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GAS DAILY

Thursday, October 19, 2017

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- Proposed Cheyenne Connector to link REX to DJ
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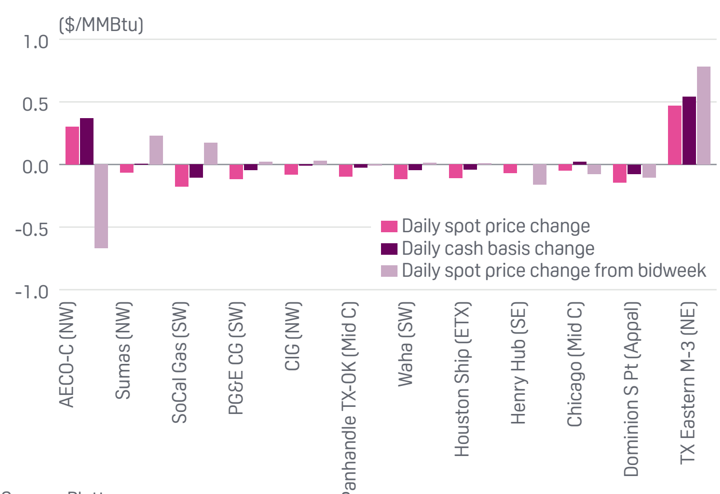
SPOT PRICE AND BASIS CHANGES



Source: Platts

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FINAL DAILY PRICE SURVEY - PLATTS LOCATIONS ($/MMBtu)

NATIONAL AVERAGE PRICE: 2.520
Trade date: 18-Oct
Flow date(s): 19-Oct

		Midpoint	+/-	Absolute	Common	Vol.	Deals
Northeast							
Algonquin, city-gates	IGBEE21	2.900	-0.060	2.850-2.950	2.875-2.925	250	46
Algonquin, receipts	IGBDK21	1.050	-0.150	1.050-1.050	1.050-1.050	10	1
Dracut, Mass.	IGBDW21	—	—	——	——	—	—
Iroquois, receipts	IGBCR21	2.900	-0.080	2.895-2.925	2.895-2.910	88	20
Iroquois, zone 2	IGBEJ21	2.925	-0.100	2.920-2.950	2.920-2.935	50	11
Niagara	IGBCS21	—	—	——	——	—	—
Tennessee, z6 (300 leg) del.	IGBJC21	—	—	——	——	—	—
Tennessee, zone 6 del.	IGBEI21	2.755	-0.060	2.700-2.800	2.730-2.780	34	7
Tx. Eastern, M-3	IGBEK21	1.960	+0.470	1.540-2.100	1.820-2.100	129	30
Transco, zone 5 del.	IGBEN21	2.755	-0.140	2.700-2.890	2.710-2.805	1	2
Transco, zone 5 del. North	IGCGL21	2.755	-0.145	2.700-2.890	2.710-2.805	1	2
Transco, zone 5 del. South	IGCHL21	—	—	——	——	—	—
Transco, zone 6 N.Y.	IGBEM21	2.780	-0.025	2.680-2.800	2.750-2.800	33	10
Transco, zone 6 non-N.Y.	IGBEL21	2.775	-0.040	2.700-2.900	2.725-2.825	112	21
Transco, zone 6 non-N.Y. North	IGBJS21	2.775	-0.040	2.700-2.815	2.745-2.805	112	20
Transco, zone 6-non-N.Y. South	IGBJT21	2.900	+1.400	2.900-2.900	2.900-2.900	1	1
Northeast regional average	IGCAA00	**2.535**					
Appalachia							
Columbia Gas, App.	IGBDE21	2.615	-0.055	2.580-2.630	2.605-2.630	148	35
Columbia Gas, App. non-IPP	IGBJU21	—	—	——	——	—	—
Dominion, North Point	IGBDB21	1.005	-0.140	0.940-1.090	0.970-1.045	35	9
Dominion, South Point	IGBDC21	0.995	-0.145	0.800-1.100	0.920-1.070	173	48
Lebanon Hub	IGBFJ21	2.680	-0.060	2.670-2.695	2.675-2.685	20	3
Leidy Hub	IGBDD21	—	—	——	——	—	—
Millennium, East receipts	IGBIW21	0.780	-0.215	0.750-0.830	0.760-0.800	18	6
REX, Clarington Ohio	IGBGO21	—	—	——	——	—	—
Tennessee, zone 4-200 leg	IGBJN21	1.995	-0.240	1.900-2.000	1.970-2.000	23	5
Tennessee, zone 4-300 leg	IGBFL21	0.835	-0.140	0.750-0.920	0.795-0.880	59	11
Tennessee, zone 4-313 pool	IGCFL21	1.785	-0.185	1.770-1.820	1.775-1.800	8	4
Tennessee, zone 4-Ohio	IGBHO21	—	—	——	——	—	—
Texas Eastern, M-2 receipts	IGBJE21	0.940	-0.200	0.830-1.010	0.895-0.985	240	53
Transco, Leidy Line receipts	IGBIS21	0.860	-0.195	0.750-1.030	0.790-0.930	139	33
Appalachia regional average	IGDAA00	**1.450**					
Midcontinent							
ANR, Okla.	IGBBY21	2.535	-0.055	2.500-2.575	2.515-2.555	99	13
Enable Gas, East	IGBCA21	2.570	-0.060	2.550-2.580	2.565-2.580	38	10
NGPL, Amarillo receipt	IGBDR21	2.630	-0.065	2.620-2.640	2.625-2.635	58	9
NGPL, Midcontinent	IGBBZ21	2.605	-0.085	2.575-2.650	2.585-2.625	115	13
Oneok, Okla.	IGBCD21	2.485	+0.015	2.450-2.500	2.475-2.500	107	19
Panhandle, Tx.-Okla.	IGBCE21	2.490	-0.095	2.460-2.530	2.475-2.510	92	20
Southern Star	IGBCF21	2.400	-0.120	2.390-2.410	2.395-2.405	64	12
Tx. Eastern, M-1 24-in.	IGBET21	2.720	-0.055	2.720-2.720	2.720-2.720	5	1
Midcontinent regional average	IGEAA00	**2.555**					
Upper Midwest							
Alliance, into interstates	IGBDP21	2.725	-0.050	2.700-2.740	2.715-2.735	360	41
ANR, ML 7	IGBDQ21	—	—	——	——	—	—
Chicago city-gates	IGBDX21	2.745	-0.050	2.700-2.800	2.720-2.770	801	112
Chicago-Nicor	IGBEX21	2.745	-0.050	2.710-2.770	2.730-2.760	368	53
Chicago-NIPSCO	IGBFX21	2.745	-0.055	2.725-2.750	2.740-2.750	341	42
Chicago-Peoples	IGBGX21	2.735	-0.040	2.700-2.740	2.725-2.740	88	16
Consumers city-gate	IGBDY21	2.955	+0.040	2.890-2.990	2.930-2.980	17	7
Dawn, Ontario	IGBCX21	2.845	-0.075	2.820-2.955	2.820-2.880	451	75
Emerson, Viking GL	IGBCW21	2.535	-0.060	2.410-2.620	2.485-2.590	195	47
Mich Con city-gate	IGBDZ21	2.765	-0.020	2.750-2.780	2.760-2.775	324	36
Northern Bdr., Ventura TP	IGBGH21	2.640	-0.065	2.620-2.670	2.630-2.655	50	7
Northern, demarc	IGBDV21	2.640	-0.070	2.600-2.650	2.630-2.650	153	26
Northern, Ventura	IGBDU21	2.625	-0.085	2.605-2.655	2.615-2.640	58	10
REX, Zone 3 delivered	IGBRO21	2.675	-0.070	2.650-2.705	2.660-2.690	635	78
Upper Midwest regional average	IGFAA00	**2.715**					

Forwards predict colder winter in Northeast

ANALYSIS Forward markets see colder temperatures and stronger gas demand in the Northeast this winter, lifting prices at market-area hubs to a steep premium over 2016 spot prices.

At the region's most liquid consumer hubs stretching from New York to Boston, calendar-month forward prices for January, February and March are trading as much as $5/MMBtu above monthly average spot prices last winter.

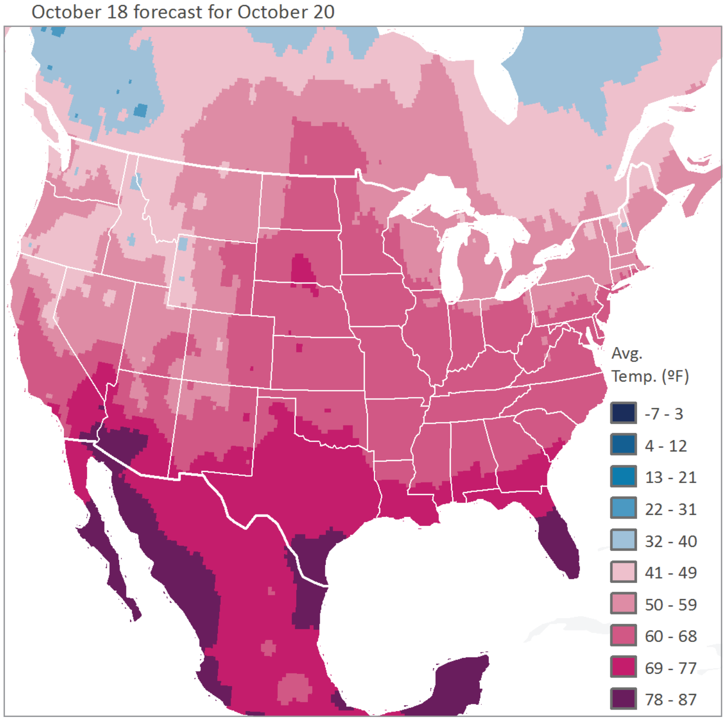
Assuming more normal weather returns to the Northeast this season, temperatures from January to March could be expected to average more than 3 degrees Fahrenheit below last year. Platts Analytics sees that drop fueling a 1.9-Bcf/d rise in residential-commercial heating demand this winter.

Tack on additional demand from Dominion Energy's Cove Point LNG export terminal and higher anticipated burn from regional power generators and industry, and total Northeast gas demand could rise this winter by more than 3.5 Bcf/d, Platts Analytics forecasts show.

(continued on page 3)

2-DAY-AHEAD TEMPERATURE FORECAST MAP

October 18 forecast for October 20



Source: Platts, Custom Weather

ASSESSMENT RATIONALE

Platts Gas Daily indices are based upon trade data reported to Platts by market participants. The indices are calculated using detailed transaction level data from these providers. Platts editors screen the data for outliers that may be further examined and potentially removed. A volume weighted average is then calculated from the remaining set of data. For more details on this methodology please see our North American Natural Gas Methodology and Specifications Guide on Platts.com, located at http://www.platts.com/IM.Platts.Content/MethodologyReferences/MethodologySpecs/na_gas_methodology.pdf

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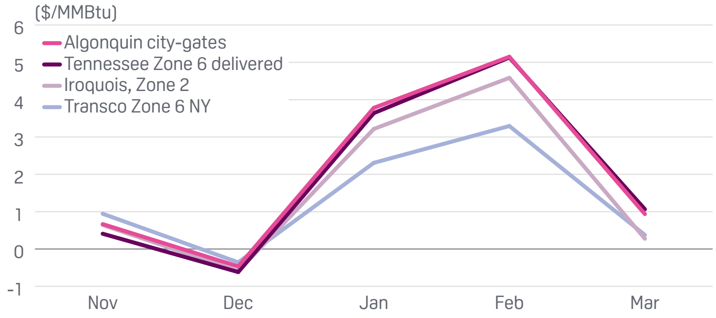
DAILY PRICE SURVEY - FINAL PLATTS LOCATIONS ($/MMBtu)

Trade date: 18-Oct
Flow date(s): 19-Oct

		Midpoint	+/-	Absolute	Common	Volume	Deals
East Texas							
Agua Dulce Hub	IGBAV21	—	—	——	——	—	—
Carthage Hub	IGBAF21	2.750	-0.070	2.750-2.800	2.750-2.765	27	6
Florida Gas, zone 1	IGBAW21	2.780	-0.100	2.770-2.805	2.770-2.790	38	4
Houston Ship Channel	IGBAP21	2.890	-0.110	2.885-2.890	2.890-2.890	27	2
Katy	IGBAQ21	2.860	-0.115	2.860-2.880	2.860-2.865	186	20
NGPL, STX	IGBAZ21	2.760	-0.070	2.745-2.820	2.745-2.780	79	8
NGPL, Texok zone	IGBAL21	2.700	-0.085	2.690-2.710	2.695-2.705	245	29
Tennessee, zone 0	IGBBA21	2.725	-0.090	2.700-2.730	2.720-2.730	26	9
Tx. Eastern, ETX	IGBAN21	2.755	-0.040	2.730-2.760	2.750-2.760	142	20
Tx. Eastern, STX	IGBBB21	2.825	-0.020	2.820-2.825	2.825-2.825	118	11
Transco, zone 1	IGBBC21	2.750	-0.055	2.750-2.750	2.750-2.750	6	2
Transco, zone 2	IGBBU21	—	—	——	——	—	—
East Texas regional average	IGGAA00	**2.780**					
Louisiana/Southeast							
ANR, La.	IGBBF21	2.715	-0.075	2.650-2.770	2.685-2.745	128	20
Columbia Gulf, La.	IGBBG21	2.735	-0.055	2.700-2.750	2.725-2.750	61	9
Columbia Gulf, mainline	IGBBH21	2.695	-0.065	2.670-2.730	2.680-2.710	264	34
Florida city-gates	IGBED21	—	—	——	——	—	—
Florida Gas, zone 2	IGBBJ21	2.775	-0.070	2.760-2.800	2.765-2.785	123	5
Florida Gas, zone 3	IGBBK21	2.820	-0.080	2.790-2.850	2.805-2.835	346	45
Henry Hub	IGBBL21	2.810	-0.070	2.795-2.835	2.800-2.820	163	22
Southern Natural, La.	IGBBO21	2.780	-0.070	2.750-2.790	2.770-2.790	438	63
Tennessee, 500 Leg	IGBBP21	2.780	-0.075	2.740-2.795	2.765-2.795	125	22
Tennessee, 800 Leg	IGBBQ21	2.755	-0.075	2.735-2.770	2.745-2.765	134	27
Tx. Eastern, ELA	IGBBS21	2.750	-0.050	2.730-2.770	2.740-2.760	173	18
Tx. Eastern, M-1 30-in.	IGBDI21	2.720	-0.010	2.720-2.720	2.720-2.720	1	1
Tx. Eastern, WLA	IGBBR21	2.790	-0.055	2.790-2.790	2.790-2.790	10	1
Tx. Gas, zone 1	IGBAO21	2.695	-0.070	2.670-2.750	2.675-2.715	236	31
Tx. Gas, zone SL	IGBBT21	—	—	——	——	—	—
Transco, zone 3	IGBBV21	2.790	-0.065	2.755-2.830	2.770-2.810	208	23
Transco, zone 4	IGBDJ21	2.790	-0.075	2.775-2.810	2.780-2.800	245	39
Trunkline, ELA	IGBBX21	2.750	-0.030	2.750-2.750	2.750-2.750	1	1
Trunkline, WLA	IGBBW21	2.820	-0.070	2.820-2.820	2.820-2.820	30	1
Trunkline, zone 1A	IGBGF21	2.720	-0.050	2.700-2.750	2.710-2.735	33	9
Louisian/Southeast regional average	IGHAA00	**2.760**					
Rockies/Northwest							
Cheyenne Hub	IGBCO21	2.515	-0.080	2.500-2.530	2.510-2.525	51	7
CIG, Rockies	IGBCK21	2.510	-0.080	2.500-2.520	2.505-2.515	43	10
GTN, Kingsgate	IGBCY21	1.250	-1.245	1.250-1.250	1.250-1.250	5	1
Kern River, Opal	IGBCL21	2.570	-0.120	2.550-2.600	2.560-2.585	433	48
NW, Can. bdr. (Sumas)	IGBCT21	2.580	-0.065	2.570-2.650	2.570-2.600	182	36
NW, s. of Green River	IGBCQ21	2.500	-0.095	2.490-2.520	2.495-2.510	97	15
NW, Wyo. Pool	IGBCP21	2.565	-0.065	2.560-2.575	2.560-2.570	37	5
PG&E, Malin	IGBDO21	2.605	-0.080	2.570-2.640	2.590-2.625	220	30
Questar, Rockies	IGBCN21	2.535	-0.065	2.510-2.540	2.530-2.540	28	6
Stanfield, Ore.	IGBCM21	2.580	-0.055	2.570-2.580	2.580-2.580	81	15
TCPL Alberta, AECO-C*	IGBCU21	0.530	+0.300	0.250-0.700	0.420-0.645	766	121
Westcoast, station 2*	IGBCZ21	0.510	+0.290	0.420-0.600	0.465-0.555	89	22
White River Hub	IGBGL21	2.520	-0.075	2.520-2.530	2.520-2.525	100	14
Rockies/Northwest regional average	IGIAA00	**2.430**					
Southwest							
El Paso, Bondad	IGBCG21	2.445	-0.125	2.440-2.450	2.445-2.450	130	12
El Paso, Permian	IGBAB21	2.430	-0.105	2.395-2.500	2.405-2.455	412	45
El Paso, San Juan	IGBCH21	2.445	-0.125	2.435-2.450	2.440-2.450	24	6
El Paso, South Mainline	IGBFR21	2.845	-0.040	2.840-2.870	2.840-2.855	84	11
Kern River, delivered	IGBES21	2.840	-0.120	2.820-2.870	2.830-2.855	123	10
PG&E city-gate	IGBEB21	3.190	-0.115	3.150-3.210	3.175-3.205	389	45
PG&E, South	IGBDM21	2.540	-0.125	2.530-2.550	2.535-2.545	84	13
SoCal Gas	IGBDL21	2.765	-0.175	2.650-2.850	2.715-2.815	131	17
SoCal Gas, city-gate	IGBGG21	3.995	-1.115	3.950-4.000	3.985-4.000	55	10
Transwestern, Permian	IGBAE21	2.415	-0.160	2.400-2.420	2.410-2.420	101	18
Transwestern, San Juan	IGBGK21	2.430	-0.150	2.420-2.440	2.425-2.435	40	5
Waha	IGBAD21	2.455	-0.115	2.430-2.500	2.440-2.475	285	37
Southwest regional average	IGJAA00	**2.735**					

*Price in C$ per gj; C$1=US$0.8009; Volume in 000 MMBtu/day. Symbols represent gas flow date.

