S&P Global
Platts

GAS DAILY

Wednesday, November 8, 2017

NEWS HEADLINES

US gas demand sets seasonal record

- Low gas prices are driving fuel adoption
- 2018 demand forecast is expected to surge

(continued on page 2)

EIA trims Q4 Henry Hub price forecast

- Q4 Henry Hub spot price lowered to $2.99/MMBtu
- Production growth to continue in year ahead: EIA

(continued on page 3)

Parties spar on scope of Atlantic Sunrise stay

- Groups OK with operation of pipe already in service
- Administrative stays generally short-lived: attorneys

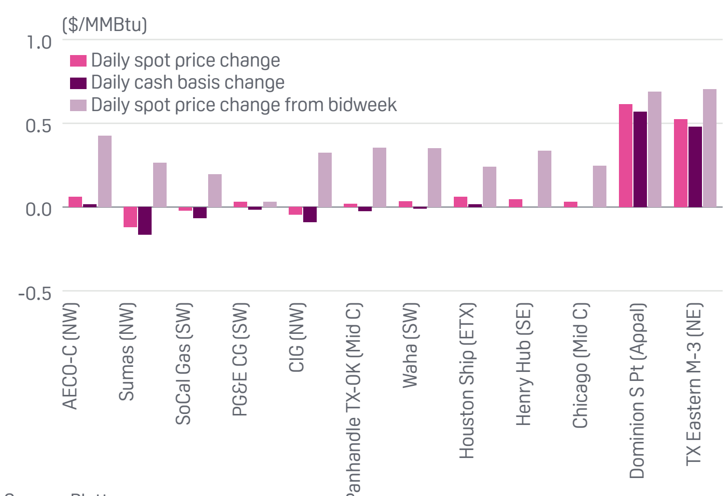
(continued on page 4)

Pemex turns to onshore, shale resources

- Pemex bets on shale in Burgos, other basins
- Mezcalapa a top priority: 14 wells across four blocks

(continued on page 5)

SPOT PRICE AND BASIS CHANGES



Source: Platts

INSIDE THIS ISSUE

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

NATIONAL AVERAGE PRICE: 2.900
Trade date: 07-Nov
Flow date(s): 08-Nov

		Midpoint	+/-	Absolute	Common	Vol.	Deals
Northeast							
Algonquin, city-gates	IGBEE21	3.010	+0.765	2.800-3.250	2.900-3.125	223	54
Algonquin, receipts	IGBDK21	2.470	+0.535	2.460-2.500	2.460-2.480	21	4
Dracut, Mass.	IGBDW21	--	--	-----	-----	--	--
Iroquois, receipts	IGBCR21	3.320	+0.205	3.260-3.350	3.300-3.345	134	47
Iroquois, zone 2	IGBEJ21	3.330	+0.160	3.270-3.400	3.300-3.365	59	28
Niagara	IGBCS21	2.825	+1.425	2.750-2.900	2.790-2.865	26	10
Tennessee, z6 (300 leg) del.	IGBJC21	2.150	+0.450	2.150-2.150	2.150-2.150	1	1
Tennessee, zone 6 del.	IGBEI21	3.315	+0.805	3.000-3.600	3.165-3.465	211	39
Tx. Eastern, M-3	IGBEK21	2.505	+0.525	2.450-2.640	2.460-2.555	474	105
Transco, zone 5 del.	IGBEN21	3.125	+0.015	3.070-3.180	3.100-3.155	500	85
Transco, zone 5 del. North	IGCGL21	3.135	+0.135	3.100-3.150	3.125-3.150	78	10
Transco, zone 5 del. South	IGCHL21	3.125	+0.015	3.070-3.180	3.100-3.155	422	75
Transco, zone 6 N.Y.	IGBEM21	3.085	+0.055	3.030-3.150	3.055-3.115	162	36
Transco, zone 6 non-N.Y.	IGBEL21	3.115	+0.070	3.010-3.150	3.080-3.150	427	79
Transco, zone 6 non-N.Y. North	IGBJS21	3.115	+0.070	3.010-3.150	3.080-3.150	427	79
Transco, zone 6-non-N.Y. South	IGBJT21	--	--	-----	-----	--	--
Northeast regional average	IGCAA00	**2.930**					
Appalachia							
Columbia Gas, App.	IGBDE21	2.940	+0.070	2.910-3.010	2.915-2.965	964	164
Columbia Gas, App. non-IPP	IGBJU21	2.420	+0.710	2.410-2.450	2.410-2.430	25	8
Dominion, North Point	IGBDB21	2.270	+0.660	2.210-2.390	2.225-2.315	240	49
Dominion, South Point	IGBDC21	2.260	+0.615	2.050-2.400	2.175-2.350	1686	316
Lebanon Hub	IGBFJ21	2.985	+0.010	2.980-3.000	2.980-2.990	55	11
Leidy Hub	IGBDD21	--	--	-----	-----	--	--
Millennium, East receipts	IGBIW21	2.210	+0.605	2.140-2.290	2.175-2.250	121	41
REX, Clarington Ohio	IGBGO21	--	--	-----	-----	--	--
Tennessee, zone 4-200 leg	IGBJN21	2.700	+0.280	2.550-2.750	2.650-2.750	290	52
Tennessee, zone 4-300 leg	IGBFL21	2.110	+0.615	2.000-2.210	2.060-2.165	135	39
Tennessee, zone 4-313 pool	IGCFL21	2.330	+0.425	2.300-2.380	2.310-2.350	84	29
Tennessee, zone 4-Ohio	IGBHO21	--	--	-----	-----	--	--
Texas Eastern, M-2 receipts	IGBJE21	2.280	+0.575	2.220-2.400	2.235-2.325	860	154
Transco, Leidy Line receipts	IGBIS21	2.180	+0.630	2.120-2.350	2.125-2.240	363	86
Appalachia regional average	IGDAA00	**2.425**					
Midcontinent							
ANR, Okla.	IGBBY21	2.810	-0.030	2.800-2.900	2.800-2.835	148	29
Enable Gas, East	IGBCA21	2.835	+0.070	2.800-2.860	2.820-2.850	50	16
NGPL, Amarillo receipt	IGBDR21	2.970	+0.010	2.950-3.000	2.960-2.985	198	34
NGPL, Midcontinent	IGBBZ21	2.770	-0.020	2.740-2.800	2.755-2.785	371	70
Oneok, Okla.	IGBCD21	2.700	-0.045	2.670-2.760	2.680-2.725	282	42
Panhandle, Tx.-Okla.	IGBCE21	2.725	+0.020	2.700-2.770	2.710-2.745	221	36
Southern Star	IGBCF21	2.800	+0.015	2.780-2.830	2.790-2.815	191	27
Tx. Eastern, M-1 24-in.	IGBET21	2.965	+0.045	2.940-3.010	2.950-2.985	10	4
Midcontinent regional average	IGEAA00	**2.820**					
Upper Midwest							
Alliance, into interstates	IGBDP21	3.035	+0.015	3.020-3.090	3.020-3.055	1255	150
ANR, ML 7	IGBDQ21	3.090	+0.340	3.090-3.090	3.090-3.090	5	1
Chicago city-gates	IGBDX21	3.075	+0.030	3.055-3.110	3.060-3.090	1284	169
Chicago-Nicor	IGBEX21	3.070	+0.020	3.055-3.110	3.055-3.085	549	80
Chicago-NIPSCO	IGBFX21	3.080	+0.040	3.060-3.095	3.070-3.090	343	47
Chicago-Peoples	IGBGX21	3.075	+0.030	3.060-3.100	3.065-3.085	392	42
Consumers city-gate	IGBDY21	3.050	+0.020	3.040-3.120	3.040-3.070	449	65
Dawn, Ontario	IGBCX21	3.200	+0.080	3.155-3.240	3.180-3.220	612	93
Emerson, Viking GL	IGBCW21	2.905	-0.010	2.850-3.000	2.870-2.945	301	68
Mich Con city-gate	IGBDZ21	3.055	+0.030	3.040-3.100	3.040-3.070	602	95
Northern Bdr., Ventura TP	IGBGH21	3.035	+0.015	3.030-3.060	3.030-3.045	216	35
Northern, demarc	IGBDV21	3.040	+0.020	3.020-3.060	3.030-3.050	585	68
Northern, Ventura	IGBDU21	3.040	+0.025	3.025-3.080	3.025-3.055	354	52
REX, Zone 3 delivered	IGBRO21	3.000	+0.015	2.950-3.030	2.980-3.020	1109	167
Upper Midwest regional average	IGFAA00	**3.050**					

US gas demand sets seasonal record

ANALYSIS US demand for natural gas is surging this autumn. Thanks largely to LNG exports, gas demand this shoulder season is at its highest level since at least 2005.

From October 1 to date, generators, industry, residential-commercial customers and liquefaction facilities have consumed an average 68.5 Bcf/d, outpacing demand over the same period last year by 5.5 Bcf/d, or nearly 9%, according to data compiled by Platts Analytics.

While gas consumption for LNG exports has tipped the scales for producers and helped to balance the domestic market, gas consumption from every other sector is also higher this year.

Recent changes in the US power-generation stack, including the retirement of more than 3,000 MW of coal-fired capacity this year have lifted power-burn demand by 1.2 Bcf/d this year compared to last — despite comparable temperatures and gas prices.

Incremental gains in industrial consumption also are piling up in 2017. The recent completion of two fertilizer plants in Iowa and the startup of gas-to-liquids projects in Texas and Oklahoma have helped

(continued on page 3)

ASSESSMENT RATIONALE

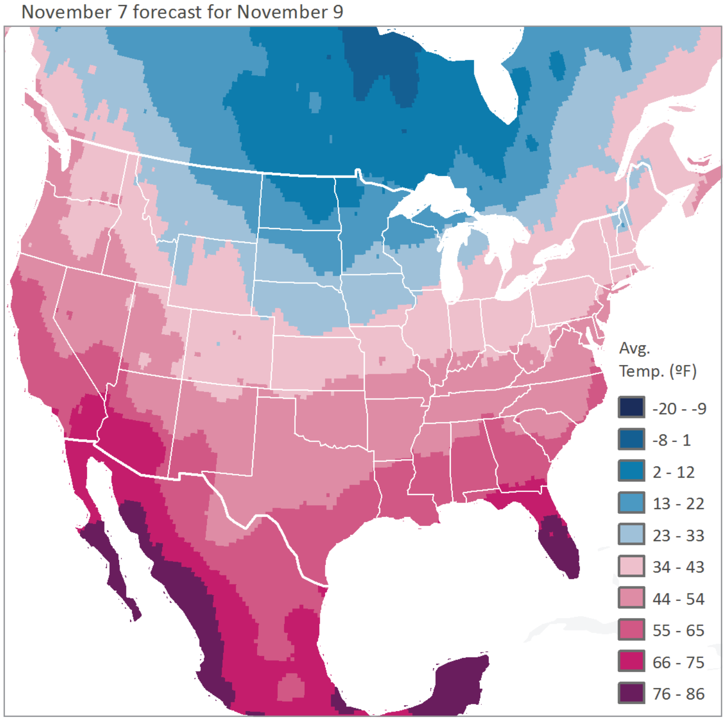
Platts Gas Daily indices are based upon trade data reported to Platts by market participants and the Intercontinental Exchange.

