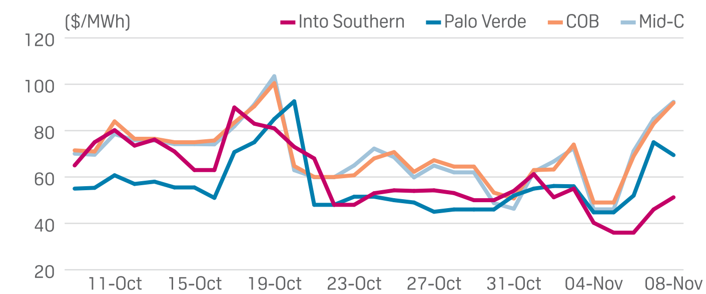
REGIONAL DAY-AHEAD PRICE CHANGES

	Day-ahead peak prices			Regional weather trends		
	09-Nov	Daily chg	Prior 7-day avg	09-Nov	Daily chg	7-day forecast
Southeast Bilateral Indices						
Into Southern	49.25	-2.00 ▼	45.11	63.2	-6.1 ▼	56.9
Into GTC	50.00	-2.00 ▼	52.30	56.8	-11.4 ▼	51.5
Florida	52.75	-2.00 ▼	54.89	69.4	-6.1 ▼	69.2
Into TVA	48.75	-2.25 ▼	52.07	65.8	-1.1 ▼	47.5
VACAR	49.00	-1.25 ▼	51.43	55.2	-3.2 ▼	55.6
West Bilateral Indices						
Mid-C Hourly	—	—	70.02	35.5	-3.8 ▼	37.1
Mid-C Day-Ahead	106.41	13.97 ▲	67.29	35.5	-3.8 ▼	37.1
John Day	108.50	14.00 ▲	69.29	35.5	-3.8 ▼	37.1
COB	105.00	13.00 ▲	67.61	35.5	-3.8 ▼	37.1
NOB	107.50	14.00 ▲	68.50	51.3	-3.3 ▼	51.9
Palo Verde	62.00	-7.46 ▼	57.30	55.2	-3.2 ▼	55.6
Mona	90.00	5.00 ▲	66.86	55.2	-3.2 ▼	55.6
Four Corners	67.50	-7.50 ▼	59.43	55.2	-3.2 ▼	55.6
Pinnacle Peak	65.75	0.00 —	53.57	55.2	-3.2 ▼	55.6
Westwing	81.50	13.25 ▲	53.71	55.2	-3.2 ▼	55.6
Mead	71.00	-7.00 ▼	62.00	55.2	-3.2 ▼	55.6
ISO Price Locations						
CAISO NP 15	84.94	-9.99 ▼	80.09	54.5	-3.1 ▼	55.9
ERCOT North Hub	38.30	-6.70 ▼	36.03	73.3	0.0 ▼	53.9
ISONE Internal Hub	45.78	5.66 ▲	40.74	42.1	-3.9 ▼	48.5
MISO Indiana Hub	44.45	-1.79 ▼	53.67	55.3	7.7 ▲	37.8
NYISO Zone G	46.78	5.94 ▲	39.74	45.5	-2.2 ▼	48.1
PJM West Hub	51.00	3.22 ▲	45.08	51.0	-0.5 ▼	46.4
SPP South Hub	31.97	-3.56 ▼	45.91	67.4	8.4 ▲	39.6

Source: S&P Global Platts

PLATTS BILATERAL DAY-AHEAD POWER INDEXES



Source: S&P Global Commodity Insights

PLATTS PEAK DAILY DEMAND (GW)

									Daily change		Season		Season average			
ISO	31-Oct	01-Nov	02-Nov	03-Nov	04-Nov	05-Nov	06-Nov	07-Nov	Chg	% Chg	Min	Max	2022	2021	Chg	% Chg
BPA-Puget	6.62	7.14	7.44	7.89	7.25	6.67	7.57	8.05	0.48	6.34	5.62	8.05	6.49	6.52	-0.03	-0.46
IESO	16.59	16.40	16.64	16.54	15.99	15.11	15.43	17.20	1.77	11.47	13.55	20.35	16.61	16.53	0.08	0.50
CAISO	26.57	27.19	27.14	27.21	26.53	24.60	25.22	27.64	2.42	9.60	24.60	51.29	32.74	30.86	1.89	6.11
ERCOT	45.45	44.36	47.04	52.11	52.80	42.56	48.53	53.32	4.79	9.87	39.70	70.98	57.04	56.48	0.56	0.99
SPP	29.25	29.99	24.94	30.86	30.39	28.45	28.71	31.02	2.31	8.05	24.94	48.26	34.72	34.73	-0.01	-0.03
MISO	71.09	73.67	74.47	75.55	74.04	66.82	71.48	78.31	6.83	9.56	65.87	106.75	79.87	81.82	-1.96	-2.39
PJM	84.53	87.08	86.26	85.88	84.36	81.17	84.81	69.60	-15.21	-17.93	23.29	126.95	91.74	96.46	-4.71	-4.89
NYISO	17.25	17.90	17.63	17.60	17.35	16.67	17.37	18.37	1.00	5.76	13.79	23.26	18.38	18.91	-0.53	-2.80
NEISO	13.50	14.49	14.11	14.13	13.72	13.29	14.20	14.68	0.48	3.38	10.23	17.60	14.21	14.77	-0.56	-3.77
AESO	10.08	10.37	10.77	10.88	10.77	10.84	10.88	11.34	0.46	4.23	9.43	11.34	10.08	9.83	0.25	2.54

Season definitions: Summer (June – August), Fall (September – November), Winter (December – February), and Spring (March – May).
Source: S&P Global Platts

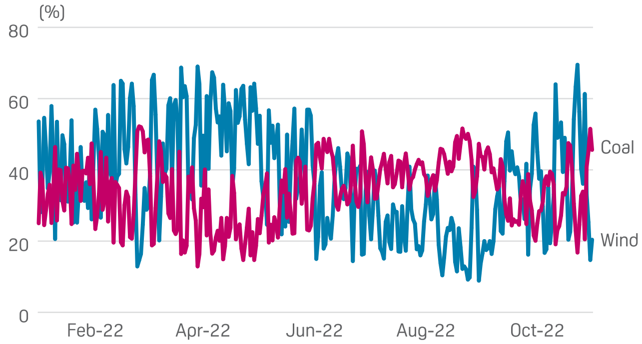
NEWS

US POWER TRACKER: Nuclear fleet outage drives up coal, gas usage, power prices

- Without nuclear, gas reaches near 13-month high
- Nuclear outages occur the same season every four years
- Power forwards trended near or below year-ago packages

Southwest Power Pool wholesale power prices rose by an average of 23.4% year over year in October, the biggest annual jump across the nation, as SPP's entire nuclear fleet went offline, leading to a shift to higher cost coal and gas generation.

WIND, COAL CONTINUE TO COMPETE FOR TOP SPOT



Source: SPP

Wind-powered generation returned to the top of the fuel stack, averaging 38.5% of the total fuel mix for October, up 6 percentage points month on month but little changed from a year ago, according to SPP data.

"Currently, it appears that wind may edge out coal as the largest source of generation in SPP this year," said Morris Greenberg, senior manager for North American power analytics with S&P Global Commodity Insights.

Coal and wind have been battling for the top fuel spot in SPP the last few years, with wind topping the stack in 2020, a first for a US grid operator, and coal at the top in 2021. So far this year, wind has accounted for roughly 37.8% of SPP's fuel mix, compared to 33.9% coal-fired generation, according to SPP data.

Generation mix

Coal-fired generation averaged 33.3% of the total fuel mix in October, little changed year over year, as gas-fired generation increased 6.5 percentage points to 24% of the mix, according to SPP data.

Nuclear generation slipped 6.3% percentage points year over year to average less than 1% of the fuel mix in October after nuclear generation disappeared from the stack after Oct. 6.

"All of SPP's nuclear generation was on scheduled outage at that time," SPP Spokeswoman Meghan Sever said.

Nebraska Public Power District's 836-MW Cooper began a refueling and maintenance outage Oct. 1, while Wolf Creek Nuclear Operating Corp.'s 1,249-MW Wolf Creek-1 in Kansas began a refueling and maintenance outage Oct. 6. According to S&P Global data, the average

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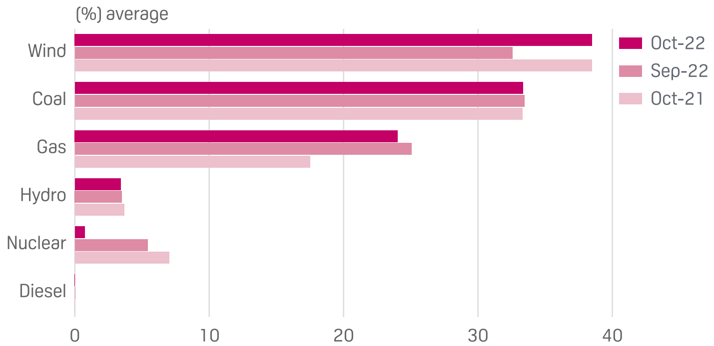
length of US nuclear refueling outages in 2021 was 31.7 days.

Loads were similar on average, as was wind generation, so the outage of both nuclear plants resulted in increased dispatch of higher cost gas and coal resources, Greenberg said. The last time both nuclear plants were offline at the same time was in October 2016. Wolf Creek is on an 18-month cycle and Cooper is 24 months so they should occur in the same season every four years, Greenberg added.

SPP GENERATION MIX COMPARISON



Source: SPP

Spot prices

As nuclear left the fuel stack, gas generation rose to a daily average of 40.5% of the total fuel mix Oct. 6, a near 13-month high, according to SPP data.

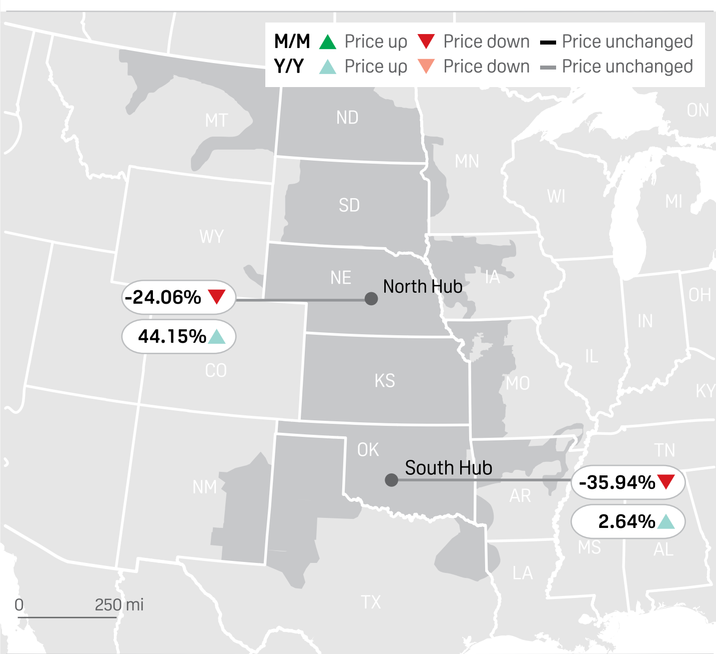
Panhandle Texas-Oklahoma averaged $4.827/MMBtu in October, down 5.5% year over year, even as prices reached a monthly high of $6.105/MMBtu Oct. 7 after the nuclear outages caused a shift to increased gas generation usage, according to S&P Global's pricing data.

The shift to gas generation usage also impacted power prices.

South Hub on-peak day-ahead locational marginal prices averaged $60.75/MWh in October, 2.6% higher than a year ago, as on-peak real-time prices were 21.7% higher at an average of $65.14/MWh, according to SPP data. The day of the Wolf Creek outages, South Hub prices climbed to $89.31/MWh, the high for the month.

North Hub on-peak day-ahead LMP averaged $49.10/MWh, a jump of 44.2% year over year, according to SPP data.

SOUTHWEST POWER POOL DAY-AHEAD POWER PRICE CHANGES



DAY-AHEAD ON-PEAK AVERAGE PRICE COMPARISON ($/MWh)

Location	Oct-22	Sep-22	Oct-21	M/M	Y/Y
SPP North Hub	49.09	64.65	34.06	-15.56	15.04
SPP South Hub	60.75	94.83	59.19	-34.08	1.56

Source: S&P Global Commodity Insights

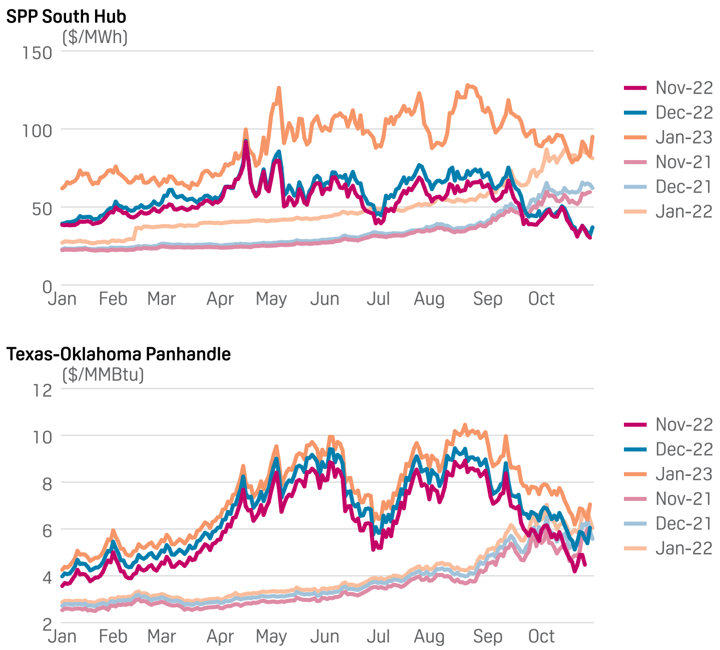
Forwards curve

In power forwards, packages trended near or below year-ago packages, following gas contracts.

South Hub on-peak November rolled off the curve at $37.30/MWh, 42% lower than where the 2021 package ended, according to S&P Global data.

South Hub on-peak December is currently in the mid-$60s/MWh, 6% below where its 2021 counterpart was, while the on-peak January package is in the upper $90s/MWh, 8% higher than its 2021 counterpart, according to S&P Global data.

POWERS, GAS FORWARDS FALL NEAR, BELOW YEAR-AGO PACKAGES



Source: S&P Global Commodity Insights

Summarily, Panhandle Texas-Oklahoma November rolled off the curve at $4.471/MMBtu, 26% below its 2021 counterpart, according to S&P Global data. The December contract is currently around $6.075/MMBtu, 4.3% higher than its 2021 counterpart, while the January contract is about $7.139/MMBtu, 13% higher.

The six-to-10 day outlook indicates a greater probability for below-normal temperatures across the SPP region, while the three-month outlook shows mixed expectations for temperatures, according to the US National Weather Service's Climate Prediction center.

— Kassia Micek

Another cyclone threatens Florida power grid, still rebuilding after Hurricane Ian

- Nicole forecast to land as hurricane
- Duke, FPL preparing to restore service
- Power, gas price, power demand effects likely

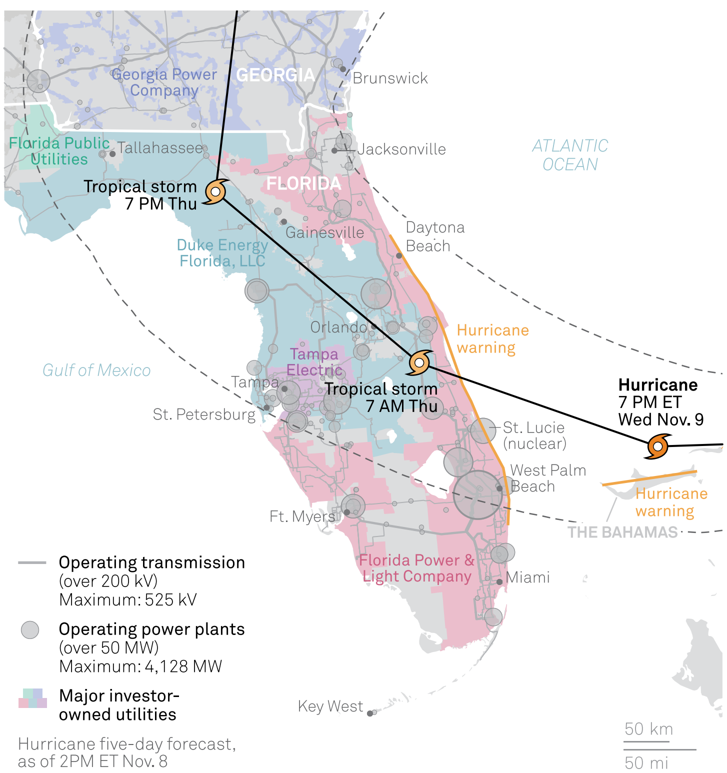
Tropical Storm Nicole, packing winds of 50 mph, is approaching Florida's Atlantic Coast, likely making landfall as a hurricane by Thursday, which has prompted Florida utilities to gear up for service interruptions and caused some power and natural gas price gyrations.

As of 1 pm ET Nov. 8, Nicole was about 420 miles east of West Palm Beach Florida, packing winds of 60 mph and moving due west at 9 mph, according to the National Hurricane Center, which issued a hurricane warning from Boca Raton to the Flagler/Volusia county line on Florida's Atlantic Coast.

The forecast path is for west to southwest through early Wednesday and a west to northwest movement beginning Wednesday night.