NORTHEAST MARKET-AREA HUB PRICES, 17-18 FORWARD VS. 16-17 SPOT



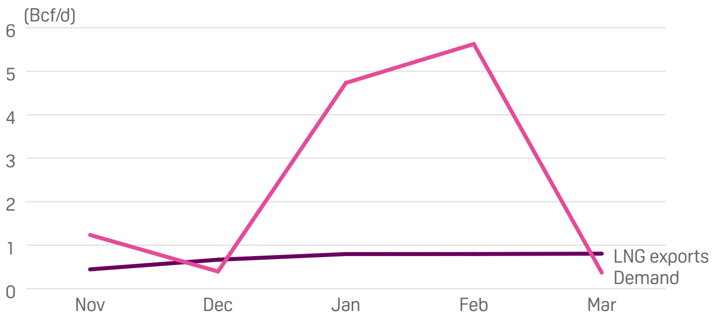
Source: Platts Analytics' Bentek Energy

While rising production in the Marcellus and Utica shales has lifted regional gas supply by an average 1.8 Bcf/d this year, net gas transmissions out of the Northeast have climbed by 2.1 Bcf/d over the same period. With Rover Pipeline, Columbia Gas' Leach XPress and other pipeline expansion projects promising to move increasing volumes of gas out of the region this winter, Northeast supply-demand fundamentals are looking significantly tighter this season.

Res-Com, LNG to lift regional demand most

During the approaching winter season, residential-commercial gas consumption and LNG exports together are expected to lift total regional demand by roughly 2.7 Bcf/d between January and March.

NORTHEAST DEMAND, LNG EXPORTS: 2017-18 VS. 2016-17



Source: Platts Analytics' Bentek Energy

Colder, more seasonal temperatures will make res-com the largest component of that gain. But feedgas flows to Cove Point, too, are expected to add an average 0.8 Bcf/d to the regional demand equation this winter.

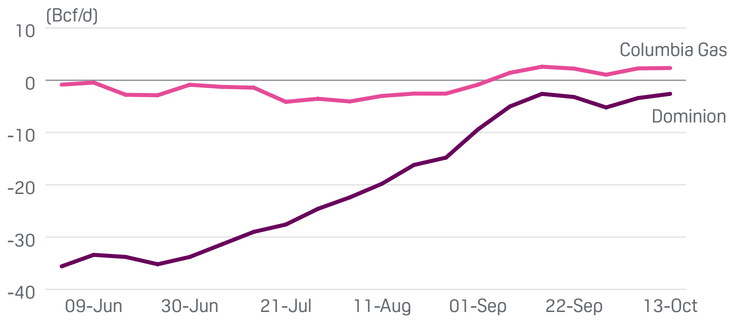
From January through March, Platts Analytics also sees power generators burning an additional 0.7 Bcf/d this winter and regional industry consuming nearly 0.2 Bcf/d more gas.

High inventories temper December prices

Tighter gas supply in the Northeast this year has been partially offset by a recent surge in natural gas storage levels, which could be weighing on December forward prices.

At Dominion and Columbia Gas, where roughly half of the region's underground storage capacity is contained, inventory levels are currently at 95% and 102%, respectively, of stated capacity, Platts Analytics data shows. Those levels are comparable to record stocks seen around this time last year.

NORTHEAST REGION GAS INVENTORY: 2017 VS. 2016



Source: Platts Analytics' Bentek Energy

Total implied regional inventory levels, meanwhile, show just over 40 Bcf of remaining injection capacity in the Northeast with nearly four weeks to go before the withdrawal season begins in earnest.

Those bearish storage levels could be weighing on forward prices for December, when excess gas supply might be expected to lower regional hub prices.

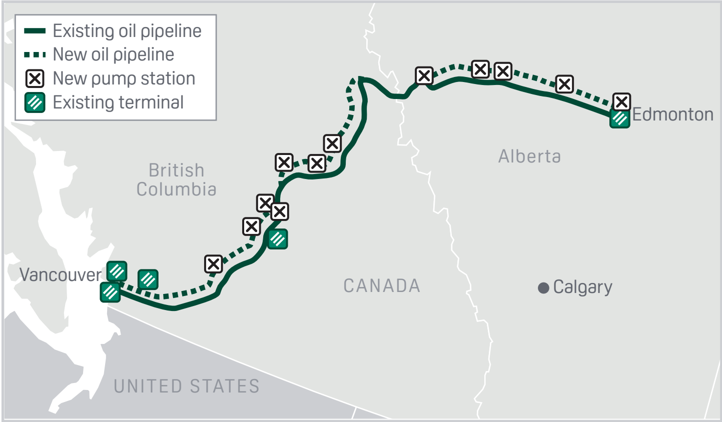
At Algonquin city-gates, Tennessee Zone 6 delivered, Iroquois Zone 2 and Transco Zone 6-NY calendar-month forwards for December are currently trading at roughly 35 cents to 60 cents/MMBtu below last year's monthly average spot prices, Platts data shows.

— J. Robinson

KM says Trans Mountain delay possible

Kinder Morgan said Wednesday that completion of its Trans Mountain crude pipeline expansion could be delayed by up to nine months because of the impact of permitting and court challenges in Canada, as it reported that it swung to a profit in its latest quarter despite lower overall revenue and a hit to natural gas operations due to Hurricane Harvey.

TRANS MOUNTAIN PIPELINE EXPANSION PROJECT ROUTE



Source: Kinder Morgan

The developments come as the midstream sector is increasingly looking for opportunities to move abundant North American supplies of oil and natural gas to demand markets, both for local use and for exports to other countries. Many have been selling stakes in their projects, forming joint ventures or seeking financing through an initial public offering to reduce the financial risk associated with the buildout.

With its internal expectations assuming average annual US prices for crude of $53/b and gas of $3/MMBtu, Kinder Morgan is eager to take advantage of increasing demand for feedgas for LNG exports from the US while also being careful in its crude transport operations. It said its spending this year on growth initiatives will be slightly less than previously forecast amid a small decrease in its project backlog.

"The cash flow of KMI remains strong and demonstrates in my mind the strength of the assets," Chairman Richard Kinder said during an investor conference call.

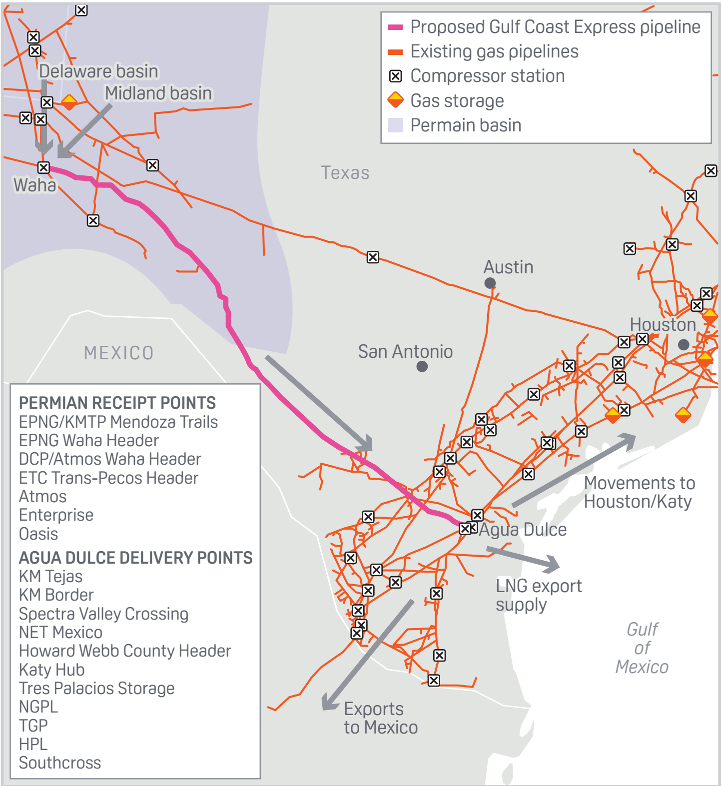
But, he added later in response to a question from an analyst, "Clearly, we are not happy with our stock price."

For the July-September quarter, Kinder Morgan reported net income available to common shareholders of $334 million, or 15 cents per share, compared with a net loss of $227 million, or 10 cents per share, for the third quarter of 2016. Revenue in the latest quarter slid 1.5% to $3.28 billion from $3.33 billion in the same quarter last year.

Kinder Morgan, which transports more than one-third of the gas consumed in the US, has been aggressive at seeking ways to limit its exposure to forces affecting market supply and demand.

Earlier this month, it announced that DCP Midstream and Targa Resources would help it develop its 1.9 Bcf/d Gulf Coast Express Pipeline, which will boost gas takeaway capacity from the Permian Basin to the Texas Gulf Coast, where growing volumes of gas are being exported to Mexico and other countries. Kinder previously launched an IPO to help finance Trans Mountain. It also secured a joint-venture partner for its Elba Island LNG export project in Georgia.

GULF COAST EXPRESS PIPELINE ROUTE TERRITORY



Source: Kinder Morgan

With the market especially focused on pipeline project timelines amid strong shale production of both oil and gas, Kinder Morgan has said it wants to keep its eye on execution.

It faces some challenges on Trans Mountain.

Kinder Morgan has Canadian federal approval and British Columbia environmental approvals for the project at hand, CEO Steve Kean said. But the approvals are being challenged in court.

The company said construction preparation activity is off to a slower start than planned in the project schedule due primarily to the time required to file for, process and obtain all necessary permits and regulatory approvals. It said it is working on a mitigation plan that allows it to keep its current start-up plans of December 31, 2019. If those efforts are not successful, project completion could be delayed by up to nine months, Kinder Morgan said.

"The key for us is access to land and permitting," Kean said. "We recently received good news from BC granting access for half of the crown land [needed] and received permits from Alberta granting permitting to many of those parcels. These are positive developments."

He said the project is "vitally important to our customers."

The Trans Mountain expansion, at an expected cost of $5.9 billion (C$7.4 billion) includes twinning the existing pipeline, where possible, within the existing right-of-way between Strathcona County, Alberta, to Burnaby, British Columbia, adding new pump stations and increasing capacity from 300,000 b/d to 890,000 b/d.

Project spending plans are adjusted slightly

Previously, the company had budgeted to invest $3.2 billion in growth projects during 2017, to be funded with internally generated cash flow without the need to access equity markets.

In its earnings release Wednesday, it said it now expects the figure to be slightly less at $3.1 billion. Kinder Morgan said its current project backlog is $12 billion, a small decrease from the prior quarter, primarily due to projects going into service faster than new projects entering the queue.

Execution also has meant trying to limit service disruptions.

Hurricane Harvey had a significant impact on the gas industry when it hit the Texas Gulf Coast in late August, forcing both onshore and offshore producers and pipeline operators to reduce flows.

Kinder Morgan estimates that the hurricane will have a $20 million impact on cash flow for 2017, excluding repair costs that are treated as certain items. It expects to be able to recover much of the repair costs from insurance.

The main impact on the company from the storm was in its natural gas pipeline segment, which also faced other declines in the third quarter from reduced volumes on many of its midstream gathering and processing assets.

— Harry Weber, Starr Spencer

Encana charts output growth, targets four plays

Encana expects to grow production from its four core North American assets by 30% by the end of the year, compared with the fourth quarter of 2016, company officials said at a conference in New York on Wednesday.

The productivity gains are being driven by strong increases in per-well productivity as well as the recent successful start-up of two gas processing plants in the Montney Shale play of northwestern Canada, President and CEO Doug Suttles said at the Encana Investor Day conference. Suttles and other executives outlined the producer's performance this year to date and updated the company's five-year plan.

"We had a strong 2017 So far. We are set to enter 2018 with a lot of momentum," Suttles said. Encana is on track "to deliver leading corporate returns, strong cash flow growth and substantial free cash flow, without any improvement in commodity prices," he said.

Encana anticipates seeing its cash flow grow at about a 25% compounded annual rate for the years 2017 through 2022, while its rate of return on capital employed climbs to 10 to 15%.

The producer plans to spend 99% of its capital on its four core assets: the Duvernay and Montney shale plays in western Canada and the Eagle Ford Shale and Permian Basin in Texas. Suttles said the focus on the four plays gives the company exposure to the price upside seen in the production of Texas oil as well as Canadian condensate.

As a result, only about 4% of Encana's revenues are exposed to AECO natural gas pricing, Suttles said.

"Our business works well at today's prices. Using a flat $50[/b] WTI and a flat $3[/MMBtu] NYMEX gas price, we expect our return on capital employed will climb into the teens over the plan period," Suttles said.

Producer active in heart of Permian, Montney

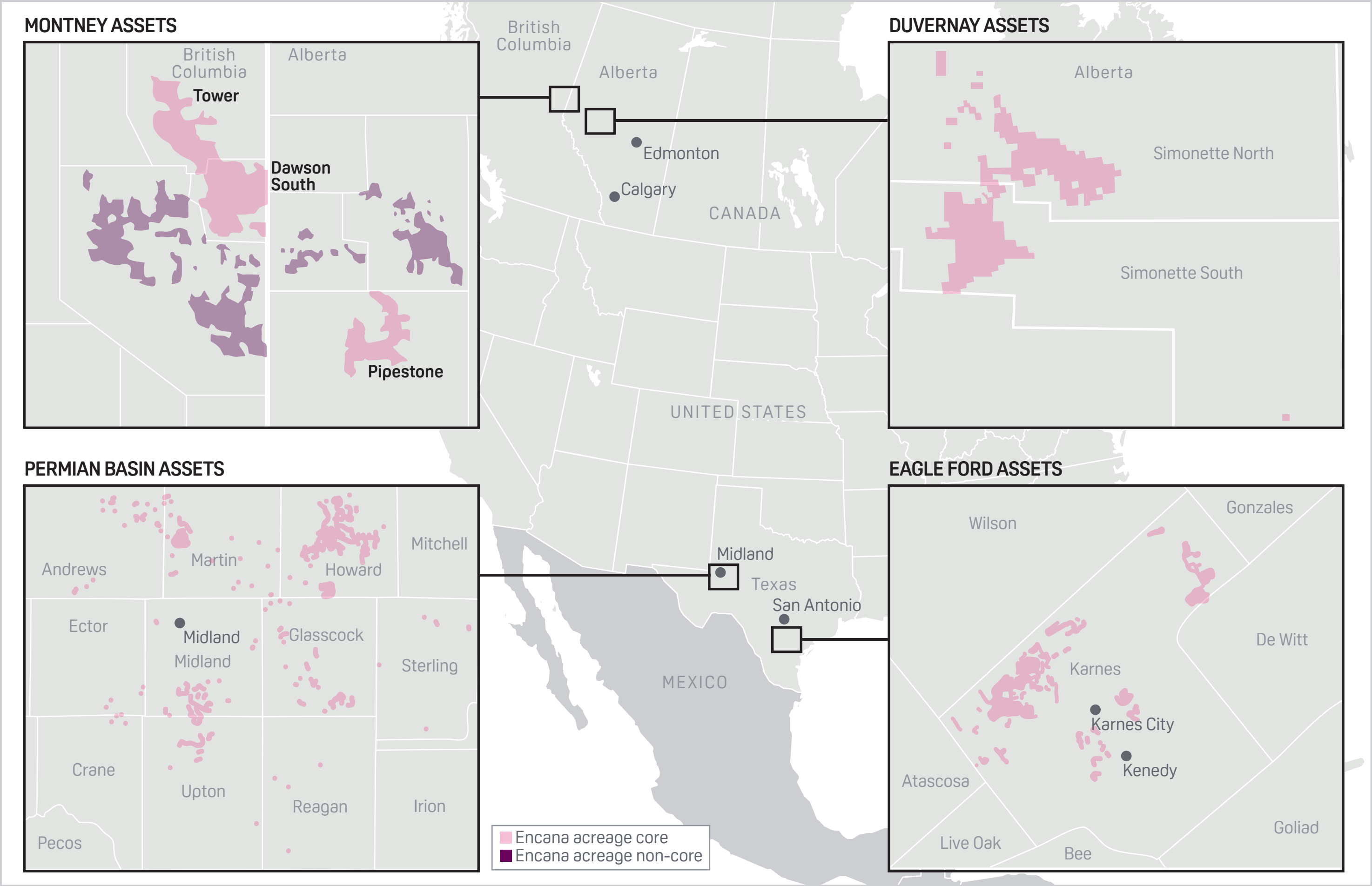
"We're the only E&P at scale in the heart of both the Permian and the Montney. These two plays provide a combination of leading returns and scale that is hard to beat," he said.