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

Questions may be directed to Ryan Ouwerkerk at 713-655-2202 or ryan.ouwerkerk@platts.com.

2-DAY-AHEAD TEMPERATURE FORECAST MAP

November 7 forecast for November 9



Source: Platts, Custom Weather

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

Trade date: 07-Nov
Flow date(s): 08-Nov

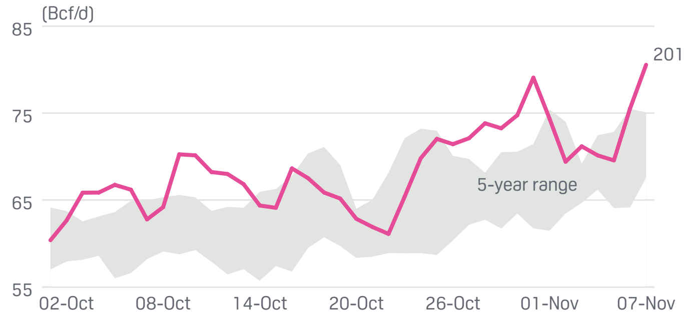
		Midpoint	+/-	Absolute	Common	Volume	Deals
East Texas							
Agua Dulce Hub	IGBAV21	--	--	-----	-----	--	--
Carthage Hub	IGBAF21	2.960	+0.025	2.950-2.990	2.950-2.970	122	28
Florida Gas, zone 1	IGBAW21	3.065	+0.055	3.050-3.070	3.060-3.070	32	3
Houston Ship Channel	IGBAP21	3.000	+0.060	2.990-3.010	2.995-3.005	74	11
Katy	IGBAQ21	3.000	+0.080	2.985-3.020	2.990-3.010	246	28
NGPL, STX	IGBAZ21	--	--	-----	-----	--	--
NGPL, Texok zone	IGBAL21	2.955	+0.025	2.900-2.980	2.935-2.975	318	55
Tennessee, zone 0	IGBBA21	2.920	+0.100	2.900-2.950	2.910-2.935	110	23
Tx. Eastern, ETX	IGBAN21	2.955	+0.035	2.950-3.000	2.950-2.970	58	10
Tx. Eastern, STX	IGBBB21	3.000	+0.055	2.990-3.040	2.990-3.015	131	19
Transco, zone 1	IGBBC21	3.040	+0.015	3.015-3.050	3.030-3.050	44	16
Transco, zone 2	IGBBU21	3.030	+0.025	3.000-3.050	3.020-3.045	59	14
East Texas regional average	IGGAA00	**2.995**					
Louisiana/Southeast							
ANR, La.	IGBBF21	3.015	+0.035	2.990-3.030	3.005-3.025	258	41
Columbia Gulf, La.	IGBBG21	3.005	+0.055	2.980-3.020	2.995-3.015	54	12
Columbia Gulf, mainline	IGBBH21	2.990	+0.060	2.970-3.020	2.980-3.005	498	124
Florida city-gates	IGBED21	3.275	+0.030	3.270-3.300	3.270-3.285	35	3
Florida Gas, zone 2	IGBBJ21	3.045	+0.055	3.040-3.070	3.040-3.055	225	9
Florida Gas, zone 3	IGBBK21	3.090	+0.025	3.025-3.150	3.060-3.120	354	39
Henry Hub	IGBBL21	3.075	+0.045	3.050-3.095	3.065-3.085	371	60
Southern Natural, La.	IGBBO21	3.015	+0.030	2.950-3.070	2.985-3.045	748	117
Tennessee, 500 Leg	IGBBP21	2.995	+0.030	2.980-3.030	2.985-3.010	239	57
Tennessee, 800 Leg	IGBBQ21	2.990	+0.030	2.980-3.005	2.985-2.995	575	110
Tx. Eastern, ELA	IGBBS21	2.985	+0.040	2.970-3.000	2.980-2.995	75	18
Tx. Eastern, M-1 30-in.	IGBDI21	2.980	+0.055	2.980-2.980	2.980-2.980	12	8
Tx. Eastern, WLA	IGBBR21	3.000	+0.065	2.960-3.030	2.985-3.020	101	16
Tx. Gas, zone 1	IGBAO21	2.990	+0.040	2.980-3.010	2.985-3.000	633	80
Tx. Gas, zone SL	IGBBT21	3.000	+0.050	3.000-3.000	3.000-3.000	2	2
Transco, zone 3	IGBBV21	3.035	+0.030	3.020-3.070	3.025-3.050	282	62
Transco, zone 4	IGBDJ21	3.050	+0.030	3.020-3.070	3.040-3.065	1268	194
Trunkline, ELA	IGBBX21	2.960	+0.040	2.960-2.960	2.960-2.960	2	2
Trunkline, WLA	IGBBW21	--	--	-----	-----	--	--
Trunkline, zone 1A	IGBGF21	2.995	+0.010	2.980-3.005	2.990-3.000	98	28
Louisian/Southeast regional average	IGHAA00	**3.025**					
Rockies/Northwest							
Cheyenne Hub	IGBCO21	2.890	-0.005	2.875-2.925	2.880-2.905	244	36
CIG, Rockies	IGBCK21	2.855	-0.045	2.810-2.860	2.845-2.860	103	18
GTN, Kingsgate	IGBCY21	2.730	-0.080	2.650-2.780	2.700-2.765	184	44
Kern River, Opal	IGBCL21	2.920	-0.055	2.880-2.960	2.900-2.940	1062	139
NW, Can. bdr. (Sumas)	IGBCT21	2.915	-0.120	2.895-2.950	2.900-2.930	84	22
NW, s. of Green River	IGBCQ21	2.860	-0.005	2.840-2.870	2.855-2.870	159	26
NW, Wyo. Pool	IGBCP21	2.895	-0.075	2.890-2.920	2.890-2.905	146	22
PG&E, Malin	IGBDO21	2.940	-0.070	2.890-2.970	2.920-2.960	294	62
Questar, Rockies	IGBCN21	2.880	-0.025	2.860-2.910	2.870-2.895	14	5
Stanfield, Ore.	IGBCM21	2.875	-0.110	2.850-2.900	2.865-2.890	264	48
TCPL Alberta, AECO-C*	IGBCU21	2.585	+0.060	2.550-2.610	2.570-2.600	1067	141
Westcoast, station 2*	IGBCZ21	0.875	-0.320	0.750-1.050	0.800-0.950	111	29
White River Hub	IGBGL21	2.870	-0.005	2.860-2.885	2.865-2.875	144	30
Rockies/Northwest regional average	IGIAA00	**2.875**					
Southwest							
El Paso, Bondad	IGBCG21	2.735	+0.045	2.720-2.800	2.720-2.755	201	18
El Paso, Permian	IGBAB21	2.735	+0.025	2.700-2.840	2.700-2.770	530	79
El Paso, San Juan	IGBCH21	2.760	+0.040	2.720-2.790	2.745-2.780	177	13
El Paso, South Mainline	IGBFR21	3.065	-0.030	3.050-3.090	3.055-3.075	219	32
Kern River, delivered	IGBES21	3.060	-0.050	3.035-3.085	3.050-3.075	346	64
PG&E city-gate	IGBEB21	3.240	+0.030	3.210-3.270	3.225-3.255	1176	125
PG&E, South	IGBDM21	2.825	+0.050	2.810-2.850	2.815-2.835	76	20
SoCal Gas	IGBDL21	3.065	-0.020	2.980-3.080	3.040-3.080	165	26
SoCal Gas, city-gate	IGBGG21	3.865	-0.110	3.700-4.050	3.780-3.955	253	57
Transwestern, Permian	IGBAE21	2.720	+0.020	2.720-2.720	2.720-2.720	3	2
Transwestern, San Juan	IGBGK21	2.750	+0.050	2.730-2.780	2.740-2.765	74	22
Waha	IGBAD21	2.790	+0.035	2.750-2.840	2.770-2.815	324	72
Southwest regional average	IGJAA00	**2.970**					

*Price in C$ per gj; C$1=US$0.7822; Volume in 000 MMBtu/day. Symbols represent gas flow date.

lift industrial consumption this autumn by nearly 0.5 Bcf/d compared to 2016.

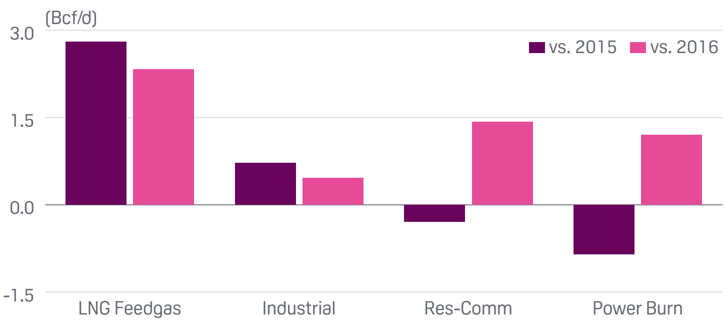
Colder average temperatures in the Midwest, the Rockies and the Southeast have also spurred a gain in residential-commercial gas demand this year. Compared to 2016, shoulder-season heating demand is up by more than 1.4 Bcf/d.

US: TOTAL GAS DEMAND



Source: Platts Analytics' Bentek Energy

AUTUMN 2017 GAS DEMAND VS. HISTORICAL AVERAGES



Source: Platts Analytics' Bentek Energy

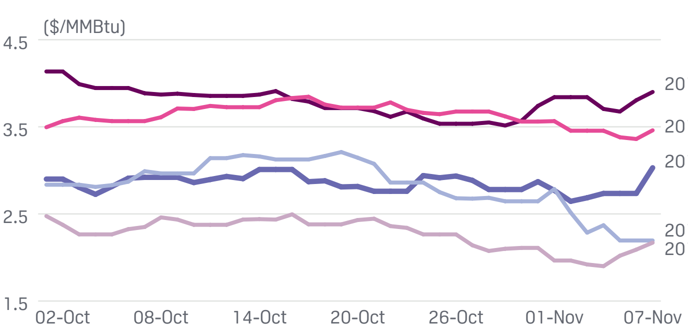
Low prices drive fuel adoption

Over the longer term, lower gas prices are helping to drive the adoption of natural gas as a fuel source.

Nowhere is this more apparent than in the export market. The steady decline of winter-season gas prices that typically traded at $6-7/MMBtu, or higher, prior to 2010, has spurred the single-largest gain in US demand, which has come from LNG liquefaction facilities.

But lower gas prices have also played a critical role in reshaping the US power-generation stack. Since 2010, US generators have retired nearly 42,000 MW of coal-fired generating capacity.

HENRY HUB SPOT PRICE



Source: Platts

In late 2015, record-low gas prices even prompted short-term coal-to-gas switching by generators with dual-fuel capacity. That additional demand lifted power-burn consumption to a record-high average of 25.5 Bcf/d in the autumn of that year. By comparison, gas consumption this shoulder season has averaged about 24.6 Bcf/d.

But looming changes in the generation stack are likely to increasingly limit generators' fuel-switching capabilities. By the end of 2018, US generators are scheduled to retire an additional 11,000 MW of coal-fired generating capacity, according to data compiled by S&P Global Market Intelligence.

