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Thursday, November 16, 2017

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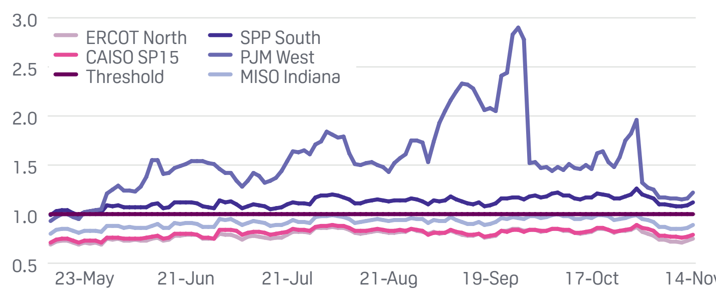
REGIONAL DAY-AHEAD PRICE CHANGES

	Day-ahead peak prices			Regional weather trends		
	16-Nov	Daily chg	Prior 7-day avg	16-Nov	Daily chg	7-day forecast
ISO Price Locations						
CAISO NP 15	41.45	1.28 ▲	39.65	62.8	0.7 ▲	62.1
ERCOT North Hub	24.19	-3.61 ▼	26.19	67.0	-0.7 ▼	57.6
ISONE Internal Hub	41.50	-2.27 ▼	58.53	44.7	6.3 ▲	38.8
MISO Indiana Hub	32.80	-0.04 ▼	34.51	36.3	-6.2 ▼	35.6
NYISO Zone G	34.49	-3.26 ▼	42.81	45.9	5.2 ▲	39.1
PJM West Hub	35.33	2.10 ▲	43.64	44.9	2.0 ▲	39.8
SPP South Hub	24.28	-2.31 ▼	25.57	46.2	-4.4 ▼	45.7
Bilateral indexes						
Into Southern	29.25	-0.25 ▼	30.39	59.3	2.4 ▲	54.4
Palo Verde	28.00	-0.25 ▼	30.62	63.5	0.8 ▲	61.8
COB	31.00	0.75 ▲	38.75	43.9	-1.6 ▼	45.6
Mid-C	25.16	0.30 ▲	24.47	43.9	-1.6 ▼	45.6

Source: Platts

COAL-TO-GAS POWER PRICE RATIOS AT MAJOR TRADING HUBS



The Platts coal-to-gas power price ratios are used to asses the regional competitiveness between coal and gas generation at the major power trading hubs. The ratio is defined as the coal $/MWh dispatch price divided by the gas $/MWh dispatch price; gas generation is more competitive than coal when the ratio is a ratio greater than one and vice versa. All price data is for prompt month fuel contracts.

Source: Platts daily OTC coal prices and M2MS gas prices

PLATTS PEAK DAILY DEMAND (GW)

						Daily change		Five day forecast					Season		Season average			
ISO	12-Nov	13-Nov	14-Nov	15-Nov	16-Nov	Chg	% Chg	17-Nov	18-Nov	19-Nov	20-Nov	21-Nov	Min	Max	2017	2016	Chg	% Chg
BPA-Puget	6.59	7.25	7.21	7.68	7.83	0.15	1.95	7.76	7.17	7.15	7.38	7.38	5.30	8.29	6.70	6.41	0.29	4.52
IESO	19.05	20.20	19.36	20.29	20.43	0.14	0.69	21.36	18.43	19.72	22.02	21.49	15.67	22.54	18.38	19.52	-1.14	-5.84
CAISO	26.62	29.31	29.13	30.33	30.00	-0.33	-1.09	29.41	27.44	28.39	30.85	31.08	26.16	49.91	32.09	30.82	1.27	4.12
ERCOT	39.13	41.22	41.99	39.09	39.08	-0.01	-0.03	43.06	35.24	34.08	37.27	38.12	33.15	63.67	49.65	48.42	1.23	2.54
SPP	28.30	29.95	29.61	25.64	25.62	-0.02	-0.08	27.32	23.46	23.94	25.62	25.81	24.07	44.18	32.43	31.51	0.92	2.92
MISO	76.17	82.13	80.39	79.05	80.43	1.38	1.75	79.00	72.01	78.14	82.86	79.10	70.55	114.50	83.42	82.33	1.09	1.32
PJM	92.86	101.55	100.08	99.22	97.37	-1.85	-1.86	100.24	87.00	97.84	112.46	96.73	77.41	132.63	96.52	97.12	-0.60	-0.62
NYISO	18.90	20.44	20.40	19.85	19.58	-0.27	-1.36	20.22	17.66	17.87	21.41	19.56	16.73	27.60	20.16	20.23	-0.07	-0.35
NEISO	15.70	16.93	16.65	16.55	16.01	-0.54	-3.26	16.55	14.52	14.51	17.36	16.02	12.40	20.96	15.52	15.77	-0.25	-1.59
AESO	10.63	10.94	11.04	10.26	10.42	0.16	1.56	10.70	9.83	9.56	9.90	10.04	9.03	11.04	9.84	9.75	0.09	0.92

Seasons are defined as: Summer (June – August), Fall (September – November), Winter (December – February), and Spring (March – May).

Source: Platts

NEWS

Electricity storage tops 600 MW at end of Q3

Forty-nine operating electricity storage systems in the US owned by 25 companies had a total power rating of 602.7 MW by the end of the third quarter, according to industry data.

The total of installed and operating storage facilities increased 35.2 MW since the end of Q2 2017, and 205.7 MW since the end of Q3 2016. There is now expected to be just over 30 MW of storage added in Q4, and 22 MW in Q1 2018, according to data compiled by Platts from industry reports to various government agencies.

There are three storage systems under construction at wind farms in Texas owned by NRG Energy and E.ON Climate & Renewables North America.

According to the data, there was 71.6 MW of storage in the Electric Reliability Council of Texas at the end of Q3.

However, PJM Interconnection is the region with the most storage. Twenty-three battery facilities and one flywheel facility had combined power ratings of 302 MW. The grid-connected facilities sell into PJM's regulation and frequency response markets.

Companies have installed 114 MW of storage in the California Independent System Operator market, according to the data.

ERCOT wind farms attracting batteries

On November 7, Toshiba and NRG Energy announced they are collaborating on a 2 MW lithium–ion battery storage system that will be charged by the 135.4 MW Elbow Creek Wind farm near the West Texas town of Big Spring, which is in the heart of Texas wind country.

The battery system being deployed was manufactured at Toshiba's one million square foot manufacturing facility in Houston. ERCOT recently concluded final certification testing on the battery system, and the project is funded in part by the Texas Commission on Environmental Quality, as part of the state's Emissions Reduction Plan, NRG said in a release.

Calling it its largest storage project so far, NRG said the system is "expected to help correct short-term grid imbalances by providing high-speed frequency regulation services." It said the system will have the ability "to move blocks of generation from the hours when wind generation is high to the hours when load support is needed the most."

In early September, E.ON said it began construction on its Texas Waves storage projects that will be charged by its 249 MW Pyron and 197 MW Inadale wind farms that have been operational for eight years and are near the town of Roscoe, which is east of Big Spring.

Texas Waves consists of two 9.9 MW short duration energy storage projects using lithium-ion battery technology and will be "an integral part of the wind farm facilities" near Roscoe.

E.ON has said that its Texas Waves are designed to provide ancillary services to the ERCOT market and "will be capable of responding to shifts in power demand more quickly, increasing system reliability and efficiency."

NextEra Energy Resources tops AES in rankings

The company with the largest amount of operational storage is NextEra Energy Resources, with 106.4 MW. Ranked second is AES Companies with 83.5 MW.

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According to the data, NextEra has seven operational wind farms, with its largest, the 30 MW Blue Summit Storage facility, coming online in August, according to a company spokesman.

The facility is charged by NextEra Energy Resources' 135.4 MW Blue Summit Wind farm near the town of Vernon, Texas, on the state's northwest plains near the border with Oklahoma.

Prior to bringing Blue Summit online, NextEra Energy Resources' largest facility was its 20 MW Frontier Battery Energy Storage System in DeKalb County, Illinois, west of Chicago.

It also owns the 18 MW Meyersdale Battery Energy Storage facility in Somerset County, southeast of Pittsburgh, the 16.2 MW Casco Bay Energy Storage facility in Cumberland County, Maine, just north of Portland, and the 10 MW Pima Storage Project in Arizona that is under contract with Tucson Electric Power.

The renewables arm of NextEra Energy is aiming at an integrated solar and battery project in Pinal County, Arizona.

NextEra Energy Resources said Wednesday it will begin construction "within the next couple of weeks" on the 20 MW solar PV facility that will charge a 10 MW lithium-ion battery storage unit.

The Salt River Project has announced a 20-year power purchase agreement for the power off-take. NextEra Energy Resources said it expects the facility to be operational in Q2 2018.

— Jeffrey Ryser

Q3 2017 OPERATING INSTALLATIONS BY REGION

Region	MW	MWh
PJM	302.0	NA
CAISO	114.2	405.0
ERCOT	71.6	72.7
WECC	56.2	37.5
MISO	20.0	20.0
NYISO	20.0	5.0
ISONE	18.7	15.0
Total	**602.7**	

Q3 2017 ENERGY STORAGE RANKINGS (MW) (1)

Owner	MW	MWh (2)
NEXTERA ENERGY RESOURCES	106.4	53.2
AES COMPANIES	83.5	NA
INVENERGY INVESTMENT	68.1	27.0
SOUTHERN CALIFORNIA EDISON	48.0	120.4
RES AMERICAS	43.6	18.4
DUKE COMMERCIAL POWER	40.0	25.6
ROCKLAND CAPITAL	40.0	10.0
SAN DIEGO GAS & ELECTRIC	37.5	150.0
IMPERIAL IRRIGATION DISTRICT	30.0	20.0
ALTAGAS POWER HOLDINGS (US)	20.0	80.0
EDF RENEWABLE ENERGY	20.0	8.6
AMERICAN ELECTRIC POWER	11.2	75.2
E ON CLIMATE & RENEWABLES NORTH AMERICA	10.0	2.5
EXELON GENERATION	10.0	2.5
HALF MOON VENTURES	7.0	2.9
PACIFIC GAS AND ELECTRIC	6.7	46.6
PERENNIAL POWER HOLDINGS (SUMITOMO)	6.0	2.0
SNOHOMISH COUNTY PUBLIC UTILITY DISTRICT NO 1	4.2	9.0
ALEVO USA	2.0	1.0
CITY OF GLENDALE CA	2.0	1.0
STERLING MUNICIPAL LIGHT DEPT	2.0	3.9
POWIN ENERGY CORP	2.0	8.0
HITACHI CAPITAL AMERICA	1.0	0.5
OCI SOLAR POWER	1.0	0.5
CONVERGENT ENERGY AND POWER	0.5	3.0
Total	**602.7**	

(1) Table represents total grid connected energy storage facilities at the end of Q3 2017 by company in terms of installed MW (power rating) and MWh (energy rating). Includes battery and flywheel facilities that are for the most part larger than 1 MW. Does not include behind-the-meter facilities.

(2) For energy rating "NA" shows up on entities and regions where one or more facilities energy ratings are unknown.

Source: Government filings compiled by Platts.

Conflicting interests hurting ISOs: researchers

A combination of competing state, public, private, political, economic and environmental interests and actions is resulting in "Balkanized logic," creating "suboptimal economic outcomes" and "unprecedented legal risks" for power market stakeholders, researchers said Tuesday.

A plenary session of the annual North American conference of the US Association for Energy Economics and the International Association for Energy Economics focused on "rapidly evolving characteristics within electricity markets."

During that session, Elizabeth Wilson, Dartmouth College professor of environmental studies, noted that most people do not realize that independent system operators or regional transmission organizations exist or what they do.

Factors affecting ISO decisions include generation, transmission and distribution utilities, state regulators, various classes of power customers, the US Federal Energy Regulatory Commission and federal courts, Wilson noted.

"What I see are overlapping political jurisdictions … that are driving market compromises resulting in all kinds of suboptimal economic outcomes," Wilson said, calling it "Balkanized logic."

For example, South Dakota has a number of utilities that are members of Southwest Power Pool and another set of utilities that are members of Midcontinent Independent System Operator, which have "really quite different" power markets, but power goes from SPP to MISO and back to SPP

Far from achieving consensus on how the bulk power system should operate, the various stakeholders are developing differences of opinion, in which "we have very substantially opposing interests."

"It affects who talks to whom on the phone," Wilson said.

Wilson said she heard from an executive who called two of his company's representatives on an ISO committee into the office to explain why they voted against each other in that committee. "I was voting for reliability and he was voting for markets," said one of the representatives, adding that Wilson "didn't tell us what you wanted to do."

Stress up from low power prices, Paris exit

Michael Wara, director of the climate energy policy program at Stanford University's Woods Institute for the Environment, said that "ISOs are under economic and political stress."

"We see extremely cheap wind and solar costs … driven by continuing technological improvements and the growing scale of turbines," Wara said.

States' establishment of zero-emissions credits, which subsidize nuclear power, and the growth of renewable technologies that have subsidies plus near-zero marginal costs "are leading to falling wholesale power costs," Wara said, which reduces the cost for "ambitious private sector" investment in zero-carbon power.

Meanwhile, President Donald Trump's decision to cease participation in the 2015 Paris Agreement on climate change mitigation "has put carbon pricing back on blue state legislative agendas," Wara said.

"Moving carbon pricing legislation through any legislature is very hard work," Wara said, but lawmakers are doing so because "it has become a wedge issue."

The recent election of Democratic governors in New Jersey and Virginia "dramatically increased the chances for" New Jersey to rejoin the Regional Greenhouse Gas Initiative and Virginia to join it for the first time, Wara said.

'A clear tension' between carbon pricing, NOPR

"Blue states are attempting to fill in the [climate change mitigation] gap left by the Trump administration," Wara said. "Not everyone agrees with that move. … I think it creates really unprecedented legal risks, in terms of market design."

The footprints of independent system operators and emissions markets do not overlap completely. If system operators include carbon prices in dispatching power for one area, but not another, it is an open question as to whether the new majority of the US Federal Energy Regulatory Commission would consider this "undue discrimination" under the interstate commerce clause of the US Constitution, Wara said.