In the Permian Basin Encana has seen its 30-day and 180-day initial production rates increase by about 20%, Jeff Balmer, general manager of Encana's Southern Operations, said.

Balmer said technological innovation is helping drive the company's production gains in the basin, where Encana has employed a "cube" development strategy to drill and complete a number of wells simultaneously from a single pad.

The, result, Balmer said, is "highly productive, low-cost wells," producing from the basin's stacked-pay zones. This production strategy "means that we can keep our capital highly focused on drilling wells and not building expensive infrastructure that won't be used until far out into the future," he said. "Our just-in-time approach to infrastructure development keeps our non-well spend small and connected to near-term drilling."

ENCANA'S FOUR CORE PRODUCING REGIONS



Source: Encana

In the condensate-rich Montney, the producer plans to increase its margins through condensate output growth. The producer expects to grow its liquids production to 50,000 b/d to 60,000 b/d by the end of next year, said Jim Roberts, general manager of Northern Operations.

Roberts said Encana has developed drilling strategy to derive the greatest the value from the reservoir's liquids content. "Full-life average liquids yields change with time. Our type curves show liquids decline in the Montney," especially for the liquids-rich parts of the play, he said.

"Our volatile oil wells come on stream at 800 barrels per million cubic feet and stabilize at around 200 to 225 b/MMBtu," he said.

This stabilized level represents about 50% of liquids production coming from the well.

"The bulk of our program is gas condensate and enriched gas condensate wells where the yields stabilize between 20% and 40% liquid," Roberts said.

Two processing plants start up in Montney play

During the third quarter, Encana successfully started up two of three processing plants slated for operation in the Montney region. The Sunrise processing plant was started on September 27, under budget and more than one month ahead of original schedule, the company said. Earlier in the quarter, the producer announced the start-up of the Tower processing facility in the play.

The plants were built under an agreement with Veresen Midstream that enables Encana, via its Cutbank Ridge Partnership with Mitsubishi, to construct and operate the Tower, Sunrise and soon-to-be completed Saturn plants, as well as any future build opportunities, on behalf of Veresen Midstream on a contracted basis.

Veresen Midstream is funding and owns the facilities and Encana pays to use them through a fee-for-service agreement.

In the Eagle Ford play of South Texas, Encana holds a core position in the oil window located in Karnes County, Eric Greager, general manager, of Encana's Western Operating Area, said.

About 80% of the production from the play comprises high-value liquids and Encana ranks third among its peers in oil production from the play.

— Jim Magill

Tallgrass touts vision of fully bi-directional REX

Tallgrass Energy Partners has a long-term goal to make Rockies Express Pipeline a fully bi-directional header system across the entirety of the pipeline, which stretches from gas fields in the Rocky Mountains to the Marcellus and Utica shales of Appalachia.

"2019 is a critical date for us," said Tallgrass Energy Partners President Crystal Heter, at the Rockies and West LDC Gas Forum in Broomfield, Colorado, on Tuesday afternoon. "We are going to have a lot of opportunities at that point in time with existing shippers and future shippers.

"We plan to look at the potential of making Zone 2 as well as Zone 1 bi-directional as well. We see the potential to have a capacity of 6.2 Bcf/d compared to an original capacity of 1.8 Bcf/d."

Entering service in 2009, Rockies Express was originally a 1.8-Bcf/d line able to ship gas west to east from the Rockies all the way to Northeast markets. In 2014, Tallgrass Energy altered Zone 3 of the pipeline, which stretches from Indiana to the Appalachian gas supply region, to a bi-directional line to move gas from emerging plays into the Midwest.

The capacity in Zone 3 was more recently expanded from 1.8 Bcf/d to 2.6 Bcf/d. Tallgrass's vision for the long-term fully bi-directional Rockies Express line has total capacity in Zones 1 and 2 increased to 3.6 Bcf/d while Zone 3 is boosted to 4.4 Bcf/d. The purpose is to transform Rockies Express into the northernmost header system in the Lower 48 "creating superior supply and demand optionality for its customers."

Proposed Cheyenne Connector to join DJ to REX

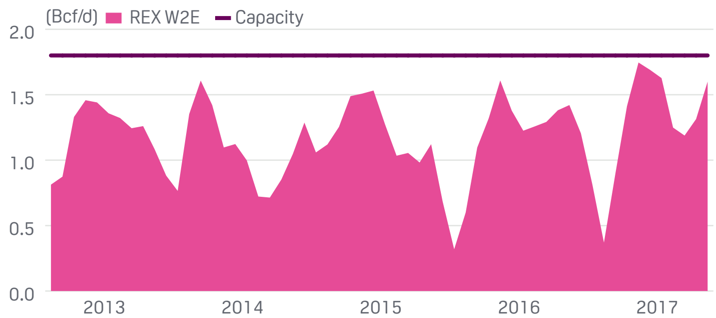
At the same time, Tallgrass Energy is considering construction of the proposed Cheyenne Connector, a pipeline that could transport associated gas produced in the heart of the Denver-Julesburg Basin up to the Rockies Express Cheyenne Hub. The proposed pipeline would be coupled with a capacity enhancement at the Cheyenne Hub as well.

An open season that Tallgrass Energy held on the proposed projects closed in late September. Heter said the results of the open season are under evaluation, which could lead to possible alterations to the proposed capacity.

REX west-to-east volumes hit capacity in 2017

Rockies Express volumes to the Midwest have averaged about 1.3 Bcf/d over the course of the year and have reached near its 1.8 Bcf/d capacity on a number of occasions, according to Platts Analytics' Bentek Energy. These volumes are largely driven by western Rockies volumes, with about 0.9 Bcf/d coming from the Piceance Basin this year.

WEST TO EAST ROCKIES EXPRESS PIPELINE FLOWS



Source: Platts Analytics' Bentek Energy

In the past, little to no DJ gas has traveled east on Rockies Express due to differing levels of compression. This suggests that a sizeable increase from DJ eastbound flows on Rockies Express would need to compete with that western Rockies supply moving east.

Rockies Express volumes are also competing with Northeast supply for Midwest market share; although to this point those volumes have remained competitive, averaging nearly 1.4 Bcf/d since the September 1 startup of Rover Pipeline.

DJ volumes have typically not traveled to the western markets out of Cheyenne, largely because of the area's lack of significant infrastructure and unfavorable market conditions, which do little to incentivize additional volumes to move to the Opal area.

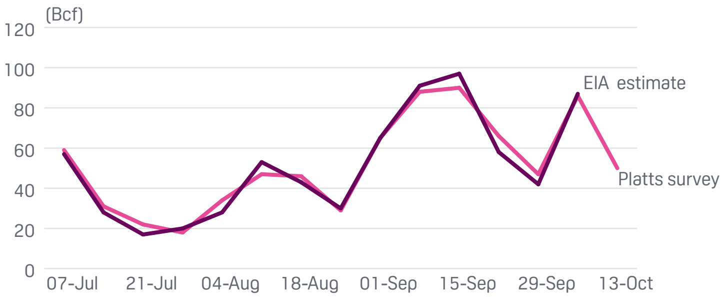
— Brandon Evans, Mason McLean

Higher temps suppress storage injection

The US Energy Information Administration will estimate a 50-Bcf injection to natural gas in underground storage for the reporting week that ended October 13, according to a consensus of analysts surveyed by Platts.

Responses to the survey ranged from a build of 43 Bcf to a build of 58 Bcf. The EIA plans to release its weekly storage report at 10:30 am EDT Thursday.

PLATTS STORAGE SURVEY VS. EIA ESTIMATE



Source: Platts, US Energy Information Administration.

A 50-Bcf injection would be much less than the 77-Bcf injection reported at this time in 2016 as well as the five-year average injection of 78 Bcf.

An injection within analysts' expectations of 50 Bcf would grow stocks to 3.645 Tcf. It would increase the deficit to the five-year average to 36 Bcf and also grow the deficit versus the corresponding week in 2016 to 180 Bcf. It would also measure much less than the injection reported the week prior.

For the week ended October 6 the EIA reported an 87-Bcf build that elevated inventories to 3.595 Tcf, which was 4.1% less than the year-ago inventory of 3.748 Tcf, and 0.2% less than the five-year average of 3.603 Tcf.

Population-weighted temps up 6.2 degrees week over week

Average US temperatures increased last week, prompting a surge in demand, particularly in the EIA's South Central region.

On a US population-weighted basis, temperatures over the course of the week averaged significantly higher than the average 62.8 degrees and last year's 64 degrees, at 69 degrees, according to Platts Analytics' Bentek Energy. The South Central region is expected to post a net-withdrawal of 3 Bcf compared with an injection of 37 Bcf last year and a 22-Bcf build during the week prior.

Meanwhile, estimated production averaged 1.8 Bcf/d stronger last week than over the course of the same week last year, according to Platts Analytics. Demand estimates were stronger by nearly 5.6 Bcf/d, with about half attributable to stronger LNG feedgas flows and half due to a 4.8-Bcf/d increase in power burn demand, which was partially offset by residential and commercial averaging about 2.1 Bcf/d lower.

"It's pretty clear we had some heat last week that has affected the injection activity," said Gene McGillian with Tradition Energy. "Either way, the market seems to be ignoring it."

November gas futures plummeted 10 cents to $2.86/MMBtu by late afternoon trading on Wednesday.

Although an early forecast demonstrates injections for the rest of October more voluminous than last week, they are still expected to be at or below the five-year average. The weeks ending October 20 and 27 are expected to combine for a build of 124 Bcf into storage, according to Platts Analytics, less than both the five-year average of 135 Bcf and last year's 130-Bcf addition over the same time frame.

Although storage levels are 3% or more below this time last year, two storage systems in the East region are on track to finish the injection season equal to last year's elevated levels.

East storage fields on track to finish near 5-year high

Columbia Gas Transmission's storage system is nearly 10 Bcf above the five year average, according to Platts Analytics. In the last five years, Columbia Gas storage inventories hit a maximum of 256 Bcf, and with current levels at nearly 250 Bcf, TCO storage is 97.6% full compared with its five-year high.

Dominion Transmission storage continues to make up ground on last year's inventories and is currently only 10 Bcf behind 2016, tied for the narrowest weekly margin compared with 2016. This injection brings overall Dominion Transmission storage levels to 276 Bcf, which is 16 Bcf behind last year's closing inventory volume of 292 Bcf.

Injections on Dominion Transmission traditionally end in the first or second week of November, leaving four more weeks for injections. Last year, the four injections following an inventory level similar to Dominion's current inventory level, totaled 20 Bcf, making the ability to inject at least 16 Bcf over the next four weeks a definite possibility.

— Brandon Evans

Resiliency call could spur gas infrastructure

Whether the US Department of Energy's push for electric generation fuel resilience dampens gas demand or inspires gas infrastructure investment will depend on how the Federal Energy Regulatory Commission interprets the directive, mainly seen as supporting baseload coal and nuclear generation.

The DOE directed FERC to make sure the US power grid puts a higher value on resilience and operators' ability to rebound from major problems. The department highlighted the value of having a 90-day on-site fuel supply — a criteria that is much more readily met by coal and nuclear generators than gas-fired plants.

"In our view, that's a starting point in the discussion," Michael Sloan, a principal with the research and consulting firm ICF International, said in an interview.

"Are they going to start to evaluate alternatives to the 90-day on-site fuel supply that would provide the same resiliency benefits? Nobody knows that for sure, but it's logical given the rationale behind the [DOE proposal] that they would or perhaps should be looking at the question more broadly."

For the gas industry, similar resilience might be achievable through requirements for firm pipeline capacity, perhaps on multiple systems; interconnects with multiple systems; or direct access to local gas storage or local gas production, Sloan said on the sidelines of the LDC Gas Forums Rockies and West conference in Broomfield, Colorado.

Under a scenario in which FERC and the DOE explore those options, the industry would probably need to invest in infrastructure redundancy, Sloan said.

“The pipeline companies may see an incremental demand for new investment, and it presumably would be recoverable through rates,” Sloan said. “That would give them an opportunity to expand their systems, but it’s going to increase the costs to everybody else.”

How much gas infrastructure investment the DOE and FERC would consider justified depends heavily on how the DOE evaluates the national security benefits of having a more resilient grid, Sloan added.

Gas system should meet federal standards: Brown

Will Brown, vice president of business development at Kinder Morgan, expressed confidence that the gas system would be able to meet the standards being laid out at the federal level. Between storage and keeping pipes pressurized, Brown said, pipeline operators have historically been able to guarantee highly regular supply access.

“When you have line pack and you have natural gas storage, it’s awfully hard to argue its reliability,” Brown said on the sidelines of the conference. “It’s not to say that the natural gas industry operates risk-free. It doesn’t, but it’s got a fairly good track record.”

If FERC takes the DOE’s interest in on-site fuel storage more literally and begins ensuring that coal and nuclear generators are compensated for their ability to maintain physical fuel supplies nearby, the policy will likely stave off expected coal and nuclear facility retirements, Sloan said.

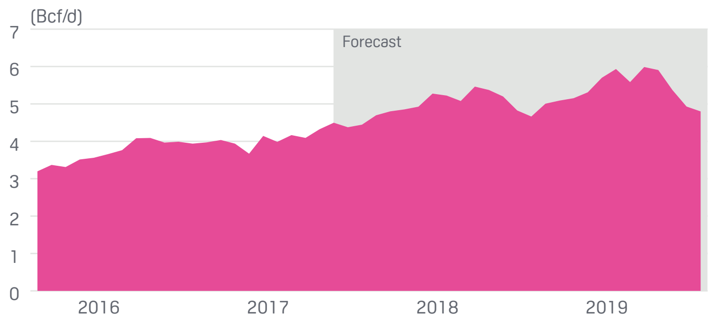
While keeping coal and nuclear facilities online would not necessarily change the degree to which existing gas plants are dispatched to provide power, it would eat into gas’ expected gains in the power sector.

— *Sarah Smith, S&P Global Market Intelligence*

KM Border to increase border capacity

The Federal Energy Regulatory Commission has issued a response posing no objection to Kinder Morgan Border Pipeline’s request to expand the design capacity of its US-Mexico border facilities from 300 MMcf/d to 450 MMcf/d.

U.S. EXPORTS TO MEXICO



Source: Platts Analytics' Bentek Energy

Kinder Morgan Border stated in its initial July request that no construction or modification to its existing border crossing facilities in Hidalgo County, Texas, would be necessary to increase capacity, as this would be accomplished through upstream adjustments to its intrastate system, including new compression.

Increased capacity will allow Kinder Morgan Border to reach growing demand in Mexico, which Platts Analytics’ Bentek Energy estimates to have averaged 4.0 Bcf/d, year-to-date, a 0.4-Bcf/d (10%) build over the same period in 2016. Forecasts call for this growth to continue, reaching an average of 5.4 Bcf/d in 2019.

According to Energy Information Administration data, exports on Kinder Morgan Border averaged 124 MMcf/d through July, a 26-MMcf/d (26%) increase over last year, but still well below the previous average annual high of 218 MMcf/d hit in 2014. While there is currently substantial unused border capacity, the additional upstream adjustments will likely support greater exports at that point.

Sample exports from South Texas have averaged nearly 1.2 Bcf/d this month-to-date, a 0.3-Bcf/d build over a year ago. However, downstream constraints in Mexico, as well as actual connections to demand sources, currently reduce the amount of gas Mexico can import, and delays to construction are now expected into 2019.