2018 demand forecast to surge

Through October, total US gas demand this year has averaged 71.5 Bcf/d, actually falling about 1.5 Bcf/d, or roughly 2%, compared to total demand over the same period in 2016.

But with the looming growth in LNG exports and upcoming changes to the US generation stack, total gas demand during the full-2018 calendar year is forecast to average nearly 79 Bcf/d. That figure compares to the current full-year demand forecast of 74 Bcf/d and total 2016 demand, which averaged nearly 74.7 Bcf/d, Platts Analytics data shows.

— J. Robinson

EIA trims Q4 Henry Hub price forecast

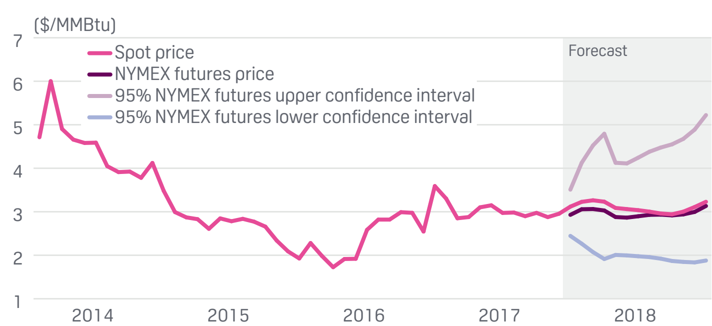
The US Energy Information Administration on Tuesday lowered its short-term forecasts for natural gas prices, as well as natural gas production and consumption, even as it continued to expect that a rebound in natural gas consumption and export growth will help bolster prices in the coming year.

The agency lowered its forecast for the average fourth-quarter 2017 Henry Hub natural gas spot price to $2.99/MMBtu, 8 cents below its estimate released in October, and cut its first-quarter 2018 price estimate by 6 cents to $3.24/MMBtu.

In its November Short-Term Energy Outlook, the agency projected the spot Henry Hub gas price will average $3.01/MMBtu for full-year 2017 and $3.10/MMBtu in 2018, for cuts of 2 cents and 9 cents compared with the agency's October projections.

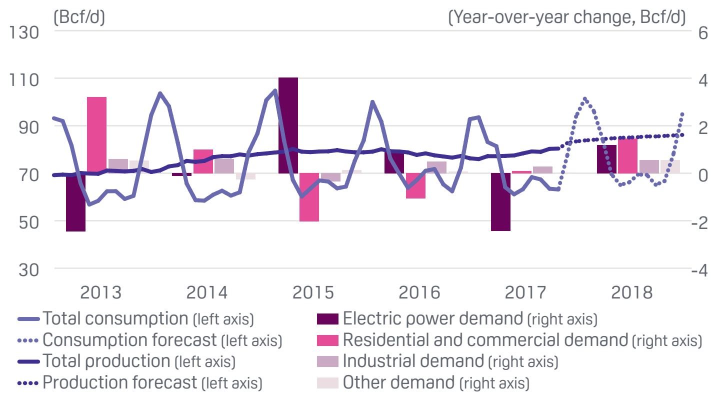
"Expected growth in natural gas exports and domestic natural gas consumption in 2018 [will] contribute to the forecast Henry Hub natural gas spot price rising from an annual average of $3.01/MMBtu in 2017 to $3.10/MMBtu in 2018," the outlook said.

HENRY HUB NATURAL GAS PRICE



Note: Data for November 2017 and beyond are forecasts.
Source: EIA's Short-Term Energy Outlook

US NATURAL GAS SUPPLY AND DEMAND



Note: Data for November 2017 and beyond are forecasts.
Source: EIA's Short-Term Energy Outlook

The agency also lowered by 0.64 Bcf/d to 81.87 Bcf/d its marketed gas production estimate for the US in Q4, while increasing its estimate for Q1 2018 production by 0.17 Bcf/d to 83.81 Bcf/d.

The EIA lowered its full-year 2017 overall gas production forecast by 0.23 Bcf/d to 78.76 Bcf/d and raised its full-year 2018 forecast by 0.36 Bcf/d to 84.8 Bcf/d.

Production growth to continue in year ahead

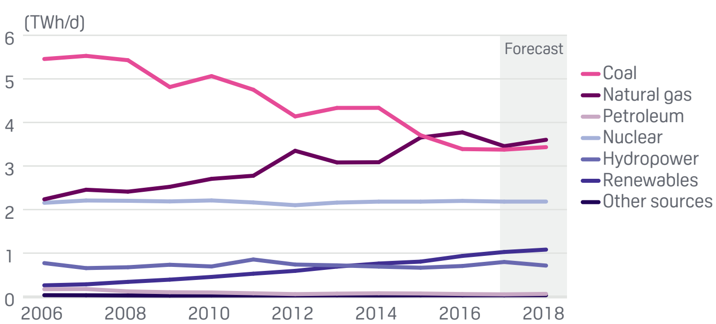
Overall, the agency expects production to be up from the 2016 level on average in 2017 and 2018.

"US dry natural gas production is forecast to average 73.4 Bcf/d in 2017, a 0.6 Bcf/d increase from the 2016 level. Natural gas production in 2018 is forecast to be 5.5 Bcf/d higher than the 2017 level," the agency said in the outlook.

The agency also lowered its consumption estimates but still anticipated an uptick in gas use this winter.

"We foresee a likely rebound in average household residential consumption of natural gas this winter as we expect temperatures to be closer to average and therefore colder than last year," said EIA Acting Administrator John Conti. "Following last year's very warm winter, consumption could climb by 8% this winter."

US ELECTRICITY GENERATION BY FUEL



Note: Data for 2017 and 2018 are forecasts.
Source: EIA's Short-Term Energy Outlook

The agency lowered its gas consumption estimate for Q4 by 0.27 Bcf/d month on month to 77.87 Bcf/d, as well as lowering its Q1 2018 estimate by 0.05 Bcf/d to 93.63 Bcf/d.

The agency said gas demand for full-year 2017 is expected to average 73.06 Bcf/d, down 0.05 Bcf/d from its October estimate, while full-year 2018 demand is expected to be 76.84 Bcf/d.

Coal, gas generation shares dead even in 2017

The share of gas-fired generation in the power sector mix is expected to fall to 31% in 2017 from 34% in 2016, amid higher gas prices and more generation from renewables and coal, according to the outlook. Coal's share of utility-scale generation is seen rising from 30% in 2016 to 31% in 2017, according to the report.

"The share of utility-scale electricity generation for natural gas and coal continues to be evenly split at about 31% for each fuel source in 2017," Conti said.

According to the outlook, non-hydro renewable generation will grow from 8% of the power mix in 2016 to about 9% in 2017 and reach 10% in 2018, while nuclear generation will stay level at nearly 20%.

— Maya Weber

Parties spar on scope of Atlantic Sunrise stay

With a court poised for quick action on the closely watched Atlantic Sunrise pipeline project, parties tussled Tuesday over the impact that a court-ordered stay would have on the key production-takeaway project.

Transcontinental Gas Pipe Line on Tuesday asked the DC Circuit Court of Appeals to clarify that a temporary administrative stay of the certificate authorization for the pipeline ordered by the court Monday applies only to one construction spread in Pennsylvania — not to other facilities in the state as well as in Maryland, Virginia, North Carolina and South Carolina.

Transco warned that if the stay applied beyond Pennsylvania — including to parts of the project already in service — it could impede service to existing Transco customers. Existing facilities integrated into Transco's mainline currently provide "partial path" firm service of up to 400,000 Dt/d, the company said.

The short-term stay paused construction to give the court time to consider an emergency stay request that environment groups filed late October (*Allegheny Defense Project, et al., v. US Federal Energy Regulatory Commission*, 17-1098).

The court Tuesday ordered the petitioners to respond to Transco's motion for clarification by 2 pm the same day.

Groups OK with operation of pipe already in service

Environmental groups in their filing Tuesday said they would not object to the court clarifying that the stay applies only to construction, not to operation of completed facilities that are already in service. The groups, represented by Appalachian Mountain Advocates and Sierra Club, however, opposed Transco's motion to limit the stay to one section in Pennsylvania and to require the petitioners to post security of $8 million per day.

The US Federal Energy Regulatory Commission told the court Tuesday that the stay is "overly broad" and should not apply generally to the commission's February 2017 certificate order, but only to "'construction activities in Pennsylvania' (or similar formulation)" that are the focus of petitioners' claim for relief. It added that the stay should be extinguished and the emergency motion for a stay should be denied as quickly as possible.

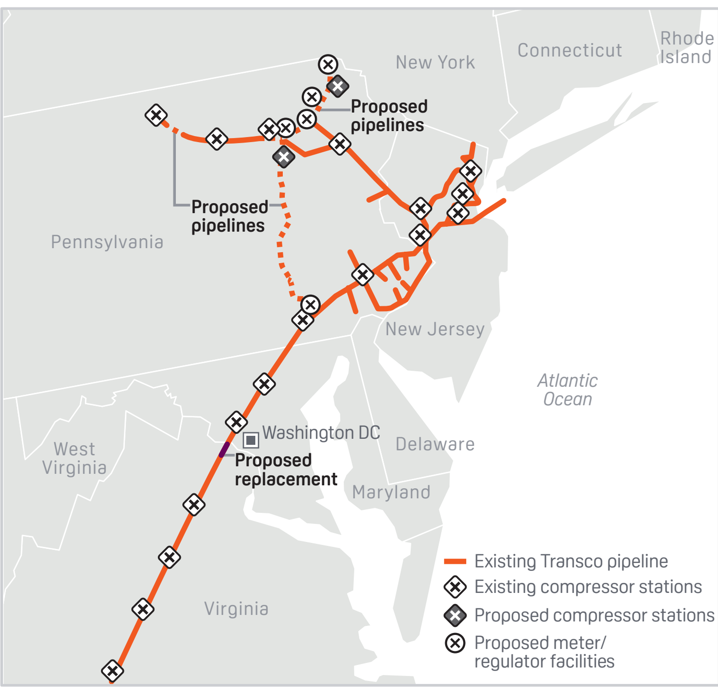
Citing the $2.8 billion price tag of the project, Transco also had asked the court require the petitioners to post security of $8 million a day for the estimated length of the stay if all construction in Pennsylvania were affected. Such security "is the only means by which the court can actually preserve the status quo; otherwise the stay imposes harsh, irreversible, sanctions on Transco in advance of any ultimate decision on the merits," the company said.

The environmental groups, by contrast, cited FERC's prior "explicit warning" to the project sponsors that if Transco proceeded with construction, it bore the risk that FERC would revise its own orders denying a stay or be overruled on appeal.

Administrative stays generally short-lived

The temporary stay was generating multiple questions about how long the important project could be delayed. DC attorneys and policy analysts noted that "administrative" stays are typically very short and only in place until the court can decide whether a longer stay pending appeal is warranted.

ATLANTIC SUNRISE PIPELINE EXPANSION PROJECT ROUTE



Source: Williams

But if the court were ultimately to grant the emergency stay, it would appear to endure during the balance of the litigation, said Christi Tezak of ClearView Energy Partners. The current briefing schedule in the underlying case suggests that oral argument might not take place until the second quarter of 2018, she said.

Micheal Dunn, Williams Partners' chief operating officer, said Tuesday he expects the court will expeditiously complete its review of the request for an emergency stay.