ISO boundaries are not static, Wilson said, but when those footprints change, "it has caused a lot of bad feelings," as when certain utilities in eastern MISO joined PJM, and when MISO integrated Entergy utilities in Arkansas, Louisiana, Mississippi and Texas, which had once been part of Southwest Power Pool.

Another issue is how states' efforts to incorporate carbon pricing in wholesale power markets might integrate with the US Department of Energy's notice of proposed rulemaking designed to ensure that coal and nuclear plants are compensated for their resiliency attributes, Wara said.

"There is a clear tension" between the idea of pricing carbon and what may amount to a subsidy for coal plants, Wara said.

"The problem is probably tractable" in ISO New England, the New York Independent System Operator and ISO New England, Wara said, but "a much harder case would be in a Western [regional transmission organization]" because of deep philosophical differences between the coastal states and states in the Great Plains, the Rocky Mountains and the Southwest.

Wilson said that in some parts of the West, there is a feeling that California is "taking all your water and all your energy." Nevertheless, the establishment of a Western RTO is "a major priority for the governor of California," Wara said.

"That effort got going in a big way two years ago," Wara said. "My sense is that Gov. [Jerry] Brown views that as a key piece of his legacy, changing the governance structure of Cal-ISO, whoever those parties will be. … When Gov. Brown wants to get something done, he has a way of making things happen."

— Mark Watson

DOE NOPR can avoid altering dispatch: Chatterjee

A proposed interim step to keep struggling coal and nuclear generators afloat while the US Federal Energy Regulatory Commission completes a more-thorough analysis of grid resilience can be implemented without altering dispatch or market behavior, Chairman Neil Chatterjee said Wednesday.

FERC in September received a notice of proposed rulemaking (RM18-1) from the Department of Energy seeking new market rules that would provide full cost recovery and a return on investment to generators with 90-day on-site fuel supplies.

Speaking at a forum hosted by Roll Call Live, Chatterjee said the commission was on track to meet DOE's December 11 deadline for acting on that proposal. He reiterated his desire for FERC to move forward with an interim solution linked, using a sunset provision, to longer-term analysis that solves broader concerns over grid resilience and baseload generation.

He stressed the need to mitigate further premature retirements of coal and nuclear plants until more is known about the attributes necessary to ensure the resilience of the grid and how to properly value those characteristics.

Responding to criticism about the potential distortive impact the NOPR could have on the wholesale power markets, Chatterjee said a limitation could be crafted into his interim step that would require generators "to bid in their costs so that ... they're not getting an advantage from that cost recovery" and so the markets are not harmed.

Interim step similar to RMR contract

Chatterjee expanded on this idea while speaking to reporters after the Roll Call Live event, likening it to reliability-must-run contracts that allow grid operators to prevent specific units from retiring until an alternative reliability solution can be implemented.

A common concern among those opposed to the NOPR, Chatterjee said, is "if you have generating sources that are getting external compensation, that will alter market behavior and that will alter dispatch, the order in which resources are put out."

"What I'm saying is that if we have a limitation — and again we're looking at this, we haven't fully fleshed it out — that these units getting cost recovery would have to bid in their costs, then that wouldn't alter market behaviors in this RMR construct," he said, offering more detail on the plan he is trying to get a majority of fellow commissioners to agree to.

The interim step he envisions "would be based on the precedent of an existing RMR [but] focus more so on resilience attributes and making sure that these potentially critical plants stay afloat," Chatterjee added. "If you can do it in a way that they have to bid in their costs and not alter dispatch, then that really minimizes the behavioral impact that people are worried about."

Of note, the owners of a few nuclear units have said their plants failed to clear capacity auctions in recent years. Several of those plants have shut or are slated to do so for economic reasons.

Electric Power Supply Association President and CEO John Shelk said in an email Wednesday that his organization "and all other affected parties would need to see the details of such a proposal in writing with sufficient notice and specificity to determine all of the impacts including whether such a plan is feasible and lawful."

Shelk added: "EPSA appreciates Chairman Chatterjee's keen recognition that FERC cannot alter compensation for one subset of competitors without negatively altering whether other competitors also receive just and reasonable rates as required by law."

EPSA has been a vocal advocate for protecting price formation and the dispatch of power plants in wholesale markets from any adverse impacts that could result from federal or state subsidies such as cost-based rates and zero emissions credit programs.

Cost of interim step 'justified'

Chatterjee, during the Roll Call Live event, also acknowledged that costs associated with the NOPR could raise rates for consumers. "But I think it's an absolutely justified cost to preserve our existing fleet while we look to answer this longer-term question because if we get it wrong, the costs will be far more severe than a short-term, defined interim step ... with minimal effects to the market," he said.

Chatterjee later told reporters that FERC has not proffered an estimate on consumer cost impacts. "We've got to work out how this will look first and then others will do that," Chatterjee said. "I can't stress enough that to the extent that there are consumer costs, these are totally legitimate costs."

"Paying for security, paying for resilience, that's something that's in consumers' interest," he continued. "Consumers pay for a lot of things that I would argue they may not necessarily get value for. This is something, particularly since it's a defined, short-term interim step, that I think is thoroughly defensible and in consumers' interest."

— *Jasmin Melvin*

ERCOT yields lessons for ISOs: researchers

The Electric Reliability Council of Texas has provided a series of valuable lessons for other power markets, according to research presented Tuesday at an energy economics conference in Houston.

For example, ERCOT's Operating Reserve Demand Curve, developed in an effort to ensure long-term sufficient generation capacity, has resulted in higher prices during periods of scarcity, but has not been enough to ensure ERCOT's resource adequacy. That is according to a study by Raul Bajo-Buenestado, an assistant professor of economics at the University of Navarra in Pamplona, Spain.

Also, ERCOT's burgeoning wind fleet has put downward pressure on prices, including for conventional generation not near wind resources. At the same time, wind growth has not always resulted in lower emissions, according to research by Chen-Hao Tsai, University of Texas Center for Energy Economics senior economist, and Derya Eryilmaz, an economist at NERA Economic Consulting.

Bajo-Buenestado and Tsai spoke about their work during the annual joint North American conference of the US Association for Energy Economics and the International Association for Energy Economics, in Houston.

ORDC intended to find 'missing money'

ERCOT adopted the ORDC, which produces an adder to real-time prices as generation reserves decrease, in order to address the "missing money problem," Bajo-Buenestado said. In 2011, ERCOT forecast that it would have insufficient generation capacity to meet forecast peakload — *i.e.,* a negative reserve margin — as early as 2019.

With ERCOT's approval this fall of the retirement of 4,618 MW of coal- and gas-fired generation by mid-February, ERCOT's reserves are expected to dive well below its 13.75% target, which is designed to ensure that the system has a blackout related to insufficient capacity no more than once in 10 years.

Based on the most recent spate of retirements, plus expectations for delayed commercial operations dates for a number of planned ERCOT resources, Dana Lazarus, senior analyst for North American power at S&P Global PIRA, has estimated that ERCOT's planning reserve margin would be in the range of 10% to 11% for the summer of 2018 and the range of 9% to 10% for the summer of 2019.

To ensure sufficient supplies to meet forecast load, other power markets have established capacity requirements, allowed regulators to mandate sufficient capacity, or established formal capacity markets, but ERCOT and its regulators have steadfastly refused these options, Bajo-Buenestado said.

Other markets, such as those in Mexico and Belgium, have considered implementing an ORDC approach, Bajo-Buenestado said, but he would advise against it, because it has resulted in higher prices when demand rises in relation to supply and lower prices when supply rises in relation to demand, and it has not proven to be sufficient to ensure long-term resource adequacy.

"Does the ORDC provide sufficient and clearly perceivable long-term price signals?" Bajo-Buenestado said. "I think the answer is no. They need to do something that is sufficiently long-term related."

Emissions sometimes up with more wind

Independent power producers have cited Texas' growth in wind generation as one cause of ERCOT's insufficient capacity prospects, UT's Tsai said. ERCOT's nameplate wind capacity has doubled since 2011 to a forecast of more than 20 GW by the end of 2017, Tsai said, and wind farms supplied more than 15% of ERCOT's load in 2016.

Subsidized wind generation has suppressed power prices, IPPs claim, and some have questioned whether the rapid ramping of fossil-fuel power plants to compensate for intermittent resources may be negating renewables zero-carbon attributes, Tsai said.

Tsai and Eryilmaz analyzed ERCOT 15-minute nodal data from 2014 to 2016 to separate prices at wind farms from prices at conventional generation, under different conditions of load, wind generation and natural gas prices.

They broke down the data for the summer months of June through September, the winter months of December through February, and the shoulder months. They also broke down the data between on-peak and off-peak.

The research concludes that in an environment of low natural gas prices, "the impact of renewables on suppressing prices is not negligible" — that it is significant enough to make a difference across different seasons and peak/off-peak hours, Tsai said.

However, he added, "During some seasons, for every additional 1,000 MW of wind generation, coal plant emissions actually go up."

For example, during on-peak and off-peak summer hours, sulfur dioxide emissions from coal plants increased significantly for every 1,000 MW of additional wind generation, while the same wind addition dropped SO_2 emissions during on-peak shoulder-month on-peak hours by more than twice as much, the research shows.

During winter months, nitrous oxide emissions from natural gas plants increased slightly during winter on-peak and off-peak hours, but dropped sharply during summer hours and dropped less significantly during shoulder months.

Based on this result, Tsai said it appears that shutting down coal plants would more effectively cut emissions than adding more wind generation.

After the 4,200 MW of coal-fired generation slated for retirement by February occurs, Tsai said, "We expect we are going to see a big drop in ... emissions."

— *Mark Watson*

PJM official: We have no fuel mix problem to fix

Panelists, including one representing a clean coal group, told state regulators that more analysis is needed before federal regulators consider changing power market rules to support "fuel secure" generating resources.

The Tuesday panel discussion during the National Association of Regulatory Utility Commissioners' annual meeting in Baltimore centered on the US Department of Energy's notice of proposed rulemaking, or NOPR, to prop up struggling nuclear and coal-fired power plants in certain competitive markets.

DOE officials repeatedly have cited the reliability issues brought on in the PJM Interconnection by the polar vortex of 2014 as one of the main reasons the NOPR should be adopted, but that assertion has left Steve Herling, vice president-planning for PJM, puzzled.

Natural gas-fired generating plants experienced outages during the Polar Vortex, but so too did some fueled by coal due to frozen coal piles and other reasons, Herling recalled. But even then, he said, most of the problems related to the polar vortex were not created by fuel supply issues.

Moreover, Herling stressed that the PJM region has perhaps the most diverse fuel mix in the whole country, with gas, coal and nuclear/renewable generation each contributing roughly the same amount of capacity. He also reported that during the winter months, PJM has probably the least dependence on gas, and the most dependence on coal and nuclear power, of all the organized markets.

'Certainly not a reliability issue': PJM

"So honestly, if this is all about fuel mix, this is not a PJM problem," Herling said. He further insisted that "this certainly is not a reliability issue," saying that the U.S. and PJM grids are incredibly reliable.

Herling also said PJM and the NOPR look at resilience very differently. PJM has defined resilience as preparing for, operating through, and recovering from an event, while the NOPR considers it to be having 90 days of on-site fuel supply. The grid operator has taken a much more holistic approach to the issue, he said.

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Platts restates erroneous database records for US Natural Gas and Power data

■ As part of its ongoing review of historic data sets, S&P Global Platts has identified certain erroneously recorded historic data in US Natural Gas and Power market data categories GD,GM and ES. To ensure Platts database contains fully representative data, Platts has restated these erroneous values in its database. Please copy and paste the entire link below to your browser to see the complete list of symbols and correct values. Both previous and current low, high and close prices have been listed, and the values highlighted in red show exactly which prices have been corrected. There were also some invalid values removed. https://www.platts.com/IM.Platts.Content/Downloads/Data/price-changes-us-natgas-power-nov2017.xlsx. Please note that this update is part of a series of reviews made to historic data. On June 23, 2017, Platts restated data where low and high values recorded in the Platts database had been transposed, or where certain data points had been databased with incorrect decimal place settings. That announcement can be found here: https://www.platts.com/new-code-details/26758908 On August 3, Platts identified and amended data where close values were erroneously stated out of the published high and low range. That announcement can be found here: https://www.platts.com/new-code-details/26783236. On August 25, 2017, Platts restated data regarding erroneously recorded historic database records in physical market database categories for oil, agricultural, coal, European natural gas, and petrochemicals markets. That announcement can be found here: https://www.platts.com/new-codedetails/26793753. On October 23, 2017, Platts restated data regarding erroneously recorded historic database records in oil market derivatives market data categories. That announcement can be found here: https://www.platts.com/new-code-details/26826304. Please send any comments or questions about this announcement by contacting Platts Client Services or emailing support@platts.com.

For instance, Herling noted that the power outages caused by recent hurricanes were not due to the lack of generating fuel but rather a result of downed transmission and distribution lines. PJM therefore is looking at transmission planning and a whole range of other issues, including cyber and physical security to prevent bad actors attacking the system, he said.

Thus, Herling continued, "the way to solve this problem is to figure out what are the attributes of the resources that we need, how much of that attribute do we need ... and then figure out how to introduce those attributes into the market so we get the behaviors that we need" to ensure grid reliability. He later added that security may be just one of many attributes that need to be valued.

Kathleen Barron, vice president for federal regulatory affairs for Exelon, agreed that a wide range of issues needs to be examined but asserted that no one was looking at the fuel security issue before the DOE issued its NOPR.

Barron nevertheless said the focus should be on ensuring that the market rules are effective before concluding that certain resources are not receiving adequate support. To do that, Barron said, "let's get the data first," urging that more studies of the risks to the grid be undertaken and the results of those studies be shared with FERC. For instance, she said a study is needed on whether too much capacity is tied to a single type of fuel supply.

"[We should determine] what exactly is the threat we're concerned about, and only then should we take the next step of figuring out what's the best way to mitigate that threat," she said.