While Mexico is still reliant on LNG imports and fuel oil burn in the power markets, the country has shown momentum in its move toward natural gas generation, indicating this incremental import capacity is likely to see utilization into the future.

— *Kyle Gatton*

Rarely used statute complicates DOE NOPR

The Department of Energy’s dotted-line authority over the US Federal Energy Regulatory Commission is legally untested and presents an unclear path for how the commission may address DOE’s contentious energy market proposal, attorneys with Troutman Sanders said Wednesday.

DOE used authority it possesses under Section 403 of the Department of Energy Organization Act to initiative a rulemaking at FERC last month. The department’s notice of proposed rulemaking (RM18-1) would require independent system operators and regional transmission organizations to guarantee full cost recovery and a return on investment for generators that maintain 90-day on-site fuel supplies.

Energy Secretary Rick Perry established a 60-day window following publication of the NOPR in the *Federal Register* for FERC to take final action on the proposal.

What FERC’s responsibility is under Section 403 “is a largely unwritten slate at this point,” Daniel Larcamp, a partner with Troutman Sanders, said during a webinar Wednesday.

Law at issue ‘a bit unusual’

“We have to start with the posture that the DOE Organization Act is a bit unusual in terms of the jurisdictional line drawing, if you will,” he said, adding that when the department was formed under President Jimmy Carter in 1977, the country was dealing with the ramifications of the Arab oil embargo.

Under Section 403(a) of the act, both the head of DOE and FERC may propose rules with respect to any function within FERC's jurisdiction, including rules addressing rates and charges for the transmission or sale of electricity under the Federal Power Act. Those issues are at the core of DOE's grid resilience NOPR, explained Larcamp, a 22-year veteran of FERC, where he served as Chairman Joseph Kelliher's chief of staff and held other senior staff positions.

Thus, Perry's authority to issue the NOPR is fairly clear, Larcamp said. What is less clear is how and when FERC must respond.

Section 403(b) of the act requires FERC to consider and take final action on any proposal made by the DOE secretary pursuant to Section 403(a), and allows the secretary to set reasonable time limits for FERC's action.

But what final action means, how strict the timeframe is and what would happen if FERC did not respond are interesting questions that have not been tested in the courts, said Clifford Sikora, also a partner at Troutman Sanders with more than 20 years of experience representing clients in the energy industry.

Chatterjee took 'expansive view'

FERC Chairman Neil Chatterjee told reporters last week that the commission had a range of tools available for responding within the 60-day deadline. Among those were: an advanced NOPR, a NOPR superseding DOE's, a final rule, a denial of the DOE NOPR, an extension of the comment period, a solicitation of further comments, a technical conference, a notice of inquiry and FPA Section 206 review proceedings.

"One could conceivably think of a situation in which FERC said … we have considered and hereby take final action on the proposal and we reject it; however, here's a new one" with more detail that is better thought out, Sikora said. "Conceivably, that could meet the terms of the statute."

But lawyers right now are pondering "who would be harmed by that and what cause of action would they have if a party believes that FERC did not undertake its responsibility relative to DOE," Sikora added, potentially narrowing FERC's breadth of options if it hopes to not be taken to court.

Larcamp said he thought Chatterjee's comments "took a more expansive view of what the commission needs to undertake to satisfy their responsibilities under 403."

Limited precedent to consider

He pointed to albeit limited precedent in which Section 403 was invoked in 1979 and in 1985. In the first instance, on a NOPR for the issuance of natural gas transportation certificates for end-users seeking to displace fuel oil, FERC was told to act by May 17, 1979. The commission issued a final rule on that date.

In 1985, DOE issued a NOPR that started the process of deregulating natural gas prices at the wellhead with instructions to take final action by June 1, 1986. FERC issued its final rule on June 6, 1986.

Though just five days late, Larcamp said it demonstrates that FERC may have some flexibility on the DOE-directed deadline for action. By his firm's count, FERC would be expected to issue a final rule on the grid resilience NOPR by December 11.

Sikora contended that ultimately Section 403 "is a very unique part of the statute," untested in the courts, that appears to allow "a bit of pole-vaulting over normal due process."

"A lot of folks think they know where the cards will land, but I'm not sure anybody knows," he said.

— *Jasmin Melvin*

Bill would codify DOE plan on small-scale LNG

On the heels of a Department of Energy proposed regulation to speed approval of small-scale LNG exports, Senators Bill Cassidy, Republican-Louisiana, and Marco Rubio, Republican-Florida, have floated legislation intended to codify DOE's rule.

The legislation would deem exports of 51.1 Bcf/year or less to be consistent with the public interest and granted without modification or delay. Supporters contend small-scale projects are often not cost-effective because of high permitting costs.

DOE's September proposal is intended to target small-scale exports to markets in the Caribbean, Central America and South America.

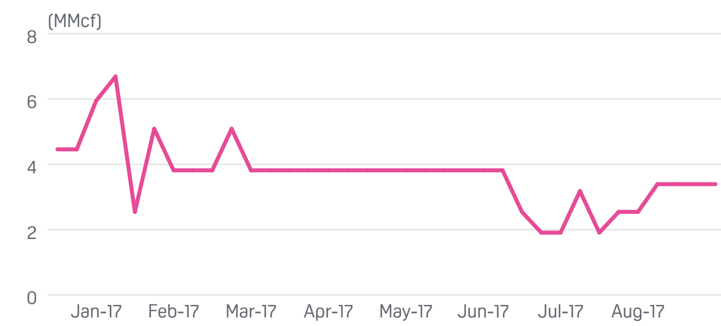
"In addition to the economic advantages for Florida, this measure would bolster our existing ties with Caribbean and Latin American nations while ensuring that bad actors in the region, including Cuba and Venezuela, do not reap its benefits," Rubio said in a statement.

The legislation joins a growing number of bills to expedite LNG permit approvals that have been floated in Congress in recent years but have yet to cross the finish line.

In outlining the rationale for the latest legislation, backers cite a need to provide assurances to foreign buyers amid a competitive market. The lack of DOE approval or guarantee of future approval slows the process and may send buyers to other markets, said one supporter who discussed the bill on background. There also are worries a DOE regulation could be reversed by future administrations.

"Legislative certainty is essential for the LNG industry as the capital costs are high and timelines are years long," said Charlie Riedl, executive director of the Center for LNG. "Anything that seeks to provide certainty and clarity in the space is welcome and we look forward to working with policymakers to create a clear cut regulatory framework."

US WEEKLY LNG EXPORTS BY ISO CONTAINER



Source: US Department of Energy

DOE's proposed regulation is already getting pushback from some quarters. The Sierra Club in October 16 comments to DOE called the proposed regulation "overbroad," contending "DOE cannot, under the guise of interpreting the public interest, do away with public notice and comment opportunities."

Under DOE's proposed rule, DOE would grant exports of LNG to non-free trade agreement countries if an applicant proposes to export no more than 0.14 Bcf/d and the export qualifies for a categorical exclusion under the National Environmental Policy Act.

In its comment on the proposal, Sierra Club argued that DOE should more narrowly tailor the document to ensure it meets DOE's intent of facilitating exports delivered via ISO containers loaded onto container ships and barges, rather than through traditional LNG tankers. "Insofar as DOE seeks to offer a categorical interpretation of the public interest, the public must be provided with an opportunity to argue that application of this interpretation is inappropriate for particular individual proceedings," the group said.

One potential vehicle for the legislation would be energy policy legislation by Senate Energy and Natural Resources Chairman Lisa Murkowski, Republican-Alaska, and ranking member Maria Cantwell, Democrat-Washington, that is awaiting action on the Senate floor.

Murkowski joined Cassidy and Senator John Barrasso, Republican-Wyoming, in a letter to Rick Perry October 5 supporting the DOE proposal.

"The Caribbean small-scale LNG export market represents a relatively untapped outlet as the United States only exported approximately three billion cubic feet of natural gas to the region in 2016," the senators said. "Increasing exports of US LNG will decrease Caribbean and Central American reliance on Venezuelan fuel oil, increase economic opportunities, and offer a cleaner-burning fuel source for those nations."

— Maya Weber

Industry track record on resilience positive

With the Department of Energy narrowing its scope of grid resilience to on-site fuel supplies, a panel at the Energy Bar Association's mid-year forum Tuesday took a broader look at energy supply uncertainty, finding that industry was on top of the issue prior to DOE's contentious market proposal.

Suzanne Lemieux, manager of midstream and industry operations at the American Petroleum Institute, pointed to the recent slew of hurricanes and industry's quick response as evidence of the significant efforts energy companies have made to maintain resilient systems.

"From API's perspective, we see through the actions that our industry takes — whether it's through voluntary standards …, through compliance with regulations or thorough voluntary processes with some of our regulators — that we are able to provide reliable supplies without concerns about shortages" or potential long-term disruptions, she said.

"In Texas, in particular, we saw almost no disruptions to the natural gas system," Lemieux added. "Overall I think we are quite confident in the industry's ability to maintain reliable services and to maintain reliable prices even in global marketplaces that have some uncontrollable dynamics."

Speaking from the electric utility industry's point of view, Charles Patton, executive vice president of external affairs at American Electric Power, offered that there are significant regulations and fines in place to keep utilities in line with regard to ensuring reliability and resilience.

"I like to think that our industry is very responsive outside of the threat of fines in terms of being creative and deploying technologies to make us better because not only are we regulated at the federal level but we're also regulated at the state level," he said. "The thing that will get you in the most hot water with a state regulator is poor customer service and that's in the form of poor reliability and resiliency."

Market design, regulatory changes needed periodically

Terry Boss, senior vice president of environment, safety and operations for the Interstate Natural Gas Association of America, said operating and maintenance practices can be adjusted to account for possible stresses to the system. However, he conceded, "periodically you need to adjust the design of the system, the design of the market and the design of the regulatory structure," he asserted.

On that front, the US Federal Energy Regulatory Commission is currently considering a contentious energy market proposal from DOE that critics have said unfairly favors coal-fired and nuclear generation. The notice of proposed rulemaking (RM18-1) would require independent system operators and regional transmission organizations to guarantee full cost recovery and a return on investment for generators that maintain 90-day on-site fuel supplies.

But "no matter what your fuel choice is — be it renewable, coal, nuclear, whatever — there are things you could do to increase the resiliency of that energy supply," Boss said.

For instance, renewable generators have the ability to add batteries to address some intermittency concerns, he said. "The point being there are mechanisms to increase the reliability and resilience of all these energy sources; it isn't necessarily subject to one particular type of fuel."

FERC urged to steer clear of prescriptive rules

Patton said he agreed wholeheartedly that the RTOs and market structures in place have helped. "But one of the big challenges where the market is not necessarily responsive is in the area of reliability and resiliency in that large coal and nuclear plants are not being dispatched today because of the market structure, and those attributes that may bring value to a reliable grid are not priced in the market," Patton contended.

"I'm not saying that every coal, every nuclear plant necessarily needs a subsidy or should be there," Patton continued. "But if you look at maintaining the reliability and resilience of the grid, I would like to know … that the appropriate resources that we need in order to maintain the most reliable and resilient system possible are there, and I'm not sure you can do that from the current market construct."

Richard Doying, Midcontinent Independent System Operator's executive vice president of operations, said the NOPR has created a dialogue, in which industry will offer their opinions and FERC will decide what direction to take.

Given that the power sector is already heavily regulated, Doying said he hoped FERC would take a path on grid resilience that is performance-based, rather than prescriptive.

— Jasmin Melvin

Pemex gas, oil output decline in September

Pemex's gas production, excluding nitrogen, decreased to 3.46 Bcf/d in September, 510 MMcf/d less than in August, as Pemex curtailed oil production due to several natural disasters.

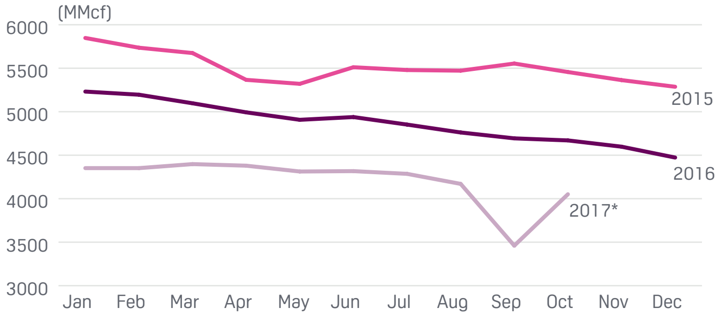
Pemex's associated gas production suffered from oil output cuts at Cantarell and Ku-Maloob-Zaap, or KMZ. Year to August, more than three-quarters of Pemex's total gas output came from associated production.

The state company's oil production fell to 1.730 million b/d in September, its lowest level since 1980, according to a company report published Tuesday.

Early in September, Hurricane Harvey closed the Houston Ship Channel as well as many refineries in Texas, Pemex's main export markets. Also, lower utilization rates at Pemex's refineries in September saw Pemex decrease its output.

Pemex's 330,000 b/d Salina Cruz refinery in southern Mexico was hit by an earthquake on September 7. The plant is expected to restart operations at the end of October. Also, Pemex's 190,000 b/d Madero refinery is offline as it is undergoing scheduled maintenance until December.

PEMEX GAS PRODUCTION



*Data for gas production between October 1-8
Source: Pemex

In mid-September, Hurricane Katia hit the Mexican Gulf Coast, closing Pemex's crude export terminals in the states of Tamaulipas and Veracruz, forcing the company to cancel many of its crude shipments and further decrease its output.

However, production increased to 1.936 million b/d during the first week of October, 6,000 b/d higher than in August before Harvey made landfall on the Texas coast.

During the first week of October, Pemex's gas output rose to 4.05 Bcf/d. Gas production, excluding nitrogen, was down 26.3% year on year from 4.69 Bcf/d. The historical high was 6.534 Bcf/d in 2009.

Oil production was down 8.4% year on year from 2.113 million b/d in September 2016 and just over half the historical high of 3.4 million b/d in 2004.

Pemex said at the end of September it was forced to decrease output due to lower demand. However, the company still expects to be able to meet its 2017 production target of 1.944 million b/d.

The bulk of Mexico's crude and gas is still produced by Pemex. Mexico is liberalizing its oil industry and has been holding exploration and production tenders in an effort to boost its output.

The decrease in Pemex's crude and thus associated gas production came from the lower output at Cantarell and KMZ, where oil output decreased 40% and 16%, respectively.

Cantarell's output halved to 85,000 b/d in September. As a result, associated gas production, including nitrogen, also halved to 560 MMcf/d in September.

Because of the closure of Houston's ports, Pemex brought forward maintenance at its Zaap field, reducing its overall output by 330,000 b/d between September 5 and 11.

KMZ's production decreased 137,000 b/d month on month to 696,000 b/d in September. Along with it, the complex's gas output, including nitrogen, declined month on month 122 MMcf/d to 424 MMcf/d in September.

During the first week of October, KMZ and Cantarell's production recovered to 840,000 b/d and 139,000 b/d, respectively.

Pemex's non-associated gas production at onshore fields in the Burgos and Veracruz regions had slight variations between August and October. Year to August, both regions produced a quarter of Pemex's gas production excluding nitrogen.

Production at Burgos grew 9 MMcf/d in the first week of October to 710 MMcf/d compared with August. Production at the Veracruz region decreased 12 MMcf/d to 243 MMcf/d during the same period.

— *Daniel Rodriguez*

Supply more secure with LNG flexibility: IEA

The increasing flexibility of LNG deliveries is improving global gas supply security as spot cargoes can more easily make their way to parts of the world that may urgently need gas, the International Energy Agency said Wednesday.

In its latest Global Gas Security Review, the Paris-based energy watchdog said newly signed LNG supply contracts were becoming more flexible, with fewer deals containing strict destination clauses.

With the LNG market currently widely perceived as oversupplied, buyers are able to negotiate more favorable terms — including shorter-term agreements and more flexible terms around LNG re-sales.

"This report's updated analysis of new signed contracts shows clear evidence of contractual structures becoming less rigid," the IEA said. "This trend is evidenced by the growing share of flexible destination contracts as well as by the decrease in duration."

Peter Fraser, the head of the IEA's Gas, Coal and Power Markets Division, told a press webinar this week that the LNG glut has led to a decline in LNG plant utilization rates. "The fact is we have a glut, so as a consequence we have a lot of spare capacity available," Fraser said.

According to the report, a combination of capacity increases from new plants, a slight decrease in off-line capacity, and slower demand expansion has resulted in the lower liquefaction utilization rates.

The rates have come down from 96% in 2015 to 95% in 2016, and an anticipated 87% for 2017.

"This increases the potential for LNG supply response in case of tightness," IEA said. "It has to be noted, however, that despite the increased liquefaction capacities relative to LNG demand, upswing LNG production capacities remain modest."