Tropical Storm Nicole targets Florida's battered power grid

As Florida's power utilities continue to rebuild after September's devastating major Hurricane Ian cut off power for almost 2.8 million Florida customers and caused more than $50 billion in damage in the Southeast, Tropical Storm Nicole threatens to strengthen into a hurricane before hitting the Sunshine State's Atlantic Coast Nov. 10. Ian had an impact on power and natural gas prices and on power demand, coinciding with a 41.5% decrease in power prices, a 23.8% decrease in gas prices and a 13.1% decrease in average load levels.



Source: S&P Global Commodity Insights, NOAA National Hurricane Center, S&P Global Market Intelligence

"On the forecast track, the center of Nicole will approach the northwestern Bahamas today and tonight, move near or over those islands on Wednesday, and approach the east coast of Florida within the hurricane warning area Wednesday night," the National Hurricane Center said in its public advisory. "Nicole's center is then expected to move across central and northern Florida into southern Georgia Thursday and Thursday night."

The storm is forecast to become a hurricane Wednesday near the Bahamas and remain a hurricane as it approaches Florida, the NHC said. Tropical-storm-force winds extend outward as much as 380 miles from the center.

Duke Energy on Nov. 8 urged customers to prepare for the storm, for which its Florida utility has stationed "crews and resources ... strategically throughout Florida – near areas that will likely be affected – to respond quickly and safely once the storm passes."

"As witnessed with Hurricane Ian, Duke Energy Florida is committed to restoring power as safely and quickly as possible," said Melissa Seixas, Duke Energy Florida state president. "Should outages occur, our crews and contractors are ready to respond."

Florida Power & Light, which serves most of the Atlantic Coast area in the hurricane warning zone, said Nov. 7 that it has activated its "emergency response plan and urges customers to take precautions ahead" of the storm.

Following Hurricane Ian's widespread destruction in late September, Nicole could topple storm-weakened trees throughout FPL's service area, especially in the western and central part of Florida, FPL said. Also, heavy rains, storm surge and flooding may slow access for service crews after the storm.

"We recognize our customers are experiencing storm season fatigue after Hurricane Ian, but it's important to be vigilant and focused as this storm approaches," said Eric Silagy, chairman and CEO of FPL.

Lingering effects of Ian

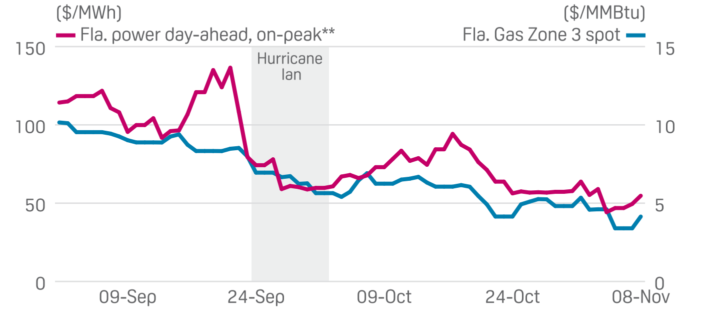
Ian made landfall as a major hurricane with 155 mph winds on Florida's southwest coast Sept. 28 and created massive destruction as it marched to the northeast, entered the Atlantic Sept. 29 and made landfall as a resurrected hurricane in South Carolina, finally dissipating as a post-tropical cyclone Oct. 2 in southern Virginia.

The National Oceanic and Atmospheric Administration estimated Ian's damage to total more than $50 billion in the US, while RMS, a Moody's Analytics company, estimated the insured losses at $67 billion.

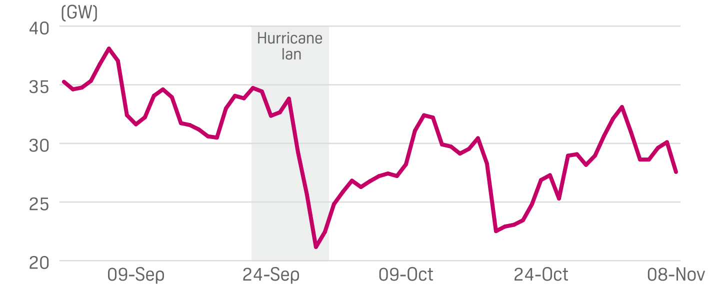
Ian also had an impact on energy markets. For the 10 days of its influence on the Southeast, it coincided with a 41.5% decrease in S&P Global's Florida day-ahead on-peak power indexes, a 23.8% decrease in Florida Gas Transmission Zone 3 spot prices and a 13.1% decrease in the Florida Reliability Coordinating Council's load levels, compared with the previous 10 days.

The FRCC is the North American Electric Reliability Corporation's regional reliability entity for all of Florida except the panhandle, which is another reliability entity footprint. The load level data is from the US Energy Information Administration.

FLORIDA POWER AND GAS ASSESSMENTS, AVERAGE LOAD LEVELS



FRCC average load levels*



- **23-Sep** Tropical Depression 9 forms
- **24-Sep** TD 9 becomes Tropical Storm Ian; state of emergency declared for Florida
- **26-Sep** TS Ian becomes Hurricane Ian
- **27-Sep** Hurricane Ian makes landfall at Cuba; mandatory evacuations ordered for certain low-lying areas of Florida
- **28-Sep** Ian makes landfall on Florida's southwest Gulf Coast
- **29-Sep** Ian weakens to tropical storm, exits Florida's northeast Gulf Coast
- **30-Sep** Ian strengthens to a hurricane, makes landfall in South Carolina
- **01-Oct** Ian weakens to post-tropical cyclone, moves through North Carolina
- **02-Oct** Post tropical cyclone dissipates over southern Virginia

*FRCC is the North American Electric Reliability Corporation's Florida Reliability Coordinating Council, which covers all of Florida execept the panhandle.
**For consistency, weekend/holiday on-peak prices were averaged between prices for the Friday before and the Monday/Tuesday after.

Sources: S&P Global Commodity Insights; US Energy Information Administration, National Hurricane Center

Energy market impacts

In the Southeast, wholesale power prices trade bilaterally and with little liquidity, as utilities are vertically integrated, and the Intercontinental Exchange had no trading activity in Florida power day-ahead on-peak power for Nov. 9-10 as of 3 pm ET Nov. 8.

S&P Global assessed Florida power at $54.75/MWh for delivery Nov. 8, which was up from $49.50/MWh for Nov. 7 delivery but down sharply from the $63.75/MWh index for the previous Tuesday.

Natural gas has a much more liquid market, and Florida Gas Transmission Zone 3 spot gas fell about 47 cents to trade around $3.68/MMBtu for delivery Nov. 9, the second-lowest level of 2022, barely above Nov. 4's $3.395/MMBtu. The range was $3.50-$4/MMBtu on Nov. 8, compared with October's closing price ranges of $4.145-$6.915/MMBtu.

Regarding FRCC average load levels, the EIA's mixture of actual and forecast hourly numbers for Nov. 8 was 27.6 GW, down 2.5 GW or 8.4% from Nov. 7 and down 4.5 GW or 14.1% with the previous Tuesday.

— Mark Watson, Tyler Godwin, Karen Rivera

US to see surge of offshore wind lease sales in coming years along all coasts

- US to have 8 GW of floating offshore wind by 2027
- Offshore wind workforce needs to be developed
- Port terminals 'nexus' for offshore wind development

The United States is about to see a surge of offshore wind lease sales in the next few years, even as challenges remain around permitting and workforce development, experts said Nov. 8 during the Offshore Wind Executive Summit in Galveston, Texas.

Globally, there is 50.5 GW of fixed bottom offshore wind, compared to only 123 MW of floating offshore wind, said Ankur Tohan, a partner with the law firm K&L Gates who focuses on energy infrastructure and natural resource development. By 2027, the US is expected to have 8 GW of floating offshore wind resources.

"There will be lease sales rolling out over the next couple of years," Tohan said about East Coast, West Coast and Gulf of Mexico.

In the US, there have been 10 offshore wind lease sales since 2013 and the Biden administration is targeting 30 GW of offshore wind by 2030, with an additional 15 GW of floating offshore wind by 2035. California is targeting 5 GW offshore wind by 2030 and 25 GW by 2045, while Oregon is targeting 3 GW by 2030 and Washington state is trailing, Tohan said.

However, it's very hard to build a new industry, including building a workforce and developing the supply chain, said Patrick Kinsman, vice president of offshore wind development with the Port of Virginia.

"If it was easy, someone else would have done it," Kinsman said.

It takes roughly 10 years to develop an offshore wind project from start - identifying call areas – to finish – putting steel in the water, Tohan said.

Port play

"The energy transition means we have to shift from one source of energy to multiple sources of energy and offshore wind is one of them," said Amol Phadke, project executive with developer Equinor. "I think we are at the forefront of figuring out this new industry" by using the knowledge developed from oil and gas offshore operations.

To develop offshore wind projects, onshore infrastructure will have to be developed within ports.

"We consider the terminals the nexus part for everything offshore wind related," said Jeffery Andreini, vice president at Crowley Marine Services, a vessel management, owner and supply chain logistics services company.

While existing ports have a lot of unused land, that doesn't mean the space available is suitable for offshore wind operations, Andreini said about considering area size, height requirements, water access and anchor tenants for offshore port operations.

"There's not a lot of places like that that exist in the United States," Andreini said about the space needed for offshore wind onshore operations. "I don't think people realize that there's only a handful of ports in the US able to do that."

Challenges

While port operations are needed to develop offshore wind resources, it doesn't come without challenges, panelists said about the time it takes for permitting, the rising costs from inflation, supply chain issues and finding funding to support project development.

A big component is having the workforce in place to handle to workload required to develop offshore wind and that doesn't begin with steering college or high school students into workforce, Andreini said. Rather, sixth, seventh and eight graders need to be inspired to go into the field as they will be the ones working there by the time offshore wind needs its workforce.

"You can have all the terminals and all the vessels, but without a workforce to move the vessels and to work offshore, you're not going to go anywhere," Andreini said.

— Kassia Micek

Industry, observers offer FERC recommendations to help New England reliability

- NGSA calls for market design changes
- Some call for further studies, analysis

Industry representatives and observers have offered varying recommendations for the Federal Energy Regulatory Commission to consider as it seeks to address winter reliability concerns in the Northeast.

In September, FERC held a forum in Vermont to discuss electric reliability and natural gas supply challenges facing New England, particularly in times of especially harsh winter conditions. The commission then sought comment following the forum (AD22-9).

ISO-New England's power market has at times struggled to meet demand, partially due to a reliance on gas-fired generation and pipeline system constraints that led to high prices and supply shortages. While the grid operator has said it expects to operate reliably through a mild or moderate winter, it would need additional fuel to handle more severe weather.

Several power and gas industry groups in addition to other parties offered recommendations to FERC Nov. 7.

In its comments, ISO-NE outlined its plan to address energy adequacy in the region, noting that its initiatives include short-, medium- and longer-term plans to better prepare for harsh winter conditions.

"The ISO has also committed to investigate other potential market changes that may improve energy adequacy, including, consistent with the suggestion of Commissioner [Allison] Clements, the transition to a seasonal capacity market and the evaluation of shortage pricing in the energy and ancillary services markets," the grid operator said.

Industry response

The Natural Gas Supply Association noted that there is a "central disconnect between the gas and power markets: generators are going to look to the natural gas industry for more flexibility as steeper, increased ramping is demanded to balance greater levels of intermittent resources."

Organized power markets do not incentivize advance natural gas contracting and purchasing, "which runs counter to what is required to ensure reliability," the group said. FERC could address some of these market challenges rather than turning to mandated fuel procurement practices, it added.

"FERC and ISO-NE should continue to collaborate with regional stakeholders to develop market design changes that eliminate or mitigate the financial risk associated with advance fuel procurement and contracting by gas generators by placing more value on reliability," the association said. "Also, other ways to encourage improved contracting and fuel procurement practices should be explored, such as adopting measures that provide greater awareness of generator contractual commitments, enhancing power market capacity accreditation, and adopting new flexible pipeline services."

Meanwhile, the Electric Power Supply Association said that the wholesale market design was not a "culprit in this reliability shortfall." Reliability risks will need to be clearly identified, so that "needed market design reforms can be developed to install effective, longer-term market-based solutions to winter reliability anxieties."

The association called for a new study on fuel security in the region, given that ISO-NE is still relying on a 2018 analysis.

"Specifically identifying the reliability target will assist in the ability to define and develop specific products and services that would help to solve the region's winter issues," EPSA said. "Given the urgency around this issue, there is no reason that any study cannot be completed expeditiously – this undertaking cannot delay action but instead is necessary to inform the appropriate action needed at this time."

Both the Advanced Energy Economy and the Advanced Energy Management Alliance pointed to ISO-NE's proposal to implement FERC Order 2222, which required grid operators to better integrate distributed energy resource aggregations into their markets.

Among other recommendations, AEE asked FERC to reject ISO-NE's filing to comply with that order, saying such action will "increase load flexibility, help to reduce energy demand during times of highest grid need, and make additional supply resources available."

"DERs alone will not solve the region's winter reliability challenges, but they can help to shrink the problem," AEE said.

Public interest organizations – including the Natural Resources Defense Council and Sierra Club – called for a "comprehensive, detailed study of the energy adequacy problem."

"In our view, a major stumbling block to achieving any degree of consensus around the extent of the winter energy adequacy problem, and the optimal solutions and acceptable costs for mitigating it, has been the absence of such a study that reflects careful stakeholder engagement and provides adequate transparency," the groups said in their joint comments.

— Ellie Potter

NYISO submits Long Island offshore wind transmission proposals to state regulators

- 17 potential projects submitted
- Transmission upgrades needed for offshore wind

The New York Independent System Operator has submitted transmission proposals to be evaluated by state regulators as a part of the 2022–2023 public policy transmission planning cycle, including 17 projects proposed in response to the Long Island Offshore Wind Export Public Policy Transmission Need.

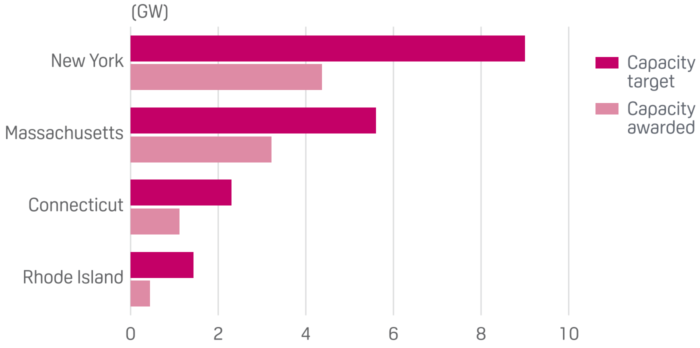
In the case of submittals proposing transmission needs that need a physical modification to transmission facilities in the Long Island transmission district, the grid operator's tariff requires the Long Island Power Authority to review those submittals driven by a public policy requirement, in consultation with the New York State Department of Public Service, according to a letter NYISO submitted to the NYSPSC Nov. 17.

On August 31, NYISO invited stakeholders and interested parties to submit proposed transmission needs driven by public policy requirements to NYISO on or before October 31, 2022.

One of the main public policy requirements impacting Long Island transmission infrastructure is the 2019 Climate Leadership and Community Protection Act that mandates 9,000 MW of offshore wind capacity by 2035, 70% renewable electricity by 2030, 100% zero-emissions electricity by 2040, along with a host of additional targets.

According to NYISO's Long Island Offshore Wind Export Public Policy Transmission Need Viability & Sufficiency Assessment completed in April, the baseline assessment results showed that the existing Long Island transmission system and tie lines are not capable of exporting offshore wind power to the rest of New York State that exceeds native Long Island power demand.

OFFSHORE WIND CAPACITY PROCUREMENT BY SELECTED STATES



Source: Eversource Energy

Multiple transmission constraints were identified at various volumes of offshore wind power injection to the Long Island power grid.

As part of its analysis, NYISO determined that the variability of load hour-by-hour, combined with the variability of offshore wind, results in the need for a robust intertie between Long Island and the rest of New York. Additionally, to meet power demand while always maintaining appropriate levels of operating reserves in Long Island, transmission projects capable of supporting power transfer both into and out of Long Island will be highly preferred, according to the results of a 2021 technical conference on the matter.

As a result of the process to date, 17 proposals for Long Island transmission needs driven by public policy requirements have been submitted to the grid operator by developers including:

- AES Clean Energy
- Avangrid Networks
- City of New York
- Con Edison Transmission
- Hydro Québec Energy Services
- Invenergy
- LS Power Grid New York Corporation
- National Grid Ventures
- NextEra Energy Transmission New York
- New York Transco
- The New York Power Authority
- Ørsted Wind Power North America
- PSEG Long Island
- Rise Light & Power

— Jared Anderson

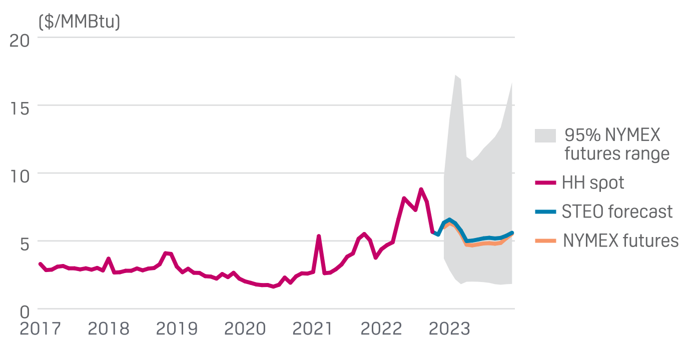
US EIA trims near-term spot gas price forecasts on faster storage injections

- Lowers Q4 Henry Hub spot forecast $1.59 to $5.82/MMBtu
- Potential for price spikes, volatility in event of extreme cold

The US Energy Information Administration pared back its forecast for Henry Hub spot natural gas prices in fourth quarter of 2022 and the early part of 2023, pointing to gas storage levels that have risen more than expected as winter approaches.