To Marty Durbin, executive vice president and chief strategy officer for the American Petroleum Institute, the DOE's NOPR is simply a solution in search of a problem. He agreed that resilience issues should be examined, but noted that FERC and grid operators already were doing just that.

Moreover, Durbin said no resiliency crisis exists, asserting that the markets have worked and produced "one of the most diverse, efficient and reliable and resilient systems out there." He also insisted that natural gas has earned the market share it has now, while agreeing with others that the focus should be identifying needed attributes before market rules are changed.

Grid less reliable because of baseload retirements: ACCCE

Offering a different view, Paul Bailey, who heads the American Coalition for Clean Coal Electricity, said he supports the NOPR because the grid is becoming less reliable due to the retirement of baseload capacity. He noted that about 108,000 MW of coal-fired capacity, approximately a third of the nation's coal fleet, already has retired or will do so soon. About two-thirds of the coal fleet is located in regions with organized markets, and about 45,000 MW of that capacity already has retired, with another 14,000 MW to 15,000 MW slated to follow.

Suggesting that all those retirements are not a good thing, Bailey noted that ACEEE has proposed its own market-based solution — a two-tier capacity market, with the second tier being a "resilient on-site fuel services market."

Furthermore, Bailey maintained that all the DOE has done with the NOPR is try to put a value on fuel security. He nevertheless suggested that his group would also like to see more analysis done before the NOPR is implemented, citing one such study PJM conducted on "what if" another polar vortex were to hit its region.

Bailey also reported that the coal industry did not tell the DOE that 90 days of on-site fuel supplies is the right figure, and he is not sure who did. He recalled that the industry over the last 10 years has averaged between 70 days' and 80 days' supply. Thus, he said, the 90-day threshold outlined in the NOPR should be reevaluated over time.

Durbin then chimed in to say no one has shown that number is appropriate and stress that the added costs of keeping that much fuel on site also has to be considered.

On a different issue, Bailey said his group never has viewed the NOPR to be about subsidizing coal-fired units but rather about finding a market-based way to value resilience attributes.

Noting that coal and nuclear provides nearly half of all of PJM's capacity, Herling said subsidizing all those resources "would massively be disruptive to our markets." But Barron pointed out that about 30% of PJM's capacity already is subsidized. Still, she maintained this is not about increasing or decreasing subsidies but rather about looking at a whole range of potential solutions.

— *Glen Boshart, S&P Global Market Intelligence*

DAILY CSAPR ALLOWANCE ASSESSMENTS, NOV 15 ($/st)

	2017	change	2018	change
NOx Annual	2.75	0.00	2.75	0.00
NOx Seasonal	200.00	0.00	150.00	0.00
SO_2 Group 1	2.50	0.00	2.50	0.00
SO_2 Group 2	3.25	0.00	3.25	0.00

RGGI CARBON ALLOWANCE FUTURES, NOV 14 ($/allowance)

ICE	Settlement	Volume
Dec17 V16	4.23	0
Dec18 V16	4.33	0
Dec19 V16	4.45	0
Dec17 V17	4.23	0
Dec18 V17	4.33	0
Dec19 V17	4.45	0
Dec17 V18	4.23	0
Dec18 V18	4.33	0
Dec19 V18	4.45	0
Dec17 V19	4.23	0
Dec18 V19	4.33	0
Dec19 V19	4.45	0

The Regional Greenhouse Gas Initiative is a carbon cap-and-trade program for power generators in nine Northeast and Mid-Atlantic US states. One RGGI allowance is equivalent to one short ton of CO2. The volume listed is the number of futures contracts traded. Each futures contract represents 1,000 RGGI allowances.

PJM proposes energy price formation changes

Due to changes in the PJM Interconnection's fuel mix and weak power demand growth in recent years, the grid operator on Wednesday proposed energy price enhancements to introduce more flexibility into its real-time and day-ahead markets to more accurately value load-serving resources.

"We need to more accurately reflect the resources required to serve load, to incent flexible resources, and to minimize out-of-market uplift payments," Stu Bresler, PJM's senior vice president of operations and markets, said in a statement.

Downward pressure on gas prices due to production increases from shale resources coupled with lower power demand resulting from efficiency gains over the past several years have led to lower power prices. These lower prices have revealed “shortcomings” in PJM’s energy pricing mechanism, according to a paper released Wednesday outlining the grid operator’s proposal.

Higher-cost flexible units traditionally set price “often enough” that all resources needed to serve load could earn sufficient energy and capacity market revenues to drive efficient resource investments. However, both flexible and inflexible resources are needed to meet demand, and currently inflexible units are not permitted to set price.

PJM contends this limitation has led to artificially low wholesale energy prices that do not always accurately reflect the “true cost” of meeting power demand because inflexible unit costs may not be included in the price even though they can serve load.

“Inflexible units are those with declining average costs that are unable to economically produce power within a certain range, or that require an economic minimum output,” according to the paper.

Bresler sees 'a better way'

“We think there is better way to form price that provides resources incentives to be more flexible,” Bresler said during a media briefing call to announce the proposal.

The proposal is not aimed at any resource in particular, but the result is energy market prices will likely increase with the impact on generating units varying based on their individual economics.

However, PJM broadly estimates the net impact of the proposed changes will be an increase in total energy and capacity market costs of between 2% and 5%.

PJM also proposes adjusting its shortage pricing system that increases prices when supply and demand tighten. The current shortage pricing mechanism does not does not kick in until the system is short 10-minute reserves and the grid operator wants to implement a real-time, 30-minute operating reserve product.

“Signaling through prices that the system is getting tight earlier will provide better price signals for resources to kick in,” which could eliminate the possibility of going to short ten-minute reserves, Bresler said.

Concern about pace of proposal

“There’s a real concern that the PJM proposal is rushed,” Abram Klein, managing partner at energy trading firm Appian Way, said in an email.

“From my perspective, the core issue is that there is an endless supply of private equity capital willing to accept single-digit returns and build new, modern, efficient, baseload gas-fired combined cycle generation that is cheaper in the long run than the existing resources that the Trump Administration is trying to subsidize,” he said.

“This is not evidence of a problem — it’s evidence that competition is working.” He added that PJM’s reserve margins are “over and above what it needs to reliably operate the system, despite recent retirements, and more inefficient units need to be retired so the market can reach a stable equilibrium.”

Bresler said PJM plans to issue a problem statement at its December 7 Markets and Reliability Committee meeting and then move ahead with stakeholder discussions. The goal would then be to file a proposal with the US Federal Energy Regulatory Commission “by fall 2018.”

— *Jared Anderson*

OUTAGES

GENERATION UNIT OUTAGE REPORT, NOV 14

Plant/Operator	Cap	Fuel	State	Status	Return	Shut
Northeast						
Atikokan-1/OPG	205	bio	Ont.	MO	Unk	11/07/17
Darlington-3/OPG	876	n	Ont.	PMO	Unk	11/13/17
Lennox-1/OPG	525	g	Ont.	MO	Unk	08/23/17
Lennox-2/OPG	525	g	Ont.	MO	Unk	08/23/17
Pickering-1/OPG	500	n	Ont.	MO	Unk	08/21/17
Pickering-8/OPG	500	n	Ont.	MO	Unk	10/09/17
Sithe Goreway-12/Sithe	195	g	Ont.	MO	Unk	09/20/17
Ta Douglas/TransAlta	122	g	Ont.	MO	Unk	04/24/17
Thunderbay CTS/Resolute	116	bio	Ont.	MO	Unk	11/02/17
Thunderbay-3/OPG	153	bio	Ont.	MO	Unk	09/29/17
West Windsor/TransAlta	128	g	Ont.	MO	Unk	09/05/17
PJM & MISO						
Callaway/Ameren	1279	n	Mo.	RF	Unk	10/07/17
Cook-1/AEP	1041	n	Mich.	RF	Unk	09/13/17
Dresden-2/Exelon	925	n	Ill.	MO	Unk	10/30/17
Prarie Island-2/NextEra	604	n	Minn.	RF	Unk	10/14/17
Southeast & Central						
Oconee-2/Duke	934	n	S.C.	RF	Unk	10/27/17
Watts Bar-2/TVA	1210	n	Tenn.	RF	Unk	10/28/17
West						
Alamitos-2/AES	495	g	Calif.	MO	Unk	11/02/17
Alamitos-4/AES	336	g	Calif.	MO	Unk	11/09/17
Belden/PG&E	119	H	Calif.	MO	Unk	11/14/17
Caribou-2/PG&E	120	h	Calif.	PMO	Unk	10/31/17
Chevron/Chevron	114	o	Calif.	PMO	Unk	11/01/17
Colgate-2/YWCA	176	h	Calif.	PMO	Unk	10/31/17
Delta/Calpine	880	g	Calif.	PMO	Unk	10/12/17
Desert Star/SDG&E	495	g	Calif.	PMO	Unk	10/31/17
Eastwood/SCE	200	h	Calif	MO	Unk	10/11/17
El Cabo/Avangrid	298	w	N.M.	MO	Unk	11/07/17
Gianelli/USBR	374	h	Calif.	PMO	Unk	11/14/17
Helms-2/PG&E	407	h	Calif.	PMO	Unk	09/10/17
Helms-3/PG&E	404	h	Calif.	PMO	Unk	09/10/17
Mandalay-3/NRG	130	g	Calif.	MO	Unk	11/12/17
Mountainview-3/SCE	525	g	Calif.	PMO	Unk	10/19/19
Mountainview-4/SCE	525	g	Calif.	PMO	Unk	11/09/17
Pine Flat/KRCD	210	h	Calif.	PMO	Unk	11/13/17
Sutter-2/Calpine	525	g	Calif.	MO	Unk	02/20/17

Daily generation outage references: MO=unplanned maintenance outage; RF=refueling outage; PMO=planned maintenance outage; Unk=unknown; OA=offline/available. Fuels: Nuclear=n; Coal=c; Natural gas=g; Hydro=h ; Wind=w; Solar=s

Sources: Generation owners, public information and other market sources.

CORRECTION

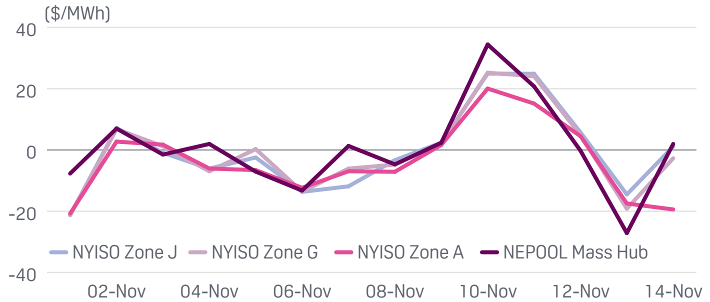
■ A November 15 story titled "Asia focus may double Cheniere's business size" included incorrect totals for Sabine Pass LNG cargoes to date. The terminal has exported a total of 228 cargoes, 214 or which have landed. A total of 14 cargoes have been delivered to Japan, 24 to South Korea and 44 to Mexico. The cargo numbers shown on the map for those countries were incorrect.

NORTHEAST POWER MARKETS

NORTHEAST DAY AHEAD POWER PRICES ($/MWh)

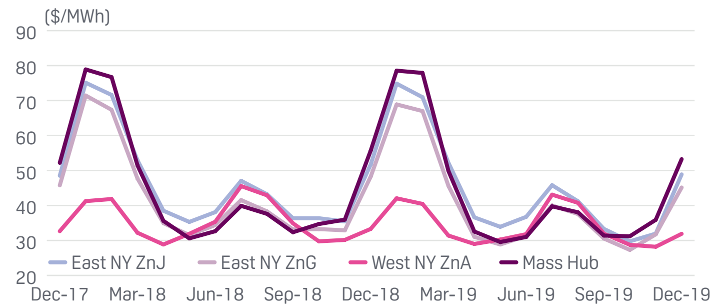
Hub/Index	Symbol	16-Nov	Marginal heat rate	Spark spread @7K	Spark spread @12K	Price change Chg	Price change % Chg	Prior 7-day Average	Month Min	Month Max	Yearly change Nov-17	Yearly change Nov-16	Yearly change Chg	Yearly change % Chg
On-Peak														
ISONE Internal Hub	IINIM00	41.50	12223	17.73	0.76	-2.27	-5.2	58.53	15.54	74.30	40.56	27.08	13.48	49.8
ISONE NE Mass-Boston	IINNM00	42.18	12423	18.41	1.44	-2.48	-5.6	59.01	15.53	74.41	40.86	28.47	12.39	43.5
ISONE Connecticut	IINCM00	40.43	12015	16.88	0.05	-2.36	-5.5	57.64	15.89	73.05	40.14	26.94	13.20	49.0
NYISO Zone G	INYHM00	34.49	10248	10.93	-5.90	-3.26	-8.6	42.81	20.20	53.81	35.10	28.11	6.99	24.9
NYISO Zone J	INYNM00	35.38	11377	13.61	-1.94	-5.29	-13.0	43.93	21.38	54.72	36.04	28.73	7.31	25.4
NYISO Zone A	INYWM00	31.00	12206	13.22	0.52	-1.85	-5.6	34.96	13.76	41.22	28.99	24.16	4.83	20.0
NYISO Zone F	INYCM00	33.50	10771	11.73	-3.82	-4.13	-11.0	42.96	19.70	54.91	35.17	26.44	8.73	33.0
Off-Peak														
ISONE Internal Hub	IINIP00	30.59	9009	6.82	-10.16	-0.11	-0.4	45.96	9.11	76.06	29.97	20.84	9.13	43.8
ISONE NE Mass-Boston	IINNP00	30.75	9058	6.99	-9.99	-0.26	-0.8	46.07	10.92	76.41	30.38	21.03	9.35	44.5
ISONE Connecticut	IINCP00	30.07	8935	6.51	-10.32	-0.09	-0.3	45.27	9.25	74.91	29.67	20.61	9.06	44.0
NYISO Zone G	INYHP00	22.51	6689	-1.05	-17.87	-5.56	-19.8	32.71	12.25	46.52	24.67	19.28	5.39	28.0
NYISO NYC Zone	INYNP00	22.70	7297	0.92	-14.63	-5.65	-19.9	33.04	12.38	47.05	24.93	19.45	5.48	28.2
NYISO West Zone	INYWP00	12.18	4794	-5.60	-18.31	-6.49	-34.8	21.27	5.91	31.22	15.98	16.19	-0.21	-1.3
NYISO Capital Zone	INYCP00	27.54	8855	5.77	-9.78	-4.47	-14.0	35.76	12.42	50.14	27.36	19.69	7.67	39.0

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



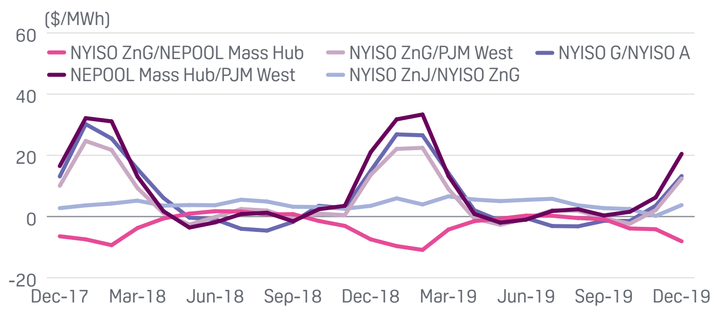
Source: Platts

NORTHEAST PLATTS M2MS FORWARD CURVE: ON-PEAK



Source: Platts

NORTHEAST PLATTS M2MS LOCATIONAL SPREADS: ON-PEAK



Source: Platts

Northeast spot power prices down on demand

Northeast day-ahead power prices fell Wednesday as temperatures were forecast to fall on lower demand.