Supply security is 'live issue'

IEA stressed that gas supply security was still a "live issue", pointing to a number of events from the past year. It highlighted events such as the diplomatic tensions between Qatar and several Gulf countries and Hurricane Harvey in the US, which had the potential to disrupt LNG supplies.

"These proved to be more threats than real supply issues since they did not have actual consequences on LNG output level. Nevertheless, they did show that supplying countries, however important and reliable, are still exposed to high-impact, low-probability events with potentially substantial consequences for global gas supply," it said.

On the demand side, the IEA pointed to the price spikes in southern Europe in the 2016-17 winter following a combination of events that triggered a risk of gas shortage. It led to triggering emergency response mechanisms in several countries.

"Although no gas outages were experienced in any of the affected countries, prices rose sharply and some demand-side measures had to be adopted, showing that even in mature and well-interconnected markets, unexpected shocks can still put strong pressure on physical balancing," the IEA said.

— Stuart Elliott

California gas plant repowering raises questions

Glendale, California, community members and analysts are questioning whether energy storage, distributed energy and energy efficiency are better options to repowering its aging 267-MW gas-fired power plant.

"We've seen very rapid deployment of storage solutions in the context of Aliso Canyon, so there is no reason to believe we couldn't see a similar speed of deployment in Glendale," Eric Gimon, senior fellow at Energy Innovation, a California-based think tank, said in a Wednesday phone interview. The Aliso Canyon gas storage facility sustained a massive leak from October 2015 to February 2016.

The city of Glendale owns the plant. The Glendale Water & Power Commission this week at a public hearing presented a draft Environmental Impact Report on a proposal to rebuild seven of the plant's eight gas turbines, but the plan met with opposition from local residents. The proposal would replace existing equipment with new combined-cycle and simple-cycle gas turbines at a cost of about $500 million.

The existing units — except for the 48-MW Unit 9, which is not being replaced — were built between 1941 and 1977 and are at least 40 years old. The plant has seen unplanned and forced outages more frequently, according to the city.

In June 2015, Glendale authorized plans to move forward with a 250-MW gas-fired project with a $350 million estimated cost.

"We think the city should be looking at a more robust demand response program, energy efficiency and rooftop solar," Angela Johnson Meszaros, an attorney at Earthjustice, which has been working with the local community to address their energy requirements, said in a phone interview Wednesday. "We think they can be more thoughtful about how they meet their energy needs."

Statewide move away from gas underway

Precedent is being set in other parts of the state where natural gas power plant projects have been put on hold while other options are considered. NRG Energy on Tuesday asked the California Energy Commission to suspend its review of the 262-MW, natural gas-fired Puente power plant while the Houston-based independent power producer considers entirely halting the project because of widespread public opposition.

"The Puente plant decision represents a turning of the tide where Californians are looking much more to preferred resources like solar and storage to satisfy system needs instead of gas combustion turbines," Gimon said.

A concern expressed by Glendale residents is that investing in new gas capacity at a time when it appears the fuel is being phased out across the state could be risky. By 2030 gas-fired generation will be declining to make way for more renewable power, which will supply about two-thirds of the state's electricity, according to a draft paper released recently by the California Independent System Operator.

"I would agree with the citizens of Glendale that now is a risky time to make a $500 million dollar bet on new gas capacity," Gimon said.

The draft environmental impact report for the Glendale repowering project considered an energy storage alternative, but found it would "not feasibly meet the project objectives" to the same extent as the gas-fired option, the report said.

Nevertheless, the gas plant opponents argue it would be prudent to allow more time for study.

"Glendale is a medium-sized city that's proposing to spend a half a billion dollars to meet its energy needs," Johnson Meszaros said. She contends the better option would be to pause now and spend six months studying the issue.

"The cost is going up and other communities in the state are pulling back from fossil-fueled plants and choosing other options because they can meet their needs in other ways that are not going to give them a stranded asset in the future," she said.

The Glendale Water and Power Commission did not immediately return a request for comment.

— Jared Anderson

Virginia trustees OK conversions for pipelines

After gaining approval from the US Federal Energy Regulatory Commission, Atlantic Coast Pipeline and Mountain Valley Pipeline cleared another hurdle this week when the Virginia Outdoors Foundation signed off on the conversion of open space to allow construction of the major pipelines.

The VOF signoff marks one less sticking point for the projects, both of which would pick up gas from producing areas in West Virginia, moving it east, where the majority of volumes target deliveries in the Transcontinental Gas Pipe Line Zone 5 market, including Virginia and the Carolinas.

Atlantic Coast also pressed forward Thursday by filing its implementation plan at FERC that spells out how it will meet numerous conditions in the certificate order approving the project.

The 604-mile, 1.5-Bcf/d Atlantic Coast (CP15-554) would move gas from Harrison County, West Virginia, to delivery meters in Virginia and North Carolina. The 301-mile, 2-Bcf/d Mountain Valley (CP16-10) will transport gas from a receipt point in northern West Virginia into Columbia's WB System and finally into Transco Zone 5.

Trustees of the VOF, a public private conservation entity, on Monday unanimously approved the access to conservation land for 11 VOF open space easements in five counties, mostly affected by the Atlantic Coast route. Environmental groups had contended Virginia law did not allow for the conversion of the easements.

Ten of those properties, in Highland, Bath, Augusta and Nelson counties became an issue after Atlantic Coast agreed to reroute the pipeline to avoid sensitive areas in national forests flagged by the US Forest Service. The altered route ran through some privately held conservation lands in Virginia.

Under Atlantic Coast's conversion application filed with VOF, about 53 acres of open space easement would be permanently affected, but roughly 1,100 acres would be transferred by the project as a substitute.

Mountain Valley, for its part, proposed a permanent access road on an easement in Roanoke County that would require right of way of 675 feet over 0.32 acres. In exchange, the developer would convey a 10.25 acre parcel in Roanoke.

In approving the applications, the trustees said developers failed to show the projects met the Virginia Open-space Land Act requirement that the projects are "essential to the orderly development and growth to the locality."

They conceded, however, that FERC's certificate order approving the project supersedes that authority. On the other hand, VOF retained authority to review the projects and require substitute land of greater conservation value.

"The fact that we can't stop the federal government or FERC from deciding to put a pipeline across our easement doesn't diminish the power of VOF in the state, or our ability to maintain the integrity of the easements to the extent that we can," said VOF Chair Stephanie Ridder.

VOF reduced number of easements that the pipeline would cross from 33 to 11, and reduced the impact, she said, questioning those who assert that VOF would do better to have the easements condemned by eminent domain.

"Were it my choice, I would stand in front of the pipeline and stop it. But that's not going to work," she said. "Were we to go to court and were the court to find, as it would, that FERC has eminent domain, there exists the possibility that nobody gets anything but a few pennies on the acreage."

PROPOSED ROUTE OF ATLANTIC COAST PIPELINE

Source: Dominion Energy

Dominion Energy spokesman Aaron Ruby, in a statement, said the decision "shows that by working together industry and the conservation community can responsibly develop public infrastructure in a way that preserves the environment."

According to Platts Analytics' Bentek Energy, both Atlantic Coast and Mountain Valley will help fill power demand in the Mid-Atlantic as natural gas continues to replace coal for power generation. Atlantic Coast will work more to alleviate the constraint of natural gas leaving the Northeast, while Mountain Valley is backed by producers and therefore can be expected to increase production coming out of West Virginia, Platts Analytics data suggest.

— Maya Weber, Eric Brooks

PIPELINE MAINTENANCE

Start date	End date	Pipeline	Description
28-Sep	31-Oct	NGPL	NGPL restricts Station 302 flows through October 31 to conduct repairs, causing flow direction to change
01-Jun	31-Oct	Westcoast	Update: Station 4B South is scheduled to be restricted to 1.05 Bcf/d starting September 1 and lasting through September 21, a decrease of 26 MMcf/d from where restrictions were at for end of Aug

SUBSCRIBER NOTE

Platts announces natural gas parallel publishing dates and details

After several months of preparation and testing, Platts is ready to begin parallel publishing of natural gas indices with ICE. Key dates and details of the parallel publishing period are as follows:

DAILY INDICES

August 31: Platts to publish new preliminary daily indices in parallel with ICE daily indices. The preliminary indices will be available through market data subscription or via a free trial on the Gas Daily Preliminary Price Report website.

September 1: Platts to make available two Excel files for index comparison purposes each business day. The first file is a comparison of ICE daily indices to Platts preliminary daily indices (ICE Exchange trades only), Platts current final daily indices (data submitted by price reporters), and Platts future final daily indices (data submitted by price reporters in addition to non-price reporter ICE Exchange trades) for selected locations. The second file is a comparison of Platts current final daily indices to Platts future final daily indices for all Platts locations. These files will be posted on the Gas Daily Preliminary Price Report website and on the natural gas agreement resource page located at www.platts.com/ice.

October 31: The methodology for Platts final daily indices changes. Final daily indices will now include non-price reporter ICE Exchange trades. In addition, Platts may assess daily prices.

MONTHLY INDICES:

September 25: Platts to publish new monthly indices in parallel with ICE monthly indices. The preliminary indices will be available through market data subscription or via a free trial on the Inside FERC Bidweek Watch website.

October 2: Platts to make available two Excel files for index comparison purposes when final monthly indices are published. The first file is a comparison of ICE final monthly indices to Platts current final monthly indices (data submitted by price reporters) and Platts future final monthly indices (data submitted by price reporters in addition to non-price reporter ICE Exchange trades) for selected locations. The second file is a comparison of Platts current final monthly indices to Platts future final monthly indices for all Platts locations. These files will be posted on the Inside FERC Bidweek Watch website and on the natural gas agreement resource page located at www.platts.com/ice.

December 1: The methodology for final monthly indices changes for December bidweek. Final monthly indices will now include non-price reporter ICE Exchange trades.

Please send any Platts questions or comments to gas_survey_comments@platts.com and pricemethodology@spglobal.com. Send any ICE questions or comments to NaturalGas@theice.com.

For Platts 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.

NATURAL GAS FUTURES

NYMEX Nov. gas slides 10.8 cents to $2.854

The NYMEX November natural gas contract slid considerably Wednesday, changing hands around 10.8 cents lower at $2.854/MMBtu during morning trading, as fundamentals point toward a prolonged period of above-average temperatures and a late start to substantive heating demand.

The prompt-month gas contract's losses mimicked movement seen across other winter month contracts, collectively taking the Winter 2017-2018 strip 6.6 cents lower to trade at $3.096/MMBtu.

The movement comes as the most recent National Weather Service forecasts project above-average temperatures holding over the entire western half of the country and portions of the Northeast through the end of the month, in turn signaling that substantial residential/commercial heating demand may not ramp up until November, slightly later than historically normal.

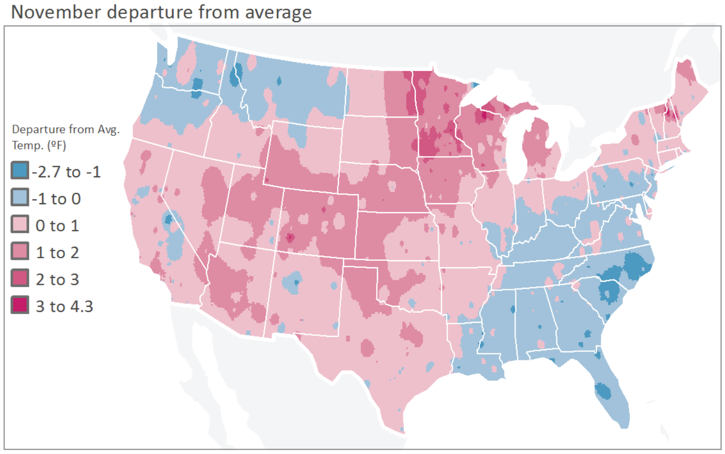
While national level power burn, month to date, has averaged 26.5 Bcf/d, its strongest October average on record and 13%, or 3 Bcf, above the corresponding five-year average, heating demand during the same period, sitting at 14.7 Bcf/d, has fallen to its lowest October average since 2011 and 10%, or 1.8 Bcf, below the corresponding five-year average, Platts Analytics' Bentek Energy data shows.

The stronger power-burn levels have more than offset the weaker heating demand, and helped drive total demand to an average of 70 Bcf/d, in turn keeping the prompt month contract buoyed within an 18-cent range above and below $2.90/MMBtu, despite production levels continuing to build.

Looking slightly forward though, with above-average temperatures expected to linger, heating demand through the end of the month is expected to remain below the five-year average, at 20.1 Bcf/d, while the previously supportive power burn registers a considerable decline of 4 Bcf, to average 26.4 Bcf/d, Platts Analytics projects. This, in turn, paints a bearish picture for the start of winter.

MONTH-AHEAD TEMPERATURE FORECAST MAP

November departure from average



Source: Platts, Custom Weather

NYMEX HENRY HUB GAS FUTURES CONTRACT, OCT 18

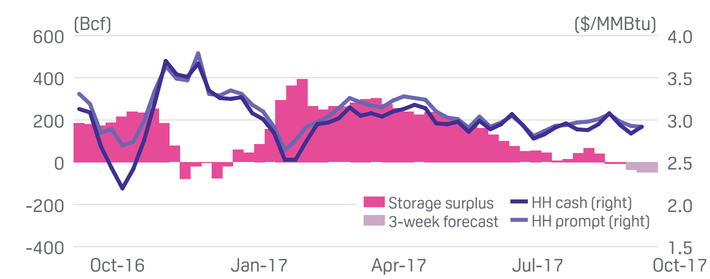
	Settlement	High	Low	+/-	Volume
Nov 2017	2.854	2.941	2.851	-0.108	89960
Dec 2017	3.065	3.113	3.059	-0.063	33222
Jan 2018	3.194	3.233	3.187	-0.054	6432
Feb 2018	3.203	3.241	3.196	-0.054	1900
Mar 2018	3.164	3.202	3.158	-0.054	3842
Apr 2018	2.946	2.960	2.936	-0.024	3026
May 2018	2.926	2.934	2.915	-0.020	922
Jun 2018	2.956	2.959	2.944	-0.019	152
Jul 2018	2.987	2.994	2.975	-0.018	277
Aug 2018	2.990	2.991	2.978	-0.018	785
Sep 2018	2.972	2.973	2.959	-0.017	161
Oct 2018	2.995	2.997	2.980	-0.016	669
Nov 2018	3.052	3.052	3.035	-0.013	66
Dec 2018	3.188	3.188	3.170	-0.010	257
Jan 2019	3.270	3.270	3.249	-0.009	128
Feb 2019	3.241	3.241	3.223	-0.008	21
Mar 2019	3.165	3.165	3.153	-0.006	38
Apr 2019	2.787	2.787	2.775	0.005	33
May 2019	2.744	2.744	2.734	0.004	7
Jun 2019	2.766	2.768	2.761	0.004	2
Jul 2019	2.789	2.793	2.784	0.004	3
Aug 2019	2.790	2.795	2.785	0.004	2
Sep 2019	2.772	2.780	2.764	0.003	3
Oct 2019	2.796	2.799	2.793	0.003	3
Nov 2019	2.856	2.856	2.856	0.003	0
Dec 2019	3.006	3.006	3.006	0.005	0
Jan 2020	3.108	3.108	3.108	0.003	0
Feb 2020	3.085	3.085	3.085	0.003	0
Mar 2020	3.030	3.030	3.030	0.003	0
Apr 2020	2.717	2.717	2.717	0.000	0
May 2020	2.691	2.691	2.691	0.000	0
Jun 2020	2.714	2.714	2.714	0.000	0
Jul 2020	2.740	2.740	2.740	0.000	0
Aug 2020	2.750	2.750	2.750	0.000	0
Sep 2020	2.746	2.717	2.717	0.000	0
Oct 2020	2.772	2.772	2.772	0.000	0

Contract data for Tuesday
Volume of contracts traded: 431,399
Front-months open interest:
Nov, 139,206; Dec, 226,628; Jan, 196.562
Total open interest: 1,371,570
Data is provided by a third-party vendor and is accurate as of 5:30 pm Eastern time.

NYMEX PROMPT MONTH FUTURES CONTINUATION

Note: The entire wick of the candlestick depicts the high and low daily front-month Henry Hub futures price range. The body of the candlestick depicts the price range between the open and close, with a red candlestick indicating a close on the downside and a green candlestick indicating a close on the high end.
Source: Platts

BENTEK US GAS STORAGE SURPLUS VS. ROLLING 5-YEAR AVERAGE



NORTHEAST GAS MARKETS

Northeast spot prices fall on warm weather

US Northeast spot natural gas prices mostly fell Wednesday on a warmer-than-normal weather forecast expected to weigh on both heating and gas-fired power demand.

In New England, high temperatures are forecast to rise above Wednesday's levels, but short of record highs.

"Highs should end up a few degrees warmer than today, mainly in the low to mid-70s, except 60s near the south coast, Cape Cod and Islands," said the US National Weather Service.