The agency, in its November Short-Term Energy Outlook, lowered its Q4 spot gas price forecast by $1.59 to $5.82/MMBtu, and cut its Q1-23 forecast by 91 cents from the previous month's estimate to $6.21/MMBtu.

HENRY HUB NATURAL GAS PRICE AND NYMEX CONFIDENCE INTERVALS



Note: Confidence interval derived from options market information for the five trading days ending Oct 6, 2022. Intervals not calculated for months with sparse trading in near-the-money options contracts.

Sources: US EIA's Short-Term Energy Outlook, CME Group, Refinitiv an LSEG Business

"Higher-than-average injections of natural gas into storage in September and October reduced the deficit of natural gas inventories to the five-year average and contributed to falling natural gas prices," the agency said in the outlook.

But those lowered price forecasts are unlikely to present much relief from higher retail natural gas prices this winter, because of the typical lag between changes in wholesale and retail prices for gas, the agency indicated.

In the event of extremely cold weather, the EIA said the possibility is high this winter for gas price spikes and volatility, and this could affect Henry Hub and regional pricing hubs, especially in New England. In warning of volatility risk, the agency noted that inventory draws in December and January are forecast to exceed the five-year average, "driven by a seasonal decline in natural gas production, rising demand for space heating, and increases in LNG exports that largely result from the return of Freeport LNG."

The June shutdown at the Freeport terminal pushed about 2 Bcf/d in lost feedgas demand back into the East Texas market, but the terminal has targeted a partial restart in November.

The EIA is assuming 2% more heating degree days than the prior winter, based on the US National Oceanic and Atmospheric Administraton forecast.

Overall, Henry Hub natural gas prices are forecast to average $6.49/MMBtu for full-year 2022 and $5.46/MMBtu in 2023, down from the previous month's estimates of $6.88 /MMBtu in 2022 and $5.77/MMBtu in 2023.

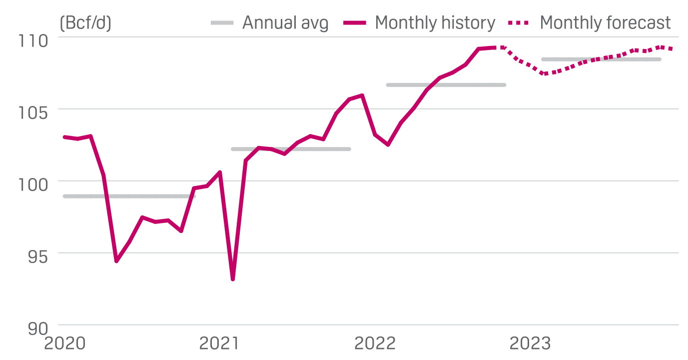
Production

On the supply side, the EIA bumped up its US natural gas marketed production estimate for Q4 2022 by 1.09 Bcf/d to 108.97 Bcf/d, but then trimmed the prior month's forecast for Q1 2023 by 260 MMcf/d to 107.67 Bcf/d.

"We expect declines in natural gas production during the winter months due to the possibility of extreme weather, which can cause production shut-ins," the outlook said, In addition, lower prices and some pipeline constraints are likely to reduce drilling activity, the agency said, estimating that dry gas production will average 99.7 Bcf/d in 2023, down from the current monthly average, but 2% above 2022 levels.

Total US gas marketed production is seen averaging 106.69 Bcf/d in 2022 and 108.45 in 2023, up from 102.27 in 2021.

US MARKETED NATURAL GAS PRODUCTION



Source: EIA's Short-Term Energy Outlook

On the demand side, the agency raised its natural gas consumption estimates by 940 MMcf/d to 91.14 Bcf/d for Q4, but shaved its forecast by 60 MMcf/d to 102.9 Bcf/d for Q1 2023.

The agency expected downward pressures on prices would emerge in Q2 2023.

"In 2023, the combination of natural gas consumption and exports in our forecast falls by more than 1 Bcf/d on average compared with 2022, while combined production and imports rise by a similar amount, leading to strong injections during the 2023 refill season."

Dip in generation

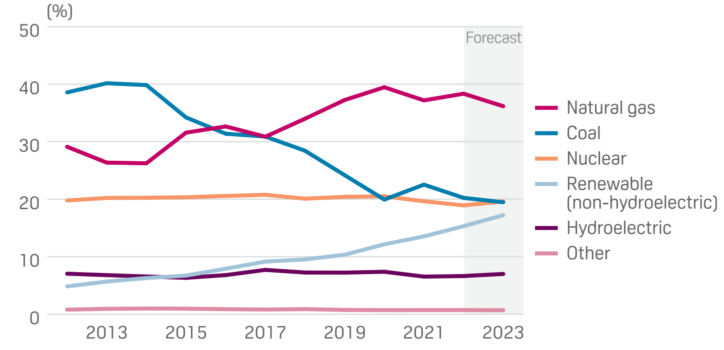
On the power side, the EIA expected that 2% lower US generation in 2023, driven by lower expected air conditioning demand, would lead renewables to grow their share of total US generation. Renewables are forecast to rise from 22% of the mix in 2022 to 24% in 2023, representing the only source to increase its share.

"We expect notable decreases in electricity generation from natural gas and coal next year," said EIA Administrator Joe DeCarolis, in a statement accompanying the outlook.

Gas-fired generation is expected to slip to 36% in 2023, down from 38% in 2022, despite a decline in prices year over year. And the share from coal is seen falling further, to 19% in 2023 from 20% in 2022.

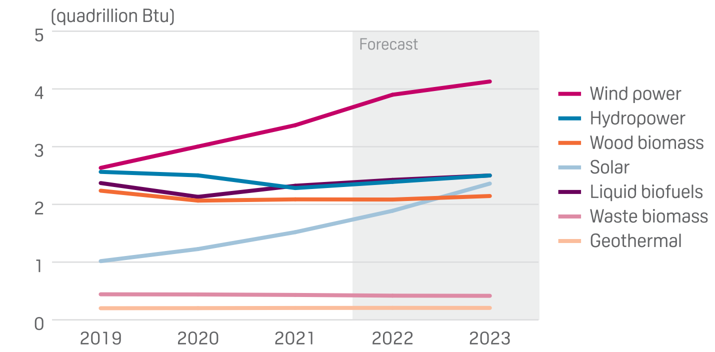
"Generators plan to retire 12 GW of coal-fired capacity in 2022 and 9 GW in 2023," the EIA said.

US ELECTRICITY GENERATION BY FUEL SOURCE



Source: EIA's Short-Term Energy Outlook

US RENEWABLE ENERGY SUPPLY



Source: EIA's Short-Term Energy Outlook

— Maya Weber

US needs to increase electric generation by up to 480% to meet 2050 goals: study

- Fossil fuel-based generation could fall to as low as 9%
- In all scenarios, hydrogen-based generation plays a role

The US economy will need to increase its electric generation capacity by up to 480% if the nation is to reach its 2050 decarbonization goals, according to a study unveiled Nov. 8 during the UN Climate Change Conference in Sharm el-Sheikh, Egypt.

The study, jointly released by the Electric Power Research Institute and GTI Energy, found that the US would need to build its firm capacity to between 1,140 GW and 1,450 GW – compared to 850 GW today – and its wind and solar capacity to between 800 GW and 3,700 GW – compared to 200 GW today – to reach the midcentury climate goals set in the Paris Accord.

Within each of these ranges are various scenarios that project different technology advancements and fuel costs. The high end of the wind and solar capacity projection, for instance, assumes high levels of hydrogen produced via electrolysis. Firm capacity resources, which is needed to balance intermittent resources, include nuclear, geothermal, hydrogen, hydro, bioenergy and natural gas with or without carbon capture.

On the low end, combined firm and intermittent resources would need to increase by 160% from today's levels to 1,650 GW. On the high end, electric generation resources would need to increase by 480% to 4,860 GW.

"The optimal mix of renewables and clean firm resources varies by region and depends on interactions with decarbonization options outside the electric sector, such as opportunities for negative emissions and demand for electrolytic hydrogen," the study said. "In all scenarios, new gas and/or hydrogen-fueled electric generating capacity plays a critical role in providing resource adequacy and flexibility for reliable power generation."

Fossil fuel to low-carbon fuels

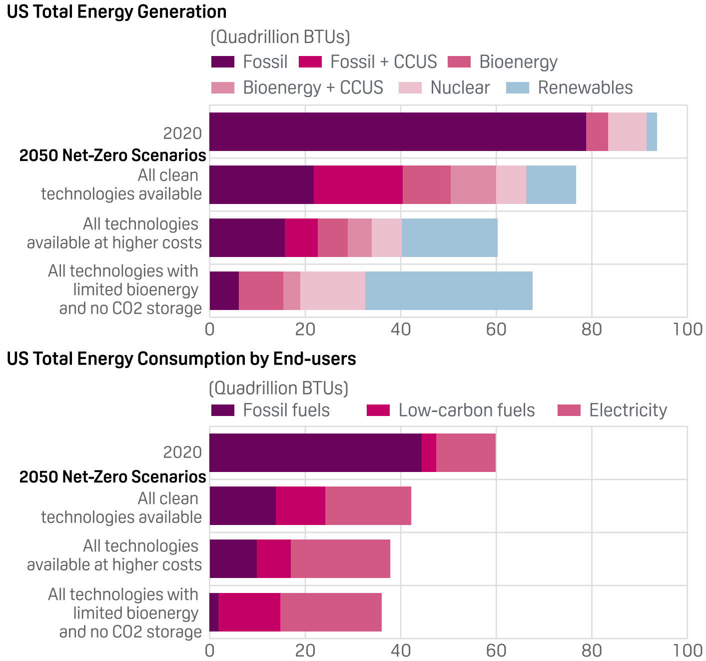
The US currently uses fossil fuels for 86% of its electricity generation, but by 2050 that share could fall to between 53% and 9%, depending on the deployment of carbon management technologies, the study found.

In of 2020, the US produced a total of 93.6 quadrillion Btus of power. While fossil fuels made up the largest portion of that share, bioenergy comprised 5%, nuclear comprised nearly 9% and renewables comprised over 2%.

Fossil fuels are projected to drop to a projected 9% level in a 2050 scenario where geologic storage of CO2 is unavailable and bioenergy feedstock supply is limited. And under a 2050 scenario where fossil fuel feedstock costs and CO2 transport and storage costs are high, total generation is expected to be at around 60 quadrillion Btus, where fossil fuels would comprise 25% of that fuel mix and fossil fuels with carbon capture would comprise around 11%.

In a 2050 scenario where all clean energy and carbon management technologies are fully developed and widely deployed, and where fossil fuel feedstock costs are low, total generation would amount to 76.6 quadrillion Btus. Fossil fuels would comprise around 28% of the fuel mix while fossil fuel combined with carbon capture is at 24%.

2050 NET-ZERO SCENARIOS



Low-carbon fuels = hydrogen, hydrogen-derived fuels (e.g. synthetic fuels and ammonia), and bioenergy

Source: EPRI, GTI Energy

According to Neva Espinoza, vice president of low-carbon resources at EPRI, the analysis highlights the importance of optionality in meeting nationwide clean energy targets.

"Above all else, the energy system of tomorrow will need greater flexibility if the US is to reach its mid-century climate goals affordably, reliably, and equitably," Espinoza said. "When it comes to developing the full portfolio of energy resources, the decisions industry and government leaders make today will directly impact the options available in the decades ahead."

— Brandon Mulder

US gas executives express frustration at reliability scrutiny in NAESB sessions

- Greater gas-electric cooperation urged
- Supply issues key in New England: executives

Gas industry executives expressed frustration Nov. 8 at a North American Energy Standards Board meeting on natural gas and electric industry coordination, suggesting that sessions on the topic routinely boil down to how the gas industry should change to meet the needs of gas-fired generators whereas the power sector must also give ground to strengthen grid reliability in regions dependent upon gas-fired generation.

All stakeholders, including the power generation sector, must be willing to adjust expectations or negotiate in order to strengthen grids against extreme cold, when demand peaks for gas used for both power generation and home heating, said Andreas Thanos, gas policy specialist with the Massachusetts Department of Public Utilities. “It’s not about me, me, me,” Thanos told power sector counterparts during the latest Gas-Electric Harmonization Forum of NAESB.

Although the Federal Energy Regulatory Commission has compelled more gas-electric coordination over the years with some success, the discussions seem to examine what the gas industry should do to improve power grid reliability and less about what the power sector should do, added Eric Soderman of Eversource Energy.

In Eversource utility territories in New England during the coldest days of winter, “it’s a physical molecule problem” in that natural gas is in limited supply due to constrained pipeline capacity and opposition to building new pipelines, Soderman said.

A similar point was made by the Interstate Natural Gas Association of America (INGAA) in a Nov. 7 letter to the White House days after Eversource President and CEO Joseph Nolan asked President Biden to use emergency powers to ensure gas supplies are available in New England this winter.

Even the emergency actions sought by Nolan would be insufficient to fix the problems caused by policies that allow for obstruction of pipeline development, wrote Amy Andryszak, president and CEO of INGAA.

“I encourage your administration to pursue a long-term solution that addresses the root cause of the region’s long-standing electric reliability problems—a lack of adequate natural gas infrastructure—rather than focus only on short-term, ‘emergency’ solutions that were neither intended nor designed to address systemic issues like those present in New England,” Andryszak wrote.

In his letter, Nolan suggested Energy Secretary Jennifer Granholm convene the federal agencies that have relevant emergency authorities; the region’s governors and electricity regulators; ISO-New England; LNG terminal operators; power generators that supply the region; fuel suppliers and utilities.

Andryszak said pipelines need to be part of any discussion in New England, and during an interview with The Energy Daily Tuesday she emphasized that fuel supply concerns in the region are longstanding and require a long-term solution.

“These are not new concerns. We’ve been having these conversations for 10 years, and so we just felt like we needed to reemphasize that this is a longstanding issue and we’re going to need long-term solutions to address it, not just short-term emergency solutions as Mr. Nolan advocated in his letter,” Andryszak said.

New England gas squeeze

The natural gas squeeze in New England is the result of increased use of gas for power generation, recent extreme weather events and limited pipeline capacity. Power generators say they cannot afford to sign expensive, firm-supply contracts with pipelines because they are dispatched rarely, while pipelines say they cannot expand facilities with lower revenues from the cheaper, interruptible contracts that the generators sign instead.

Pat Wood, former chairman at FERC and the Texas Public Utility Commission and one of three co-chairs on the gas and electric harmonization forum at NAESB, said he is hoping to find some tangible fixes to present to the North American Electric Reliability Corp. and FERC, which called on NAESB earlier this year to convene the gas-electric coordination meetings.

Identifying points of disagreement can be helpful because “I don’t want to put forth a milquetoast report” to FERC, said Wood.

Another co-chair of the forum and former state regulator from Texas, Robert Gee, encouraged stakeholders to try to engage in give-and-take from their traditional positions heading into further meetings. “We have to find a way to bridge some gaps” to get some solid recommendations to FERC and NERC, Gee said.

Points of disagreement were clear in comments from Texas participants, with Michele Richmond, executive director of Texas Competitive Power Advocates, taking issue with the common refrain from Texas intrastate pipelines that generators must sign firm shipping contracts.

“I’d love it if we could have a dialogue about some of the problems,” but intrastate pipelines are not willing to engage in such discussions, Richmond said.

Intrastate pipelines in Texas have enacted changes mandated by state officials after Winter Storm Uri and believe that any problems are associated with electricity rate design in Texas, countered James Mann, legal advisor for the Texas Pipeline Association.

“The Texas market has been quite successful” because of the relative ease of building intrastate pipelines compared with interstate pipelines, Mann said. Seeking changes by the natural gas industry to address power market concerns does not seem like a wise solution, Mann said, noting that he only recently became aware of the NAESB forum.

“We’re always willing to talk” with Richmond’s group, but “there’s a wide gulf” between what TCPA believes the gas market should look like and the intrastate pipeline group’s views, said Mann.

The NAESB forum has been meeting for several months, after FERC and NERC asked the group to try and bridge any gaps that could help the gas and power sectors coordinate operations during extreme weather events.

— Tom Tiernan

Clean energy groups seek clarity, flexibility on US climate law’s tax provisions

- Projects must meet requirements for full credits
- Bonus credits also available based on location

Industry groups representing clean energy producers and manufacturers filed initial thoughts to the US Treasury Department on how to structure the roughly $270 billion worth of energy and climate-related tax breaks in the Inflation Reduction Act.

The tax incentives make up the bulk of the law’s $369 billion in climate and energy spending over the next decade. But without certainty on a range of areas, including wage requirements and bonus incentives, companies have warned that investment could be stifled.

"Clear, workable and flexible Treasury guidance is the key to incentivizing taxpayers and the clean energy industry to develop projects in a timely way — and at levels that will ensure the [Inflation Reduction Act] lives up to its promise," the American Clean Power Association's interim CEO and chief advocacy officer, J.C. Sandberg, said in a Nov. 4 statement.

The Inflation Reduction Act, or IRA, extended existing production and investment tax credits for wind, solar and other qualifying renewable energy resources by 10 years. It also created new incentives for stand-alone energy storage, existing nuclear plants and hydrogen and other carbon-free resources.

To receive the full value of the credits projects must meet prevailing wage and apprenticeship requirements. Developers can also receive bonus credits if projects are located in low-income areas or "energy communities" affected by a shift away from oil, gas and coal production or electricity generation from fossil fuels.

Energy communities

The IRA allows projects located in energy communities to qualify for a 10% bonus credit. Those communities can include brownfield sites affected by pollution, US census tracts where coal mines or coal-fired power plants have closed in recent decades, and areas where industries tied to fossil fuels contribute a certain percentage of local tax revenue and the unemployment rate is above the national average.