Mass Hub on-peak fell 50 cents in the mid-$30s/MWh for Thursday delivery on the Intercontinental Exchange.

Mass Hub on-peak balance-of-the-week packages traded in the upper $30s/MWh, as on-peak next-week packages were also in the upper $30s/MWh.

The ISO New England predicted peakload around 16,425 GW Wednesday, 16,375 GW Thursday and 16,025 MW Friday.

High temperatures for Boston were forecast up 3 degrees to the upper 40s with lows in the upper 30s, according to CustomWeather.

ISO-NE Internal Hub real-time prices jumped to about $106/MWh at about 5:25 am EST during the morning ramp up as demand started to outpace forecast levels. Natural gas generation averaged 51.7% for October 30-November 5, down from 52.3% the previous week, according to New England Independent System Operator data. Nuclear generation averaged 26.6%, down from 27.2% the previous week.

In the New York ISO territory, NYISO Zone G Hudson Valley on-peak next-week was in the mid-$30s/MWh, while NYISO Zone A West on-peak next-week was in the low $30s/MWh.

NYISO predicted peakload near 19,550 MW Wednesday, 19,500 MW Thursday and 19,225 MW Friday.

In the NYISO territory, coal- and oil-fired generation kicked up this week, averaging 2.3% since Saturday. In comparison, the November 2016 average was 0%, December 2016 averaged 0.5%, January averaged 0.9% and February averaged 0.5%, according to NYISO data.

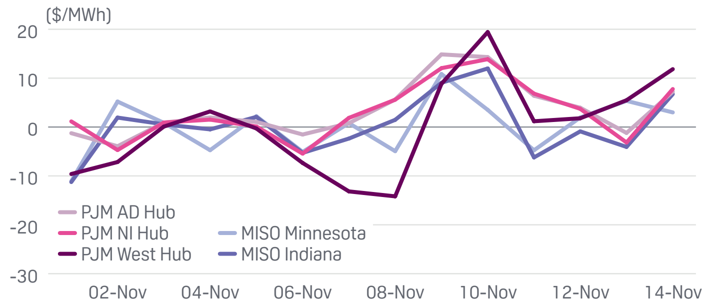
In New York City, high temperatures were projected to rise 8 degrees to the mid-50s Thursday with lows up to the upper 40s.

PJM/MISO POWER MARKETS

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

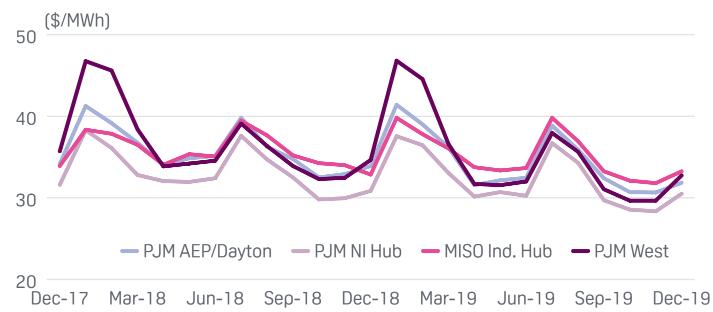
Hub/Index	Symbol	16-Nov	Marginal heat rate	Spark spread @7K	Spark spread @12K	Price change Chg	Price change % Chg	Prior 7-day Average	Month Min	Month Max	Yearly Change Nov-17	Yearly Change Nov-16	Yearly Change Chg	Yearly Change % Chg
On-Peak														
PJM AEP Dayton Hub	IPADM00	35.55	11504	13.92	-1.53	2.54	7.7	39.63	23.72	49.47	35.68	28.16	7.52	26.7
PJM Dominion Hub	IPDMM00	36.76	11688	14.74	-0.98	0.48	1.3	44.34	25.05	55.47	38.77	30.45	8.33	27.4
PJM Eastern Hub	IPEHM00	30.98	11370	11.91	-1.72	0.97	3.2	40.35	20.62	57.64	36.35	23.99	12.36	51.5
PJM Northern Illinois Hub	IPNIM00	35.85	11582	14.18	-1.29	3.84	12.0	37.34	21.84	47.61	33.96	27.09	6.87	25.4
PJM Western Hub	IPWHM00	35.33	12965	16.25	2.63	2.10	6.3	43.64	23.88	57.99	37.82	28.73	9.09	31.6
MISO Indiana Hub	IMIDM00	32.80	10598	11.14	-4.34	-0.04	-0.1	34.51	25.63	38.85	32.88	30.77	2.11	6.9
MISO Minnesota Hub	IMINM00	27.37	9137	6.40	-8.58	1.39	5.4	29.10	23.20	38.27	29.81	21.45	8.36	39.0
Off-Peak														
PJM AEP Dayton Hub	IPADP00	24.76	8014	3.13	-12.32	-1.74	-6.6	29.52	18.86	36.40	25.72	22.53	3.19	14.2
PJM Dominion Hub	IPDMP00	26.22	8337	4.20	-11.52	-2.78	-9.6	33.01	19.02	41.78	27.62	24.30	3.32	13.7
PJM Eastern Hub	IPEHP00	23.81	8738	4.74	-8.89	-1.71	-6.7	32.01	15.85	40.16	28.01	18.37	9.64	52.5
PJM Northern Illinois Hub	IPNIP00	23.31	7533	1.65	-13.82	5.76	32.8	23.40	17.55	27.74	22.01	20.05	1.96	9.8
PJM Western Hub	IPWHP00	25.15	9229	6.07	-7.55	-1.97	-7.3	30.72	18.90	37.36	26.34	23.02	3.32	14.4
MISO Indiana Hub	IMIDP00	24.57	7939	2.91	-12.57	0.69	2.9	26.00	20.08	28.69	24.44	22.11	2.33	10.5
MISO Minnesota Hub	IMINP00	19.21	6414	-1.76	-16.73	0.74	4.0	21.26	18.26	23.85	20.82	13.85	6.97	50.3

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



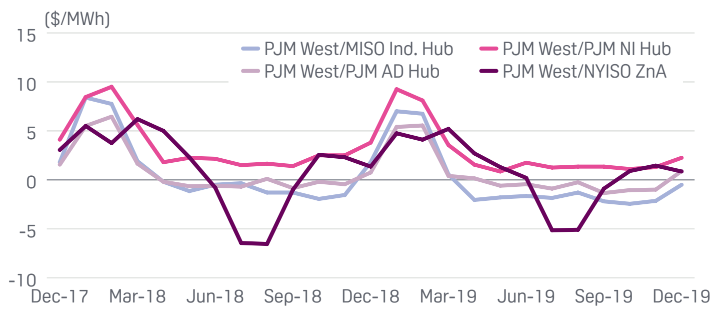
Source: Platts

PJM/MISO PLATTS M2MS FORWARD CURVE: ON-PEAK



Source: Platts

PJM/MISO PLATTS M2MS LOCATIONAL SPREADS: ON-PEAK



Source: Platts

Indiana Hub jumps $1.75 to mid-$30s/MWh

Power dailies in the PJM Interconnection and Midcontinent Independent System Operator were mixed Wednesday on load expectations and temperature forecasts.

PJM West on-peak day-ahead fell nearly $2 to the low $30s/MWh for Thursday delivery on the Intercontinental Exchange. On-peak balance-of-the-week was seen in the low $30s/MWh, and on-peak next-week in the mid-$30s/MWh.

Likewise, AD Hub on-peak day-ahead dipped 50 cents in the low $30s/MWh, with on-peak next-week in the low $30s/MWh.

NI Hub On-peak rose $1.25 in the low $30s/MWh on ICE.

PJM forecast peakload would be around 99,275 MW on Wednesday and 98,400 MW on Thursday.

High temperatures across the PJM footprint were forecast to range from the low 40s to the upper 60s Thursday, as much as 7 degrees Fahrenheit below and 7 F above seasonal averages, according to CustomWeather.

Coal-fired plants' share of the PJM fuel mix has averaged 33.6% so far in November, down from 37.2% in October and 37% last November, according to PJM data.

Nuclear's share has averaged 35.6% month to date, down from 36.8% in October and 37.5% in November 2016. Natural gas-fired plants' share has averaged 24.6%, up from 22.9% in October and 21.8% last November.

In MISO, Indiana Hub on-peak day-ahead jumped $1.75 in the mid-$30s/MWh. On-peak balance-of-the-week was seen in the low $30s/MWh with on-peak next-week also in the low $30s/MWh.

MISO forecast peakload across its footprint would be around 80,625 MW Wednesday and 82,250 MW Thursday.

High temperatures in Indianapolis are forecast to fall 4 degrees to the mid-40s Thursday, 8 degrees below normal.

Coal plants' share of the MISO fuel mix has averaged 50.8% so far this month, up from 45.4% in October and 44.8% last November, according to MISO data. The wind share of the fuel mix has averaged 7.5%, down from 11.2% in October and 10.4% last November.

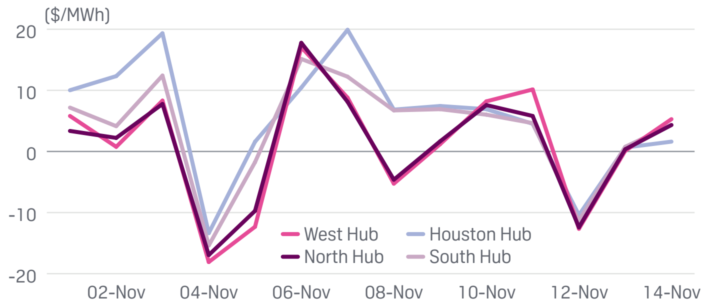
In the Southwest Power Pool, South Hub fell $2.25 in the mid-$20s/MWh as Oklahoma City high temperatures are forecast to reach the low 60s Thursday

SOUTHEAST POWER MARKETS

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

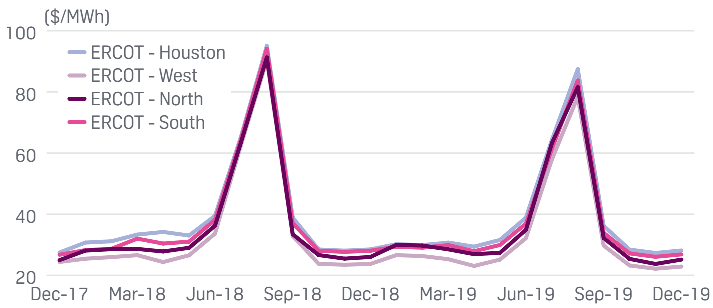
Hub/Index	Symbol	16-Nov	Marginal heat rate	Spark spread @7K	Spark spread @12K	Price change Chg	Price change % Chg	Prior 7-day Average	Month Min	Month Max	Yearly change Nov-17	Yearly change Nov-16	Yearly change Chg	Yearly change % Chg
On-Peak														
MISO Texas Hub	IMTXM00	36.24	12304	15.62	0.90	0.45	1.3	33.58	28.62	49.77	34.38	28.04	6.34	22.6
MISO Louisiana	IMLAM00	30.86	10252	9.79	-5.26	0.13	0.4	32.28	29.83	43.96	33.17	29.34	3.83	13.1
SPP North Hub	ISNOM00	14.19	4736	-6.78	-21.76	-10.71	-43.0	25.66	14.19	40.30	27.21	23.18	4.03	17.4
SPP South Hub	ISSOM00	24.28	8992	5.38	-8.12	-2.31	-8.7	25.57	21.29	31.36	25.45	25.95	-0.50	-1.9
ERCOT Houston Hub	IERHM00	26.88	8870	5.67	-9.49	-1.91	-6.6	27.70	23.94	55.59	33.90	23.65	10.25	43.3
ERCOT North Hub	IERNM00	24.19	8212	3.57	-11.16	-3.61	-13.0	26.19	20.62	40.19	26.65	21.32	5.33	25.0
ERCOT South Hub	IERSM00	26.20	8912	5.62	-9.08	-2.86	-9.8	27.50	23.51	45.94	29.93	23.32	6.61	28.4
ERCOT West Hub	IERWM00	23.23	8667	4.47	-8.93	-4.20	-15.3	25.57	18.62	41.14	26.54	21.53	5.01	23.3
Off-Peak														
MISO Texas Hub	IMTXP00	24.87	8446	4.26	-10.47	2.62	11.8	23.81	18.49	24.95	22.65	20.91	1.74	8.3
MISO Louisiana	IMLAP00	22.40	7443	1.33	-13.71	0.11	0.5	23.84	19.14	25.41	22.49	21.34	1.15	5.4
SPP North Hub	ISNOP00	12.11	4045	-8.85	-23.82	1.39	13.0	15.38	4.27	24.36	15.45	14.43	1.02	7.1
SPP South Hub	ISSOP00	15.22	5636	-3.68	-17.19	0.20	1.3	17.32	7.57	22.84	16.20	20.54	-4.34	-21.1
ERCOT Houston Hub	IERHP00	19.81	6539	-1.40	-16.54	0.41	2.1	20.33	17.61	23.28	20.43	13.79	6.64	48.1
ERCOT North Hub	IERNP00	16.98	5765	-3.64	-18.36	0.37	2.2	17.78	8.77	19.56	16.55	13.36	3.19	23.9
ERCOT South Hub	IERSP00	18.57	6315	-2.01	-16.72	0.02	0.1	19.29	14.22	20.53	18.64	13.81	4.83	35.0
ERCOT West Hub	IERWP00	16.11	6012	-2.65	-16.05	0.76	5.0	17.29	8.56	19.59	16.38	13.28	3.10	23.3