The Atlantic Sunrise project is expected to have a significant market impact in the eastern US. Its 1.7 Bcf/d of upstream takeaway capacity is expected to provide a major outlet for capacity-constrained production in the northeastern Pennsylvania producing region.

Once those volumes reach Transco's mainline, the project will support up to 1.7 Bcf/d of incremental north-to-south flows between Zones 4 and 6 on the system, which extends from Alabama to the New York City market area.

Crucially, the project is expected to supply up to half of the roughly 850 MMcf/d of export demand at the forthcoming Dominion Energy Cove Point LNG facility, which is scheduled to begin exports by the end of the year. Atlantic Sunrise is scheduled to enter full service by mid-2018.

In their request for an emergency stay, Appalachian Mountain Advocates and Sierra Club, filing on behalf of Allegheny Defense Project and seven other groups, in an appeals court motion October 30, said the federal environmental review of the Atlantic Sunrise project failed to meet the standard that the court laid out for evaluating greenhouse gas emissions under the Sabal Trail project decision.

They also raised due process arguments, casting FERC's issuance of additional tolling orders, extending decisions on petitioners' request for hearing, as a "brazen attempt to block this court's jurisdiction over the notices to proceed" with construction.

— Maya Weber, Eric Brooks

Pemex turns to onshore, shale resources

Mexico's National Hydrocarbon Commission on Tuesday approved Pemex's plan to drill 73 exploratory wells across 45 blocks over the next two years with the expectation of incorporating 1.5 billion boe to Pemex reserves.

Pemex is showing a slight strategic shift back to onshore fields, and a stronger focus on shale resources, the CNH said. Pemex will drill 43 wells across 25 onshore blocks.

"Pemex has a strategy to return to onshore exploration," said Alma America Porres, a CNH commissioner, at the webcast session. Higher onshore activity will translate to an increase in domestic production, she added.

Pemex has the option to drill an additional 36 wells in increments across the 45 blocks, incorporating another 654 million boe.

This group of 45 blocks is part of the 101 blocks the Mexican government granted Pemex in 2014, and gave an additional two-year extension to explore despite Pemex not fulfilling its minimum work plan on all of them.

To date, CNH has approved extended exploration plans to 60 of the 101 blocks, approving the drilling of more than 100 wells. CNH expects to approve at least one exploration well for each of the pending blocks.

Pemex will have to double its exploration budget and the number of wells it drilled since 2014 over the next two years. To accomplish this feat, CNH considers Pemex will have to farm out a portion of its exploration portfolio.

Pemex bets on shale

Pemex will drill 18 non-conventional exploratory wells over the new two years across three blocks in the southern portion of the Burgos Basin — AE-0069-M-Anhelido-01, AE-0069-M-Anhelido-02, AE-0069-M-Anhelido-03 — and two blocks in the Tampico-Misantla basin — AE-0073-M-Puchut-01 and AE-0073-M-Puchut-02.

These wells have prospective resources of 340 million boe with a geological success probability rate of 71-74%. The company expects to incorporate 203 million boe of that into its reserves.

Pemex has the option to drill an additional 11 wells with 184 million boe of prospective resources with a similar geological probability success rate. Pemex expects to incorporate 130 million boe from these wells.

Pemex's geological target for all 18 non-conventional blocks is the Upper Jurassic formation. In this horizon at the Tampica-Misantla basin is located the prolific Pimienta formation.

In the past, the company has said the Pimienta formation holds 20 billion boe of recoverable shale resources, mostly liquids hydrocarbons.

Pemex will invest Peso 1.7 billion ($96 million) in its oil and gas shale exploration projects in 2018, up 178% from last year.

Over the last couple of years, the company has invested Peso 2.4 billion ($135 million) in shale exploration. However, it plans to spend Peso 4.2 billion ($220 million) over the coming two years and Peso 7.7 billion ($400 million) beyond 2021, the company's 2018 proposed budget shows.

Pemex will explore the Burro-Picachos, Burgos, Tampico-Misantla, Veracruz, and Chihuahua basins, which hold a combined 60.2 billion boe of prospective shale resources, according to the proposed budget.

CNH Commissioner Hector Moreira Rodriguez said it is a positive sign Pemex is looking to develop unconventional resources as they represent two-thirds of Mexico's prospective resources.

CNH Commissioner Gaspar Franco Hernadez said it was positive Pemex plans to evaluate Mexico's shale gas potential. Something he described as a priority for Mexico's energy security amid higher imports from the US.

"We need to know the country's shale gas potential … not only with maps, seismic or geological information but by drilling wells to know its potential and try new technologies," Franco said.

CNH has said that the Upper Jurassic formation in the Sabinas-Burro-Picachos-Burgos basin holds mean prospective gas resources of 109 Tcf of gas.

Mezcalapa a top priority

Another area of priority for Pemex is Mezcalapa in the onshore portion of the southern Cuencas del Sureste Basin where it will drill 14 wells across four blocks — AE-0052-M-Mezcalapa-02, AE-0055-M-Mezcalapa-05, AE-0056-M-Mezcalapa-06, AE-0059-2M-Mezcalapa-09.

Pemex will drill 15 wells across 12 other onshore and offshore blocks in the Cuencas del Sureste Basin southern region, CNH said. These 36 wells have 1.4 billion of prospective resources with a geological success probability rate of 16-49. Pemex expects to incorporate 461 million boe.

Pemex has the option to drill another 21 wells in this region with potential resources of 1.6 billion boe with a geological success probability rate of 18% to 35%. Pemex expects to incorporate 451 million boe of that into its reserves.

SUBSCRIBER NOTE

Platts announces natural gas parallel publishing dates and details

Platts will continue to publish monthly natural gas indices in parallel with ICE. Key dates and details of the parallel publishing period have been as follows:

MONTHLY INDICES:

September 25:

Platts began publishing new monthly indices in parallel with ICE monthly indices. The preliminary indices are 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.

Pemex will drill eight wells across eight onshore and offshore wells in the Veracruz and Salina basins. The prospective resources of these eight blocks is 1.96 billion boe with a geological success probability rate of 18-35%. Pemex expects to incorporate 433 million boe.

Pemex will drill five wells across four blocks in the Presalt Belt in the northern portion of Mexico's deep gulf, CNH said. The prospective resources of these four blocks is 722 million boe with a geological success probability rate of 17-33%. Pemex expects to incorporate 203 million boe of that.

Pemex will drill 11 exploratory wells in 10 shallow-water blocs in the Cuencas del Sureste Basin northern region where Ku-Maloob-Zaap and Cantarell complexes are located.

These groups of blocks have 507 million boe of potential resources with a geological success probability rate of 19%–48%. Pemex expects to incorporate 176 million boe.

Pemex has the option to drill an additional four wells in this region with potential resources of 190 million with a geological success probability rate of 24%–28%. Pemex expects to incorporate 73 million boe.

— *Daniel Rodriguez*

Plains prefers to build in Permian rather than buy

Plains All American Pipeline will continue to build out its midstream infrastructure to boost takeaway capacity from the Permian Basin to the US Gulf Coast amid increasing demand in the region, but it is unlikely to pursue an acquisition to accomplish that strategy, CEO Greg Armstrong said Tuesday.

The comments come as Plains, like many of its peers, focuses on the Permian in West Texas and southeastern New Mexico, and the SCOOP/STACK in Oklahoma, as key areas for growth, amid surging producer activity in both regions. Operations in other plays, such as the Eagle Ford in South Texas and the Bakken in North Dakota, are taking a back seat to those efforts.

During a conference call to discuss third-quarter financial results, Armstrong said the frenzy of M&A activity in the Permian has driven up costs of entry, affecting decisions by Plains, a master limited partnership that owns and operates a large pipeline network and provides logistics services for crude oil, NGLs, natural gas and refined products in the US and Canada.

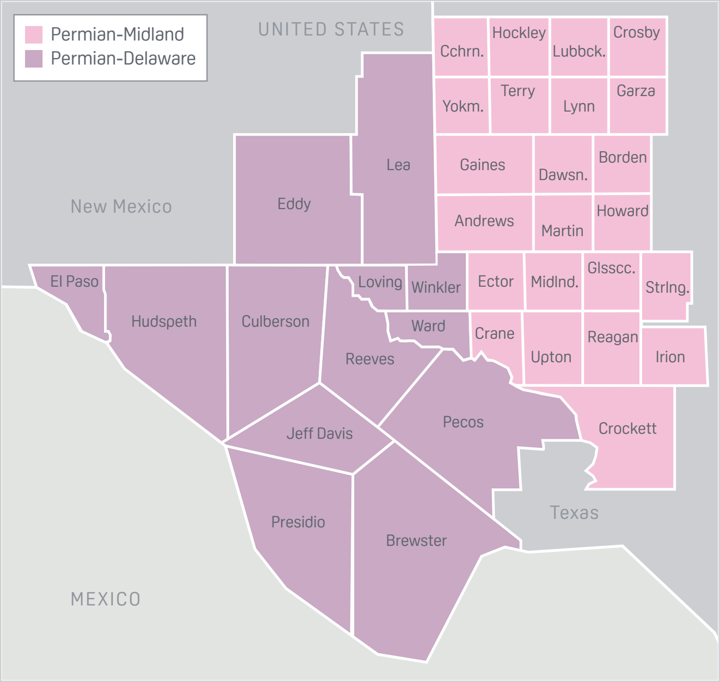
"So far it's been really tough to chin the bar," Armstrong said. "Still a lot of capital out there, a lot of competition. It's probably more economic for us to build something than to buy something."

Many other industry players are being lured to the Permian by the potential for higher returns and the proximity to Gulf Coast energy infrastructure. The SCOOP/STACK is a source of feedgas for LNG production and for pipeline deliveries to Mexico. Plains executives have said that company priorities include developing new takeaway pipes in the Permian and SCOOP/STACK.

Armstrong said that rather than buy for a high price, Plains would consider a joint venture or some other consolidation transaction to assist with its Permian build-out.

"One of the things we've learned is to never underestimate the disruptive impact of excess capital," he said.

PERMIAN'S MIDLAND AND DELAWARE BASINS



Source: Platts

With Plains expecting year-end crude oil production in the Permian of 2.7 million b/d to 2.8 million b/d, the company is "paying attention" to producers' return on capital and growth plans, Armstrong said.

Plains is moving ahead with the Sunrise project, which will at the initial stage add 120,000 b/d of new crude takeaway capacity from the Delaware area in the Permian to Cushing, Oklahoma, by early 2019, he said.

However, for the Cactus Phase II project, Plains is yet to take a final investment decision and remains in talks with shippers, Chief Operating Officer Willie Chiang told analysts.

"Talks with shippers are ongoing, and we still have lots of interest," Chiang said, without divulging further details on the timeline.

The second phase of the Cactus project is aimed at adding some 500,000 b/d of takeaway capacity post 2020 from the Permian to Corpus Christi, Texas, on the Gulf Coast, and the talks come amid growing fears of a pipeline overbuild from the basin.

"Despite an uptick in oil prices in the past two days, overall there is a nervousness amongst midstream players of a producer pullback in terms of output volumes," Danilo Juvane, an analyst with BMO Capital Markets, said in an interview.

Producer growth plans are monitored

The focus for producers is on increasing cash flows and generating higher rates of return.