"With energy communities, mostly the comments were around having some certainty around what would qualify ... so that [developers] can start to have those conversations about financing with their tax equity investor, their lender for that matter, around what the capital stack is going to look like," Eli Hinckley, a partner at Baker Botts LLP focused on energy tax policy, said in an interview.

In its comments to Treasury, the American Clean Power Association, or ACP, said brownfields should include sites designated under the Comprehensive Environmental Response, Compensation, and Liability Act of 1980, known as CERCLA, as well as additional sites identified by the IRS and US Environmental Protection Agency.

More broadly, ACP asked the IRS to adopt a standard for deciding whether a facility is located in an energy community. The group said onshore projects should qualify if at least 10% of the total project is located in an energy community, which can be based on the project's nameplate capacity, total cost or area by acreage.

Offshore projects should be eligible if their interconnection facility, port used for staging and crewing, or node at which power from the project is "commercially settled" is located in an energy community, ACP said.

Furthermore, taxpayers should be able to certify or seek the energy community designation "before construction begins, up until project completion," the group said. To determine the "previous year" for unemployment rates, ACP suggested using the calendar year before the certification process starts, a designation it said should apply through the entire life of the tax credit.

In addition, Treasury should "clearly delineate" the list of jobs used to determine employment-based energy community designations and allow "multiple pathways" to certify that an area qualifies as an energy community based on its fossil fuel-derived tax revenue, the group said.

The Solar Energy Industries Association, or SEIA, asked the government to set "clear and inclusive definitions" for retired coal plants and mines. SEIA also urged flexibility for taxpayers to choose among various census tracts and statistical areas when determining a project's eligibility.

"Census tract shapes change frequently and IRS should allow the taxpayer to elect any census tract vintage between the year a retired coal-fired generating unit or closed coal mine was placed in service and the year the qualifying property is placed in service," the solar power advocate said.

Prevailing wage, apprenticeship requirements

The groups are also seeking more clarity on the wage and labor requirements. To receive full production and investment tax credits under the IRA, project developers, contractors and subcontractors must pay prevailing wages for the construction, alteration or repair of qualifying facilities. In addition, any project that needs four or more people to do such work must employ one or more qualified apprentices from a registered apprenticeship program to get full credits, although good-faith exemptions exist if qualified apprentices are unavailable.

The mandates apply to any project starting construction 60 days or more after the IRS issues final guidance on the wage and apprenticeship requirements.

SEIA asked that the IRS first release draft guidance, with the chance for public comment, before issuing the final guidance that triggers the 60-day clock. It also requested a detailed list of what prevailing wage and apprenticeship information must be kept to show compliance, as well as key definitions and lists of occupations for construction, alteration and repair.

Domestic content, timing of guidance

The IRA provides another 10% bonus credit for projects if 100% of construction materials, including steel and iron, and 40% of the cost of manufactured products (20% for offshore wind projects) are produced in the U.S. The percentage for manufactured products rises in future years.

Both ACP and SEIA said the iron and steel requirements should only apply to structural or load-bearing materials and not to manufactured products. Industry groups also want confirmation that any iron ore used to make construction materials does not have to be mined in the U.S., said Keith Martin, a tax and project finance lawyer with Norton Rose Fulbright.

Martin said the IRS is expected to issue wage and apprenticeship guidance by the end of 2022, but most other guidance will not be available until the first half of 2023, with final regulations arriving later.

"I wouldn't expect any regulations before late next year," Martin said in an interview.

S&P Global Commodity Insights reporter Molly Christian produces content for distribution on Capital IQ Pro*.*

— Molly Christian

HYDROGEN

Alaska pushes rebuild of Kenai ammonia/ hydrogen plant in DOE proposal

- Alaska pitches DOE to be designated as hydrogen hub
- Rebuild of closed Kenai ammonia plant also planned
- Project would aid large Alaska LNG Project to tap North Slope gas

Alaska is pushing to restart a mothballed ammonia plant at Kenai, south of Anchorage, as part of a plan to export liquid ammonia and hydrogen as a clean fuels alternative.

Alaska Gasline Development Corp, the state-owed gas corporation, has made the plan part of a proposal to the US Department of Energy that Alaska be designated as a DOE "hydrogen hub," an AGDC spokesman said Nov 7.

Several states including Alaska are competing for $7 billion in funds designated for six to 10 hydrogen hubs under the federal Infrastructure Investment and Jobs Act passed by Congress.

Alaska is requesting $850 million in DOE funding that would be matched with $3.75 billion in private-sector funds backed by offtake agreements from hydrogen customers in the US and Asia, according to an announcement by AGDC.

The state's plan includes a rebuilding of a closed Agrium Corp. ammonia plant at Nikiski, near Kenai in south Alaska, along with pipelines and injection facilities to sequester carbon dioxide in depleted gas reservoirs in Cook Inlet.

ADGC, Mitsubishi Corp., Toyo Engineering and Hilcorp Energy, a major Cook Inlet gas producer, also signed an agreement to study the commercial feasibility of producing ammonia from natural gas and sequestering carbon dioxide produced in the ammonia process.

"Natural gas is an essential fuel for the US and other nations to achieve future emissions targets, first as a replacement for widescale coal use and eventually as a source of zero-emission hydrogen," said Frank Richards, AGDC's president.

Hydrogen, in the form of liquid ammonia, emits no CO_2 when used to produce energy and is easier to store than liquid hydrogen, AGDC said in a statement.

North Slope pipeline needed

The project could use gas produced in Cook Inlet but it would also need construction of the Alaska LNG Project, a $40 billion project that would build an 800-mile pipeline to reach 35 trillion cubic feet of North Slope gas now stranded because of the lack of a pipeline.

Alaska LNG also involves a large liquefied natural gas plant at Nikiski, the terminus of the proposed pipeline. The project is now fully permitted but faces obstacles because of its huge front-end cost and competition from other LNG producing regions.

AGDC hopes the ammonia project could be a major customer for gas moved through a 42-inch pipeline.

Liquid ammonia, carrying hydrogen, could be used in turbines for power generation, becoming a clean fuel alternative to natural gas. Japanese utilities have been experimenting with liquid ammonia to power turbines and are interested in the concept to meet their goals to switch to cleaner burning fuels.

Alaska Sen. Lisa Murkowski said the Alaska LNG project, with costs estimated at about $40 billion, is fully permitted and at an advanced planning stage. "Adding hydrogen production to this project enhances and extends Alaska LNG's financial rationale with climate benefits," Murkowski said in a statement.

DOE's guidelines require that projects it funds be capable of producing 50 tons of hydrogen per day. Alaska LNG said its proposal can produce 600 tons of hydrogen daily.

Sequestration of carbon dioxide is a key part of the plan and ate and federal geologists say Cook Inlet has the best potential for carbon sequestration of any site on the west coast for sequestration due to the characteristics of depleted gas reservoirs in the region. There is an estimated 50 gigatons of CO_2 sequestration capacity, according to reports.

Cook Inlet, a decades-old oil and gas production region, has extensive infrastructure including the ammonia plant that operated from 1969 until 2010, when the plant closed due to worries over gas reserves in Southcentral Alaska being depleted.

Studies have been underway for several years on the potential for reopening the plant but the key consideration has always been a reliable supply of natural gas.

If approved, the project would require five years of planning and pre-construction activities and three years of construction for initial operations, according to AGDC spokesman Tim Fitzpatrick.

— Tim Bradner

SUBSCRIBER NOTES

Veterans Day US bilateral power and gas trading schedule

Daily North American power and natural gas data are as follows:

West bilateral assessments performed Nov. 8 will include day-ahead on-peak and off-peak for Nov. 9-10 flow.

West bilateral assessments performed Nov. 9 will include day-ahead on-peak and off-peak for Nov. 11-12 flow.

West bilateral assessments performed Nov. 10 will include day-ahead on-peak Nov. 14 flow, day-ahead off-peak for Nov. 13-14 flow, and weekend off-peak and on-peak for Nov. 13 flow.

Southeast bilateral assessments performed Nov. 10 will include day-ahead on-peak for Nov. 14 flow, day-ahead off-peak for Nov. 11-14 flow, and weekend on-peak for Nov. 11-13 flow.

Natural gas assessments performed Nov. 10 will be for physical flow Nov. 11-14.

For power price data questions, please contact Daryna Kotenko at daryna.kotenko@spglobal.com.

For natural gas price data questions, please contact Pam Libby at pam.libby@spglobal.com.

Platts invites feedback on US renewable energy certificates methodology

As part of its commitment to open and transparent pricing and product specifications, Platts, part of S&P Global Commodity Insights, would like to invite feedback on its US Renewable Energy

Certificates methodology, specifically the guidelines described in the methodology guide posted online at https://www.spglobal.com/commodityinsights/PlattsContent/_assets/_files/en/our-methodology/methodology-specifications/usrec.pdf. Platts reviews all methodologies annually to ensure they continue to reflect the physical markets under assessment. Platts regularly assesses the relevance of methodologies through continuous contact with the market. Feedback on methodologies is always welcomed by Platts. Platts is committed to providing advance notice in a clear time frame that gives users sufficient opportunity to analyze and comment on the impact of such proposed changes. Time frames vary depending on Platts analysis of the overall circumstances of a particular change. Methodology changes that materially alter an assessment and require an update to the methodology specification are preceded by extensive bilateral discussions with market stakeholders and open public forums. Routine changes or clarifications generally do not materially alter an assessment. Platts holds open public forums in which material methodology changes and feedback are presented, and at which further feedback may be given. Please send all comments, feedback, and questions to ElectricityPrice@spglobal.com and pricegroup@spglobal.com. For written comments, please provide a clear indication if comments are not intended for publication by Platts for public viewing. Platts will consider all comments received and will make comments not marked as confidential available upon request.

Platts to streamline hydrogen content distribution

In line with the development of its Energy Transition offering, Platts, part of S&P Global Commodity Insights, will continue to streamline the distribution of its hydrogen pricing content. As a result, several changes will affect the distribution of hydrogen price assessments in the coming months.

On Nov. 14, Platts will launch a dedicated daily market PDF report for hydrogen. The report will be entitled Platts Hydrogen Daily and will feature hydrogen price assessments, as well as relevant ammonia prices and market news and insights. The report will be available to Energy Transition subscribers on Platts Dimension Pro, via email and on Platts Energy Transition Alert (ETA).

From Jan. 16, hydrogen pricing content available on a complimentary basis to non-Energy Transition subscribers on Platts Dimensions Pro will be adjusted to a selection of key price assessments. A selection of hydrogen price assessments will also remain available alongside related content on the Platts LIVE Energy Transition page. For further content including our full suite of hydrogen price assessments, please contact our Client Service team via support@platts.com and ask about our Energy Transition packages.

For questions regarding our hydrogen market coverage and methodology, please reach out to hydrogenassessments@spglobal.com and pricegroup@spglobal.com. For written comments, please provide a clear indication if comments are not intended for publication by Platts for public viewing. Platts will consider all comments received and will make comments not marked as confidential available upon request.

Platts decides to launch new daily hydrogen market report

Platts, part of S&P Global Commodity Insights, has decided to launch Nov. 14 a dedicated daily market report for hydrogen.

The report will be called Platts Hydrogen Market Report and will feature existing and new hydrogen pricing along with relevant ammonia prices. It will also include summary of the topical hydrogen news of the day along with a commentary of the global hydrogen market. This will provide analysis of market fundamentals, trends and discuss the factors driving prices, thereby bringing better access to the market and greater transparency.

The report will be available in the Energy Transition section of Platts Dimension Pro as well as be emailed directly in a PDF format to subscribers.

Please address any questions or comments to hydrogenassessments@spglobal.com and pricegroup@spglobal.com.

For written comments, please provide a clear indication if comments are not intended for publication by Platts for public viewing. Platts will consider all comments received and will make comments not marked as confidential available upon request.

EMISSIONS MARKETS

EMISSIONS MARKETS, NOV 03 (Current Year Vintage)

	Symbol	Close	Change
RGGI Current Month Strip ($/Allowance)	ARJAF00	13.660	0.620
RGGI Next Month Strip ($/Allowance)	ARJAG00	13.730	0.630
RGGI Next December Strip ($/Allowance)	ARECA04	13.730	0.570
CCA Current Month Strip ($/Allowance)	ARJAH00	28.800	0.570
CCA Next Month Strip ($/Allowance)	ARJAI00	29.030	0.730
CCA Next December Strip ($/Allowance)	ARECB04	29.030	0.540
CCO Current Month Strip ($/mt)	ARJAJ00	18.965	-0.215
CCO Next Month Strip ($/mt)	ARJAK00	19.550	0.350
CCO Next December Strip ($/mt)	ARECC04	19.550	0.330

REC MARKETS

RENEWABLE ENERGY CERTIFICATE MARKETS, NOV 03 ($/MWh)

	Symbol	Close	Change
RECs Current Year Vintage*			
Connecticut REC Class 1	RECCTC1	36.200	-0.250
Massachusetts REC Class 1	RECMAC1	36.250	-0.200
Maine REC Class 1	ARFAQ00	31.500	0.500
New Hampshire REC Class 1	ARFAV00	36.150	-0.500
Rhode Island REC Existing	ARGAB00	10.250	0.000
Rhode Island REC New	ARGAC00	36.400	-0.100
Vermont REC Tier 1	ARGAG00	NA	NA
NEPOOL REC Dual Qualified Class 1	ARHAA00	36.400	-0.200
Maryland REC Tier 1	RECMDT1	25.150	0.050
New Jersey REC Class 1	RECNJT1	25.480	0.340
New Jersey REC Class 2	AREAW00	17.380	2.380
Pennsylvania AEC Tier 1	RECPAT1	25.200	0.200
Ohio non-Solar REC	RECOHI0	3.600	0.520
DC REC Tier 1	ARGAO00	10.500	-0.500
Delaware REC Tier 1	ARGAS00	NA	NA
Virginia non-Solar REC	ARGAW00	11.350	0.310
PJM Tri-Qualified REC Tier 1	ARHAD00	25.400	0.350
Texas non-Solar Compliance REC	RECTX00	2.250	-0.175
Texas Green-e Eligible Wind REC	ARFAI00	2.250	-0.175
Michigan non-Solar REC	ARFAM00	3.750	0.000
New York REC Tier 1	ARGAK00	24.000	-0.500
New York Wind REC	ARGAM00	17.250	0.000
M-RETS Compliance REC from CRS Listed Facilities FH	ARHAF00	1.700	0.000
M-RETS Compliance REC from CRS Listed Facilities BH	ARHAG00	1.800	0.000
NAR Any REC	ARHAI00	1.700	0.000
NAR Any Green-e Eligible REC	ARHAK00	1.700	0.000
NAR Green-e Eligible Wind REC	ARHAN00	1.700	0.000
California Bundled REC Bucket 1	RECCAB1	12.750	0.000
California Bundled REC Bucket 2	RECCAB2	9.000	0.000
California Bundled REC Bucket 3	RECCAB3	5.200	0.000
National Green-e Certified REC Any Technology	RECUSAV	2.190	-0.070
National Green-e Certified Wind	RECUSWV	2.200	-0.060
Solar RECs Current Year Vintage*			
Massachusetts SREC 1	RECMAS0	336.000	0.000
Massachusetts SREC 2	ARHAW00	278.500	-0.500
Maryland SREC	RECMDS0	61.000	0.000
New Jersey SREC	RECNJS0	224.500	0.000
Pennsylvania SAEC	RECPAS0	46.000	0.000
Ohio SREC	RECOHSI	3.750	0.000
DC SREC	ARIAL00	382.500	0.000
Delaware SREC Class 1	ARIAO00	NA	NA
Virginia In-State SREC \<1MW	ARIAX00	40.000	0.000
Texas SREC	ARIAR00	2.600	0.000
Texas Compliance SREC from CRS Listed Facilities	ARIAT00	2.600	0.000
New York SREC	ARIAE00	NA	NA
NAR SREC	ARJAA00	NA	NA
NAR SREC CRS Listed	ARJAC00	NA	NA

*Prices are for the value of the environmental attribute of the renewable energy certificate only and do not include energy. Additional pricing for California Bundled RECs, National Voluntary RECs, additional Classes/Tiers, and Prior and Next year Vintages can be found on https://dimensionspro.spglobal.com/.