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



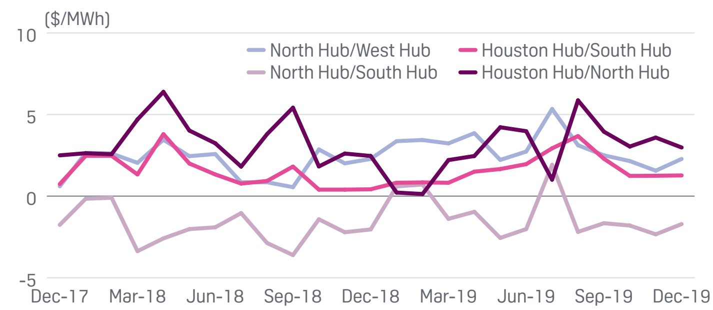
Source: Platts

ERCOT PLATTS M2MS FORWARD CURVE: ON-PEAK



Source: Platts

ERCOT PLATTS M2MS LOCATIONAL SPREADS: ON-PEAK



Source: Platts

ERCOT spot rises slightly on wind predictions

Next-day prices in the Electric Reliability Council of Texas region rose slightly Wednesday on lower wind generation expected for Thursday.

Prices for Friday delivery fell on forecasts for higher wind output.

ERCOT North Hub on-peak futures were framed in the high $20s/MWh for Thursday delivery on the Intercontinental Exchange, up about 35 cents, while Houston Hub counterparts were up about 75 cents to the low $30s/MWh.

The grid operator projected wind generation to total 210 GWh on Wednesday, falling by over 35% to about 136 GWh on Thursday before reaching about 311 GWh on Friday.

Wind output reached a five-month high of about 310 GWh on October 26, then fell to 283 GWh on October 27, when the wind-penetration rate broke a record, serving over 54% of load.

According to ERCOT data, wind generation has topped 300 GWh 15 times this year, with about half the times occurring in the first quarter.

High winds expected for Friday helped push power prices lower as North Hub balance-of-the-week on-peak for Friday delivery was valued in the low $20s/MWh on ICE.

ERCOT forecast peakload to hold steady above 42 GW on Wednesday and Thursday, then rise above 43 GW on Friday before averaging about 36 GW over the weekend.

Above-normal temperatures were projected to linger at least through Friday before falling for the weekend.

High temperatures in Dallas were expected to rise gradually from the low 70s Wednesday to the low 80s Friday, compared with seasonal averages in the high 60s, while highs in Houston were projected to linger in the low 80s over the same time, compared with seasonal norms in the low 70s, according to CustomWeather.

North Hub next-week on-peak futures were valued in the low $20s/MWh on ICE as more seasonal temperatures were expected next week.

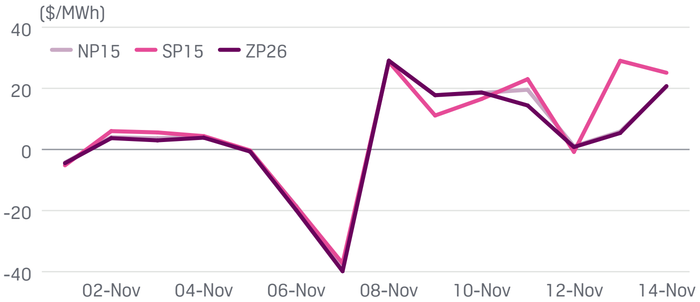
Highs in Houston were forecast from the mid-60s to mid-70s next week, nearing seasonal norms in the low 70s.

WEST POWER MARKETS

WESTERN DAY-AHEAD POWER PRICES ($/MWh)

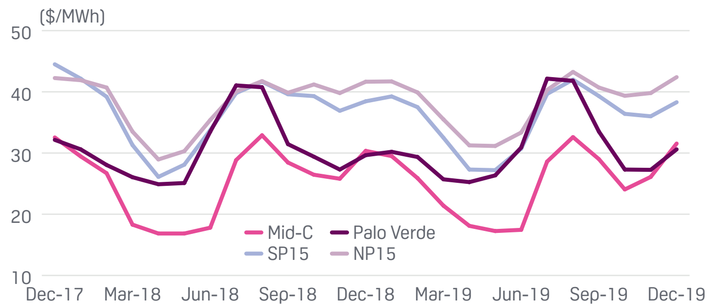
Hub/Index	Symbol	16-Nov	Marginal heat rate	Spark spread @7K	Spark spread @12K	Price change Chg	Price change % Chg	Prior 7-day Average	Month Min	Month Max	Yearly change Nov-17	Yearly change Nov-16	Yearly change Chg	Yearly change % Chg
On-Peak														
NP15	ICNGM00	41.45	13075	19.26	3.41	1.28	3.2	39.65	33.65	59.44	41.68	32.50	9.18	28.2
SP15	ICSGM00	43.39	14393	22.29	7.21	-3.79	-8.0	46.22	33.15	60.38	45.08	29.55	15.53	52.6
ZP26	ICZGM00	40.99	13596	19.89	4.81	1.64	4.2	39.03	32.81	58.83	41.04	29.49	11.55	39.2
COB	WEABE20	31.00	10745	10.80	-3.62	0.75	2.5	38.75	29.15	57.25	37.83	22.60	15.23	67.4
MEAD	AAMBW20	31.75	7479	2.03	-19.19	-0.25	-0.8	33.93	29.75	38.50	33.18	21.68	11.50	53.0
MID-C	WEABF20	25.16	9050	5.70	-8.20	0.30	1.2	24.47	22.24	41.40	26.92	19.07	7.85	41.2
Palo Verde	WEACC20	28.00	6596	-1.71	-22.94	-0.25	-0.9	30.62	26.97	38.25	30.34	19.72	10.62	53.8
Off-Peak														
NP15	ICNGP00	32.02	10102	9.83	-6.02	1.21	3.9	32.81	30.69	41.80	33.65	25.24	8.41	33.3
SP15	ICSGP00	32.71	10850	11.61	-3.47	1.34	4.3	33.74	30.75	42.43	34.23	24.48	9.75	39.8
ZP26	ICZGP00	31.98	10606	10.87	-4.20	1.45	4.7	32.66	30.47	41.63	33.48	24.38	9.10	37.3
COB	WEACJ20	25.00	8666	4.81	-9.62	1.73	7.4	24.32	21.75	34.23	26.62	17.73	8.89	50.1
MEAD	AAMBQ20	25.75	6066	-3.96	-25.19	0.00	0.0	27.25	24.25	29.00	26.52	18.65	7.87	42.2
MID-C	WEACL20	22.18	7978	2.72	-11.18	1.86	9.2	22.16	20.02	31.83	24.27	14.60	9.67	66.2
Palo Verde	WEACT20	25.00	5889	-4.72	-25.94	0.00	0.0	26.11	23.25	27.50	25.47	17.89	7.58	42.4

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



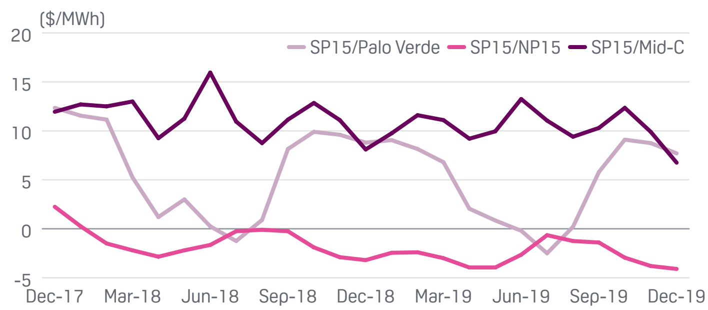
Source: Platts

WESTERN PLATTS M2MS FORWARD CURVE: ON-PEAK



Source: Platts

WESTERN PLATTS M2MS LOCATIONAL SPREADS: ON-PEAK



Source: Platts

West dailies mixed as weather forecasts diverge

West power dailies were mixed Wednesday, with California and Southwest down on lower demand and higher temperature forecasts, while the Northwest extended gains as a winter storm moved into the region from the Pacific.

In California, SP15 on-peak day-ahead dropped $2.15 to the mid-$40s/MWh, while SP15 on-peak balance of the month fell 25 cents to slightly above $39/MWh, reflecting market expectations that the recent slump in California's power prices will continue.

Weighing on these power prices, spot gas at Southern California city-gates fell nearly 50 cents to around $4.26/MMBtu.

California Independent System Operator forecast peakload around 29,294 MW Wednesday, around 400 MW below Tuesday's peak load, and 29,436 MW on Thursday.

Los Angeles high temperatures were forecast to remain in the low 70s Wednesday and Thursday, in line with historical norms, before rising nearly 10 degrees above average this weekend, while Sacramento is expected to see temperatures remain in the low 60s through the weekend, right around historical norms, according to CustomWeather.

In the Southwest, Palo Verde power prices were slightly lower, with on-peak day-ahead shedding around 40 cents, keeping the price point in the upper $20s/MWh, while off-peak packages fell less than 25 cents to remain in the mid-$20s/MWh.

The price movements come as temperatures in Phoenix are expected to remain around 10 degrees above normal through the weekend.

Further north in the Pacific Northwest, winter weather advisories and winter storm warnings remain in place for portions of the Olympics and Cascades as a low-pressure Pacific system slowly pushes inland, bringing coastal rain and heavy snowfall further into the region, according to the National Weather Service.

These storms helped move Northwest prices in the opposite direction of their southern peers, with Mid-Columbia on-peak day-ahead moving higher for the third straight session, gaining than 30 cents to trade in the mid-$20s/MWh. Mid-C off-peak day-ahead saw an even larger gain, strengthening nearly $2.25 to trade in the mid $2.30s/MWh.

BILATERALS

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

			Marginal	Spark spread		Price change		Prior 7-day	Month	Month	Yearly change			
Hub/Index	Symbol	16-Nov	heat rate	@7K	@12K	Chg	% Chg	Average	Min	Max	Nov-17	Nov-16	Chg	% Chg
On-Peak														
Florida	AAMAV20	30.00	9772	8.51	-6.84	-0.25	-0.8	30.46	28.50	32.00	30.04	26.66	3.38	12.7
GTC, Into	WAMCJ20	30.00	9804	8.58	-6.72	-0.50	-1.6	30.29	27.00	32.00	29.46	26.51	2.95	11.1
Southern, Into	AAMBJ20	29.25	9559	7.83	-7.47	-0.25	-0.8	29.50	26.00	31.00	28.75	25.36	3.39	13.4
TVA, Into	WEBAB20	30.00	10017	9.04	-5.94	0.00	0.0	31.04	27.75	32.75	30.13	27.35	2.78	10.2
VACAR	AAMCI20	30.25	9618	8.23	-7.49	-0.50	-1.6	32.89	27.75	37.00	31.23	26.64	4.59	17.2
Off-Peak														
Florida	AAMAO20	26.00	8469	4.51	-10.84	0.25	1.0	27.46	22.00	28.50	24.92	22.59	2.33	10.3
GTC, Into	WAMCC20	25.50	8333	4.08	-11.22	0.25	1.0	26.96	21.00	28.00	24.30	20.24	4.06	20.1
Southern, Into	AAMBC20	25.00	8170	3.58	-11.72	0.25	1.0	26.46	21.00	27.50	23.92	19.18	4.75	24.8
TVA, Into	AAJER20	25.25	8431	4.29	-10.69	0.50	2.0	26.54	21.00	28.25	24.19	20.22	3.97	19.6
VACAR	AAMCB20	26.75	8506	4.74	-10.99	1.00	3.9	28.64	21.00	31.75	25.23	20.27	4.96	24.5

WESTERN DAY-AHEAD BILATERAL INDEXES ($/MWh)