Growth prospects in the Permian have resulted in several midstream players such as Plains and including Magellan, NuStar, Buckeye Partners, Enterprise Products Partners and TexStar Midstream proposing new pipeline projects from the Permian to the Gulf.

But it remains to be seen if all the planned facilities will get built.

"Of the six to seven [projects] that were proposed, it was known that not all of them would be built," Armstrong said. "There is room for one solid one and another one over time."

Armstrong didn't define "solid." But Juvane said that a "solid" pipeline would be one that is backed by at least 80% MVCs, or minimum volume commitments.

"The issue today is not capacity, but filling up whatever capacity will be proposed by a midstream player as Permian producers are still not willing to commit," Juvane said.

Strategy comes amid management changes

Earlier this year, Plains said it was changing the way it manages its NGL inventory after getting hit hard by regional price differentials between Canadian and US markets in the first three months of the year. It also said it was betting on seeing a boost to utilization on its network as the new crude infrastructure projects come online.

Plains is pursuing its strategy as it prepares for changes in senior management.

The company said Monday that Armstrong will retire as CEO at the end of next year and be replaced by Chiang. Armstrong will remain board chairman until December 2019, at which time he will step down as a director. Harry Pefanis will continue as president and as a director, Plains said.

Armstrong, who has been with Houston-based Plains and its predecessor companies since 1981, said his retirement and the succession plans had been discussed and prepared internally over several years.

"We view succession as a process rather than an event at a point in time," Armstrong said Tuesday.

— Harry Weber, Ashok Dutta

Canadian gas faces stiff competition from US

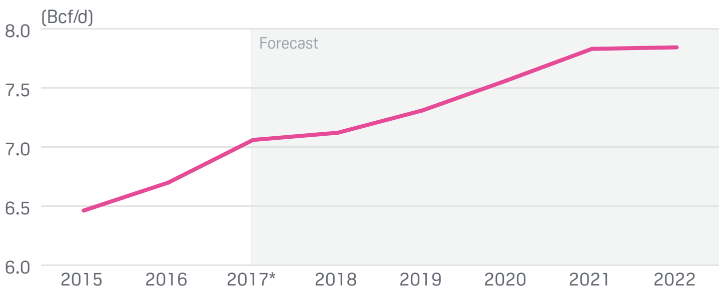
ANALYSIS Despite the potential for Canadian gas production growth over the coming years, particularly in British Columbia's Montney Shale, producers will likely be hard pressed to find a home for those extra molecules.

Canadian producers face multiple constraints, including flat to declining demand domestically as well as pressure from multiple areas of production in the US, according to a panel of experts at the LDC Gas Forum Canada in Toronto on Tuesday.

"British Columbia gas production can grow, but it is currently limited by access to markets," said Ines Piccinino, assistant deputy minister of Canada's Ministry of Energy, Mines and Petroleum Resources. "This is due to gas production in neighboring Alberta, especially the Duvernay, as well as low local demand since about 90% of all electricity in British Columbia is dominated by hydro power."

One of the few sources of demand growth in Canada is in Alberta's oil sands, where Platts Analytics' Bentek Energy does expect growth over the coming years.

WESTERN CANADA'S DEMAND FORECAST



*Demand is forecasted starting 30 Oct
Source: Platts Analytics' Bentek Energy

Finding a home for Canadian gas in the Lower 48 is becomingly increasingly difficult due to ever-growing production from the Marcellus and Utica shales and even due to associated gas production gains in North Dakota's Bakken Shale.

To compound the issue, the Northeast continues to expand takeaway capacity from the Marcellus and Utica through projects such as Nexus and Rover into the Midwest, the primary destination for Canadian exports.

The industry has recognized this as Alliance Pipeline, which delivers gas from British Columbia and Alberta all the way to Chicago, recently postponed an open season on expanding by 500 MMcf/d until 2018 with an earliest in-service date of 2021.

Northeast gas finds potential rival

Also, as US Northeast gas continues to expand transport capacity to both the Midwest and the Gulf Coast, it might soon face its own competition from the prolific Permian Basin of West Texas, according to Benjamin Gage, director of research at NextEra Energy. NextEra Energy is not only one of the world's largest electric utilities, it also has control of oil and gas assets as well as a wide array of renewables, including wind, solar and battery storage.

"The Permian is now experiencing its own de-bottlenecking," Gage said. "Once new pipeline capacity comes online to deliver Permian gas to the Gulf Coast, it would be more competitive than Northeast gas."

Although gas from the Marcellus and Utica is low margin, he referred to Permian gas as "free gas" because producers there are focused on oil and view gas as a mere byproduct.

Potential Canadian LNG struggles to compete with Gulf Coast

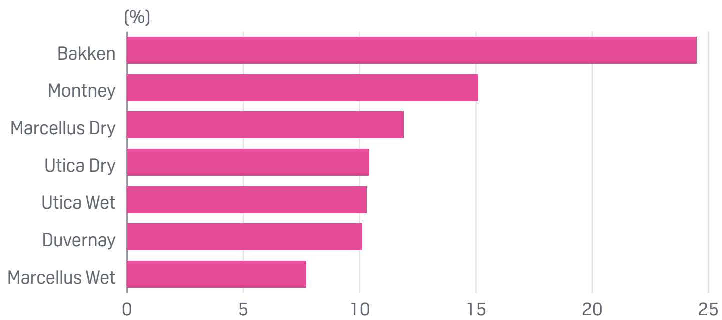
Still, Piccinino believes Canada's natural gas could find an outlet in developing nations around the globe as those nations try to limit carbon dioxide production and provide cleaner air for their citizens.

"Natural gas has a role to play in helping the world transition to a lower-carbon economy," she said. "Canada supports helping supply that demand through LNG exports. However, trying to compete with brownfield LNG export facilities in the US Gulf Coast is very difficult. If we want to export LNG from British Columbia, we have a lot of work to do to make it competitive."

Others on the panel agreed, including Michael Sloan, a managing director with ICF's Energy and Resources Group, who said his firm had completely removed all potential British Columbia LNG exports from all of its forecasts due to its inability to compete with Gulf Coast LNG.

Piccinino also touted superior internal rates of return in the Montney compared to both the Marcellus and Utica shales.

MONTNEY IRRs VERSUS COMPETING PLAYS



Source: Platts Analytics' Bentek Energy

According to Platts Analytics, Montney IRRs stand at 15.1%, well above almost all competing plays. The only one with a higher IRR is the Bakken due to the high volume of oil and NGLs in the production mix.

With multiple issues suppressing Canadian spot gas prices, Gage added, "It's a great time to be an LDC in Canada."

— Brandon Evans

Operations issues affect Ultra's Q3 output

In a quarter marked by third-party gas systems outages and drilling and completion scheduling problems in the Pinedale, Wyoming, area, its biggest operating region, Ultra Petroleum increased its total production to 71.1 Bcf of gas equivalent (773 MMcfe/d), a gain of 6% compared with the previous quarter and about 3% compared with Q3 2016.

As a result of the problems encountered in the quarter, the Houston-based producer fell short of meeting its production guidance, released in May, which called for annual 2017 production to range between 290 Bcfe (795 MMcfe/d) and 300 Bcfe (822 MMcfe/d), compared with production of 281.7 Bcfe (771 MMcfe/d) in 2016.

"Nobody here is happy about coming up light on guidance," Chairman, President and CEO Michael Watford said on the company's earnings conference call Tuesday. However, he said Ultra officials remain confident in the company's ability to grow production by 20% in 2018 while also living within free cash flow.

During the quarter, the operator, which emerged from Chapter 11 bankruptcy in April, produced 66.83 Bcf of natural gas and 705,000 barrels of oil and condensate, versus 65.24 Bcf and 680,000 barrels in the same period of last year. Production came from the Pinedale Anticline region of Wyoming, and two smaller asset areas, the Marcellus Shale of northeastern Pennsylvania and oil-producing assets in Utah.

Operational highlights during the quarter included the drilling and completion of a two-mile horizontal natural gas well on the east flank of the Pinedale play. That well is currently flowing at 21 MMcfe/d, with gas accounting for 90% of the production and oil and condensate 10%, Watford said.

The company saw improved drilling efficiencies in the Pinedale, partially as a result of ramping up eight operated rigs in the play by the end of August.

Ultra focused its drilling on the eastern flank of the field, where the gas stream has a higher content of valuable liquids, "due largely to constraints related to our bankruptcy process," Brad Johnson, senior vice president of operations, said in a statement.

"While [initial production rates] are lower in this part of the field, condensate yields are higher and provide a boost to returns. As vertical drilling moves more to the core of the field over the next two years, we expect IPs to increase back towards our historical averages," Johnson said.

Ultra brought online 45.2 net vertical Pinedale wells

In Q3, Ultra and its partners brought online 63 gross (45.2 net) vertical wells in the Pinedale play with an average IP rate of 6.8 MMcfe/d. The average condensate yield from these wells was 10.5 barrels per MMcf.

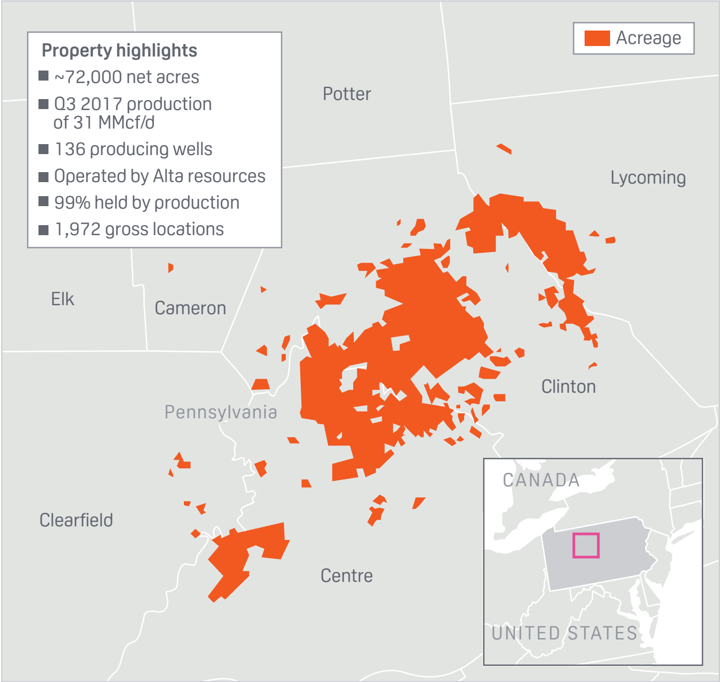
During the quarter, the company produced a total of 67.0 Bcfe in Wyoming, averaging 728 MMcfe/d, comprising 693 MMcf/d of gas and 5,851 b/d of condensate.

Third-party gas gathering system outages, which began on August 30, decreased the company's Q3 volumes. In addition, Ultra reported that its non-operated assets in the northern Pinedale field were affected by drilling and completion schedule interruptions caused by changes in operator ownership.

Ultra estimates the two events in aggregate, would have a total impact of negative 2 Bcf to the company's 2017 production. The company also said that unplanned downtime resulting from third-party ownership transition in its non-operated Pinedale properties would have a negative impact on Ultra's Q4 2017 production, which it estimated at about 75 Bcfe.