I-REC MARKETS

PLATTS GLOBAL I-RECS ASSESSMENTS

	Brazil			Turkey		India		
	BRL/MWh	USD/MWh	Eur/MWh	Eur/MWh	USD/MWh	INR/MWh	USD/MWh	Eur/MWh
Hydro								
Previous Year	1.490	0.288	0.290	0.360	0.363	—-	—-	—-
Current Year	1.490	0.288	0.290	0.440	0.443	—-	—-	—-
Wind								
Previous Year	1.910	0.370	0.372	0.440	0.443			
Current Year	1.910	0.370	0.372	0.560	0.564			
Solar								
Previous Year	1.910	0.370	0.372	0.440	0.443			
Current Year	1.910	0.370	0.372	0.560	0.564			
Biomass								
Previous Year	1.170	0.226	0.228	0.340	0.343			
Current Year	1.170	0.226	0.228	0.420	0.423			

GLOBAL BITCOIN QUARQ SPREADS

SPOT EUROPEAN, NOVEMBER 7 ($/MWh)

Nordics, Germany, France, Spain

	Spread	Renewable-Hydro	Renewable-Wind	Renewable-Solar
NO1	56.75	49.76	49.85	49.85
NO2	56.75	49.76	49.85	49.85
NO3	60.70	53.70	53.80	53.80
NO4	82.10	75.10	75.20	75.20
NO5	56.75	49.76	49.85	49.85
SE1	60.56	53.57	53.66	53.66
SE2	60.56	53.57	53.66	53.66
SE3	60.56	53.57	53.66	53.66
SE4	60.56	53.57	53.66	53.66
FI	-51.33	-58.33	-58.24	-58.24
DK1	46.09	39.09	39.18	39.18
DK2	45.42	38.42	38.51	38.51
Systemwide	53.74	46.75	46.84	46.84
Germany	23.43	16.43	16.53	16.53
France	-25.35	-32.35	-32.25	-32.25
Spain	-21.37	-28.37	-28.27	-28.27

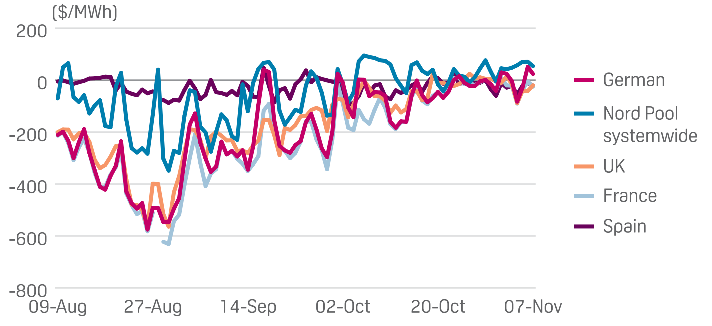
United Kingdom

	Spread	Renewable-Non-Biomass	Renewable-Biomass
GB	-20.12	-27.14	-26.33

SPOT NORTH AMERICAN, NOVEMBER 7 ($/MWh)

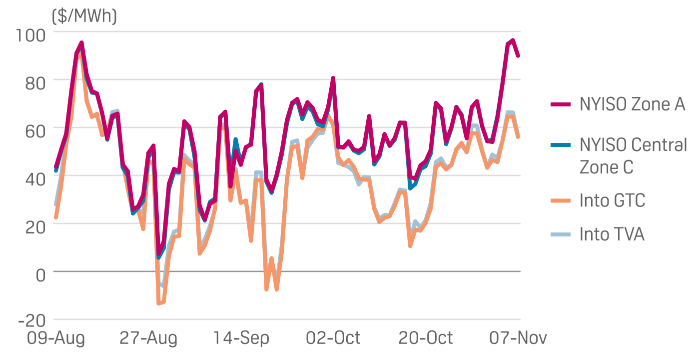
	Spread	Renewable-Any Tech	Renewable-Solar
Texas			
ERCOT AEN Zone	59.12	56.93	56.52
ERCOT Bus Average	59.57	57.38	56.97
ERCOT CPS Zone	59.00	56.81	56.40
ERCOT Houston Zone	56.48	54.29	53.88
ERCOT Hub Average	59.07	56.88	56.47
ERCOT LCRA Zone	59.08	56.89	56.48
ERCOT North Zone	59.72	57.53	57.12
ERCOT Rayburn Zone	59.60	57.41	57.00
ERCOT South Zone	59.51	57.32	56.91
ERCOT West Zone	56.39	54.20	53.79
Midwest			
SPP North Hub	78.37	76.18	75.77
SPP South Hub	70.04	67.85	67.44
Georgia			
Into GTC	56.02	53.83	53.42
Kentucky			
Into TVA	56.60	54.41	54.00
Indiana Hub	55.88	53.69	53.28
New York			
NYISO Zone A	89.89	87.70	87.29
NYISO Zone C	89.91	87.72	87.31
NYISO Zone D	95.03	92.84	92.43
NYISO Zone E	89.49	87.30	86.89
California			
CAISO NP16 Gen Hub	10.67	8.48	8.07
CAISO SP15 Gen Hub	13.13	10.94	10.53
Washington			
Mid-Columbia	19.46	17.27	16.86

BITCOIN QUARQ SPREADS NORDICS vs GERMANY, UK, FRANCE, SPAIN SPOT BASELOAD



Source: S&P Global Commodity Insights

BITCOIN QUARQ SPREAD NYISO vs INTO GTC, INTO TVA



Source: S&P Global Commodity Insights

RENEWABLE CAPTURE PRICES

RENEWABLE CAPTURE PRICE INDEXES ($/MWh)

Date: 06-Nov*

Index	Symbol	Current	Previous
CAISO			
CAISO NP15 Gen Hub Solar	ACPIC00	64.27	56.73
CAISO NP15 Gen Hub Wind	ACPIA00	76.28	68.86
CAISO SP15 Gen Hub Solar	ACPID00	31.03	27.21
CAISO SP15 Gen Hub Wind	ACPIB00	60.62	57.87
CAISO ZP26 Gen Hub Solar	ACPIE00	31.20	25.00
ERCOT			
ERCOT North Hub Solar	ACPIL00	22.42	18.04
ERCOT North Zn Weighted Average LMP Wind	ACPII00	16.05	11.07
ERCOT South Hub Solar	ACPIN00	24.44	20.95
ERCOT South Zn Weighted Average LMP Wind	ACPIK00	29.12	15.93
ERCOT West Hub Solar	ACPIM00	23.01	15.32
ERCOT West Zn Weighted Average LMP Wind	ACPIJ00	8.59	5.01
ISONE			
ISONE Internal Hub Solar	ACPXE00	28.34	30.35
ISONE Internal Hub Wind	ACPXD00	27.01	28.03
MISO			
MISO Indiana Hub Solar	ACPIT00	28.94	33.32
MISO Indiana Hub Wind	ACPIR00	29.15	32.60
MISO Louisiana Hub Solar	ACPIU00	38.78	40.86
MISO Minnesota Hub Solar	ACPIS00	8.12	20.12
MISO Minnesota Hub Wind	ACPIQ00	9.44	15.69
NYISO			
NYISO Hudson Valley Zone Wind	ACPXB00	25.51	31.25
NYISO West Zone Wind	ACPXC00	9.31	11.57
PJM*			
PJM Dominion Hub Solar	ACPXA00	47.34	59.96
PJM Dominion Hub Wind	ACPIX00	44.72	47.86
PJM Northern Illinois Hub Solar	ACPIZ00	35.66	45.07
PJM Northern Illinois Hub Wind	ACPIW00	28.21	35.72
PJM Western Hub Solar	ACPIY00	43.85	55.57
PJM Western Hub Wind	ACPIV00	42.24	41.86
SPP			
SPP North Hub Wind	ACPIO00	26.49	17.92
SPP South Hub Wind	ACPIP00	26.06	21.95

*Data is lagged 1 day, PJM data is lagged 4 days

Source: S&P Global Platts

SPP, ERCOT renewable capture prices rise amid robust renewable supply

- SPP wind penetration ramps up in November
- Wind curtailment drops
- ERCOT capture prices rise on day, decline from October levels

Southwest Power Pool wind capture prices for Nov. 6 generation were up 33.3% on average, compared with the day-before values, as wind penetration in the ISO remained strong.

Wind in SPP averaged 30.5% of the total fuel mix during on-peak hours and 39.2% during off-peak Nov. 6, in line with the previous day's level, according to Platts Renewable Penetration Index.

At the same time, the amount of curtailed wind dropped from 13.78 GW Nov. 5 to 8.96 GW Nov. 6, Platts Renewable Curtailment data showed.

Conversely, month-to-date capture prices fell, down 39% from their month-ago levels to average $24.80/MWh. Wind penetration so far in November has averaged 34.7%, up from the October average of 25.6%.

ERCOT prices follow suit

In the Electric Reliability Council of Texas , renewable prices saw significant rises Nov. 6, as the solar capture prices across the region jumped 30.4%, and wind prices rallied 66.4% from where the prices were the day before.

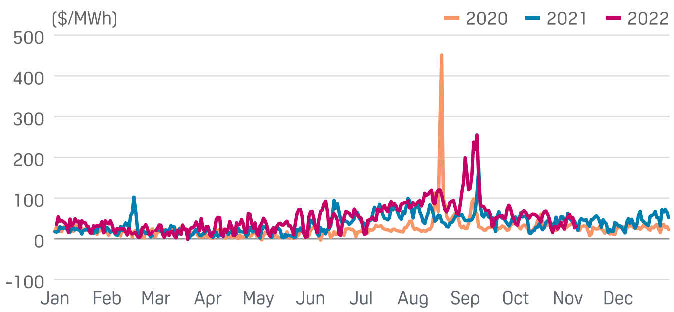
ERCOT solar production stood at 9% of the fuel mix, while wind accounted for 31.4%, up from the day-before levels of 8.5% and 29.9%, respectively.

Renewable capture prices fell considerably on the month in ERCOT, as solar across all three hubs was down 46.6% to average $25/MWh so far in November, and wind tumbled 65% to average $12.70/MWh.

Platts is part of S&P Global Commodity Insights.

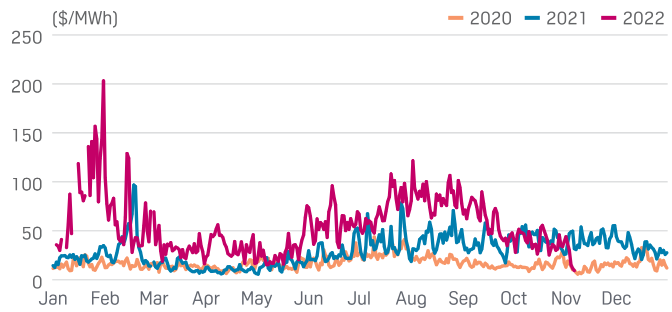
— Daryna Kotenko

CAISO SP15 GEN HUB SOLAR CAPTURE PRICE



Source: S&P Global Commodity Insights

NYISO WEST ZONE WIND CAPTURE PRICE



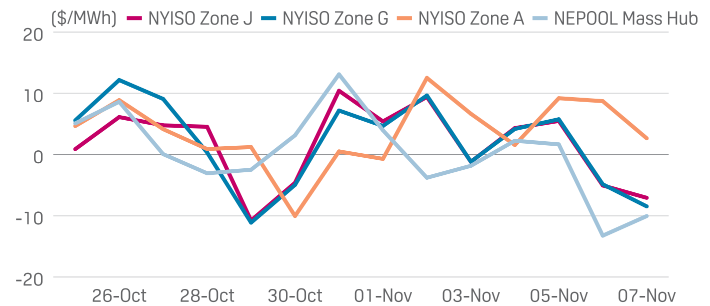
Source: S&P Global Commodity Insights

NORTHEAST POWER MARKETS

NORTHEAST DAY AHEAD POWER PRICES ($/MWh)

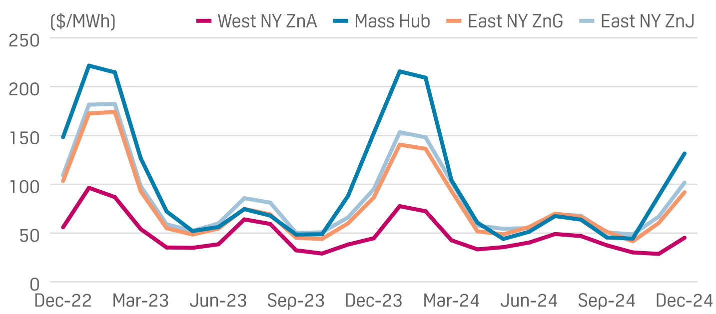
Hub/Index	Symbol	09-Nov	Marginal heat rate	Spark spread @7K	Spark spread @12K	Price change Chg	Price change % Chg	Prior 7-day Average	Month Min	Month Max	Yearly change Nov-22	Yearly change Nov-21	Yearly change Chg	Yearly change % Chg
On-Peak														
ISONE Internal Hub	IINIM00	45.78	13231	21.56	4.26	5.66	14.1	40.74	32.53	59.31	43.36	59.35	-15.99	-26.9
ISONE NE Mass-Boston	IINNM00	46.30	13382	22.08	4.78	6.07	15.1	41.02	32.75	59.95	43.71	60.38	-16.67	-27.6
ISONE Connecticut	IINCM00	44.86	10980	16.26	-4.17	5.45	13.8	40.01	31.72	57.12	42.45	57.24	-14.79	-25.8
NYISO Zone G	INYHM00	46.78	11451	18.18	-2.24	5.94	14.5	39.74	29.96	56.56	42.39	59.78	-17.39	-29.1
NYISO Zone J	INYNM00	47.07	14826	24.85	8.97	6.03	14.7	40.41	30.12	57.48	43.04	61.42	-18.38	-29.9
NYISO Zone A	INYWM00	26.27	8967	5.76	-8.89	1.39	5.6	22.93	11.40	47.42	26.02	47.74	-21.72	-45.5
NYISO Zone F	INYCM00	62.85	19796	40.63	24.75	9.29	17.3	53.27	43.38	63.06	54.90	64.44	-9.54	-14.8
Off-Peak														
ISONE Internal Hub	IINIP00	38.69	11183	14.47	-2.83	2.92	8.2	30.93	15.70	42.41	32.77	51.37	-18.60	-36.2
ISONE NE Mass-Boston	IINNP00	38.73	11193	14.51	-2.79	3.04	8.5	31.02	15.71	42.72	32.86	52.49	-19.63	-37.4
ISONE Connecticut	IINCP00	37.84	9262	9.24	-11.19	2.85	8.1	30.29	15.52	41.38	32.05	49.04	-16.99	-34.6
NYISO Zone G	INYHP00	36.91	9034	8.31	-12.12	8.49	29.9	29.01	19.86	39.98	31.11	47.46	-16.35	-34.5
NYISO NYC Zone	INYNP00	37.03	11662	14.80	-1.07	8.51	29.8	29.18	19.94	40.54	31.32	48.45	-17.13	-35.4
NYISO West Zone	INYWP00	19.91	6796	-0.60	-15.25	9.59	92.9	15.09	5.18	34.63	17.75	31.99	-14.24	-44.5
NYISO Capital Zone	INYCP00	50.66	15957	28.44	12.56	6.29	14.2	40.97	33.00	50.66	42.17	53.82	-11.65	-21.6

NORTHEAST AVG. DAY-AHEAD/REAL-TIME PEAK PRICE SPREAD



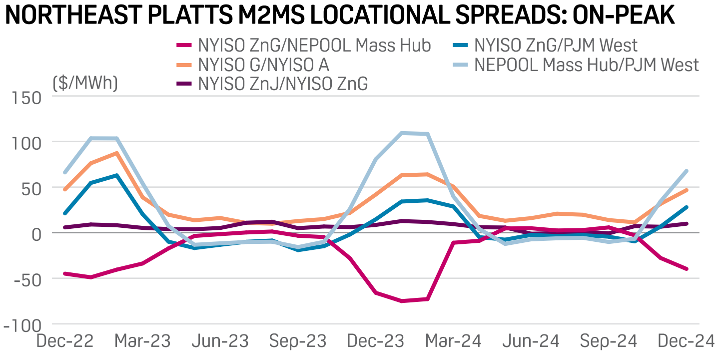
Source: S&P Global Commodity Insights, NYISO, ISONE

NORTHEAST PLATTS M2MS FORWARD CURVE: ON-PEAK



Source: S&P Global Commodity Insights

NORTHEAST PLATTS M2MS LOCATIONAL SPREADS: ON-PEAK



Source: S&P Global Commodity Insights

US Northeast power dailies continue to rise amid cooler temperatures forecast

US Northeast power prices for next-day delivery continued their upward movement in Nov. 8 trading, supported by cooler temperatures.

High temperatures in Boston and New York City were forecast in the lower 50s Fahrenheit Nov. 9, while lows trended in the mid-30s to lower 40s F, US National Weather Service data showed.

Power prices rise, forwards fall

ISO New England Mass Hub on-peak rose about $3.75 from its day-before level on the Intercontinental Exchange to trade near $44.50/MWh. Meanwhile, NYISO Zone J NYC and Zone G Hudson Valley on-peak locational marginal prices each added about $8.50 to $47/MWh and $46.75/MWh, respectively.

Prices trended higher even though ISO-NE peakload demand was set to remain flat at 14.88 GW Nov. 9, and NYISO load was forecast to slip 1.6%, peaking at 17.76 GW.

Moving in the opposite direction from power contracts, spot natural gas prices saw declines, with Algonquin city-gates down 45 cents from its previous Platts index to $3.41/MMBtu and Transco Zone 6 NY down 17 cents to $3.17/MMBtu for Nov. 9 flows.

Power forwards also fell, with Mass Hub December and January-February 2023 on-peak contracts down more than $10 on the day at $150/MWh and $218.25/MWh, respectively.

Tropical Storm Nicole

Tropical Storm Nicole was expected to become a Category 1 Hurricane before making landfall sometime on Nov. 10 in Florida, producing rainfall and damaging winds across the Southeast.

The US National Hurricane Center expected the system to move northeast and reach New York and New England by the weekend, bringing warmer temperatures in the 60s F and heavy rain.

Platts is part of S&P Global Commodity Insights.