			Marginal	Spark spread		Price change		Prior 7-day	Month	Month	Yearly change			
Hub/Index	Symbol	16-Nov	heat rate	@7K	@12K	Chg	% Chg	Average	Min	Max	Nov-17	Nov-16	Chg	% Chg
On-Peak														
Mid-C	WEABF20	25.16	9050	5.70	-8.20	0.30	1.2	24.47	22.24	41.40	26.92	19.07	7.85	41.2
John Day	WEAHF20	26.25	9442	6.79	-7.11	0.50	1.9	25.43	23.25	42.50	27.95	20.05	7.90	39.4
COB	WEABE20	31.00	10745	10.80	-3.62	0.75	2.5	38.75	29.15	57.25	37.83	22.60	15.23	67.4
NOB	WEAIF20	31.00	11151	11.54	-2.36	0.75	2.5	38.75	29.00	57.25	37.82	21.58	16.24	75.3
Palo Verde	WEACC20	28.00	6596	-1.71	-22.94	-0.25	-0.9	30.62	26.97	38.25	30.34	19.72	10.62	53.8
Mona	AARLQ20	23.25	8187	3.37	-10.83	-1.00	-4.1	26.00	22.50	37.25	26.50	20.92	5.58	26.7
Four Corners	WEABI20	26.00	9576	6.99	-6.58	-1.00	-3.7	28.93	25.25	35.00	28.43	20.33	8.10	39.8
Pinnacle Peak	WEAKF20	28.00	6596	-1.71	-22.94	-1.00	-3.4	29.36	26.00	37.75	29.39	20.27	9.12	45.0
Westwing	WEAJF20	29.00	6832	-0.71	-21.94	-0.25	-0.9	30.61	27.75	39.25	30.64	20.07	10.57	52.7
MEAD	AAMBW20	31.75	7479	2.03	-19.19	-0.25	-0.8	33.93	29.75	38.50	33.18	21.68	11.50	53.0
Off-Peak														
Mid-C	WEACL20	22.18	7978	2.72	-11.18	1.86	9.2	22.16	20.02	31.83	24.27	14.60	9.67	66.2
John Day	WEAHL20	23.25	8363	3.79	-10.11	2.00	9.4	23.11	21.00	32.75	25.23	15.53	9.71	62.5
COB	WEACJ20	25.00	8666	4.81	-9.62	1.73	7.4	24.32	21.75	34.23	26.62	17.73	8.89	50.1
NOB	WEAIL20	26.00	9353	6.54	-7.36	1.75	7.2	25.32	22.75	35.25	27.61	16.61	11.00	66.2
Palo Verde	WEACT20	25.00	5889	-4.72	-25.94	0.00	0.0	26.11	23.25	27.50	25.47	17.89	7.58	42.4
Mona	AARLO20	22.25	7835	2.37	-11.83	0.25	1.1	22.39	20.50	28.00	23.02	18.18	4.84	26.6
Four Corners	WEACR20	24.75	9116	5.74	-7.83	0.25	1.0	23.21	21.50	25.75	23.47	17.62	5.85	33.2
Pinnacle Peak	WEAKL20	23.00	5418	-6.72	-27.94	-0.50	-2.1	24.86	21.75	26.25	24.05	18.07	5.98	33.1
Westwing	WEAJL20	26.50	6243	-3.21	-24.44	0.00	0.0	27.04	23.50	29.00	25.98	18.27	7.71	42.2
MEAD	AAMBQ20	25.75	6066	-3.96	-25.19	0.00	0.0	27.25	24.25	29.00	26.52	18.65	7.87	42.2

WESTERN NEAR-TERM BILATERAL MARKETS ($/MWh)

Package	Trade date	Range
Mid-C		
Bal-month	11/15	28.50-29.00
Bal-month	11/14	28.00-28.50

PLATTS M2MS FORWARD CURVE, NOV 15 ($/MWh)

Prompt month: Dec 17

	On-peak	Off-peak
Northeast		
Mass Hub	52.20	41.50
N.Y. Zone G	45.75	35.00
N.Y. Zone J	48.50	35.95
N.Y. Zone A	32.65	21.15
Ontario*	21.40	11.58
PJM & MISO		
PJM West	35.70	28.45
AD Hub	34.15	27.55
NI Hub	31.60	24.25
Indiana Hub	33.90	26.50

*Ontario prices are in Canadian dollars

	On-peak	Off-peak
Southeast & Central		
Southern Into	31.90	26.31
ERCOT North	24.95	20.11
ERCOT Houston	27.45	20.35
ERCOT West	24.35	18.29
ERCOT South	26.71	20.26
Western		
Mid-C	32.55	25.25
Palo Verde	32.15	26.90
Mead	34.69	28.57
NP15	42.25	33.90
SP15	44.50	34.65

ISO DAY-AHEAD LMP BREAKDOWN FOR NOV 16 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
Northeast						
On-peak						
ISONE Internal Hub	41.50	0.00	-0.09	-2.27	40.56	12223
ISONE Connecticut	40.43	0.00	-1.16	-2.36	40.14	12015
ISONE NE Mass-Boston	42.18	0.00	0.58	-2.48	40.86	12423
NYISO Capital Zone	33.50	-0.25	2.17	-4.13	35.17	10771
NYISO Hudson Valley Zone	34.49	-0.15	3.26	-3.26	35.10	10248
NYISO N.Y.C. Zone	35.38	-0.48	3.82	-5.29	36.04	11377
NYISO West Zone	31.00	-0.03	-0.10	-1.85	28.99	12206
Off-Peak						
ISONE Internal Hub	30.59	0.00	0.10	-0.11	29.97	9009
ISONE Connecticut	30.07	0.00	-0.42	-0.09	29.67	8935
ISONE NE Mass-Boston	30.75	0.00	0.27	-0.26	30.38	9058
NYISO Capital Zone	27.54	-16.40	0.65	-4.47	27.36	8855
NYISO Hudson Valley Zone	22.51	-11.06	0.96	-5.56	24.67	6689
NYISO N.Y.C. Zone	22.70	-11.06	1.14	-5.65	24.93	7297
NYISO West Zone	12.18	-1.65	0.03	-6.49	15.98	4794
PJM & MISO						
On-peak						
PJM AEP-Dayton Hub	35.55	1.10	0.16	2.54	35.68	11504
PJM Dominion Hub	36.76	1.90	0.58	0.48	38.77	11688
PJM Eastern Hub	30.98	-3.01	-0.29	0.97	36.35	11370
PJM Northern Illinois Hub	35.85	2.16	-0.60	3.84	33.96	11582
PJM Western Hub	35.33	1.25	-0.21	2.10	37.82	12965
MISO Indiana Hub	32.80	0.93	0.72	-0.04	32.88	10598
MISO Minnesota Hub	27.37	-2.20	-1.59	1.39	29.81	9137
MISO Louisiana Hub	30.86	-0.39	0.09	0.13	33.17	10252
MISO Texas Hub	36.24	4.97	0.11	0.45	34.38	12304
Off-Peak						
PJM AEP-Dayton Hub	24.76	0.34	0.03	-1.74	25.72	8014
PJM Dominion Hub	26.22	1.14	0.68	-2.78	27.62	8337
PJM Eastern Hub	23.81	-0.40	-0.19	-1.71	28.01	8738
PJM Northern Illinois Hub	23.31	-0.17	-0.92	5.76	22.01	7533
PJM Western Hub	25.15	0.50	0.24	-1.97	26.34	9229
MISO Indiana Hub	24.57	1.08	0.83	0.69	24.44	7939
MISO Minnesota Hub	19.21	-1.81	-1.66	0.74	20.82	6414
MISO Louisiana Hub	22.40	-0.31	0.05	0.11	22.49	7443
MISO Texas Hub	24.87	1.91	0.30	2.62	22.65	8446
Southeast & Central						
On-peak						
SPP North Hub	14.19	-5.31	-0.63	-10.71	27.21	4736
SPP South Hub	24.28	3.76	0.39	-2.31	25.45	8992
ERCOT Houston Hub	26.88	–	–	-1.91	33.90	8870
ERCOT North Hub	24.19	–	–	-3.61	26.65	8212
ERCOT South Hub	26.20	–	–	-2.86	29.93	8912
ERCOT West Hub	23.23	–	–	-4.20	26.54	8667
Off-Peak						
SPP North Hub	12.11	-2.66	-0.52	1.39	15.45	4045
SPP South Hub	15.22	-0.37	0.29	0.20	16.20	5636
ERCOT Houston Hub	19.81	–	–	0.41	20.43	6539
ERCOT North Hub	16.98	–	–	0.37	16.55	5765
ERCOT South Hub	18.57	–	–	0.02	18.64	6315
ERCOT West Hub	16.11	–	–	0.76	16.38	6012
Western						
On-peak						
CAISO NP15 Gen Hub	41.45	-1.50	-1.28	1.28	41.68	13075
CAISO SP15 Gen Hub	43.39	0.17	-1.01	-3.79	45.09	14393
CAISO ZP26 Gen Hub	40.99	-1.46	-1.78	1.64	41.04	13596
Off-Peak						
CAISO NP15 Gen Hub	32.02	-0.02	-1.12	1.21	33.65	10102
CAISO SP15 Gen Hub	32.71	0.04	-0.49	1.34	34.23	10850
CAISO ZP26 Gen Hub	31.98	-0.02	-1.17	1.45	33.48	10606

NORTHEAST POWER MARKETS

NYISO SUPPLY MIX (GWh/d)

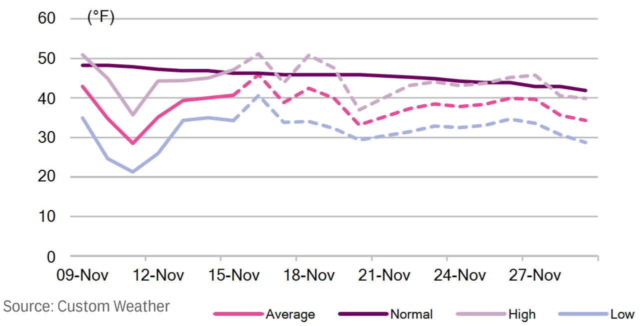
							Daily change		Season		Season average			
Category	**10-Nov**	**11-Nov**	**12-Nov**	**13-Nov**	**14-Nov**	**% Share**	**Chg**	**% Chg**	**Min**	**Max**	**2017**	**2016**	**Chg**	**% Chg**
Total Generation	376.08	365.79	353.39	359.21	347.47	85%	-11.74	-3.0%	282.89	474.16	354.05	354.41	-0.36	0.0%
Gas	146.27	131.98	128.57	141.47	133.12	33%	-8.35	-6.0%	73.36	261.99	133	124.28	8.72	7.0%
Coal	22.99	24.01	19.64	19.01	18.46	5%	-0.55	-3.0%	1.17	24.01	8.76	9.47	-0.71	-7.0%
Nuclear	126.57	134.67	134.67	134.67	134.67	33%	0	0.0%	101.49	134.67	130.87	126.63	4.24	3.0%
Other	125.08	116.75	108.37	124.98	121.53	30%	-3.45	-3.0%	101.33	181.34	141.26	154.76	-13.5	-9.0%

ISONE SUPPLY MIX (GWh/d)

							Daily change		Season		Season average			
Category	**10-Nov**	**11-Nov**	**12-Nov**	**13-Nov**	**14-Nov**	**% Share**	**Chg**	**% Chg**	**Min**	**Max**	**2017**	**2016**	**Chg**	**% Chg**
Total Generation	256.19	263.9	264.52	285.77	285.6	83%	-0.17	0.0%	230.85	350.48	270.01	275.51	-5.5	-2.0%
Gas	92.63	84.72	92.12	107.58	104.39	30%	-3.19	-3.0%	62.62	153.45	107.17	99.74	7.43	7.0%
Nuclear	67.73	67.73	67.73	67.73	72.84	21%	5.11	8.0%	59.03	95.94	82.76	93.77	-11.01	-12.0%
Coal	22.55	33.71	20.8	24.76	24.11	7%	-0.65	-3.0%	4.3	33.71	16.04	18.96	-2.92	-15.0%
Wind	24.54	16.79	1.62	1.09	3.49	1%	2.4	220.0%	0.91	24.54	8.57	6.5	2.07	32.0%
Other	101.04	120.73	133.21	143.19	138.11	40%	-5.08	-4.0%	54.31	143.19	97.62	101.96	-4.34	-4.0%

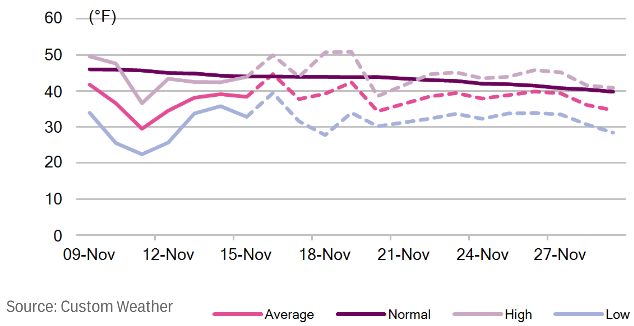
Seasons are defined as: Summer (June - August), Fall (September - November), Winter (December - February), and Spring (March - May). Source: Platts

NYISO TEMPERATURE



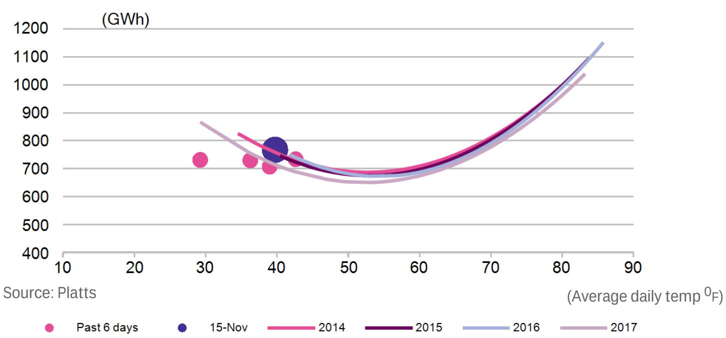
Source: Custom Weather

ISONE TEMPERATURE



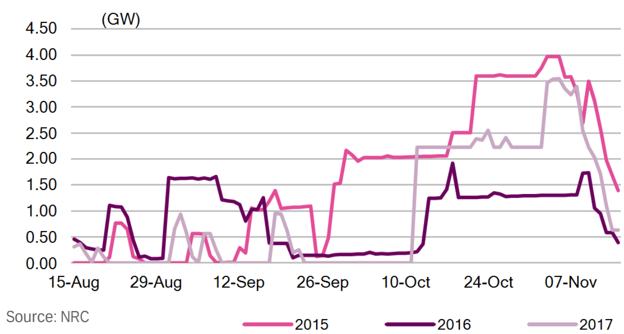
Source: Custom Weather

ISONE & NYISO LOAD PER DEGREE



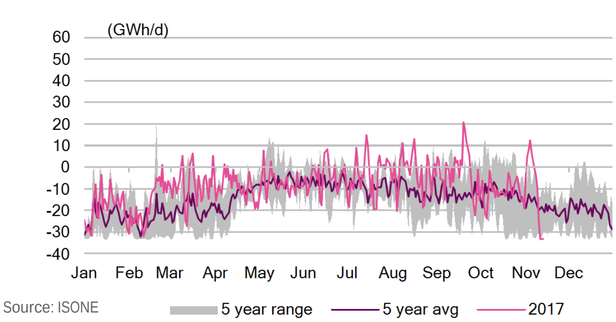
Source: Platts

ISONE & NYISO NUCLEAR GENERATION OUTAGES



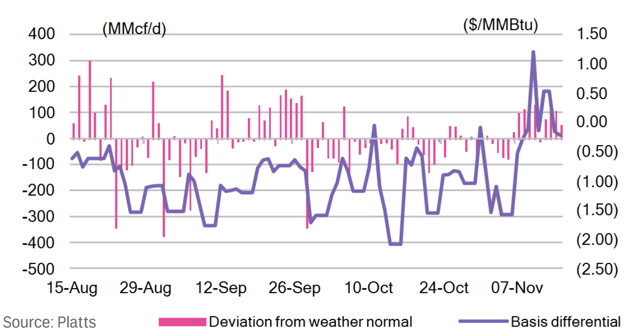
Source: NRC

ISONE-NYISO INTERTIE TRANSMISSION E-W



Source: ISONE

NYISO POWER BURN VS. GAS BASIS



Source: Platts

PJM/MISO POWER MARKETS

PJM SUPPLY MIX (GWh/d)