Ultra reported Q3 production of 2,324 barrels of oil equivalent per day from its Utah operations, while in the gas-prone Pennsylvania Marcellus play the company produced 2.8 Bcf, averaging 31 MMcf/d.

ULTRA'S MARCELLUS SHALE GAS ASSETS



Source: Ultra Petroleum

Officials said Ultra is continuing to explore options for divesting non-core assets in the Uinta Basin of Utah and in the Marcellus Shale, and said they the company is in the final stages of selecting investment banks to assist with that process.

In its financial results for the quarter, Ultra reported that total revenues increased 9% to $217.6 million as compared with $199.3 million during the third quarter of 2016.

— Jim Magill

LNG's role in Europe downplayed

LNG will continue to struggle to make a significant breakthrough on the European gas market in the coming years — despite an expected global LNG supply glut — because of competition for LNG from more premium markets elsewhere and the abundance of low-cost pipeline gas from Russia and Norway, senior industry officials said this week.

Speaking at a conference in Milan, Italy, on Monday, officials from Germany's RWE, France's Total and Engie, Norway's Statoil and trader Petronas Energy said the wave of LNG that had been forecast first for

2016 and then for this year had failed to materialize.

"This won't change much in the coming years," said Philippe Vedrenne, gas supply director at Engie.

Asian demand for LNG has been much stronger than expected — particularly in China — and Europe has been able to meet its slightly higher demand with gas from Russia and Norway. Fasluddeen Hadi, CEO of Petronas Energy Trading, said. He was doubtful that more LNG would flow to Europe as a result. "Maybe not in the near future," Hadi said.

Hadi said the UK would not be expected to import more LNG this winter given that it still has the cushion gas from the Rough storage facility to be produced. "We won't see much change this year," Hadi said.

"But that could change when Rough is totally out of the equation," he said, referring to when Rough is permanently closed and all the cushion gas produced.

LNG competition welcomed by Statoil

Statoil Senior Vice President Tor Martin Anfinnsen added that there had not been the expected volumes of LNG into Europe — and especially not from the US. But, he said, we do see this "looming volume potential" coming Europe's way.

Anfinnsen said Statoil welcomed increased competition for gas on the European market, not least because it felt it was at a major competitive advantage given its existing pipeline system and its proximity to the European market.

"We can compete with anyone," he said. "When it comes to competition, bring it on."

Andree Stracke, chief commercial officer at RWE Supply & Trading, also made the point that Europe is not the preferred market for LNG from global producers that can get a better price from more premium markets elsewhere — currently markets such as China and Bangladesh.

Stracke said there had been a significant increase in demand for gas in power generation in Germany, and with the uncertainty surrounding nuclear availability in France, there could be incremental gas demand in neighboring countries, too.

"It's not massive, but at least it is additional demand," he said.

Anfinnsen also said he was buoyed by the increased gas demand in Europe, which has come despite relatively mild winters and the fall-out from the reduction of gas output from the giant Groningen field in the Netherlands and the closure of the UK Rough gas storage facility.

Contract length still useful tool

Stracke, meanwhile, said any European gas user needed to make the most of the continued liquid gas markets in Europe to optimize its portfolio. He said that LNG term contracts were still useful tools — up to 10-12 years. "Beyond that it would not be possible, for us at least," he said.

But, he stressed, 10-year LNG supply deals were commercially realistic and RWE was "working on" developing the 10-year contract model — a hybrid of medium- and long-term arrangements.

"We feel comfortable with a 10-year horizon," Stracke said, adding, however, that the main stumbling block remained price indexation and how to optimize portfolios. "It is very hard to buy properly indexed LNG," he said, referring to a price indexed to a European hub such as TTF, NBP or NCG.

He rejected LNG indexed to oil or the US Henry Hub price. He said, for example, that US LNG sellers are reluctant to index their supply contracts to European hubs.

Jean-Pierre Mateille, vice president of trading at Total Gas & Power, said that the benchmark for LNG deliveries into Europe should be the UK NBP or Dutch TTF hubs, and that there was no need to use oil as a benchmark for LNG pricing.

For buyers, liquid markets are also needed to be able to risk manage their portfolios for the coming five years, Stracke said.

He also expressed concern at the impact of falling European gas production — from Groningen in the Netherlands and in Germany — and how that could affect the liquidity of northwest European hubs.

— *Stuart Elliott*

Cimarex downspacing helps boost gas output

Cimarex Energy reported Tuesday that a well downspacing project it conducted in the Woodford Shale play in southeastern Oklahoma helped boost the producer's natural gas production by about 15% in the third quarter of 2017, compared with the year-ago period.

The Denver-based producer reported that in the third quarter of 2017, it produced 515.9 MMcf (5.6 MMcf/d) of gas, compared with 446.7 MMcf (4.9 MMcf/d) in the same period of 2016. The company reported that its total production increased to 1.14 Bcf (12.4 MMcf) of gas equivalent per day in Q3 2017, a bump of about 20% compared with 946.6 MMcfe (10.3 MMcfe/d) in the year-earlier quarter.

Total company's production for the quarter came in slightly above the high end of the forecast it issued in February, which estimated that 2017 production would average 1.06 Bcfe to 1.11 Bcfe. The producer's Q3 oil production of 56,687 b/d was in line with the previous estimate.

Cimarex, which operates chiefly in the Midcontinent and Permian Basin regions, reported that during the third quarter, it began producing from eight Woodford Shale wells drilled as part of an increased-density pilot. The project tested both 16- and 20-well spacing per section, and preliminary results show no significant difference in well performance between the two spacing tests.

This indicates that Woodford wells can be drilled closer together in future infill projects than they have been historically, the company said.

The company's total production from the Midcontinent region averaged 512.7 MMcfe/d in Q3 2017, up 20% versus the same period of 2016. Sequentially, crude oil volumes were up 8% the company said.

During the quarter, Cimarex completed 48 gross (14 net) Midcontinent wells. At the end of the quarter, 89 gross (16 net) wells were waiting on completion. Cimarex said it currently is operating five rigs in the region.

Also in the Midcontinent, Cimarex announced drilling results from several Woodford Shale wells in its Lone Rock area. The wells, which have been brought on production over the past several quarters, show some of the best returns to date in the Woodford Shale, the company said.

Company completed seven Lone Rock wells in 2017

Cimarex, which has about 16,000 net acres in the Lone Rock area, completed seven wells in 2017, including the Hines Federal #1H, the company's best well to date in the area. The Hines had 30-day average peak production of 15.2 MMcfe/d, comprising 40% oil, 23% natural gas liquids and 37% gas.

In the oil-rich Permian Basin, production averaged 628.2 MMcfe/d in the third quarter, a 21% increase from Q3 2016. Oil volumes, which represented 42% of the region's total equivalent production, averaged 43,735 b/d.

Cimarex said it completed 29 gross (16 net) Permian wells in the quarter. A total of 42 gross (16 net) wells were waiting on completion as of September 30. Cimarex currently operates nine rigs in the Permian.

In its financial results for the quarter, Cimarex reported net income of $91.4 million, or 96 cents per share, compared to a net loss of $10.7 million, or 12 cents per share, in the same period a year ago.

— Jim Magill

North Carolina queries Atlantic Coast

The North Carolina Department of Environmental Quality wants more information from developers of the $5.1 billion Atlantic Coast natural gas pipeline before it issues a required permit related to erosion and sedimentation for the 1.5-Bcf/d project.

A Monday request to Dominion Energy, lead developer of Atlantic Coast, extended the review process for a state erosion and sedimentation control permit, part of the Sedimentation Pollution Control Act. The department asked Dominion for more information about the project, including impacts to streams, wetlands, construction activities and erosion and sedimentation measures in Northampton and Cumberland counties.

The request came in the form of a letter of disapproval. The department had sent a similar letter about the permit in late September.

"These requests are typical for projects of this size and complexity," Dominion spokesman Aaron Ruby said. The department issued similar letters in September for more information about the 42-inch-diameter pipeline project. "We're confident we can provide the additional information in short order."

Ruby said the project, a joint venture of Dominion, Duke Energy, Southern Company Gas and Piedmont Natural Gas, is still expected to secure all federal and state permits necessary for pre-construction activities by the end of 2017. "Our plan is to begin tree felling by the end of the year," Ruby said.

The most recent correspondence from the department is separate from previous requests for additional information on the project's Clean Water Act Section 401 permit application. Ruby said project developers anticipate a decision from the department on the water quality certification first and then one on the erosion and sedimentation control permit.

PROPOSED ROUTE OF ATLANTIC COAST PIPELINE

Source: Dominion Resources

Atlantic Coast will run about 600 miles through West Virginia, Virginia and North Carolina. The project, which will provide mid-Atlantic and Southeast markets access to Appalachian gas supplies, has a targeted in-service date during the second half of 2019. The US Federal Energy Regulatory Commission issued an authorizing certificate order for the project in October (CP15-554).

— Ximena Mosqueda-Fernandez, S&P Global Market Intelligence

Higher prices approved for Vaca Muerta project

Argentina's energy ministry has authorized higher prices for the biggest natural gas project in Vaca Muerta, a $2.3 billion development by Buenos Aires-based Tecpetrol, the local government said.

This should speed up drilling on Fortin de Piedra in the play to ramp up production to 14 million cu m/d, Neuquén Governor Omar Gutierrez said in a statement late Monday. Vaca Muerta is in the Neuquén province.

Tecpetrol, the fifth-biggest oil producer in the country, launched the project in March, buoyed by the possibility of getting the pricing incentives.

With the approval of the pricing incentives for its 100%-owned project, the company can now sell the output at $7.50/MMBtu through 2018 and gradually less to $6/MMBtu in 2021 before market pricing takes effect in 2022, Gutierrez said.

Fortin de Piedra "has entered the mass-development stage," he said.

Gutierrez added that the project calls for investing the $2.3 billion through 2019 by drilling 150 wells and building related infrastructure to handle the output.

The block is producing 715,000 cu m/d, according to the latest data of the Argentina Oil and Gas Institute, a trade group.

In September, Tecpetrol CEO Carlos Ormachea said production was on track to reach 1.5 million cu m/d in October and then 6.5 million cu m/d in the first quarter of 2018. With a sixth drilling rig to be deployed in March 2018, the target is to surpass 10 million cu m/d in 2019, he added.

The 10 million cu m/d would be equivalent to 8.2% of the country's current gas production of 122 million cu m/d, which the Energy Ministry has forecast to reach 185 million cu m/d in 2025, led by Vaca Muerta and offshore developments.

Ormachea has said that Fortin de Piedra's production capacity is similar to other blocks in the gas window of Vaca Muerta, a sign of the output potential of one of the world's largest shale plays.

Argentina's government of President Mauricio Macri is offering the higher gas prices and other incentives to encourage development of Vaca Muerta, helping to close a 30% gas-supply deficit. Macri has said he wants to reduce gas imports, now at 30 million cu m/d, and start exporting gas by 2018-19, first to neighboring Chile. A goal is to reduce LNG imports to the July-August winter months by 2020 or 2021, according to his administration.

— *Jeff Mower, Charles Newbery*

Tierra del Fuego extends offshore leases

Tierra del Fuego, the southernmost province of Argentina, has granted a 10-year extension to six offshore natural gas blocks under development by France's Total, Germany's Wintershall and BP-controlled Pan American Energy, the provincial government said.