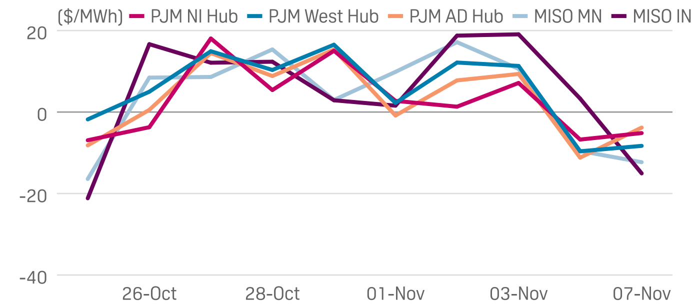
— Daryna Kotenko

PJM/MISO POWER MARKETS

PJM/MISO DAY AHEAD POWER PRICES ($/MWh)

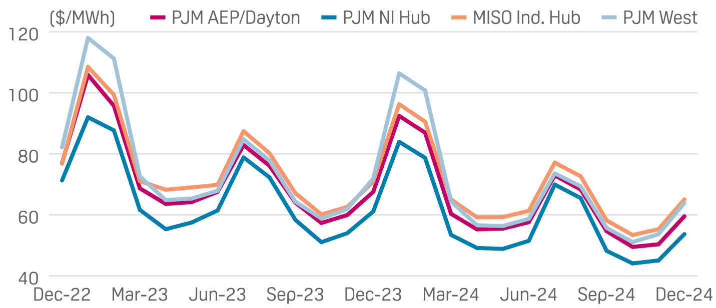
Hub/Index	Symbol	09-Nov	Marginal heat rate	Spark spread @7K	Spark spread @12K	Price change Chg	Price change % Chg	Prior 7-day Average	Month Min	Month Max	Yearly Change Nov-22	Yearly Change Nov-21	Yearly Change Chg	Yearly Change % Chg
On-Peak														
PJM AEP Dayton Hub	IPADM00	47.97	12741	21.61	2.79	0.92	2.0	44.63	32.11	55.72	46.24	64.41	-18.17	-28.2
PJM Dominion Hub	IPDMM00	53.16	14138	26.84	8.04	-3.11	-5.5	53.26	39.56	79.36	53.61	71.85	-18.24	-25.4
PJM Eastern Hub	IPEHM00	51.22	16876	29.97	14.80	12.05	30.8	32.08	19.95	55.49	36.81	52.39	-15.58	-29.7
PJM Northern Illinois Hub	IPNIM00	44.07	12485	19.36	1.71	2.01	4.8	38.55	25.95	51.17	40.57	52.15	-11.58	-22.2
PJM Western Hub	IPWHM00	51.00	16804	29.76	14.58	3.22	6.7	45.08	31.73	56.89	47.03	69.45	-22.42	-32.3
MISO Indiana Hub	IMIDM00	44.45	12592	19.74	2.09	-1.79	-3.9	53.67	44.45	60.46	51.55	70.43	-18.88	-26.8
MISO Minnesota Hub	IMINM00	29.87	8584	5.51	-11.89	8.02	36.7	35.65	21.32	48.13	32.36	51.56	-19.20	-37.2
Off-Peak														
PJM AEP Dayton Hub	IPADP00	38.70	10280	12.35	-6.48	10.55	37.5	27.67	19.88	38.70	29.94	53.99	-24.05	-44.5
PJM Dominion Hub	IPDMP00	41.39	11008	15.07	-3.73	11.87	40.2	29.79	22.36	41.39	32.00	62.37	-30.37	-48.7
PJM Eastern Hub	IPEHP00	38.33	12629	17.08	1.91	17.24	81.7	19.97	7.78	38.33	23.50	49.13	-25.63	-52.2
PJM Northern Illinois Hub	IPNIP00	33.13	9385	8.42	-9.23	10.81	48.4	19.90	12.81	34.50	22.99	38.36	-15.37	-40.1
PJM Western Hub	IPWHP00	41.20	13577	19.96	4.79	12.68	44.5	28.17	19.74	41.20	30.67	57.59	-26.92	-46.7
MISO Indiana Hub	IMIDP00	31.75	8994	7.04	-10.61	-1.89	-5.6	32.64	28.63	42.13	33.60	58.65	-25.05	-42.7
MISO Minnesota Hub	IMINP00	9.55	2744	-14.81	-32.21	5.02	110.8	10.18	3.67	21.42	11.36	37.49	-26.13	-69.7

PJM/MISO AVG. DAY-AHEAD/REAL-TIME PEAK PRICE SPREAD



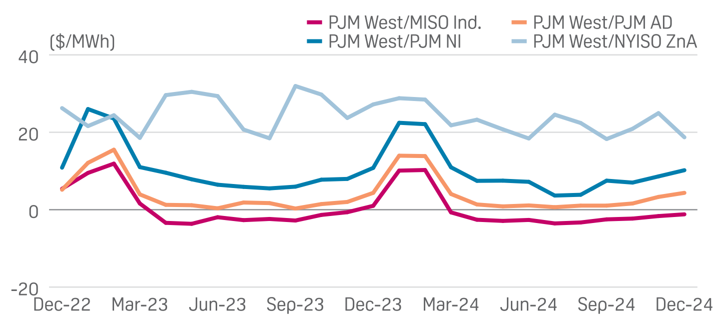
Source: S&P Global Commodity Insights, PJM, MISO

PJM/MISO PLATTS M2MS FORWARD CURVE: ON-PEAK



Source: S&P Global Commodity Insights

PJM/MISO PLATTS M2MS LOCATIONAL SPREADS: ON-PEAK



Source: S&P Global Commodity Insights

US PJM power prices varied, SPP decreases on higher wind production

Power prices in PJM were mixed on the Intercontinental Exchange for Nov. 9 delivery on Nov. 8, as West Hub day-ahead on-peak fell about $1 to price around $48.50/MWh, while the day-ahead off-peak contract rose about $2.50 to $31/MWh.

The real-time peak contract edged about $1.25 higher to price around $51.25/MWh.

On the demand side, the regional transmission operator predicted a 1.3% incline on the day in its day-ahead peakload demand to 89.1 GW Nov. 9, as Pittsburgh high temperatures trended 7 degrees above the five-day average to 61 Fahrenheit.

SPP falls on wind generation

In the Southwest Power Pool, power prices saw double-digit declines on ICE during Nov. 8 trading for day-ahead delivery as Tulsa temperature highs surged 16 degrees from the weekly average to 80 F for Nov. 9, before dropping into the low to mid 50s F by the end of the workweek and into the weekend.

South Hub day-ahead on-peak dropped near $10.50 to $31/MWh.

Further helping push prices down, SPP forecast a 15% jump in average wind production from Nov. 8 to 25.5 GWh for Nov. 9. Month-to-date wind on-peak penetration averaged about 33% of the SPP fuel mix, up 13 percentage points from last year at the same time, according to the S&P Global Commodity Insights Renewable Penetration Index.

While wind penetration has risen on the year, and so have curtailments, as wind on-peak curtailments have trended over 270% higher so far this month compared to year-ago levels to an average of 20,939 MW from 5,639 MW, according to S&P Global's Renewable Curtailment Index.

Meanwhile, the RTO projected a 3.6% jump in peakload demand from the day before to 31.4 GW for Nov. 9.

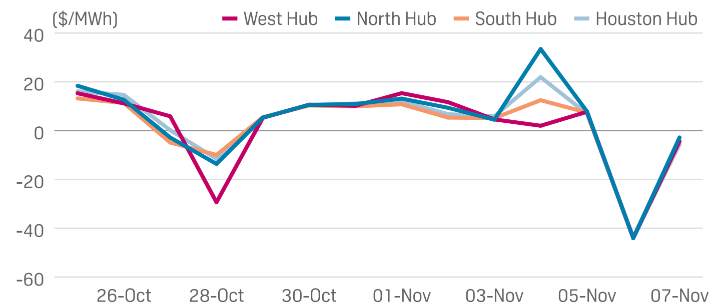
— Karen Rivera

SOUTHEAST POWER MARKETS

SOUTHEAST & CENTRAL DAY-AHEAD POWER PRICES ($/MWh)

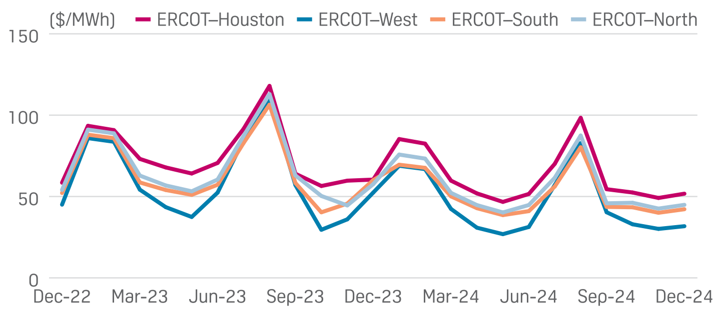
Hub/Index	Symbol	09-Nov	Marginal heat rate	Spark spread @7K	Spark spread @12K	Price change Chg	Price change % Chg	Prior 7-day Average	Month Min	Month Max	Yearly change Nov-22	Yearly change Nov-21	Yearly change Chg	Yearly change % Chg
On-Peak														
MISO Texas Hub	IMTXM00	46.28	15324	25.14	10.04	-13.61	-22.7	51.29	44.44	59.89	49.91	54.94	-5.03	-9.2
MISO Louisiana	IMLAM00	56.32	15909	31.54	13.84	-10.25	-15.4	53.85	43.94	66.57	53.92	53.51	0.41	0.8
SPP North Hub	ISNOM00	16.59	4768	-7.77	-25.16	1.00	6.4	26.21	9.54	32.39	19.62	37.48	-17.86	-47.6
SPP South Hub	ISSOM00	31.97	11315	12.19	-1.94	-3.56	-10.0	45.91	31.97	50.68	40.10	46.91	-6.81	-14.5
ERCOT Houston Hub	IERHM00	53.24	18648	33.26	18.98	-2.87	-5.1	40.72	22.21	56.11	42.41	47.58	-5.17	-10.9
ERCOT North Hub	IERNM00	38.30	12682	17.16	2.06	-6.70	-14.9	36.03	21.00	48.37	36.95	45.69	-8.74	-19.1
ERCOT South Hub	IERSM00	45.25	14643	23.62	8.17	-7.02	-13.4	37.87	24.00	52.27	39.28	43.91	-4.63	-10.5
ERCOT West Hub	IERWM00	2.19	808	-16.78	-30.33	-22.15	-91.0	22.36	1.12	49.75	22.46	40.01	-17.55	-43.9
Off-Peak														
MISO Texas Hub	IMTXP00	31.71	10501	10.57	-4.53	1.88	6.3	31.91	29.12	39.46	32.72	43.27	-10.55	-24.4
MISO Louisiana	IMLAP00	33.54	9474	8.76	-8.94	-15.79	-32.0	35.85	30.05	49.33	36.03	43.45	-7.42	-17.1
SPP North Hub	ISNOP00	0.72	206	-23.75	-41.22	-5.82	-89.0	9.17	-9.76	28.39	7.07	17.12	-10.05	-58.7
SPP South Hub	ISSOP00	5.51	1951	-14.26	-28.38	-8.10	-59.5	15.38	-4.33	27.85	12.09	25.76	-13.67	-53.1
ERCOT Houston Hub	IERHP00	24.00	8406	4.01	-10.26	-0.47	-1.9	21.93	10.07	32.17	23.30	28.92	-5.62	-19.4
ERCOT North Hub	IERNP00	18.45	6110	-2.69	-17.79	-2.32	-11.2	20.06	9.20	29.42	20.92	27.99	-7.07	-25.3
ERCOT South Hub	IERSP00	22.03	7129	0.40	-15.05	-3.72	-14.4	22.56	11.05	34.28	23.80	26.92	-3.12	-11.6
ERCOT West Hub	IERWP00	0.64	234	-18.51	-32.18	-15.79	-96.1	12.19	-1.79	31.48	13.05	24.89	-11.84	-47.6

ERCOT AVG. DAY-AHEAD/REAL-TIME PEAK PRICE SPREAD



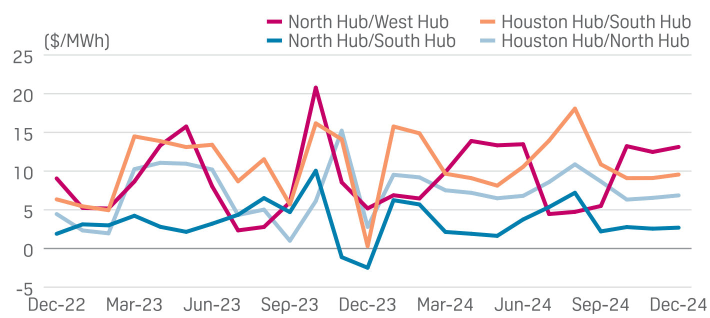
Source: S&P Global Commodity Insights, ERCOT

ERCOT PLATTS M2MS FORWARD CURVE: ON-PEAK



Source: S&P Global Commodity Insights

ERCOT PLATTS M2MS LOCATIONAL SPREADS: ON-PEAK



Source: S&P Global Commodity Insights

US ERCOT power bearish on fundamentals; tropical system Nicole to hit Southeast

Spot power in ERCOT had a bearish outlook Nov. 8 trading for Nov. 9 delivery on the Intercontinental Exchange as high temperatures continued for much of Texas, ahead of an incoming cold front that was expected to bring lows below normal Nov. 11 into the weekend.

ERCOT North Hub day-ahead on-peak was valued about $9.75 lower to price at $35.25/MWh, as the corresponding real-time peak contract slid near $3.75 to also price around $35.25/MWh. The real-time off-peak contract fell about $1.50 to trade near $22.50/MWh.

The balance-of-the-week peak Nov. 10-11 contract strengthened by about $7.25 to about $50.75/MWh, up 14% from last year at the same time on the upcoming below-normal temperature outlook, when prices trended about $44.50/MWh.

Demand falls on temperatures

Amid continued heat, highs in Dallas were expected to trend at 83 Fahrenheit Nov. 9 and were expected to trend at 77 F Nov. 10, before dropping to 62 F Nov. 11, according to CustomWeather.

Helping prices fall amid the temperature warm-up, ERCOT projected its Nov. 9 peakload demand to slide 2.4% to 52.5 GW.

Placing additional pressure on prices impacted by temperatures and demand, average systemwide wind production jumped 26% from the day before to 21.5 GWh. Average solar production would also rise across the grid operator, up 13.3% to 2 GWh Nov. 9.

Subtropical storm Nicole

Subtropical storm system Nicole was predicted by the National Hurricane Center to strengthen to a hurricane and make landfall in Florida late Nov. 9, with hurricane watches in effect for Central and South Florida.

For other parts of the Southeast, Tropical Storm Warnings and Watches in effect from South Florida to coastal Southeast Georgia.

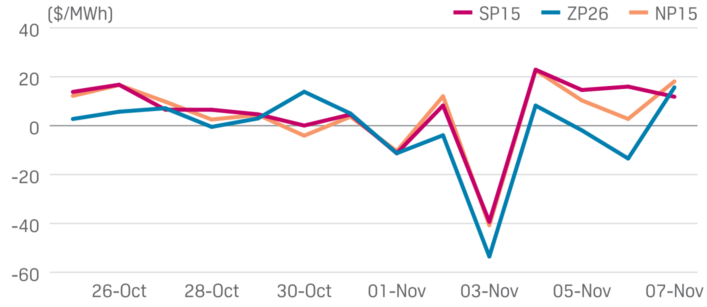
— Karen Rivera

WEST POWER MARKETS

WESTERN DAY-AHEAD POWER PRICES ($/MWh)

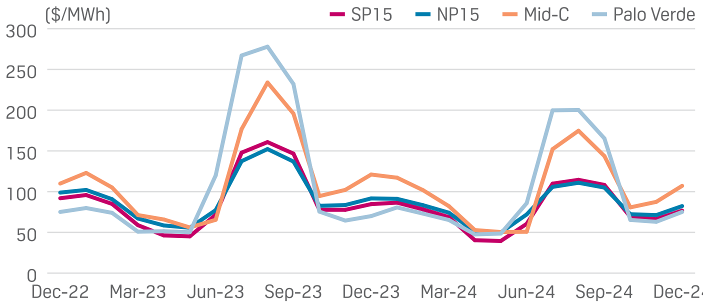
Hub/Index	Symbol	09-Nov	Marginal heat rate	Spark spread @7K	Spark spread @12K	Price change Chg	Price change % Chg	Prior 7-day Average	Month Min	Month Max	Yearly change Nov-22	Yearly change Nov-21	Yearly change Chg	Yearly change % Chg
On-Peak														
NP15	ICNGM00	84.94	10142	26.31	-15.56	-9.99	-10.5	80.09	70.12	94.93	79.77	60.61	19.16	31.6
SP15	ICSGM00	69.72	10003	20.93	-13.92	-20.82	-23.0	71.56	51.40	90.54	70.84	57.30	13.54	23.6
ZP26	ICZGM00	68.10	9770	19.31	-15.54	-22.76	-25.0	71.65	49.81	94.35	70.77	55.45	15.32	27.6
Off-Peak														
NP15	ICNGP00	76.92	9185	18.30	-23.57	-4.73	-5.8	76.18	69.33	81.65	75.50	55.33	20.17	36.5
SP15	ICSGP00	74.76	10725	25.97	-8.89	-5.14	-6.4	75.09	68.28	80.64	74.29	54.45	19.84	36.4
ZP26	ICZGP00	75.73	10865	26.94	-7.91	-5.09	-6.3	75.41	69.77	80.82	74.82	53.93	20.89	38.7

CAISO AVG. DAY-AHEAD/REAL-TIME PEAK PRICE SPREAD



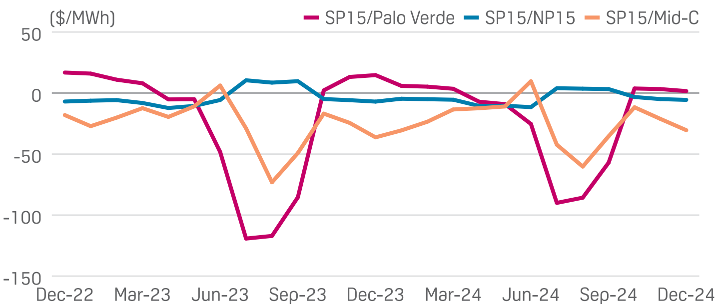
Source: S&P Global Commodity Insights, CAISO

WESTERN PLATTS M2MS FORWARD CURVE: ON-PEAK



Source: S&P Global Commodity Insights

WESTERN PLATTS M2MS LOCATIONAL SPREADS: ON-PEAK



Source: S&P Global Commodity Insights

California ISO power prices tumble as winter storm intensifies

Unsettled weather persisted across much of the California power market Nov. 8 as a powerful storm brought heavy rain and snowfall, prolonging winter weather advisories and storm warnings through the midweek.