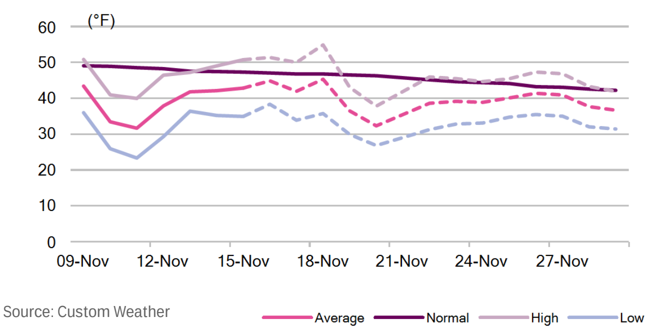
							Daily change		Season		Season average			
Category	**10-Nov**	**11-Nov**	**12-Nov**	**13-Nov**	**14-Nov**	**% Share**	**Chg**	**% Chg**	**Min**	**Max**	**2017**	**2016**	**Chg**	**% Chg**
Total Generation	2,153.22	2,187.93	2,046.94	2,126.85	2,076.88	100%	-49.97	-2.0%	1,689.41	2,534.28	2,038.99	2,066.68	-27.69	-1.0%
Gas	558.92	503.12	470.1	506.98	498.45	24%	-8.53	-2.0%	251.77	800.7	487.54	494.15	-6.61	-1.0%
Coal	699.14	801.9	713.98	724.68	696.75	34%	-27.93	-4.0%	586.28	993.33	713.16	722.31	-9.15	-1.0%
Nuclear	701.33	700.08	707.94	727.16	746.78	36%	19.62	3.0%	670.87	799.23	715.12	706.86	8.26	1.0%
Other	162.3	136.61	118.37	166.91	131.42	6%	-35.49	-21.0%	-134.36	208.64	59.35	66.16	-6.81	-10.0%

MISO SUPPLY MIX (GWh/d)

							Daily change		Season		Season average			
Category	**10-Nov**	**11-Nov**	**12-Nov**	**13-Nov**	**14-Nov**	**% Share**	**Chg**	**% Chg**	**Min**	**Max**	**2017**	**2016**	**Chg**	**% Chg**
Total Generation	1,879.07	1,756.55	1,680.62	1,802.84	1,786.76	102%	-16.08	-1.0%	1,620.12	2,273.41	1,825.52	1,802.02	23.5	1.0%
Gas	314.12	262.49	264.83	310.57	288.88	16%	-21.69	-7.0%	160.05	553.47	318.08	320.86	-2.78	-1.0%
Coal	924.1	915.49	907.94	899.43	878.49	50%	-20.94	-2.0%	615.56	1,017.02	832.88	809.37	23.51	3.0%
Nuclear	276.04	272.25	277.2	276.81	275.28	16%	-1.53	-1.0%	140.08	302.87	273.11	244.54	28.57	12.0%
Wind	204.74	115.69	36.39	143	167.04	9%	24.04	17.0%	29.07	305.03	140.76	137.14	3.62	3.0%
Other	136.42	151.68	141.04	149.16	150.03	9%	0.87	1.0%	136.42	303.21	210.54	237.16	-26.62	-11.0%

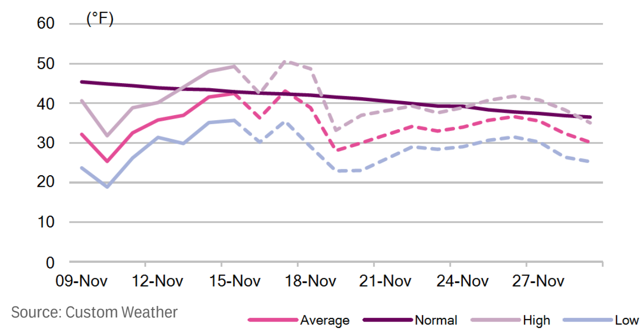
Seasons are defined as: Summer (June - August), Fall (September - November), Winter (December - February), and Spring (March - May). Source: Platts

PJM TEMPERATURE



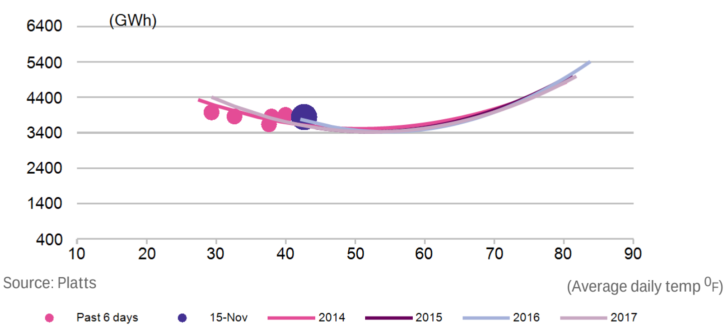
Source: Custom Weather

MISO TEMPERATURE



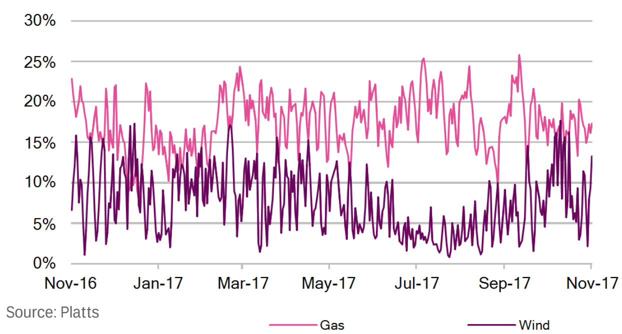
Source: Custom Weather

PJM & MISO LOAD PER DEGREE



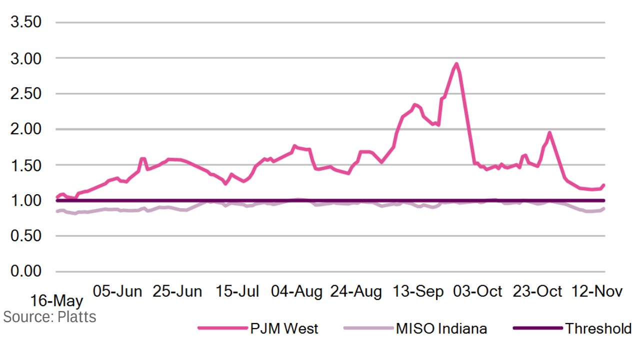
Source: Platts

MISO GENERATION MARKET SHARE - GAS VS. WIND



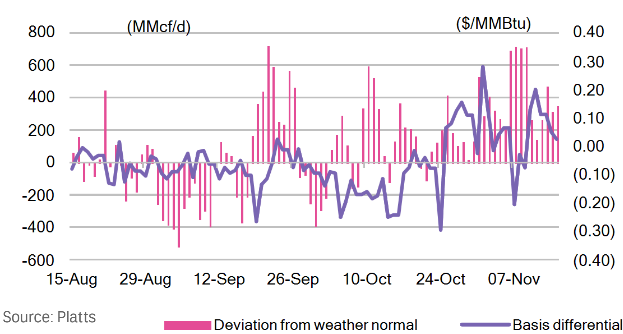
Source: Platts

PJM/MISO COAL-VS-GAS $/MWh FUEL COST RATIO



Source: Platts

MISO POWER BURN VS. GAS BASIS



Source: Platts

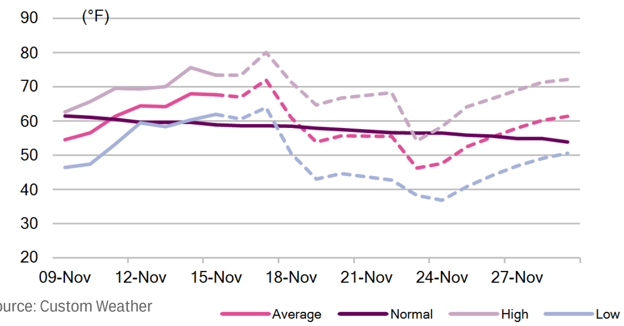
SOUTHEAST POWER MARKETS

ERCOT SUPPLY MIX (GWh/d)

							Daily change		Season		Season average			
Category	**10-Nov**	**11-Nov**	**12-Nov**	**13-Nov**	**14-Nov**	**% Share**	**Chg**	**% Chg**	**Min**	**Max**	**2017**	**2016**	**Chg**	**% Chg**
Total Generation	840.32	789.3	795.62	856.88	831.83	100%	-25.05	-3.0%	789.3	1,242.06	978.92	953.08	25.84	3.0%
Gas	256.29	263.59	290.77	277.56	314.42	38%	36.86	13.0%	256.29	571.37	412.65	409.23	3.42	1.0%
Coal	346.13	310.35	290.45	327.13	295.68	36%	-31.45	-10.0%	194.9	450.93	307.52	295.14	12.38	4.0%
Nuclear	117.79	123.33	123.33	123.33	123.33	15%	0	0.0%	93.52	123.33	109.96	110.91	-0.95	-1.0%
Wind	137.28	260.84	105.3	68.36	226.9	27%	158.54	232.0%	35.17	310.42	167.87	137.34	30.53	22.0%
Other	-17.17	-168.81	-14.22	60.5	-128.5	-15%	-189	-312.0%	-172.59	113.97	-19.07	0.47	-19.54	-4157.0%

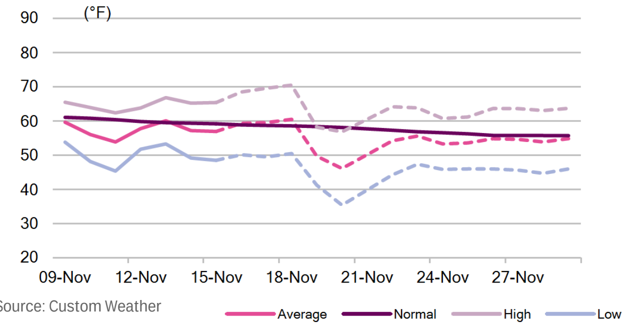
Seasons are defined as: Summer (June - August), Fall (September - November), Winter (December - February), and Spring (March - May). Source: Platts

ERCOT TEMPERATURE



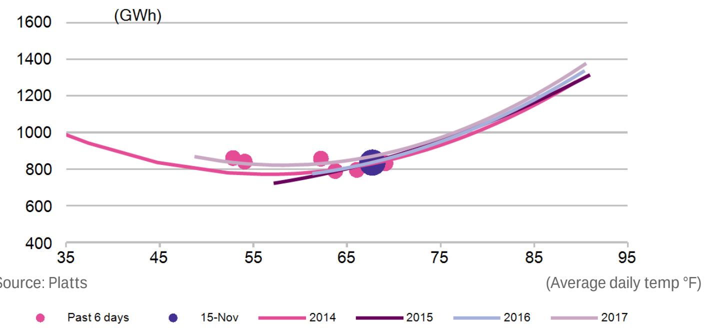
Source: Custom Weather

SOUTHEAST TEMPERATURE



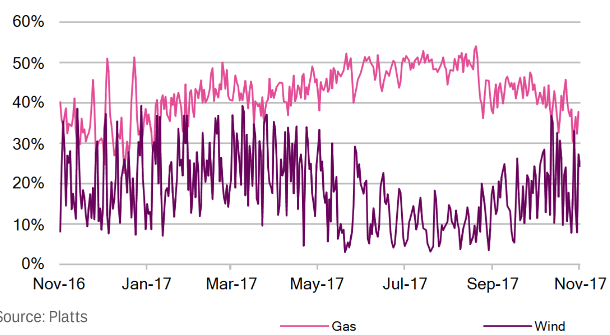
Source: Custom Weather

ERCOT LOAD PER DEGREE



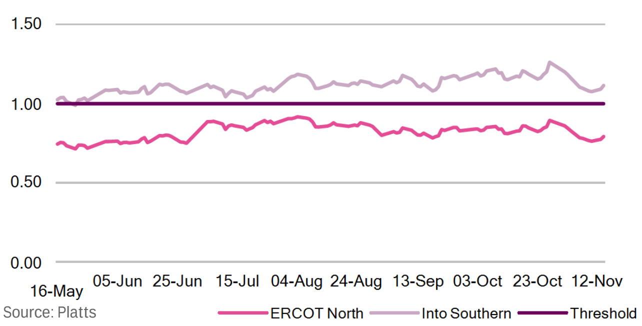
Source: Platts

ERCOT GENERATION MARKET SHARE - GAS VS. WIND



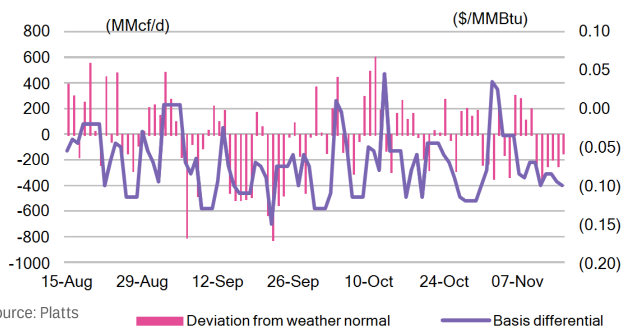
Source: Platts

SOUTHEAST COAL-VS-GAS $/MWh FUEL COST RATIO



Source: Platts

ERCOT POWER BURN VS. GAS BASIS



Source: Platts

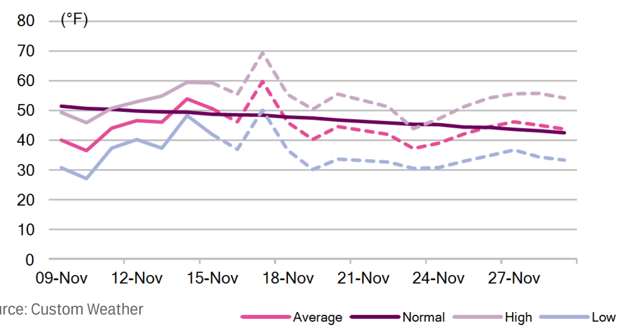
SPP POWER MARKETS

SPP GENERATION MIX (GWh/d)