"This will fall short of [Thursday's] record highs, which are in the low to mid-80s," the weather service said.

In Boston, temperatures have averaged more than 6 degrees above normal in the month to date that ended Tuesday, according to weather service data. Heating degree days totaled 73 in the period, about 83 HDD below normal.

Grid operator ISO New England is planning to lower peak load Thursday to 14,800 MW from Wednesday's 14,950 MW estimate.

On the upside, gas demand in the region has likely been supported by the shutdown of Dominion Energy's 1,276-MW Millstone-3 nuclear unit in Waterford, Connecticut, late Thursday for a scheduled refueling and maintenance outage.

Algonquin Gas Transmission city-gates spot gas prices fell 6 cents to $2.900/MMBtu.

In New York City, Thursday's temperatures are expected to reach 70-75 degrees, about 10 degrees above average for this time of year, according to the weather service.

The New York grid operator is planning a decrease in peak load in New York City Zone J to 6,184 MW Thursday from 6,254 MW Wednesday.

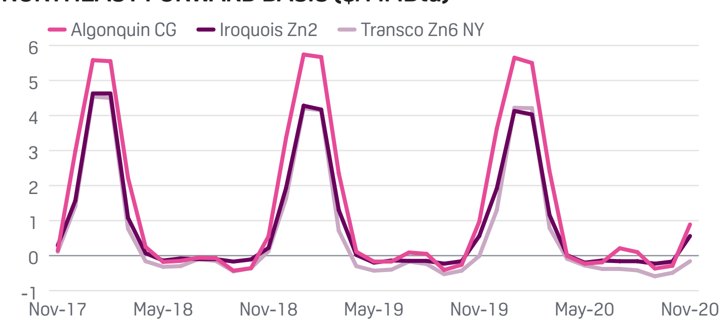
Transco Zone 6 New York spot gas prices were down 2 cents to $2.780/MMBtu.

Farther west, Texas Eastern Transmission M-3 spot gas prices were up 47 cents to $1.960/MMBtu on an expected increase in power demand. Peak load in the PJM Mid-Atlantic region is forecast at 30,822 MW Thursday, up from 29,947 MW Wednesday.

Over the weekend, TETCO M-3 spot gas prices had dipped to a year-to-date low of 53 cents as capacity through the Berne 30-inch-diameter meter had been cut to zero from 1.8 Bcf/d gas day 12, triggering a force majeure, according to Platts Analytics' Bentek Energy.

TETCO has restored full capacity to the Berne Compressor Station and flows through the 30-inch line have largely recovered to pre-outage levels, according to Platts Analytics.

NORTHEAST FORWARD BASIS ($/MMBtu)



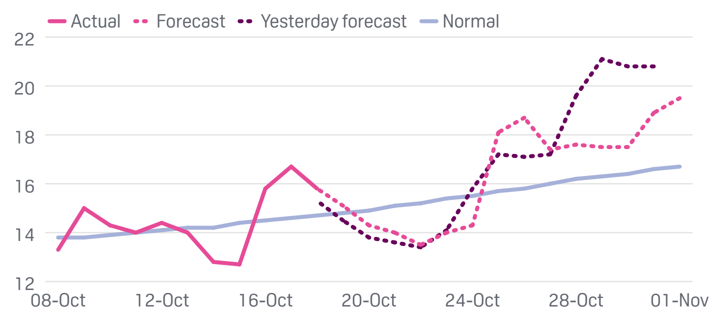
Source: Platts

NORTHEAST SPOT AND FORWARD BASIS ($/MMBtu)

	Spot basis						Prompt forward basis		
	18-Oct	17-Oct	Chg	MTD Avg.	MTD last year	Chg	18-Oct	17-Oct	Chg
Henry Hub	2.81	2.88	-0.07	2.87	3.00	-0.13	2.85	2.96	-0.11
Northeast region									
Algonquin CG	0.09	0.08	0.01	-0.04	-1.13	+1.10	0.14	0.25	-0.11
Iroquois Zn2	0.12	0.15	-0.03	0.02	-1.01	+1.04	0.29	0.29	0.00
Tenn Zn6 Dlvd	-0.06	-0.07	0.01	-0.16	-1.24	+1.08	0.04	0.15	-0.11
Transco Zn 6 NY	-0.03	-0.08	0.05	-0.36	-2.09	+1.73	0.11	0.14	-0.03
Transco Zn5 Dlvd	-0.06	0.02	-0.07	0.02	-0.29	+0.31	0.14	0.18	-0.04
Transco Zn6 Non-NY	-0.04	-0.07	0.03	-0.34	-1.74	+1.40	0.06	0.07	-0.01
TX Eastern M-3	-0.85	-1.39	0.54	-1.52	-2.20	+0.68	-0.70	-0.62	-0.08
Appalachia									
Col Gas Appal	-0.20	-0.21	0.02	-0.25	-0.21	-0.04	-0.26	-0.26	0.00
Dominion N Pt	-1.81	-1.74	-0.07	-2.07	-2.25	+0.19	-1.01	-1.00	-0.02
Dominion S Pt	-1.82	-1.74	-0.08	-2.05	-2.26	+0.20	-0.97	-0.89	-0.08
Lebanon Hub	-0.13	-0.14	0.01	-0.21	—	—	-0.13	-0.13	0.01
Millennium East Receipts	-2.03	-1.89	-0.15	-2.07	-2.26	+0.19	-1.04	-1.02	-0.02
Tenn Zn4-200 Leg	-0.82	-0.65	-0.17	-0.86	-2.11	+1.26	-0.81	-0.74	-0.07
Tennessee zone 4-300 leg	-1.98	-1.91	-0.07	-2.09	-2.28	+0.19	-1.12	-1.04	-0.08
Texas Eastern M-2 receipts	-1.87	-1.74	-0.13	-2.08	-2.28	+0.20	-0.96	-0.88	-0.08
Transco Leidy Line receipts	-1.95	-1.83	-0.13	-2.03	-2.24	+0.21	-1.05	-0.97	-0.08
Other locations									
Dracut MA	—	—	—	—	—	—	0.19	0.29	-0.10
Iroquois Receipts	0.09	0.10	-0.01	-0.02	-1.02	+1.00	0.21	0.21	0.00
Niagara	—	—	—	—	-2.35	—	-0.59	-0.60	0.01

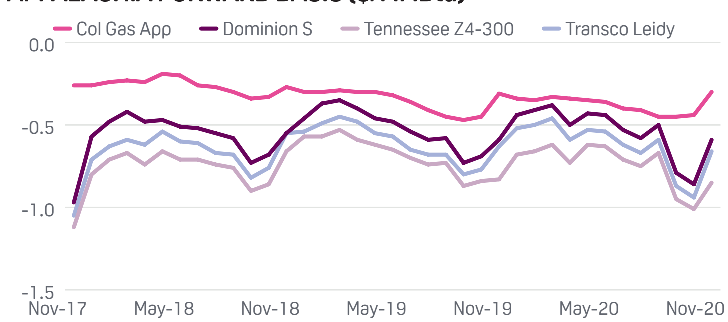
Source: Platts M2M data

NORTHEAST DEMAND FORECAST (Bcf/d)



Source: Platts

APPALACHIA FORWARD BASIS ($/MMBtu)



Source: Platts

SOUTHEAST GAS MARKETS

Spot dips on weak demand; storage report eyed

The Southeast cash market continued to see-saw Wednesday, dropping across the region following Tuesday's jump as demand is expected to weaken into the weekend, according to Platts Analytics' Bentek Energy data.

Total Southeast demand is projected to dip Thursday and continue its downward trajectory into the weekend, ultimately dropping from 17.94 Bcf/d to 17.3 Bcf/d on Saturday, according to projections.

Houston Ship Channel's reign above the $3/MMBtu level was short lived as the pricing point shed 11 cents to $2.89/MMBtu Wednesday.

Farther along the Gulf Coast, Henry Hub dropped 7 cents to $2.81/MMBtu, pulling HSC cash basis lower to plus 8 cents/MMBtu.

Compared with September, HSC has strengthened significantly against Henry Hub, with the monthly average swinging almost 8 cents to plus 6 cents/MMBtu from the September level as of Tuesday. If spreads continue throughout the remainder of October, keeping HSC basis at a premium, it would mark the first month since June that HSC has averaged a distinct premium to Henry Hub.

On the storage front, Energy Information Administration data shows that South Central stocks are currently hovering around 1.15 Tcf, nearly 5% below year-ago levels, signaling a tighter balance could persist into the winter months as LNG and exports to Mexico continue to grow.

For the next storage report to be released Thursday morning, for the week ended October 13, all metrics lead to a build in storage lower than the 22-Bcf injection experienced during the previous period, or even a withdrawal, which could widen the gap with year-ago levels.

Due to Hurricane Nate, production levels for the week ended October 13 fell by an average of 1.4 Bcf/d from the previous week, while demand increased 1.7 Bcf/d during the same time frame, largely on the backs of stronger power burn and surging LNG feedgas levels, Platts Analytics data showed.

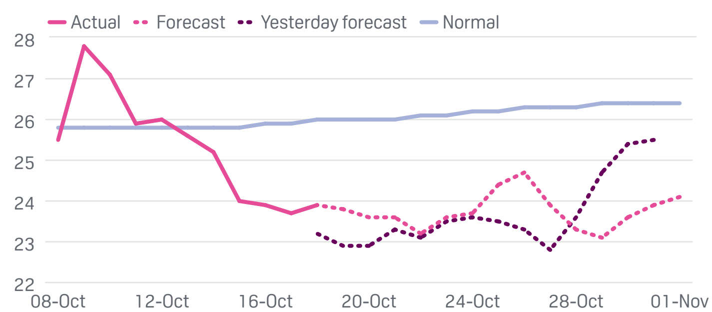
With inflows to the Southeast market dipping around 400 MMcf/d to 4.7 Bcf/d, the various fundamentals signal a weaker build into storage stocks, or even a withdrawal in the upcoming release.

SOUTHEAST SPOT AND FORWARD BASIS ($/MMBtu)

	Spot basis						Prompt forward basis		
	18-Oct	17-Oct	Chg	MTD Avg.	MTD last year	Chg	18-Oct	17-Oct	Chg
Henry Hub	2.81	2.88	-0.07	2.87	3.00	-0.13	2.85	2.96	-0.11
Southeast									
ANR LA	-0.10	-0.09	-0.01	-0.13	-0.09	-0.04	-0.12	-0.12	0.00
Col Gulf LA	-0.08	-0.09	0.02	-0.09	-0.09	+0.00	-0.10	-0.10	0.00
Col Gulf-Mainline	-0.12	-0.12	0.01	-0.13	-0.11	-0.02	-0.13	-0.14	0.00
FL Gas Zn1	-0.03	—	-0.03	-0.04	-0.04	+0.00	-0.06	-0.06	0.00
FL Gas Zn2	-0.04	-0.04	0.00	-0.04	-0.03	-0.01	-0.04	-0.04	0.00
FL Gas Zn3	0.01	0.02	-0.01	0.01	0.00	+0.00	-0.03	-0.06	0.04
Florida CG	—	—	—	0.32	0.22	+0.10	0.26	0.23	0.04
SoNat LA	-0.03	-0.03	0.00	-0.04	-0.05	+0.01	-0.10	-0.10	0.00
Tenn LA 500 Leg	-0.03	-0.03	-0.01	-0.03	-0.04	+0.01	-0.10	-0.10	0.00
Tenn LA 800 Leg	-0.06	-0.05	-0.01	-0.08	-0.06	-0.02	-0.09	-0.09	0.00
TETCO-M1	-0.09	-0.15	0.06	-0.07	-0.04	-0.03	-0.10	-0.10	0.00
Texas Gas Zn SL	—	—	—	-0.14	-0.25	+0.11	-0.14	-0.14	0.00
Texas Gas Zn1	-0.12	-0.12	0.00	-0.13	-0.13	+0.01	-0.14	-0.14	0.00
Transco Zn2	—	—	—	-0.04	-0.12	+0.08	-0.18	-0.19	0.01
Transco Zn3	-0.02	-0.03	0.01	-0.04	-0.05	+0.01	-0.06	-0.06	0.00
Transco Zn4	-0.02	-0.02	-0.01	-0.03	-0.04	+0.01	-0.04	-0.04	0.00
Trunkline E LA	-0.06	-0.10	0.04	-0.09	-0.09	+0.00	-0.12	-0.12	0.00
Trunkline WLA	0.01	0.01	0.00	0.00	0.09	-0.09	-0.08	-0.08	0.00
Tx Eastern E LA	-0.06	-0.08	0.02	-0.06	-0.05	-0.01	-0.11	-0.11	0.00
TX Eastern W LA	-0.02	-0.04	0.02	-0.04	-0.05	+0.01	-0.09	-0.09	0.00
East & South Texas									
Agua Dulce	—	—	—	—	0.12	—	-0.03	-0.03	0.00
Carthage Hub	-0.06	-0.06	0.00	-0.08	-0.10	+0.02	-0.10	-0.10	0.00
Houston Ship Channel	0.08	0.12	-0.04	0.07	0.15	-0.08	-0.03	-0.03	0.00
Katy	0.05	0.10	-0.05	0.06	0.10	-0.04	-0.03	-0.03	0.00
NGPL S TX	-0.05	-0.05	0.00	-0.04	-0.09	+0.04	-0.04	-0.04	0.00
NGPL Texok Zn	-0.11	-0.10	-0.02	-0.13	-0.13	+0.00	-0.14	-0.15	0.01
Tenn Zn0	-0.09	-0.07	-0.02	-0.11	-0.07	-0.04	-0.10	-0.10	0.00
Transco Zn1	-0.06	-0.08	0.02	-0.05	-0.14	+0.09	-0.10	-0.09	0.00
TX Eastern E Tx	-0.06	-0.09	0.03	-0.08	-0.13	+0.04	-0.09	-0.09	0.00
TX Eastern S TX	0.02	-0.04	0.05	-0.01	0.00	-0.01	-0.04	-0.05	0.01

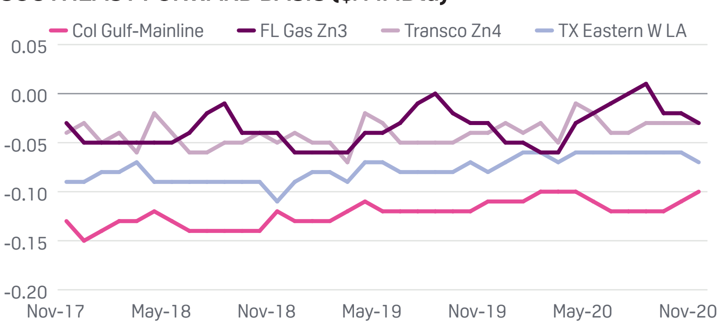
Source: Platts M2M data

SOUTHEAST & TEXAS DEMAND FORECAST (Bcf/d)



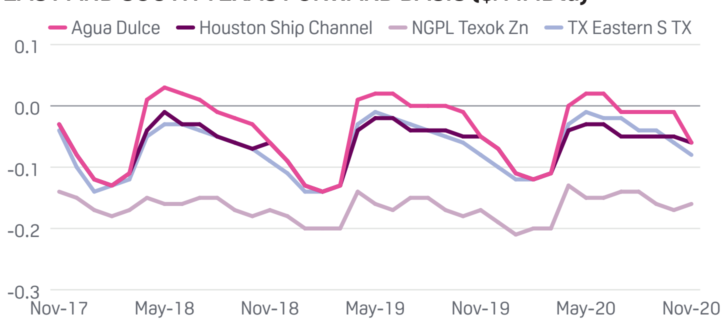
Source: Platts

SOUTHEAST FORWARD BASIS ($/MMBtu)



Source: Platts

EAST AND SOUTH TEXAS FORWARD BASIS ($/MMBtu)



Source: Platts

CENTRAL GAS MARKETS

Prices slip on anemic demand levels

The Midcontinent spot natural gas market mostly fell across the board Wednesday as declining demand levels are expected over the next few days, pulling cash prices lower.

Demand data from Platts Analytics' Bentek Energy showed total Midcontinent demand is projected to slip around 220 MMcf/d Thursday to 11.86 Bcf/d, before dropping to 10.6 Bcf/d by Saturday, the lowest since October 2.

Chicago city-gates shed 5 cents to around $2.745/MMBtu, while points indicative of supply movements toward the Chicago market, Northern Natural and Northern Border Ventura, fell by a larger margin, dipping around an average of 8 cents each to $2.625/MMBtu and $2.64/MMBtu, respectively.

Flows from the Western Canadian market reached a 30-day high Wednesday, or 4.55 Bcf/d in projected flows along all routes into the Upper Midwest market, about 240 MMcf/d above the October-to-date average.

The largest day-on-day increases occurred along the Great Lakes-Emerson interconnect, which ticked up around 56 MMcf/d day on day, while flows along Alliance USA increased 155 MMcf/d.