With substantial precipitation, flooding concerns intensified in and around Los Angeles, resulting in flood advisories and flash flood watches, according to the US National Weather Service.

Low temperatures in the region cooled to the low to mid-30s Fahrenheit, while temperature highs were forecast in the mid-50s and low 60s F.

Following the cold weather forecast, California Independent System Operator peakload demand was estimated to drop 0.8% to 28.18 GW Nov. 9 before falling 1.4% to 27.78 GW Nov. 10, according to ISO data.

Pricing falls

Tracking temperature and demand projections, NP15 on-peak locational marginal price for Nov. 9-10 delivery was valued around $85.25/MWh, sliding over $13.75 from its prior settlement on the Intercontinental Exchange.

Similarly, the SP15 on-peak LMP saw a $22 decrease to trade near $77.50/MWh, and the corresponding off-peak fell about $6 to around $78/MWh.

Natural gas prices also toppled in Oct. 8 trading, as SoCal city-gates plummeted $1.22 to $8.06/MMBtu and PG&E decreased 75 cents to $8.38/MMBtu. Opal Kern River followed suit, shedding 96 cents to $7.49/MMBtu for next-day flows.

Supply mixed

Contributing to the pricing downturn in the spot market, total CAISO generation rebounded 11% to 595.32 GWh Nov. 7, as gas-fired power generation saw an almost 41% climb to 289.00 GWh. Conversely, renewable output diminished, with solar output falling 18% to 58.62 GWh, while wind generation fell more than 19% to 62.96 GWh, according to ISO data.

CAISO solar generation fell to 10.48% of the total fuel mix Nov. 7 from 13.22% the previous day, according to Platts Renewable Penetration Index. Wind also declined several percentage points, with on-peak falling to 7.76% and off-peak to 11.16%.

— Grace Parker

BILATERALS

SOUTHEAST & CENTRAL DAY-AHEAD BILATERAL INDEXES ($/MWh)

Hub/Index	Symbol	09-Nov	Marginal heat rate	Spark spread @7K	Spark spread @12K	Price change Chg	Price change % Chg	Prior 7-day Average	Month Min	Month Max	Yearly change Nov-22	Yearly change Nov-21	Yearly change Chg	Yearly change % Chg
On-Peak														
Florida	AAMAV20	52.75	14334	26.99	8.59	-2.00	-3.7	54.89	44.25	63.75	54.18	58.31	-4.13	-7.1
GTC, Into	WAMCJ20	50.00	13532	24.14	5.66	-2.00	-3.8	52.30	42.00	60.00	51.51	57.49	-5.98	-10.4
Southern, Into	AAMBJ20	49.25	13329	23.39	4.91	-2.00	-3.9	51.29	40.25	61.25	50.61	55.63	-5.02	-9.0
TVA, Into	WEBAB20	48.75	15211	26.32	10.29	-2.25	-4.4	52.07	42.50	60.75	51.00	59.20	-8.20	-13.9
VACAR	AAMCI20	49.00	13032	22.68	3.88	-1.25	-2.5	51.43	40.25	62.00	50.43	61.30	-10.87	-17.7
Off-Peak														
Florida	AAMAO20	32.25	8764	6.49	-11.91	0.00	0.0	37.32	32.25	44.25	37.53	51.43	-13.90	-27.0
GTC, Into	WAMCC20	31.00	8390	5.14	-13.34	0.00	0.0	36.71	31.00	42.25	36.69	50.23	-13.54	-27.0
Southern, Into	AAMBC20	30.25	8187	4.39	-14.09	0.00	0.0	34.89	30.25	43.25	35.31	49.10	-13.79	-28.1
TVA, Into	AAJER20	30.50	9516	8.06	-7.96	0.00	0.0	34.68	30.50	40.25	34.83	47.52	-12.70	-26.7
VACAR	AAMCB20	30.50	8112	4.18	-14.62	0.25	0.8	33.79	30.25	42.50	34.39	52.71	-18.32	-34.8

WESTERN DAY-AHEAD BILATERAL INDEXES ($/MWh)

Hub/Index	Symbol	10-Nov	Marginal heat rate	Spark spread @7K	Spark spread @12K	Price change Chg	Price change % Chg	Prior 7-day Average	Month Min	Month Max	Yearly change Nov-22	Yearly change Nov-21	Yearly change Chg	Yearly change % Chg
On-Peak														
Mid-C	WEABF20	106.41	-	-	-	13.97	13.1	80.41	46.05	106.41	75.98	56.03	19.95	35.6
John Day	WEAHF20	108.50	-	-	-	14.00	12.9	82.42	48.00	108.50	78.00	58.00	20.00	34.5
COB	WEABE20	105.00	-	-	-	13.00	12.4	80.50	49.00	105.00	75.92	58.56	17.36	29.6
NOB	WEAIF20	107.50	-	-	-	14.00	13.0	81.54	47.25	107.50	77.17	55.42	21.75	39.2
Palo Verde	WEACC20	62.00	-	-	-	-7.46	-12.0	59.66	44.75	75.00	58.34	61.47	-3.12	-5.1
Mona	AARLQ20	90.00	-	-	-	5.00	5.6	76.17	55.00	90.00	72.00	64.20	7.80	12.2
Four Corners	WEABI20	67.50	-	-	-	-7.50	-11.1	63.00	45.00	78.00	61.22	63.86	-2.64	-4.1
Pinnacle Peak	WEAKF20	65.75	-	-	-	0.00	0.0	58.42	41.00	71.25	56.28	63.47	-7.19	-11.3
Westwing	WEAJF20	81.50	-	-	-	13.25	16.3	63.96	40.75	81.50	59.89	63.42	-3.53	-5.6
MEAD	AAMBW20	71.00	-	-	-	-7.00	-9.9	66.67	50.00	80.00	64.00	65.23	-1.23	-1.9
Off-Peak														
Mid-C	WEACL20	89.93	-	-	-	11.73	13.0	72.66	54.84	89.93	70.16	46.34	23.82	51.4
John Day	WEAHL20	91.75	-	-	-	11.75	12.8	74.43	56.50	91.75	71.90	48.08	23.83	49.6
COB	WEACJ20	82.50	-	-	-	5.25	6.4	69.18	57.00	82.50	67.63	47.55	20.08	42.2
NOB	WEAIL20	91.00	-	-	-	11.75	12.9	73.68	55.75	91.00	71.15	46.23	24.93	53.9
Palo Verde	WEACT20	75.00	-	-	-	-0.50	-0.7	67.21	59.50	75.50	66.39	56.79	9.60	16.9
Mona	AARLO20	85.00	-	-	-	5.00	5.9	70.43	56.50	85.00	67.55	56.02	11.54	20.6
Four Corners	WEACR20	72.00	-	-	-	-0.50	-0.7	64.50	50.00	72.50	62.05	57.25	4.80	8.4
Pinnacle Peak	WEAKL20	70.25	-	-	-	0.00	0.0	62.11	54.25	70.25	61.25	59.15	2.10	3.6
Westwing	WEAJL20	70.00	-	-	-	0.00	0.0	61.86	54.00	70.00	61.00	60.90	0.10	0.2
MEAD	AAMBQ20	80.00	-	-	-	-0.50	-0.6	71.93	60.00	80.50	68.65	58.20	10.45	18.0

Note: Western indices reflect Nov 9-10 delivery.

PLATTS M2MS BALANCE-OF-THE-MONTH, NOV 8, ($/MWh)

	Symbol	On-peak	Symbol	Off-peak
Northeast				
Mass Hub	EMHTB00	78.47	EMHUB00	58.65
N.Y. Zone G	ENGTB00	67.22	ENGUB00	50.94
N.Y. Zone J	ENJTB00	70.22	ENJUB00	54.04
N.Y. Zone A	ENATB00	51.12	ENAUB00	25.65
Ontario*	EONTB00	53.19	EONUB00	42.00

*Ontario prices are in Canadian dollars

	Symbol	On-peak	Symbol	Off-peak
PJM & MISO				
PJM West	EPJTB00	70.97	EPJUB00	45.65
AD Hub	EECTB00	66.97	EECUB00	44.60
NI Hub	ECETB00	60.47	ECEUB00	39.60
Indiana Hub	ECITB00	68.97	ECIUB00	45.49

	Symbol	On-peak	Symbol	Off-peak
Southeast & Central				
Southern Into	ESTTB00	60.56	ESTUB00	44.39
ERCOT North	ETNTB00	53.28	ETNUB00	38.00
ERCOT Houston	ETSTB00	58.73	ETSUB00	43.00
ERCOT West	ETWTB00	44.09	ETWUB00	33.00
ERCOT South	ETHTB00	51.48	ETHUB00	37.00
Western				
Mid-C	EMCTB00	86.00	EMCUB00	70.05
Palo Verde	EPVTB00	62.00	EPVUB00	55.05
Mead	EMDTB00	65.28	EMDUB00	57.87
NP15	ENPTB00	82.05	ENPUB00	74.75
SP15	ESPTB00	76.00	ESPUB00	70.05

HOURLY INDICES

SYSTEM-WIDE RENEWABLE GENERATION CURTAILMENTS (MW)

	Symbol	07-Nov	06-Nov
Cal ISO Solar			
		Local	
On-peak	CALSP00	18.79	1786.37
Off-peak	CALSO00	0.00	0.00
		System	
On-peak	CASSP00	19.90	0.17
Off-peak	CASSO00	0.00	0.00
Cal ISO Wind			
		Local	
On-peak	CALWP00	0.00	113.18
Off-peak	CALWO00	0.00	0.00
		System	
On-peak	CASWP00	0.28	0.92
Off-peak	CASWO00	0.00	0.61
SPP Wind			
On-peak	SPPWP00	3725.38	8524.24
Off-peak	SPPWO00	6943.17	9401.51

CURTAILMENT BY HOUR (MW), NOV 07

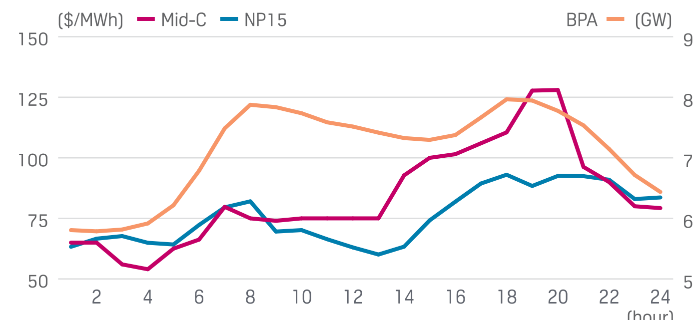
	Cal ISO Solar		Cal ISO Wind		SPP Wind
Hour	Local	System	Local	System	
1	0.00	0.00	0.00	0.00	1364.96
2	0.00	0.00	0.00	0.00	1247.43
3	0.00	0.00	0.00	0.00	1209.56
4	0.00	0.00	0.00	0.00	832.00
5	0.00	0.00	0.00	0.00	166.95
6	0.00	0.00	0.00	0.00	38.54
7	0.00	0.99	0.00	0.28	2.84
8	0.00	2.04	0.00	0.00	1.72
9	0.00	0.65	0.00	0.00	19.43
10	0.00	0.00	0.00	0.00	76.23
11	0.00	0.00	0.00	0.00	80.49
12	0.00	0.00	0.00	0.00	1.24
13	0.00	16.22	0.00	0.00	0.63
14	10.87	0.00	0.00	0.00	32.60
15	5.24	0.00	0.00	0.00	59.93
16	2.68	0.00	0.00	0.00	42.50
17	0.00	0.00	0.00	0.00	141.73
18	0.00	0.00	0.00	0.00	131.23
19	0.00	0.00	0.00	0.00	418.00
20	0.00	0.00	0.00	0.00	841.51
21	0.00	0.00	0.00	0.00	835.58
22	0.00	0.00	0.00	0.00	1039.72
23	0.00	0.00	0.00	0.00	1067.35
24	0.00	0.00	0.00	0.00	1016.38

MID-C HOURLY BILATERAL INDEXES ($/MWh)

	Symbol	07-Nov	Range	Deals	Volume (MW)
On-peak	MCRTP00	92.59	74.00-128.00	65	3204
Off-peak	MCRTO00	66.00	54.00-80.00	23	1325

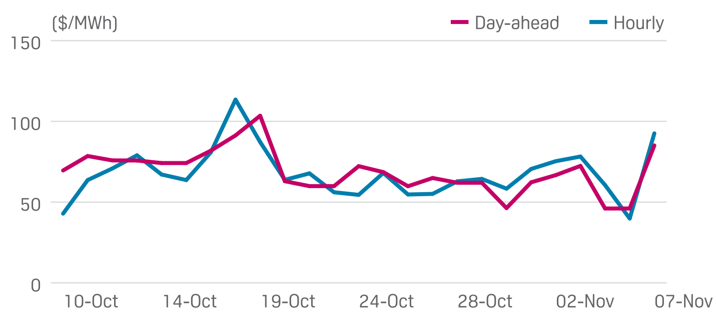
Hour ending	Symbol	07-Nov	Range	Deals	Volume (MW)	Nov-22
1	MCRTH01	65.00	65.00-65.00	1	25	53.93
2	MCRTH02	65.00	65.00-65.00	1	50	54.82
3	MCRTH03	56.00	45.00-65.00	2	90	60.61
4	MCRTH04	54.00	40.00-65.00	2	89	53.32
5	MCRTH05	62.50	60.00-65.00	2	100	57.29
6	MCRTH06	66.25	60.00-75.00	5	305	66.18
7	MCRTH07	79.75	75.00-90.00	4	193	71.82
8	MCRTH08	75.00	75.00-75.00	3	91	71.50
9	MCRTH09	74.00	70.00-75.00	6	275	68.89
10	MCRTH10	75.00	75.00-75.00	7	374	69.43
11	MCRTH11	75.00	75.00-75.00	7	333	65.75
12	MCRTH12	75.00	75.00-75.00	4	209	67.82
13	MCRTH13	75.00	75.00-75.00	5	304	60.04
14	MCRTH14	92.75	75.00-100.00	2	175	59.68
15	MCRTH15	100.00	100.00-100.00	1	150	66.96
16	MCRTH16	101.50	100.00-120.00	2	215	66.57
17	MCRTH17	106.00	87.00-120.00	3	200	71.64
18	MCRTH18	110.50	100.00-120.00	4	190	79.75
19	MCRTH19	127.75	100.00-150.00	5	138	82.43
20	MCRTH20	128.00	90.00-150.00	5	134	80.50
21	MCRTH21	96.25	95.00-105.00	3	113	71.07
22	MCRTH22	90.00	90.00-90.00	4	110	66.46
23	MCRTH23	80.00	75.00-100.00	6	366	66.14
24	MCRTH24	79.25	75.00-80.00	4	300	60.11

MID-C AND NP15 HOURLY PRICES vs BPA HOURLY DEMAND



Source: S&P Global Commodity Insights, BPA, CAISO

MID-C DAY-AHEAD/HOURLY ON-PEAK PRICE COMPARISON



Source: S&P Global Commodity Insights

RENEWABLE PENETRATION, SOLAR

PENETRATION INDICES, SOLAR (%)

	Symbol	07-Nov	06-Nov
Cal ISO			
On-peak	RPCSP00	10.48	13.22
Off-peak	RPCSO00	0.01	0.00
SPP			
On-peak	RPSSP00	0.17	0.23
Off-peak	RPSSO00	0.00	0.00
ERCOT			
On-peak	RPESP00	5.12	9.07
Off-peak	RPESO00	0.00	0.00
MISO			
On-peak	RPMSP00	0.88	0.97
Off-peak	RPMSO00	0.00	0.00
PJM			
On-peak	RPPSP00	1.17	1.09
Off-peak	RPPSO00	0.01	0.02
NYISO			
On-peak	RPNSP00	1.61	1.55
Off-peak	RPNSO00	1.74	1.76
ISO New England			
On-peak	RPISP00	1.36	0.74
Off-peak	RPISO00	0.00	0.00