In exchange for the extension, the companies agreed to invest $550 million over the next decade in the blocks, which make up the Cuenca Marina Austral 1 (CMA1), the government said in a statement late Monday.

The focus will be on ramping up gas production, it added.

CMA1 produces about 22 million cu m/d, making it the largest source of gas in Argentina, according to data from the Argentina Oil and Gas Institute, or IAPG, an industry group.

Tierra del Fuego, the only offshore region in production in Argentina, is a traditional source of gas and has seen an increase in investment over the past few years along with Vaca Muerta, a shale play in the province of Neuquen with huge gas and oil production potential.

Argentina's conservative government of President Mauricio Macri has been offering incentives, including higher wellhead prices to encourage gas exploration and production, in a bid to close a 30% supply deficit. Macri wants to reduce gas imports, now averaging 30 million cu m/d, and return to exporting supplies by 2018-19 by ramping up the development of shale and offshore gas resources.

Fenix project similar to Vega Pleyade

Total, Wintershall and Pan American Energy also plan to invest $1 billion in developing a block called Fenix, which is near CMA1, the province said in the statement.

In September, Jean-Marc Hosanski, head of Total's operations in Argentina, said the target is to bring Fenix into production in 2020.

Fenix is a project of similar characteristics to Vega Pleyade, another offshore field it operates in the area. Vega Pleyade is producing around 10 million cu m/d. This means that, with production from Fenix, it will help maintain output from the region off the coast of Tierra del Fuego at 22 million cu m/d, or "increase it a little bit more," Hosanski said at the time.

That is equivalent to 18% of the country's 122 million cu m/d of gas production, which the national Energy Ministry has forecast should reach 185 million cu m/d by 2025, led by offshore and shale developments.

Total produces 34 million cu m/d of gas in Argentina, making it the second-biggest producer after the country's state-run YPF, according to IAPG data.

— *Charles Newbery*

PIPELINE MAINTENANCE

Start date	End date	Pipeline	Description
13-Nov	15-Nov	Creole Trail	Creole Trail announces planned maintenance at the Gillis Compressor Station that will limit capacity to 1.375 Bcf/d from November 13 through November 15

NATURAL GAS FUTURES

NYMEX December gas up 1.8 cents

After seeing a sharp rise in the opening session of the week, the market took a breather Tuesday, with the NYMEX December contract settling only slightly higher.

The front-month contract settled at $3.152/MMBtu, up 1.8 cents, after trading between $3.088/MMBtu and $3.176/MMBtu. On Monday, the contract jumped some 15 cents.

"A lot of times when you have a big jump one day that happens," said Phil Flynn, senior market analyst with Price Futures Group. "This is 'Turnaround Tuesday' and the market is taking a pause. People are just locking in some prices while they wait and see what happens."

Looming over the market for the next few days, Flynn said, will be the upcoming weekly storage report from the US Energy Information Administration. That report, which will be released Thursday, will detail injections for the week ending November 3. The analyst said the market is expecting a low figure.

"This injection looks to be one of the lowest in the last 10 years," Flynn said.

The analyst said storage numbers are lagging despite US dry gas production hitting a record high of 76.4 Bcf/d Monday. For the past week, production has averaged about 75.7 Bcf/d.

"It's a combination of strong demand and production just not being able to keep up with exports."

According to Platts Analytics' Bentek Energy, US demand stood at 84.8 Bcf/d Tuesday, up 4.9 Bcf/d from Monday. Over the last seven days, demand averaged about 77.2 Bcf/d.

November demand is up sharply from that seen in 2016. This month, demand has averaged 77.1 Bcf/d. A year ago, it was 69.7 Bcf/d.

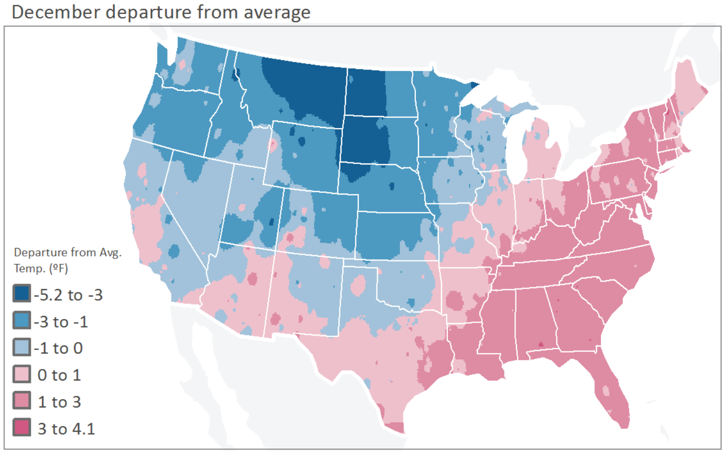
Exports to Mexico remain robust, averaging about 4.2 Bcf/d over the past week. Platts Analytics sees southbound shipments checking in at 4.3 Bcf/d over the next 14 days.

Flynn said two factors could lead to a bullish market moving forward.

"We're really just waiting to see what the weather does," he said. "We seem to be turning a corner [and heading into winter]. There are some pipelines that are on hold or delayed, and there is some concern that the gas coming out of the ground will not have a way to get to the market."

MONTH-AHEAD TEMPERATURE FORECAST MAP

December departure from average



Source: Platts, Custom Weather

NYMEX HENRY HUB GAS FUTURES CONTRACT, NOV 7

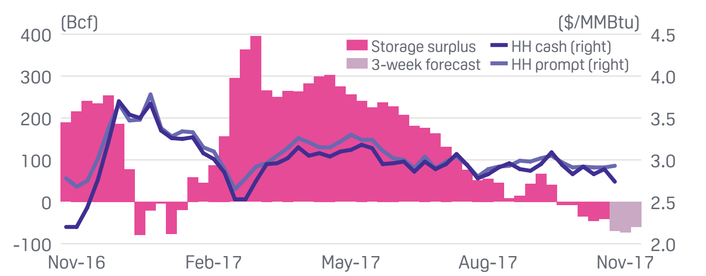
	Settlement	High	Low	+/-	Volume
Dec 2017	3.152	3.176	3.088	0.018	97376
Jan 2018	3.251	3.272	3.188	0.019	21067
Feb 2018	3.252	3.272	3.191	0.021	5811
Mar 2018	3.212	3.230	3.154	0.023	4057
Apr 2018	2.965	2.971	2.928	0.012	5665
May 2018	2.938	2.943	2.906	0.010	1245
Jun 2018	2.965	2.968	2.936	0.010	335
Jul 2018	2.995	2.999	2.969	0.009	339
Aug 2018	2.998	3.000	2.970	0.008	448
Sep 2018	2.981	2.985	2.955	0.008	194
Oct 2018	3.003	3.006	2.975	0.008	1052
Nov 2018	3.055	3.055	3.028	0.008	269
Dec 2018	3.190	3.192	3.168	0.008	137
Jan 2019	3.269	3.269	3.248	0.006	454
Feb 2019	3.234	3.235	3.216	0.004	262
Mar 2019	3.153	3.154	3.137	-0.002	165
Apr 2019	2.791	2.795	2.774	-0.002	208
May 2019	2.741	2.741	2.732	-0.007	15
Jun 2019	2.762	2.762	2.753	-0.008	19
Jul 2019	2.785	2.785	2.776	-0.008	8
Aug 2019	2.785	2.785	2.785	-0.008	0
Sep 2019	2.769	2.769	2.764	-0.007	4
Oct 2019	2.791	2.792	2.783	-0.008	0
Nov 2019	2.851	2.851	2.851	-0.011	0
Dec 2019	3.006	3.006	3.006	-0.013	0
Jan 2020	3.107	3.110	3.107	-0.013	0
Feb 2020	3.083	3.083	3.083	-0.012	0
Mar 2020	3.032	3.032	3.032	-0.012	0
Apr 2020	2.726	2.726	2.726	-0.008	0
May 2020	2.701	2.701	2.701	-0.007	0
Jun 2020	2.725	2.725	2.725	-0.007	0
Jul 2020	2.752	2.752	2.752	-0.007	0
Aug 2020	2.767	2.767	2.767	-0.007	0
Sep 2020	2.767	2.767	2.767	-0.007	0
Oct 2020	2.793	2.701	2.701	-0.007	0
Nov 2020	2.861	2.861	2.861	-0.007	0

Contract data for Monday
Volume of contracts traded: 486,077
Front-months open interest:
Dec, 273,456; Jan, 237,028; Feb, 89.122
Total open interest: 1,369,758
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 cash, balmo blow past Nov. indices

With the most recent forecasts predicting notably lower-than-average temperatures across the US Northeast through the end of the week, natural gas cash prices across the region continued to rise Tuesday, blowing past monthly November indices and taking select locations to their highest point in weeks.

Demand across the Northeast is expected to remain above the 20 Bcf/d mark for the second day in a row on Wednesday, the first time it has broken the mark since late March, Platts Analytics' Bentek Energy data shows.

On these expectations, Tennessee Gas Pipeline Zone 6 delivered gained over 80 cents to trade at $3.315/MMBtu, its highest level in six weeks and over 60 cents greater than the location's November index.

The demand-side build has overwhelmingly been weather-driven, with temperatures across the region expected to fall as much as 15 degrees below historical averages by Friday. This will in turn drive a surge in residential/commercial heating demand and buoy total demand well above the 20 Bcf/d mark through the coming week, Platts Analytics projects.

If actualized, these projections will have demand averaging 21.2 Bcf/d through November 15, over 5 Bcf/d greater than the first six days of the month.

These expectations are reflected in balance of the month trading, with Algonquin balmo trading as much as 52 cents higher Tuesday, hitting as high as 3.625/MMBtu, over 60 cents/MMBtu greater than cash markets and nearly $1/MMBtu greater than Algonquin November index.

The bullish movement comes despite Northeast production levels continuing to set all-time highs, rising to a preliminary estimate of 26.8 Bcf/d Tuesday, nearly 0.2 Bcf/d greater than Monday's previous all-time high, Platts Analytics data also showed.

With the demand build well outpacing production growth, Appalachian region cash markets also saw large bullish moves, with Dominion South Point gaining over 60 cents to trade at $2.26/MMBtu, nearly 75 cents/MMBtu greater than the DSP November index.

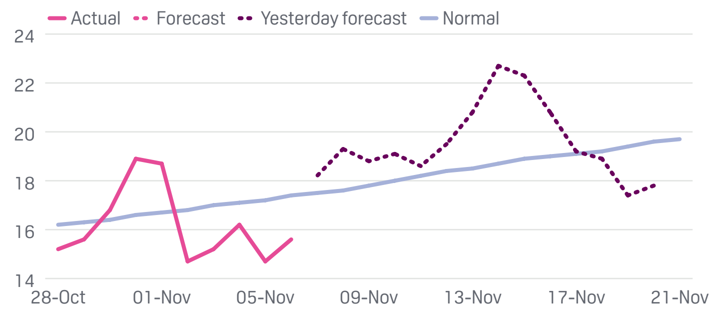
Similar to its market area peers, DSP balmo trading also saw notable day–on–day gains, tacking on nearly 20 cents to trade at around $2.20/MMBtu.