Upstream in Alberta, AECO cash prices have been battered over the last few months, with the October average around 62 Canadian cents/Gj, a stark contrast from October 2016 levels averaging C$2.935/MMBtu, Platts pricing data showed.

Flows into the Upper Midwest from Western Canada have averaged 4.3 Bcf/d this month, up from last October, when flows were around 3.4 Bcf/d, largely driven by a combination of cheaper Canadian prices and shifting patterns of flow from TransCanada Mainline to alternate routes transiting the Upper Midwest.

In the current weaker demand environment, additional flows could have led to even further downward movement among market area prices. However, the Western Canadian increase was more than offset by a drop in flows from the Rockies, and in particular, around 265 MMcf/d less inflow from the production area, weighing on prices in that market.

Decreasing outflows to the market area, combined with a dip in Texas and Southeast outflows, weighed on cash prices in the core Oklahoma and Kansas production zones.

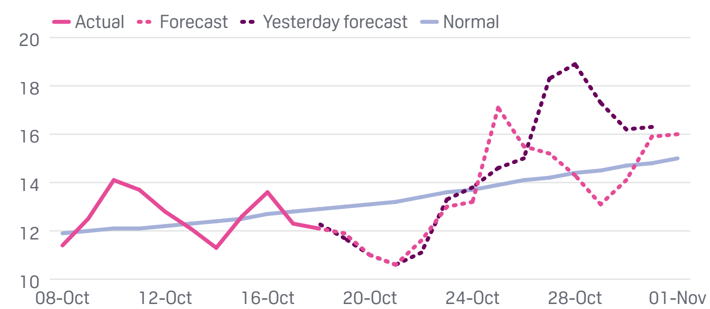
Natural Gas Pipeline Company of America-Midcontinent slipped about 9 cents to $2.605/MMBtu, while Panhandle dropped nearly 10 cents to $2.49/MMBtu.

CENTRAL SPOT AND FORWARD BASIS ($/MMBtu)

	Spot basis						Prompt forward basis		
	18-Oct	17-Oct	Chg	MTD Avg.	MTD last year	Chg	18-Oct	17-Oct	Chg
Henry Hub	2.81	2.88	-0.07	2.87	3.00	-0.13	2.85	2.96	-0.11
Midwest/East Canada									
ANR ML 7	—	—	—	-0.13	-0.12	-0.01	-0.05	-0.05	0.00
Chicago CG	-0.07	-0.09	0.02	-0.14	-0.13	-0.01	-0.09	-0.10	0.00
Consumers Energy CG	0.15	0.04	0.11	-0.02	-0.12	+0.10	-0.11	-0.12	0.01
Dawn Ontario	0.04	0.04	-0.01	-0.07	-0.14	+0.07	-0.03	-0.04	0.01
Mich Con CG	-0.05	-0.10	0.05	-0.12	-0.14	+0.02	-0.09	-0.09	0.01
Northern Ventura	-0.19	-0.17	-0.02	-0.22	-0.19	-0.03	-0.17	-0.17	0.00
Viking-Emerson	-0.28	-0.29	0.01	-0.57	-0.24	-0.33	-0.26	-0.26	0.00
Midcontinent									
ANR OK	-0.28	-0.29	0.02	-0.36	-0.31	-0.05	-0.38	-0.39	0.01
Enable Gas East	-0.24	-0.25	0.01	-0.21	-0.21	+0.00	-0.19	-0.20	0.01
NGPL Midcontinent	-0.21	-0.19	-0.02	-0.29	-0.22	-0.06	-0.35	-0.37	0.02
Northern NG Demarc	-0.17	-0.17	0.00	-0.22	-0.16	-0.05	-0.17	-0.18	0.01
Oneok OK	-0.33	-0.41	0.09	-0.46	-0.36	-0.09	-0.53	-0.54	0.01
Panhandle TX-OK	-0.32	-0.30	-0.03	-0.37	-0.30	-0.08	-0.42	-0.43	0.01
Southern Star TxOkKs	-0.41	-0.36	-0.05	-0.40	-0.34	-0.07	-0.47	-0.47	0.00

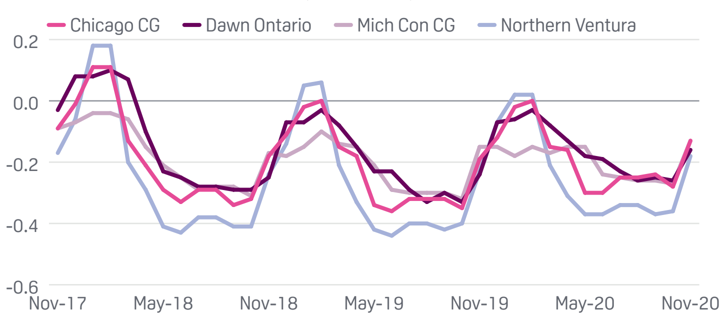
Source: Platts M2M data

MIDWEST & MIDCONTINENT DEMAND FORECAST (Bcf/d)



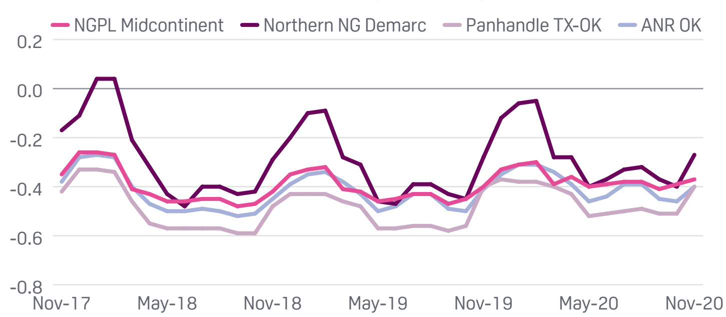
Source: Platts

MIDWEST FORWARD BASIS ($/MMBtu)



Source: Platts

MIDCONTINENT FORWARD BASIS ($/MMBtu)



Source: Platts

WEST GAS MARKETS

Mild weather tamps down So Cal market

As temperatures in Southern California dropped, so did natural gas prices in that area Wednesday.

Southern California Gas Border was being traded at about $2.76/MMBtu, down about 17 cents/MMBtu.

SoCal Gas city-gate, which was coming off a Monday spike, was down even more, working at about $3.99/MMBtu, down about 1.11/MMBtu.

Temperatures in the California Independent System Operator footprint had been averaging in the low 70s, but the forecast for the rest of the week is bearish, with average temperatures checking in around the mid-60s Fahrenheit, according to weather forecaster CustomWeather.

The futures market for the Southwest was also in decline, with the SoCal Gas Border November contract trading at about 13 cents/MMBtu, down about 4 cents.

In the Pacific Northwest, flows had different impacts on each side of the US-Canada border.

Production in Canada has remained essentially flat, averaging about 1.52 Bcf/d, with a peak of about 1.53 Bcf/d being hit on October 14, according to Platts Analytics' Bentek Energy.

Those Canadian numbers hold true for the long haul, too. So far in October 2017, production has averaged about 1.5 Bcf/d, up about 2% from the 14.9 Bcf/d mark from the corresponding month of 2016.

Year on year, 2017's 1.5 Bcf/d average is just a hair off of 2016's 15.1 Bcf/d.

But flows over the last few months have been constricted due to maintenance and a large quantity of gas has been stranded in supply areas. As maintenance has slowed, those flows have opened up in some areas.

Receipts at Sumas rose to some 890 MMcf/d Wednesday, a 200 MMcf/d increase. With gas more plentiful, the Northwest-Canada border pricing point dipped slightly, falling about 6 Canadian cents/Gj to about $2.58 Canadian/Gj.

Meanwhile, work is still ongoing at Westcoast Energy's Station 4B South compressor, but flows have risen to about 1,541,034 Gj/d, up from about 1,189,769 Gj/d.

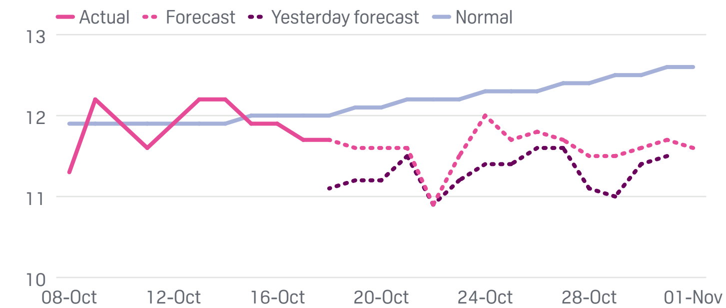
That increase has allowed gas to move south and prices at Westcoast Station 2 reacted positively, rising about 29 Canadian cent/Gj to about 51 Canadian cents/Gj.

WEST SPOT AND FORWARD BASIS ($/MMBtu)

	Spot basis						Prompt forward basis		
	18-Oct	17-Oct	Chg	MTD Avg.	MTD last year	Chg	18-Oct	17-Oct	Chg
Henry Hub	2.81	2.88	-0.07	2.87	3.00	-0.13	2.85	2.96	-0.11
Northwest									
GTN Kingsgate	-1.56	-0.39	-1.18	-0.94	-0.49	-0.45	-0.52	-0.55	0.03
Northwest Sumas	-0.23	-0.24	0.01	-0.35	-0.41	+0.06	-0.39	-0.42	0.04
Northwest Stanfield	-0.23	-0.25	0.02	-0.36	-0.40	+0.04	-0.37	-0.38	0.01
Rockies									
Cheyenne Hub	-0.30	-0.29	-0.01	-0.38	-0.33	-0.04	-0.39	-0.42	0.03
CIG Rockies	-0.30	-0.29	-0.01	-0.39	-0.37	-0.02	-0.39	-0.42	0.03
Kern River Opal	-0.24	-0.19	-0.05	-0.33	-0.32	-0.01	-0.34	-0.37	0.04
NW WY Pool	-0.25	-0.25	0.01	-0.37	-0.38	+0.01	-0.34	-0.37	0.04
Questar Rky	-0.28	-0.28	0.01	-0.38	-0.36	-0.02	-0.31	-0.34	0.03
Southwest									
El Paso Permian	-0.38	-0.35	-0.04	-0.48	-0.35	-0.13	-0.52	-0.54	0.02
El Paso San Juan	-0.37	-0.31	-0.06	-0.47	-0.34	-0.13	-0.50	-0.52	0.02
Kern River Dlvd	0.03	0.08	-0.05	-0.19	-0.21	+0.02	-0.10	-0.14	0.04
PG&E CG	0.38	0.43	-0.05	0.26	0.32	-0.06	0.27	0.24	0.03
PG&E Malin	-0.21	-0.20	-0.01	-0.29	-0.28	-0.01	-0.28	-0.31	0.03
PG&E South	-0.27	-0.22	-0.06	-0.36	-0.24	-0.13	-0.10	-0.13	0.03
SoCal Gas	-0.05	0.06	-0.11	-0.20	-0.24	+0.04	-0.12	-0.16	0.04
SoCal Gas Citygate	1.19	2.23	-1.05	0.66	-0.10	+0.75	0.42	0.20	0.22
Transwestern Permian	-0.40	-0.31	-0.09	-0.48	-0.33	-0.15	-0.50	-0.51	0.01
Waha	-0.36	-0.31	-0.05	-0.43	-0.27	-0.16	-0.48	-0.49	0.02
West Canada									
AECO-C	-2.28	-2.65	0.37	-2.26	-0.10	-2.16	-1.27	-1.34	0.07

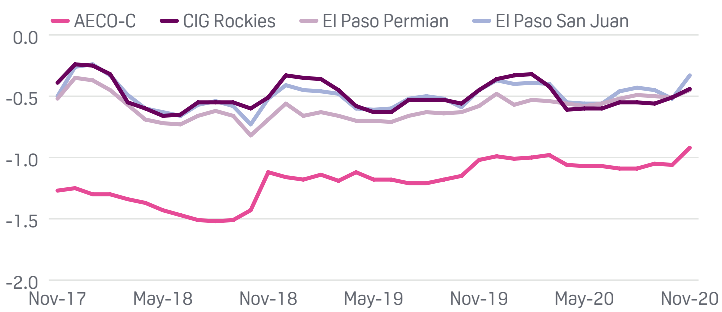
Source: Platts M2M data

SOUTHWEST, NORTHWEST, ROCKIES DEMAND FORECAST (Bcf/d)



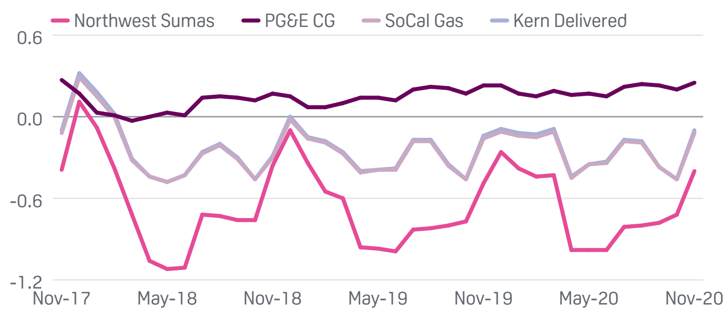
Source: Platts

WEST SUPPLY LOCATIONS FORWARD BASIS ($/MMBtu)



Source: Platts

WEST DEMAND LOCATIONS FORWARD BASIS ($/MMBtu)



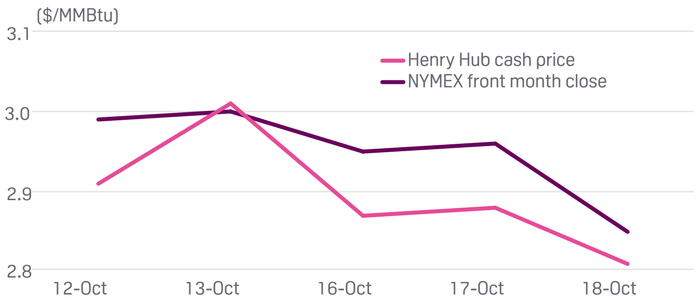
Source: Platts

TOTAL NET PIPELINE FLOWS BY REGION (MMcf/d*)

	17-Oct	18-Oct	Change	MTD avg.	MTD last year	Change
Supply regions – net pipeline outflows						
Texas	8,733	8,236	497	8,324	8,109	215
West Canada	7,934	8,291	-357	8,221	8,207	14
Rockies	6,812	6,516	296	6,635	6,644	-9
Midcontinent	3,644	3,475	169	3,265	2,856	409
Northeast	7,716	7,769	-53	7,219	5,573	1,646
Demand regions – net pipeline inflows						
Southwest	4,601	4,525	-76	4,300	4,339	39
Southeast	9,481	9,063	-418	9,004	8,278	-726
Northwest	1,769	1,977	208	1,802	1,631	-171
Midwest	11,690	11,398	-292	11,473	10,488	-985
East Canada	3,018	3,220	202	2,997	2,748	-249

* Net pipeline flows by region are the aggregated total interstate pipeline flows across the regional border. Net supply regions are those that historically have had more supply than demand within the region and have been net suppliers of gas to other regions. Net demand regions historically have had more demand than supply and have been net receivers of pipeline gas from other regions.

HENRY HUB/NYMEX SPREAD



GAS DAILY SUPPLEMENTS

To access the latest issue of the Gas Daily supplements, click below.

Gas Daily Market Fundamentals (pdf)

Gas Daily Market Fundamentals Data (xls)

Gas Daily Monthly Price Guide (pdf)

*Links require PMC login. For login help, contact support@platts.com.