HOURLY PENETRATION, SOLAR (%), NOV 7

Hour	Symbol	Cal ISO	Symbol	SPP	Symbol	ERCOT	Symbol	MISO	Symbol	PJM	Symbol	NYISO	Symbol	ISONE
1	RPCSC01	0.00	RPSSC01	0.00	RPESC01	0.00	RPMSC01	0.00	RPPSC01	0.01	RPNSC01	1.61	RPISC01	0.00
2	RPCSC02	0.00	RPSSC02	0.00	RPESC02	0.00	RPMSC02	0.00	RPPSC02	0.01	RPNSC02	1.65	RPISC02	0.00
3	RPCSC03	0.00	RPSSC03	0.00	RPESC03	0.00	RPMSC03	0.00	RPPSC03	0.02	RPNSC03	1.83	RPISC03	0.00
4	RPCSC04	0.00	RPSSC04	0.00	RPESC04	0.00	RPMSC04	0.00	RPPSC04	0.02	RPNSC04	1.92	RPISC04	0.00
5	RPCSC05	0.00	RPSSC05	0.00	RPESC05	0.00	RPMSC05	0.00	RPPSC05	0.01	RPNSC05	1.93	RPISC05	0.00
6	RPCSC06	0.00	RPSSC06	0.00	RPESC06	0.00	RPMSC06	0.00	RPPSC06	0.01	RPNSC06	1.79	RPISC06	0.00
7	RPCSC07	1.73	RPSSC07	0.00	RPESC07	0.00	RPMSC07	0.01	RPPSC07	0.01	RPNSC07	1.61	RPISC07	0.02
8	RPCSC08	12.39	RPSSC08	0.00	RPESC08	1.11	RPMSC08	0.22	RPPSC08	0.24	RPNSC08	1.51	RPISC08	0.27
9	RPCSC09	18.83	RPSSC09	0.02	RPESC09	5.68	RPMSC09	0.83	RPPSC09	1.35	RPNSC09	1.65	RPISC09	1.26
10	RPCSC10	20.25	RPSSC10	0.17	RPESC10	7.56	RPMSC10	1.56	RPPSC10	2.26	RPNSC10	1.86	RPISC10	2.75
11	RPCSC11	20.75	RPSSC11	0.34	RPESC11	8.98	RPMSC11	1.86	RPPSC11	2.65	RPNSC11	1.98	RPISC11	3.50
12	RPCSC12	20.66	RPSSC12	0.37	RPESC12	10.35	RPMSC12	1.85	RPPSC12	2.67	RPNSC12	1.95	RPISC12	3.78
13	RPCSC13	20.63	RPSSC13	0.35	RPESC13	10.93	RPMSC13	1.80	RPPSC13	2.61	RPNSC13	1.93	RPISC13	3.77
14	RPCSC14	19.18	RPSSC14	0.36	RPESC14	10.83	RPMSC14	1.77	RPPSC14	2.47	RPNSC14	1.92	RPISC14	3.22
15	RPCSC15	17.50	RPSSC15	0.37	RPESC15	10.34	RPMSC15	1.66	RPPSC15	2.20	RPNSC15	1.82	RPISC15	2.30
16	RPCSC16	12.88	RPSSC16	0.35	RPESC16	9.59	RPMSC16	1.40	RPPSC16	1.89	RPNSC16	1.62	RPISC16	0.76
17	RPCSC17	2.66	RPSSC17	0.27	RPESC17	5.77	RPMSC17	0.81	RPPSC17	0.39	RPNSC17	1.31	RPISC17	0.07
18	RPCSC18	0.12	RPSSC18	0.13	RPESC18	0.75	RPMSC18	0.23	RPPSC18	0.01	RPNSC18	1.23	RPISC18	0.02
19	RPCSC19	0.03	RPSSC19	0.03	RPESC19	0.00	RPMSC19	0.02	RPPSC19	0.01	RPNSC19	1.23	RPISC19	0.02
20	RPCSC20	0.03	RPSSC20	0.00	RPESC20	0.00	RPMSC20	0.00	RPPSC20	0.01	RPNSC20	1.29	RPISC20	0.02
21	RPCSC21	0.04	RPSSC21	0.00	RPESC21	0.00	RPMSC21	0.00	RPPSC21	0.01	RPNSC21	1.34	RPISC21	0.01
22	RPCSC22	0.03	RPSSC22	0.00	RPESC22	0.00	RPMSC22	0.00	RPPSC22	0.01	RPNSC22	1.48	RPISC22	0.00
23	RPCSC23	0.02	RPSSC23	0.00	RPESC23	0.00	RPMSC23	0.00	RPPSC23	0.01	RPNSC23	1.57	RPISC23	0.00
24	RPCSC24	0.02	RPSSC24	0.00	RPESC24	0.00	RPMSC24	0.00	RPPSC24	0.02	RPNSC24	1.64	RPISC24	0.00

RENEWABLE PENETRATION, WIND

PENETRATION INDICES, WIND (%)

	Symbol	07-Nov	06-Nov
Cal ISO			
On-peak	RPCWP00	7.76	9.62
Off-peak	RPCWO00	11.16	15.06
SPP			
On-peak	RPSWP00	30.14	30.51
Off-peak	RPSWO00	37.73	39.24
ERCOT			
On-peak	RPEWP00	13.76	19.87
Off-peak	RPEWO00	25.20	42.98
MISO			
On-peak	RPMWP00	11.60	24.61
Off-peak	RPMWO00	21.95	31.25
PJM			
On-peak	RPPWP00	3.62	6.13
Off-peak	RPPWO00	7.94	8.28
NYISO			
On-peak	RPNWP00	7.86	4.71
Off-peak	RPNWO00	8.44	10.59
ISO New England			
On-peak	RPIWP00	9.16	7.66
Off-peak	RPIWO00	7.94	9.11

HOURLY PENETRATION, WIND (%), NOV 7

Hour	Symbol	Cal ISO	Symbol	SPP	Symbol	ERCOT	Symbol	MISO	Symbol	PJM	Symbol	NYISO	Symbol	ISONE
1	RPCWC01	14.69	RPSWC01	36.11	RPEWC01	28.25	RPMWC01	23.96	RPPWC01	6.27	RPNWC01	8.47	RPIWC01	7.51
2	RPCWC02	12.56	RPSWC02	36.40	RPEWC02	26.47	RPMWC02	23.40	RPPWC02	7.51	RPNWC02	8.42	RPIWC02	7.35
3	RPCWC03	10.96	RPSWC03	36.35	RPEWC03	23.57	RPMWC03	22.69	RPPWC03	8.49	RPNWC03	8.80	RPIWC03	6.90
4	RPCWC04	10.53	RPSWC04	37.24	RPEWC04	22.22	RPMWC04	21.05	RPPWC04	8.96	RPNWC04	9.14	RPIWC04	6.85
5	RPCWC05	10.87	RPSWC05	39.21	RPEWC05	20.18	RPMWC05	19.42	RPPWC05	8.54	RPNWC05	9.79	RPIWC05	6.60
6	RPCWC06	9.16	RPSWC06	38.86	RPEWC06	17.07	RPMWC06	16.98	RPPWC06	7.51	RPNWC06	9.45	RPIWC06	6.22
7	RPCWC07	7.31	RPSWC07	37.18	RPEWC07	14.51	RPMWC07	13.51	RPPWC07	6.07	RPNWC07	8.52	RPIWC07	6.16
8	RPCWC08	5.25	RPSWC08	34.74	RPEWC08	12.05	RPMWC08	11.40	RPPWC08	4.99	RPNWC08	7.39	RPIWC08	6.17
9	RPCWC09	5.09	RPSWC09	32.86	RPEWC09	8.76	RPMWC09	10.31	RPPWC09	4.32	RPNWC09	8.00	RPIWC09	7.43
10	RPCWC10	4.99	RPSWC10	29.95	RPEWC10	8.04	RPMWC10	8.66	RPPWC10	3.37	RPNWC10	9.24	RPIWC10	8.07
11	RPCWC11	5.43	RPSWC11	28.48	RPEWC11	7.73	RPMWC11	7.76	RPPWC11	3.37	RPNWC11	9.40	RPIWC11	9.34
12	RPCWC12	5.83	RPSWC12	26.97	RPEWC12	7.45	RPMWC12	7.40	RPPWC12	2.81	RPNWC12	9.03	RPIWC12	9.82
13	RPCWC13	6.61	RPSWC13	25.25	RPEWC13	7.70	RPMWC13	7.35	RPPWC13	2.33	RPNWC13	9.26	RPIWC13	9.83
14	RPCWC14	7.90	RPSWC14	24.61	RPEWC14	8.97	RPMWC14	7.67	RPPWC14	1.91	RPNWC14	9.64	RPIWC14	9.84
15	RPCWC15	9.15	RPSWC15	24.94	RPEWC15	10.82	RPMWC15	8.46	RPPWC15	1.68	RPNWC15	9.34	RPIWC15	10.49
16	RPCWC16	10.23	RPSWC16	27.17	RPEWC16	12.35	RPMWC16	9.51	RPPWC16	1.63	RPNWC16	8.63	RPIWC16	10.01
17	RPCWC17	10.73	RPSWC17	29.51	RPEWC17	13.16	RPMWC17	10.66	RPPWC17	1.74	RPNWC17	7.85	RPIWC17	9.45
18	RPCWC18	9.36	RPSWC18	29.97	RPEWC18	14.80	RPMWC18	11.79	RPPWC18	2.00	RPNWC18	5.99	RPIWC18	8.99
19	RPCWC19	9.05	RPSWC19	29.16	RPEWC19	18.23	RPMWC19	13.59	RPPWC19	2.76	RPNWC19	5.67	RPIWC19	9.75
20	RPCWC20	8.77	RPSWC20	31.21	RPEWC20	22.55	RPMWC20	16.72	RPPWC20	4.46	RPNWC20	5.86	RPIWC20	10.12
21	RPCWC21	9.26	RPSWC21	33.73	RPEWC21	25.53	RPMWC21	19.29	RPPWC21	6.46	RPNWC21	6.03	RPIWC21	10.57
22	RPCWC22	9.27	RPSWC22	36.53	RPEWC22	27.55	RPMWC22	21.56	RPPWC22	7.96	RPNWC22	5.91	RPIWC22	10.46
23	RPCWC23	10.18	RPSWC23	38.07	RPEWC23	29.95	RPMWC23	23.57	RPPWC23	8.02	RPNWC23	6.51	RPIWC23	10.86
24	RPCWC24	10.30	RPSWC24	39.59	RPEWC24	33.91	RPMWC24	24.51	RPPWC24	8.22	RPNWC24	6.90	RPIWC24	11.24

PLATTS M2MS FORWARD CURVE, NOV 8 ($/MWh)

Prompt month: Dec 22

	On-peak	Off-peak
Northeast		
Mass Hub	148.25	136.20
N.Y. Zone G	103.30	90.35
N.Y. Zone J	109.10	89.65
N.Y. Zone A	55.90	49.35
Ontario*	49.84	35.94
PJM & MISO		
PJM West	82.15	71.00
AD Hub	77.00	67.35
NI Hub	71.30	59.90
Indiana Hub	76.75	66.70
Southeast & Central		
Southern Into	66.92	64.59
ERCOT North	54.05	43.38
ERCOT Houston	58.50	44.72
ERCOT West	45.00	38.05
ERCOT South	52.15	41.90
Western		
Mid-C	109.95	80.95
Palo Verde	75.10	72.55
Mead	79.00	76.33
NP15	98.85	87.15
SP15	91.90	83.20

*Ontario prices are in Canadian dollars

ISO DAY-AHEAD LMP BREAKDOWN FOR NOV 9 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
Northeast						
On-peak						
ISONE Internal Hub	45.78	0.00	0.01	5.66	43.36	13231
ISONE Connecticut	44.86	0.00	-0.91	5.45	42.45	10980
ISONE NE Mass-Boston	46.30	0.00	0.53	6.07	43.71	13382
NYISO Capital Zone	62.85	-38.86	0.93	9.29	54.90	19796
NYISO Hudson Valley Zone	46.78	-21.91	1.81	5.94	42.39	11451
NYISO N.Y.C. Zone	47.07	-21.93	2.09	6.03	43.04	14826
NYISO West Zone	26.27	-3.44	-0.22	1.39	26.02	8967
Off-Peak						
ISONE Internal Hub	38.69	0.00	0.28	2.92	32.77	11183
ISONE Connecticut	37.84	0.00	-0.58	2.85	32.05	9262
ISONE NE Mass-Boston	38.73	0.00	0.32	3.04	32.86	11193
NYISO Capital Zone	50.66	-32.92	0.67	6.29	42.17	15957
NYISO Hudson Valley Zone	36.91	-18.61	1.21	8.49	31.11	9034
NYISO N.Y.C. Zone	37.03	-18.66	1.29	8.51	31.32	11662
NYISO West Zone	19.91	-2.88	-0.05	9.59	17.75	6796
PJM & MISO						
On-peak						
PJM AEP-Dayton Hub	47.97	-1.85	-0.25	0.92	46.24	12741
PJM Dominion Hub	53.16	2.75	0.34	-3.11	53.61	14138
PJM Eastern Hub	51.22	1.00	0.15	12.05	36.81	16876
PJM Northern Illinois Hub	44.07	-3.63	-2.36	2.01	40.57	12485
PJM Western Hub	51.00	0.24	0.69	3.22	47.03	16804
MISO Indiana Hub	44.45	1.47	2.11	-1.79	51.55	12592
MISO Minnesota Hub	29.87	-8.41	-2.59	8.02	32.36	8584
MISO Louisiana Hub	56.32	14.98	0.47	-10.25	53.92	15909
MISO Texas Hub	46.28	5.31	0.10	-13.61	49.91	15324
Off-Peak						
PJM AEP-Dayton Hub	38.70	0.11	-0.02	10.55	29.94	10280
PJM Dominion Hub	41.39	1.87	0.90	11.87	32.00	11008
PJM Eastern Hub	38.33	-0.26	-0.03	17.24	23.50	12629
PJM Northern Illinois Hub	33.13	-3.32	-2.17	10.81	22.99	9385
PJM Western Hub	41.20	1.99	0.59	12.68	30.67	13577
MISO Indiana Hub	31.75	6.16	1.39	-1.89	33.60	8994
MISO Minnesota Hub	9.55	-12.86	-1.80	5.02	11.36	2744
MISO Louisiana Hub	33.54	8.98	0.36	-15.79	36.03	9474
MISO Texas Hub	31.71	7.18	0.33	1.88	32.72	10501
Southeast & Central						
On-peak						
SPP North Hub	16.59	-6.33	0.07	1.00	19.62	4768
SPP South Hub	31.97	10.06	-0.95	-3.56	40.10	11315
ERCOT Houston Hub	53.24	—	—	-2.87	42.41	18648
ERCOT North Hub	38.30	—	—	-6.70	36.95	12682
ERCOT South Hub	45.25	—	—	-7.02	39.28	14643
ERCOT West Hub	2.19	—	—	-22.15	22.46	808
Off-Peak						
SPP North Hub	0.72	-3.72	-0.02	-5.82	7.07	206
SPP South Hub	5.51	1.18	-0.13	-8.10	12.09	1951
ERCOT Houston Hub	24.00	—	—	-0.47	23.30	8406
ERCOT North Hub	18.45	—	—	-2.32	20.92	6110
ERCOT South Hub	22.03	—	—	-3.72	23.80	7129
ERCOT West Hub	0.64	—	—	-15.79	13.05	234
Western						
On-peak						
CAISO NP15 Gen Hub	84.94	9.54	0.00	-9.99	79.77	10142
CAISO SP15 Gen Hub	69.72	-5.68	0.00	-20.82	70.84	10003
CAISO ZP26 Gen Hub	68.10	-7.30	0.00	-22.76	70.77	9770
Off-Peak						
CAISO NP15 Gen Hub	76.92	-0.02	-0.72	-4.73	75.50	9185
CAISO SP15 Gen Hub	74.76	-0.02	-2.88	-5.14	74.29	10725
CAISO ZP26 Gen Hub	75.73	0.00	-1.93	-5.09	74.82	10865

WEEKEND BILATERAL INDEXES FOR NOV 5-6 ($/MWh)

	Saturday Index	Sunday Index
Southeast On-peak		
VACAR	36.25	36.25
Southern, into	36.00	36.00
GTC, into	36.75	36.75
Florida	39.50	39.50
TVA, into	37.00	37.00
Southeast Off-Peak*		
VACAR	33.00	33.00
Southern, into	35.00	35.00
GTC, into	37.00	37.00
Florida	37.50	37.50
TVA, into	35.25	35.25
West On-peak**		
Mid-C	46.05	71.20
John Day	48.00	73.00
COB	49.00	69.00
NOB	47.25	72.25
Palo Verde	44.75	52.00
Westwing	40.75	48.00
Pinnacle Peak	41.00	48.25
Mead	50.00	57.50
Mona	55.00	59.00
Four Corners	45.00	55.00
West Off-Peak**		
Mid-C	55.29	68.75
John Day	57.00	70.50
COB	57.00	59.00
NOB	56.25	69.75
Palo Verde	63.00	52.00
Westwing	57.50	48.00
Pinnacle Peak	57.75	48.25
Mead	65.00	57.50
Mona	56.50	59.00
Four Corners	53.50	55.00

*Southeast off-peak prices are for a Saturday-Monday package.
**West Saturday prices are for a Friday-Saturday package and Sunday prices are for Sunday only.

WEEKLY BILATERAL INDEXES FOR WEEK ENDING NOV 5 ($/MWh)

	Index	Change	Low	High
Southeast On-peak				
VACAR	52.65	-3.15	40.25	62.00
Southern, into	52.35	-1.37	40.25	61.25
GTC, into	53.46	-0.81	42.00	60.00
Florida	56.00	-0.85	44.25	63.75
TVA, into	53.35	-2.65	42.50	60.75
Southeast Off-Peak				
VACAR	39.61	-4.35	32.25	42.50
Southern, into	40.29	-3.85	33.00	43.25
GTC, into	41.11	-2.90	35.00	43.50
Florida	42.14	-3.25	35.50	44.75
TVA, into	38.21	-2.93	33.25	40.25
West On-peak				
Mid-C	56.64	-8.29	40.00	73.25
John Day	58.63	-8.29	48.00	74.50
COB	58.17	-8.04	49.00	74.00
NOB	57.88	-8.41	47.25	73.75
Palo Verde	51.44	3.52	44.75	56.25
Westwing	47.46	3.54	40.75	52.25
Pinnacle Peak	47.71	5.54	41.00	52.50
Mead	55.17	2.34	50.00	60.00
Mona	58.50	3.09	50.00	75.00
Four Corners	52.67	0.50	45.00	60.00
West Off-Peak				
Mid-C	57.07	0.52	47.00	73.00
John Day	58.79	0.43	49.75	73.75
COB	57.71	0.39	49.00	72.25
NOB	58.04	0.29	49.00	73.00
Palo Verde	58.63	7.04	45.50	70.00
Westwing	53.14	7.07	40.00	64.50
Pinnacle Peak	53.39	7.07	40.25	64.75
Mead	56.14	3.21	40.00	65.00
Mona	55.64	6.31	47.00	69.00
Four Corners	54.00	5.71	50.00	60.00

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