Category	10-Nov	11-Nov	12-Nov	13-Nov	14-Nov	% Share	Daily change Chg	Daily change % Chg	Season Min	Season Max	Season average 2017	Season average 2016	Season average Chg	Season average % Chg
Total Generation	706.49	643.71	601.9	658.11	657.86	--	-0.25	0.0%	49.88	864.41	671.6	665.02	6.58	1.0%
Coal	321.28	300.68	341.89	354.38	299.4	46%	-54.98	-16.0%	18.69	416.3	305.02	333.35	-28.33	-8.0%
Natural Gas	101.96	91.75	92.51	88.18	75.46	11%	-12.72	-14.0%	5.22	200.76	123.23	153.58	-30.35	-20.0%
Wind	207.31	176.8	95.89	141.03	208.97	32%	67.94	48.0%	20.68	296.09	168.07	133.42	34.65	26.0%
Nuclear Power	48.65	48.86	47.84	48.88	48.83	7%	-0.05	0.0%	4.07	48.88	47.3	19.58	27.72	142.0%
Hydro	26.33	24.67	22.83	24.68	24.25	4%	-0.43	-2.0%	1.14	34.89	26.28	23.44	2.84	12.0%
Diesel	0.96	0.96	0.94	0.96	0.96	--	0	0.0%	0.03	2.12	1.7	1.67	0.03	2.0%

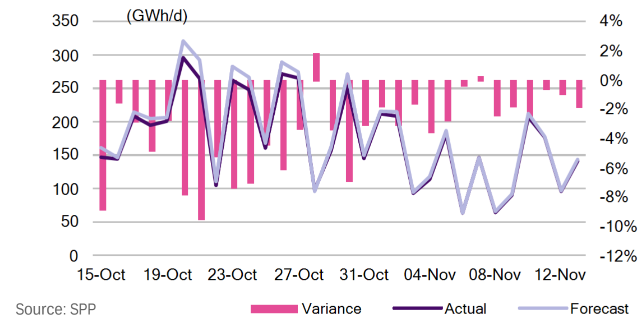
Seasons are defined as: Summer (June - August), Fall (September - November), Winter (December - February), and Spring (March - May). Source: SPP

SPP TEMPERATURE



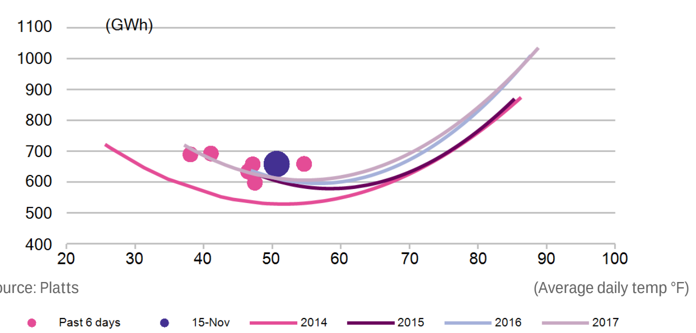
Source: Custom Weather

SPP ACTUAL WIND GENERATION VS. FORECAST



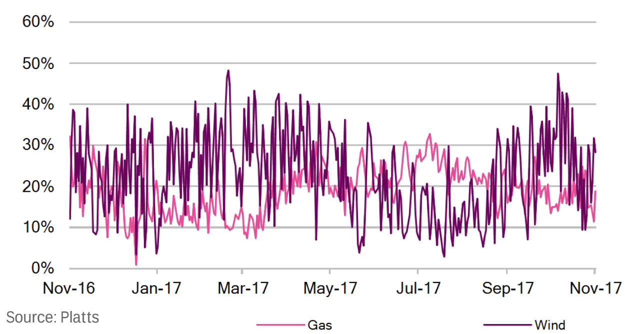
Source: SPP

SPP LOAD PER DEGREE



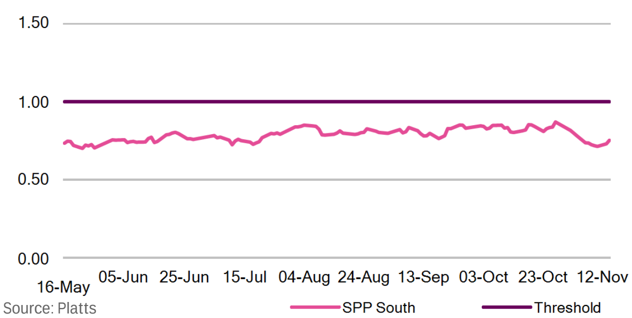
Source: Platts

SPP GENERATION MARKET SHARE - GAS VS. WIND



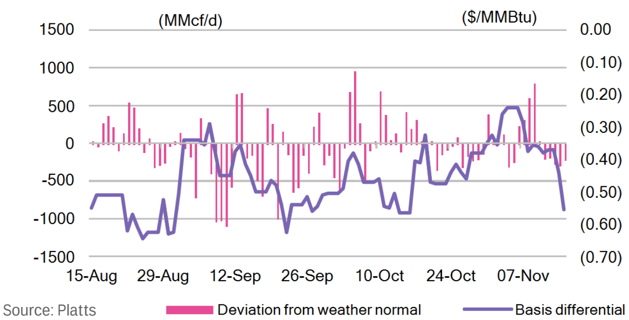
Source: Platts

SPP COAL-VS-GAS $/MWh FUEL COST RATIO



Source: Platts

SPP POWER BURN VS. GAS BASIS



Source: Platts

WEST POWER MARKETS

CAISO GENERATION MIX (GWh/d)

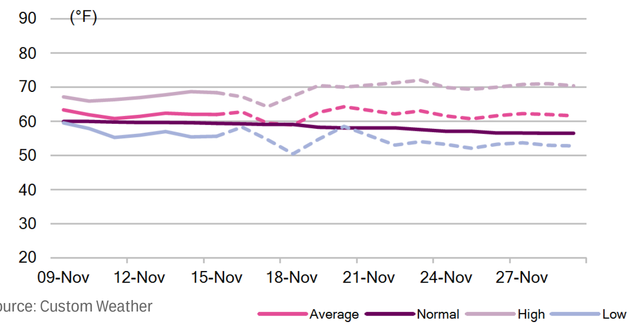
Category	10-Nov	11-Nov	12-Nov	13-Nov	14-Nov	% Share	Daily change Chg	Daily change % Chg	Season Min	Season Max	Season average 2017	Season average 2016	Season average Chg	Season average % Chg
Total Generation	580.85	531.38	524.88	585.84	588.77	--	2.93	1.0%	519.98	931.72	639.79	622.15	17.64	3.0%
Thermal Power	142.84	171.26	168.76	188.43	179.14	30%	-9.29	-5.0%	89.62	424.89	204.96	217.45	-12.49	-6.0%
Nuclear Power	54.24	54.37	54.37	54.37	54.39	9%	0.02	0.0%	53.29	54.53	54.26	53.44	0.82	2.0%
Hydro	67.37	61.9	63.66	66.19	61.87	11%	-4.32	-7.0%	53.43	107.22	75.15	59.08	16.07	27.0%
Power Imports	150.47	124.85	156.34	161.03	154.83	26%	-6.2	-4.0%	120.46	224.39	164.42	175.56	-11.14	-6.0%
Solar PV	54.88	51.47	31.05	43.39	51.25	9%	7.86	18.0%	31.05	81.5	66.18	54.15	12.03	22.0%
Solar Thermal	2.5	2.33	0.02	0.13	2.23	--	2.1	1615.0%	0.01	5.96	3.42	3.61	-0.19	-5.0%
Wind	72.93	27.98	13.44	40.29	54.12	9%	13.83	34.0%	2.56	86.74	35.33	27.09	8.24	30.0%
Bio + Geo	35.62	37.22	37.26	32.02	30.93	5%	-1.09	-3.0%	26.61	42.05	36.06	31.77	4.29	14.0%

BPA GENERATION, LOAD, and TRANSMISSION (GWh/d)

Category	10-Nov	11-Nov	12-Nov	13-Nov	14-Nov	% Share	Daily change Chg	Daily change % Chg	Season Min	Season Max	Season average 2017	Season average 2016	Season average Chg	Season average % Chg
Total Generation	272.46	240.72	257.46	286.3	278.23	--	-8.07	-3.0%	35.63	305.12	255.46	265.01	-9.55	-4.0%
Nuclear Power	28.11	28.03	28.03	27.97	27.91	10%	-0.06	0.0%	0	28.24	26.27	0	0	0.0%
Hydro	176.29	155.11	177.55	163.11	174.06	63%	10.95	7.0%	19.58	188.65	142.4	163.62	-21.22	-13.0%
Thermal Power	66.99	55.97	49.54	46.39	50.92	18%	4.53	10.0%	8.02	74.08	60.53	74.29	-13.76	-19.0%
Wind power	1.07	1.61	2.34	48.83	25.33	9%	-23.5	-48.0%	0.42	90.75	26.26	27.09	-0.83	-3.0%
Load	149.71	142.24	138.28	148.79	149.99	--	1.2	1.0%	20.71	168.8	138.71	135.6	3.11	2.0%
Net Exports	122.77	98.89	119.21	137.37	127.76	--	-9.61	-7.0%	14.93	159.37	116.75	129.43	-12.68	-10.0%

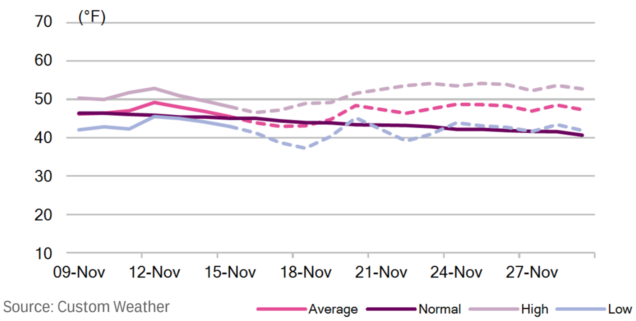
Seasons are defined as: Summer (June - August), Fall (September - November), Winter (December - February), and Spring (March - May). Source: CAISO & BPA

CAISO TEMPERATURE



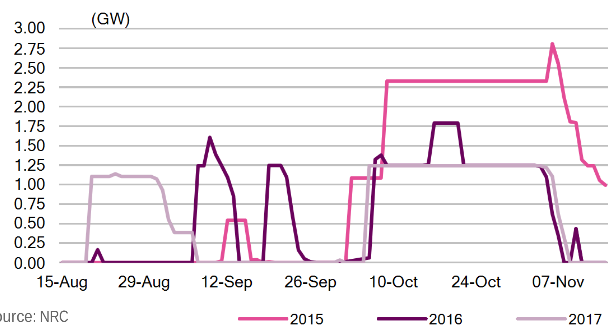
Source: Custom Weather

BPA TEMPERATURE



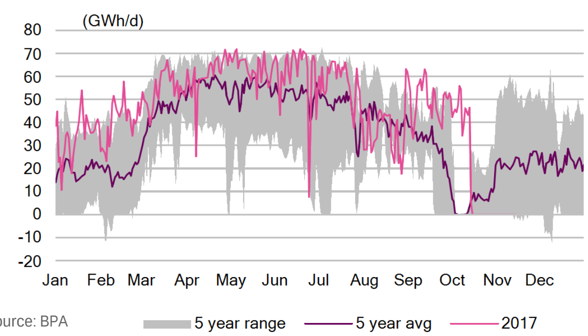
Source: Custom Weather

WESTERN NUCLEAR GENERATION OUTAGES



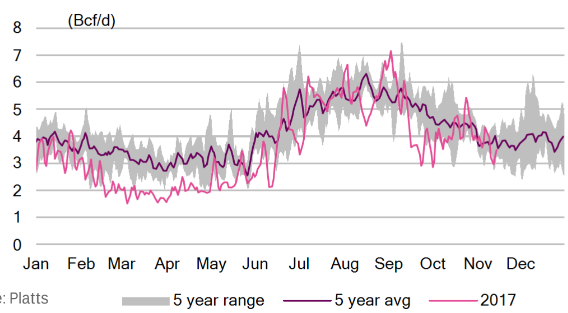
Source: NRC

BPA DC LINE TRANSMISSION FLOWS N-S



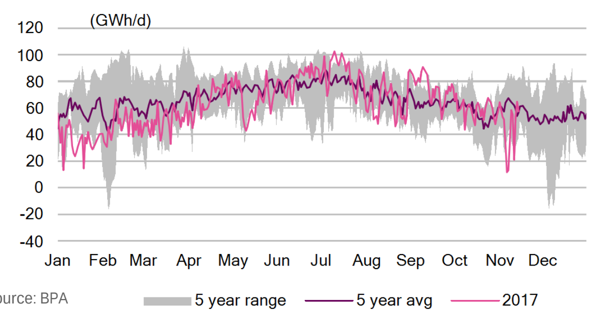
Source: BPA

YEAR-TO-DATE WEST POWER BURN



Source: Platts

BPA AC LINE TRANSMISSION FLOWS N-S



Source: BPA