SHALE VALUE CHAIN ASSESSMENTS, OCT 18

	$/MMBtu	+/-
Gulf Coast ethane fractionation spread	1.020	0.035
Gulf Coast E/P mix fractionation spread	0.907	0.035
E/P mix Midcontinent to Rockies fractionation spread	0.028	-0.070
E/P mix Midcontinent fractionation spread	-0.067	-0.065
National raw NGL basket price	7.736	-0.072
National composite fractionation spread	4.846	0.038

The methodology for these assessments is available at:
www.platts.com/IM.Platts.Content/MethodologyReferences/MethodologySpecs/shale-value-chain.pdf

PLATTS OIL PRICES, OCT 18

	($/b)	($/MMBtu)
Gulf Coast spot		
1% Resid (1)	51.54-51.56	8.25
HSFO (1)	49.79-49.81	7.97
Crude spot		
WTI (Nov) (2)	52.03-52.05	8.97
New York spot		
No.2 (1)	67.82-67.86	10.85
0.3% Resid LP (3)	56.48-56.50	9.04
0.3% Resid HP (3)	56.48-56.50	9.04
0.7% Resid (3)	52.88-52.90	8.46
1% Resid (3)	50.98-51.00	8.16

1= barge delivery; 2= pipeline delivery; 3= cargo delivery

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FINAL DAILY GAS INDICES – ICE LOCATIONS ($/MMBtu)

Powered by ICE

Trade date: 18-Oct

Flow date(s): 19-Oct

Location	Symbol	Index	Daily Change	Absolute Low	Absolute High	Common Low	Common High	Volume	Deals
Northeast									
ICE Algonquin CG (Excl. J and G Lateral deliveries)	JAAAA21	2.900	-0.060	2.850	2.950	2.875	2.925	466	106
ICE Algonquin Citygates (Excl. J Lateral deliveries)	JAAAB21	—	—	—	—	—	—	—	—
ICE Iroquois, zone 1 (delivered excl. Waddington)	JAABS21	—	—	—	—	—	—	—	—
ICE Iroquois, zone 2 (non-Hunts Point/Eastchester Lateral)	JAABT21	2.920	-0.125	2.920	2.920	2.920	2.920	41	12
ICE Iroquois, zone 2 Hunts Point/Eastchester Lateral	JAABU21	—	—	—	—	—	—	—	—
ICE Maritimes, Hubline and Beverly Salem	JAACB21	—	—	—	—	—	—	—	—
ICE Maritimes and Northeast Pipeline US (buyer's choice delivered)	JAACC21	—	—	—	—	—	—	—	—
ICE PNGTS (buyer's choice delivered)	JAADH21	—	—	—	—	—	—	—	—
ICE Stagecoach Marcellus Hub	JAAEN21	—	—	—	—	—	—	—	—
ICE Tennessee, zone 5, 200 Line, delivered downstream of station 245	JAAEU21	2.680	-0.070	2.550	2.700	2.645	2.700	54	16
ICE Texas Eastern, Manhattan Lateral (delivered)	JAAEW21	—	—	—	—	—	—	—	—
ICE Transco, Cove Point, Pleasant Valley Interconnect	JAAAY21	—	—	—	—	—	—	—	—
ICE Transco, zone 6 (non-NY north mainline)	JAAEZ21	—	—	—	—	—	—	—	—
ICE Transco, zone 6 station 210 Pool	JAAFA21	2.770	-0.070	2.650	2.790	2.735	2.790	81	20
Appalachia									
ICE Clarington Tennessee	JAAFI21	—	—	—	—	—	—	—	—
ICE Columbia Gas, A04 Pool	JAAAU21	—	—	—	—	—	—	—	—
ICE Columbia Gas, A06 Pool	JAAAV21	—	—	—	—	—	—	—	—
ICE Columbia Gas, Segmentation Pool	JAAAW21	—	—	—	—	—	—	—	—
ICE Millennium Pipeline (buyers' choice delivered)	JAAHA21	—	—	—	—	—	—	—	—
ICE Tennessee, zone 4, station 219 Pool	JAAET21	1.960	-0.235	1.900	2.000	1.935	1.985	57	18
ICE Texas Eastern, M2 Zone (delivered)	JAAEV21	—	—	—	—	—	—	—	—
Midcontinent									
ICE Bennington, Oklahoma	JAAAM21	—	—	—	—	—	—	—	—
ICE Enable Gas, Flex Pool only	JAABE21	2.565	-0.060	2.550	2.580	2.560	2.575	84	20
ICE Enable Gas, North Pool only	JAABF21	—	—	—	—	—	—	—	—
ICE Enable Gas, West (W1 or W2 as mutually agreed)	JAABI21	—	—	—	—	—	—	—	—
ICE Enable Gas, West Pool	JAABJ21	—	—	—	—	—	—	—	—
ICE NGPL, Gulf Coast Mainline Pool	JAACI21	2.700	-0.075	2.700	2.700	2.700	2.700	22	2
ICE NGPL, Mid-Continent Storage PIN	JAACO21	—	—	—	—	—	—	—	—
ICE Northern Natural, Mid 13 - 16A Pool	JAACW21	—	—	—	—	—	—	—	—
ICE Northern Natural, Mid 1-7 Pool	JAACX21	2.460	-0.045	2.450	2.470	2.455	2.465	40	4
ICE Northern Natural, Mid 8 -12 Pool	JAACY21	—	—	—	—	—	—	—	—
ICE Salt Plains Storage (buyers' choice)	JAADV21	—	—	—	—	—	—	—	—
ICE Salt Plains Storage (in-ground transfer only)	JAADW21	—	—	—	—	—	—	—	—
Upper Midwest									
ICE Alliance, Chicago Exchange Hub	JAAAC21	2.725	-0.050	2.700	2.740	2.715	2.735	513	70
ICE Alliance, ANR Interconnect	JAAAD21	—	—	—	—	—	—	—	—
ICE Alliance, Midwestern Interconnect	JAAFX21	—	—	—	—	—	—	—	—
ICE Alliance, NGPL Interconnect	JAAAF21	—	—	—	—	—	—	—	—
ICE Alliance, Nicor Interconnect	JAAAG21	—	—	—	—	—	—	—	—
ICE Alliance, Vector Interconnect	JAAAH21	—	—	—	—	—	—	—	—
ICE ANR, Joliet Hub CDP	JAAAK21	—	—	—	—	—	—	—	—
ICE Bluewater Gas Storage	JAAAN21	—	—	—	—	—	—	—	—
ICE Great Lakes Gas, St. Clair	JAABM21	—	—	—	—	—	—	—	—
ICE Guardian, Guardian Hub	JAABN21	—	—	—	—	—	—	—	—
ICE NGPL, Amarillo Pooling PIN	JAACG21	2.630	-0.070	2.620	2.640	2.625	2.635	176	24
ICE NGPL, Amarillo Storage PIN	JAACH21	—	—	—	—	—	—	—	—
ICE NGPL, Iowa-Illinios Pooling PIN	JAACJ21	—	—	—	—	—	—	—	—
ICE NGPL, Iowa-Illinios Storage PIN	JAACK21	—	—	—	—	—	—	—	—
ICE NGPL, Mid-American Citygate	JAACN21	2.730	-0.065	2.715	2.740	2.725	2.735	25	8
ICE Northern Border, Harper Transfer Point	JAACS21	—	—	—	—	—	—	—	—
ICE Northern Border, Nicor Interconnect	JAACT21	—	—	—	—	—	—	—	—
ICE Northern Border, Vector Interconnect	JAACU21	2.715	-0.060	2.700	2.740	2.705	2.725	142	24
ICE Northern Border, Will County	JAACV21	2.710	-0.060	2.700	2.735	2.700	2.720	57	12
ICE REX (East), delivered into ANR	JAADK21	2.670	-0.070	2.650	2.735	2.650	2.690	440	66
ICE REX (East), delivered into Lebanon Hub	JAAHC21	—	—	—	—	—	—	—	—
ICE REX (East), delivered into Midwestern Gas	JAADL21	2.690	-0.060	2.660	2.705	2.680	2.700	182	28
ICE REX (East), delivered into NGPL	JAADM21	2.675	-0.065	2.665	2.685	2.670	2.680	432	54
ICE REX (East), delivered into Panhandle	JAADN21	2.675	-0.060	2.660	2.680	2.670	2.680	56	8

FINAL DAILY GAS INDICES – ICE LOCATIONS ($/MMBtu)

Trade date: 18-Oct

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Location	Symbol	Index	Daily Change	Absolute Low	Absolute High	Common Low	Common High	Volume	Deals
Upper Midwest									
ICE REX (East), delivered into Trunkline	JAADO21	2.660	-0.075	2.660	2.670	2.660	2.665	34	4
ICE REX (West), delivered into ANR	JAADP21	—	—	—	—	—	—	—	—
ICE REX (West), delivered into Northern Natural	JAADQ21	—	—	—	—	—	—	—	—
ICE REX (West), delivered into Panhandle	JAADR21	—	—	—	—	—	—	—	—
East Texas									
ICE Agua Dulce Hub	JAAGI21	—	—	—	—	—	—	—	—
ICE Atmos, zone 3, receipts	JAAAL21	—	—	—	—	—	—	—	—
ICE Carthage Hub Tailgate	JAAAQ21	2.750	-0.060	2.750	2.800	2.750	2.765	49	10
ICE ETC, Maypearl	JAABK21	—	—	—	—	—	—	—	—
ICE Golden Triangle Storage & Hub	JAABL21	—	—	—	—	—	—	—	—
ICE Gulf South, Pool Area #16	JAABP21	2.725	-0.065	2.715	2.750	2.715	2.735	286	44
ICE HPL, East Texas Pool	JAABR21	—	—	—	—	—	—	—	—
ICE Katy, ENSTOR Pool (excl. Kinder Morgan Texas)	JAABW21	2.865	-0.110	2.860	2.880	2.860	2.870	147	24
ICE Katy, Lonestar (warranted as Intrastate)	JAABX21	—	—	—	—	—	—	—	—
ICE Katy, Lonestar Interstate	JAABY21	2.865	-0.105	2.860	2.880	2.860	2.870	104	14
ICE Katy, Oasis Pipeline	JAABZ21	2.880	-0.105	2.870	2.900	2.875	2.890	86	18
ICE Moss Bluff Interconnect (buyers' choice delivered)	JAACD21	2.880	-0.080	2.865	2.900	2.870	2.890	221	22
ICE Moss Bluff Storage (in-ground transfers only)	JAACE21	—	—	—	—	—	—	—	—
ICE NGPL, TXOK East Pool	JAACP21	2.700	-0.085	2.690	2.710	2.695	2.705	305	38
ICE NGPL, TXOK West Pool	JAACQ21	—	—	—	—	—	—	—	—
ICE NorTex, Tolar Hub	JAACR21	2.655	-0.085	2.650	2.655	2.655	2.655	12	6
ICE Tennessee, zone 0 North	JAAEP21	—	—	—	—	—	—	—	—
ICE Tennessee, zone 0 South	JAAEQ21	2.725	-0.090	2.700	2.730	2.720	2.730	47	14
ICE Tres Palacios Hub - Injection	JAAFE21	2.780	-0.075	2.750	2.800	2.770	2.795	143	24
ICE Tres Palacios Hub - Withdrawal	JAAFF21	2.890	-0.085	2.885	2.900	2.885	2.895	81	8
Louisiana/Southeast									
ICE ANR, SE Transmission Pool	JAAAI21	2.710	-0.080	2.650	2.770	2.680	2.740	214	38
ICE ANR, SE Gathering Pool	JAAAJ21	—	—	—	—	—	—	—	—
ICE Bobcat Interconnect (buyers' choice delivered)	JAAAO21	—	—	—	—	—	—	—	—
ICE Bobcat Storage (in-ground transfer only)	JAAAP21	—	—	—	—	—	—	—	—
ICE Egan Interconnect (buyers' choice delivered)	JAAAZ21	—	—	—	—	—	—	—	—
ICE Egan Storage (in-ground transfer only)	JAABA21	—	—	—	—	—	—	—	—
ICE Enable Gas, Perryville Hub	JAABG21	—	—	—	—	—	—	—	—
ICE Enable Gas, South Pool only	JAABH21	—	—	—	—	—	—	—	—
ICE Gulf South, Perryville Exchange Point	JAABO21	—	—	—	—	—	—	—	—
ICE Jefferson Island Storage and Hub	JAABV21	—	—	—	—	—	—	—	—
ICE MS Hub Storage	JAACF21	—	—	—	—	—	—	—	—
ICE NGPL, Louisiana Pooling PIN	JAACL21	—	—	—	—	—	—	—	—
ICE NGPL, Louisiana Storage PIN	JAACM21	—	—	—	—	—	—	—	—
ICE Pine Prairie Hub	JAADF21	2.760	-0.070	2.755	2.780	2.755	2.765	328	38
ICE Sonat, Zone 0	JAAHE21	—	—	—	—	—	—	—	—
ICE Sonat, Zone 0 South Louisiana Pool	JAAEJ21	2.775	-0.075	2.750	2.790	2.765	2.785	782	128
ICE Sonat, Zone 1 North Pool	JAAEK21	—	—	—	—	—	—	—	—
ICE Southern Pines Hub	JAAEM21	—	—	—	—	—	—	—	—
ICE Stingray, pool delivery	JAAEO21	—	—	—	—	—	—	—	—
ICE Tennessee, zone 1 100 Leg Pool	JAAER21	—	—	—	—	—	—	—	—
ICE Tennessee, zone 1, Station 87 Pool	JAAES21	2.720	-0.060	2.690	2.730	2.710	2.730	157	18
ICE Texas Gas, Mainline Pool	JAAEX21	2.705	-0.055	2.670	2.750	2.685	2.725	472	82
ICE Texas Gas, North Louisiana Pool	JAAEY21	—	—	—	—	—	—	—	—
Rockies/Northwest									
ICE CIG, Mainline (sellers' choice, non-lateral)	JAAFY21	2.510	-0.080	2.500	2.550	2.500	2.525	72	20
ICE CIG, Mainline Pool	JAAFZ21	—	—	—	—	—	—	—	—
ICE CIG, Mainline South (sellers' choice)	JAAAT21	—	—	—	—	—	—	—	—
ICE Kern River, on system receipt	JAACA21	2.560	-0.130	2.550	2.595	2.550	2.570	706	98
ICE Opal Plant Tailgate	JAADB21	2.570	-0.120	2.555	2.600	2.560	2.580	263	40
ICE PG&E, Onyx Hill	JAAHB21	—	—	—	—	—	—	—	—
ICE Pioneer Plant Tailgate	JAADG21	2.560	-0.135	2.560	2.565	2.560	2.560	45	6
ICE Questar, North Pool	JAADI21	2.530	-0.070	2.530	2.530	2.530	2.530	20	4
ICE Questar, South Pool	JAADJ21	2.535	-0.065	2.510	2.540	2.530	2.540	36	8

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Rockies/Northwest									
ICE Ruby, Onyx Hill	JAADS21	2.600	-0.085	2.580	2.620	2.590	2.610	70	10
ICE Ruby, Receipt Pool	JAADT21	—	—	—	—	—	—	—	—
ICE Ryckman Creek Gas Storage	JAADU21	—	—	—	—	—	—	—	—
ICE WIC, Pool	JAAFH21	—	—	—	—	—	—	—	—
Southwest									
ICE El Paso, Keystone Pool	JAABB21	2.420	-0.085	2.395	2.470	2.400	2.440	345	48
ICE El Paso, Plains Pool	JAABC21	2.420	+0.040	2.420	2.420	2.420	2.420	19	2
ICE El Paso, Waha Pool	JAABD21	2.440	-0.115	2.440	2.450	2.440	2.445	180	24
ICE Oasis, Waha Pool	JAACZ21	2.445	-0.075	2.430	2.480	2.435	2.460	60	12
ICE ONEOK, Westex Pool	JAADA21	2.430	-0.130	2.420	2.450	2.425	2.440	73	24
ICE PG&E, Daggett	JAADC21	—	—	—	—	—	—	—	—
ICE PG&E, Kern River Station	JAADD21	—	—	—	—	—	—	—	—
ICE PG&E, Topock	JAADE21	2.540	-0.130	2.530	2.590	2.530	2.555	163	26
ICE Socal, Blythe	JAADX21	—	—	—	—	—	—	—	—
ICE Socal, Ehrenberg (delivered)	JAADY21	2.845	-0.140	2.835	2.850	2.840	2.850	142	22
ICE Socal, Firm Storage only (Citygate)	JAADZ21	—	—	—	—	—	—	—	—
ICE Socal, In-ground transfer only (Citygate)	JAAEA21	—	—	—	—	—	—	—	—
ICE Socal, Interruptible Storage only (Citygate)	JAAEB21	—	—	—	—	—	—	—	—
ICE Socal, Kern River Station	JAAEC21	2.670	-0.125	2.650	2.750	2.650	2.695	125	14
ICE Socal, Kramer Junction	JAAED21	—	—	—	—	—	—	—	—
ICE Socal, Needles	JAAEE21	—	—	—	—	—	—	—	—
ICE Socal, sellers' choice delivered incl. CA production	JAAEF21	—	—	—	—	—	—	—	—
ICE Socal, Topock	JAAHD21	—	—	—	—	—	—	—	—
ICE Socal, Topock, El Paso	JAAEG21	—	—	—	—	—	—	—	—
ICE Socal, Topock, Transwestern	JAAEH21	—	—	—	—	—	—	—	—
ICE Socal, Wheeler Ridge	JAAEI21	—	—	—	—	—	—	—	—
ICE Transwestern, Central Pool	JAAFB21	2.415	-0.135	2.410	2.420	2.415	2.420	66	10
ICE Transwestern, Panhandle Pool	JAAFC21	—	—	—	—	—	—	—	—
ICE Transwestern, West Texas Pool	JAAFD21	2.405	-0.185	2.400	2.420	2.400	2.410	62	16
ICE Waha Hub, West Texas (buyer's choice delivered)	JAAFG21	2.480	-0.135	2.470	2.500	2.475	2.490	75	14

ICE GAS DAILY ASSESSMENT RATIONALE

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