NORTHEAST SPOT AND FORWARD BASIS ($/MMBtu)

	Spot basis						Prompt forward basis		
	07-Nov	06-Nov	Chg	MTD Avg.	MTD last year	Chg	07-Nov	06-Nov	Chg
Henry Hub	3.08	3.03	0.05	2.83	2.36	+0.47	3.15	3.13	0.02
Northeast region									
Algonquin CG	-0.07	-0.79	0.72	-1.08	-0.36	-0.72	2.71	2.54	0.17
Iroquois Zn2	0.26	0.14	0.12	-0.45	-0.19	-0.26	0.94	0.94	0.00
Tenn Zn6 Dlvd	0.24	-0.52	0.76	-0.92	-0.32	-0.60	2.74	2.57	0.17
Transco Zn 6 NY	0.01	—	0.01	-0.65	-0.69	+0.05	1.20	1.10	0.10
Transco Zn5 Dlvd	0.05	0.08	-0.03	0.00	-0.06	+0.06	0.94	0.88	0.06
Transco Zn6 Non-NY	0.04	0.02	0.03	-0.61	-0.64	+0.03	0.82	0.73	0.09
TX Eastern M-3	-0.57	-1.05	0.48	-1.36	-0.76	-0.60	0.22	0.22	0.00
Appalachia									
Col Gas Appal	-0.14	-0.16	0.03	-0.16	-0.22	+0.05	-0.20	-0.21	0.01
Dominion N Pt	-0.81	-1.42	0.62	-1.58	-0.88	-0.70	-0.70	-0.68	-0.02
Dominion S Pt	-0.82	-1.39	0.57	-1.57	-0.89	-0.68	-0.61	-0.60	-0.01
Lebanon Hub	-0.09	-0.06	-0.04	-0.06	—	—	-0.05	-0.06	0.01
Millennium East Receipts	-0.87	-1.43	0.56	-1.59	-0.85	-0.74	-0.84	-0.83	-0.01
Tenn Zn4-200 Leg	-0.38	-0.61	0.24	-1.15	-0.68	-0.47	-0.47	-0.46	-0.01
Tennessee zone 4-300 leg	-0.97	-1.54	0.57	-1.69	-0.90	-0.79	-0.89	-0.88	-0.01
Texas Eastern M-2 receipts	-0.80	-1.33	0.53	-1.55	-0.90	-0.65	-0.59	-0.57	-0.02
Transco Leidy Line receipts	-0.90	-1.48	0.59	-1.64	-0.92	-0.72	-0.83	-0.82	-0.01
Other locations									
Dracut MA	—	—	—	—	—	—	2.52	2.36	0.15
Iroquois Receipts	0.25	0.09	0.16	-0.26	-0.13	-0.13	0.69	0.69	0.00
Niagara	-0.25	-1.34	1.09	-1.13	-0.76	-0.37	-0.41	-0.43	0.02

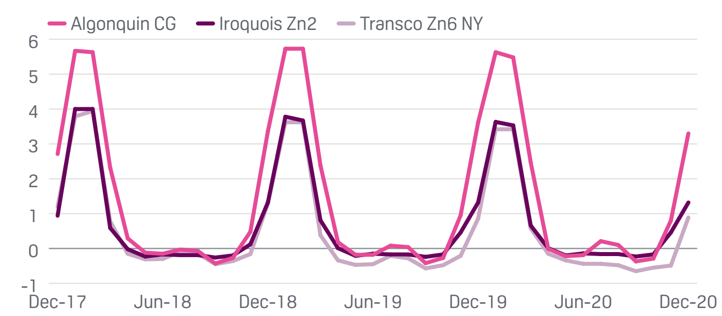
Source: Platts M2M data

NORTHEAST DEMAND FORECAST (Bcf/d)



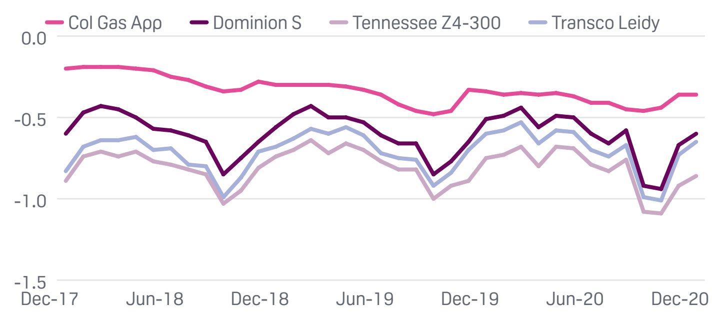
Source: Platts

NORTHEAST FORWARD BASIS ($/MMBtu)



Source: Platts

APPALACHIA FORWARD BASIS ($/MMBtu)



Source: Platts

SOUTHEAST GAS MARKETS

Elevated demand bolsters cash market

Following Monday's upward cash price swing, with some of the largest day-on-day gains in 2017, the Southeast spot market climbed higher at a lower clip Tuesday as elevated demand levels are expected to persist.

Stubbornly above-average temperatures over the Southeast have pushed power burn levels to an average of nearly 7.7 Bcf/d since Sunday, about 500 MMcf/d above the previous two-week average, according to Platts Analytics' Bentek Energy data.

One of the central culprits driving power burn levels high is found in National Weather Service data, which shows New Orleans temperatures roaring into November averaging nearly 8.5 degrees above the seasonal norm, while Houston-area has experienced average temperatures nearing 14 degrees above the norm throughout November.

Henry Hub increased nearly 5 cents to $3.075/MMBtu, the highest level since September 22. Houston Ship Channel edged 6 cents higher to $3/MMBtu.

On Tuesday, overall total demand is expected to crest at 18.7 Bcf/d Tuesday, the highest level in the first week of November. Levels are projected to persist slightly below this level into Wednesday, even eyeing a more pronounced upward bounce over the next two weeks as residential/commercial levels return.

Both Henry Hub and Houston Ship Channel balance of month contract traded up 3.5 cents/MMBtu each to $3.04/MMBtu and $3/MMBtu, respectively, largely in line with current spot prices, signaling the bullish sentiment in the market could persist throughout the month.

Additional upward pressure on spot prices comes as outflows to the Midcontinent market area from the Southeast continue to trend higher, hitting 542 MMcf/d, the highest level since the end of August, when Hurricane Harvey was wreaking havoc over the Southeast market.

After trading at a cash basis discount to Henry Hub the majority of 2017, Chicago city-gates cash basis flipped to positive towards the end of October, averaging nearly plus 7 cents since October 24.

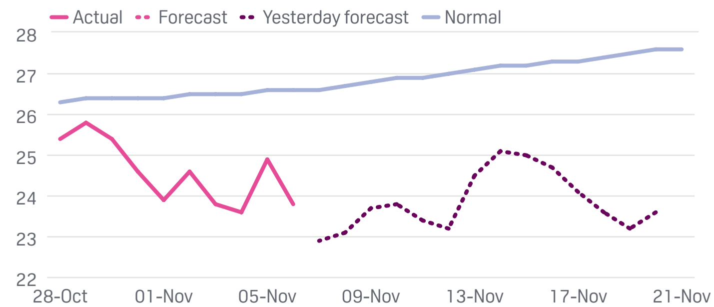
This differential was dramatically cut from plus 9 cents to plus 1.5 cents following Henry Hub's surge Monday, even coming to parity during Tuesday's session, signaling a possible ceiling could be coming to outflows to the Midcontinent as other supply basins maintain wider margins with Chicago CG than Henry Hub.

SOUTHEAST SPOT AND FORWARD BASIS ($/MMBtu)

	Spot basis						Prompt forward basis		
	07-Nov	06-Nov	Chg	MTD Avg.	MTD last year	Chg	07-Nov	06-Nov	Chg
Henry Hub	3.08	3.03	0.05	2.83	2.36	+0.47	3.15	3.13	0.02
Southeast									
ANR LA	-0.06	-0.05	-0.01	-0.02	-0.12	+0.10	-0.13	-0.13	0.00
Col Gulf LA	-0.07	-0.08	0.01	-0.04	-0.11	+0.08	-0.10	-0.10	0.00
Col Gulf-Mainline	-0.09	-0.10	0.02	-0.08	-0.14	+0.07	-0.14	-0.14	0.00
FL Gas Zn1	-0.01	-0.02	0.01	0.00	-0.08	+0.08	-0.05	-0.05	0.00
FL Gas Zn2	-0.03	-0.04	0.01	-0.03	-0.08	+0.05	-0.02	-0.03	0.00
FL Gas Zn3	0.02	0.04	-0.02	0.04	-0.05	+0.10	-0.02	-0.03	0.01
Florida CG	0.20	0.22	-0.02	0.19	0.32	-0.13	0.27	0.27	0.01
SoNat LA	-0.06	-0.05	-0.02	-0.02	-0.11	+0.08	-0.10	-0.10	0.00
Tenn LA 500 Leg	-0.08	-0.07	-0.02	-0.02	-0.11	+0.09	-0.10	-0.10	0.00
Tenn LA 800 Leg	-0.09	-0.07	-0.02	-0.04	-0.11	+0.08	-0.08	-0.08	0.00
TETCO-M1	-0.10	-0.11	0.01	-0.09	-0.26	+0.17	-0.10	-0.10	0.00
Texas Gas Zn SL	-0.08	-0.08	0.01	-0.06	-0.16	+0.10	-0.14	-0.14	0.00
Texas Gas Zn1	-0.09	-0.08	-0.01	-0.06	-0.14	+0.08	-0.16	-0.17	0.00
Transco Zn2	-0.05	-0.03	-0.02	0.00	-0.12	+0.12	-0.10	-0.10	-0.01
Transco Zn3	-0.04	-0.03	-0.02	-0.01	-0.09	+0.08	-0.04	-0.04	0.00
Transco Zn4	-0.03	-0.01	-0.02	-0.01	-0.08	+0.07	-0.03	-0.03	0.00
Trunkline E LA	-0.12	-0.11	-0.01	-0.07	-0.11	+0.03	-0.09	-0.09	0.00
Trunkline WLA	—	—	—	—	-0.24	—	-0.05	-0.05	0.00
Tx Eastern E LA	-0.09	-0.09	-0.01	-0.03	-0.14	+0.11	-0.10	-0.10	0.00
TX Eastern W LA	-0.08	-0.10	0.02	-0.02	-0.10	+0.08	-0.09	-0.09	0.00
East & South Texas									
Agua Dulce	—	—	—	—	—	—	-0.08	-0.08	0.00
Carthage Hub	-0.12	-0.10	-0.02	-0.07	-0.16	+0.09	-0.09	-0.09	0.00
Houston Ship Channel	-0.08	-0.09	0.02	0.00	0.06	-0.06	-0.08	-0.08	0.00
Katy	-0.08	-0.11	0.04	-0.01	0.02	-0.03	-0.08	-0.08	0.00
NGPL S TX	—	—	—	-0.07	-0.15	+0.08	-0.11	-0.11	0.00
NGPL Texok Zn	-0.12	-0.10	-0.02	-0.07	-0.13	+0.06	-0.14	-0.14	-0.01
Tenn Zn0	-0.16	-0.21	0.06	-0.09	-0.12	+0.03	-0.14	-0.13	-0.01
Transco Zn1	-0.04	-0.01	-0.03	0.00	-0.08	+0.08	-0.10	-0.10	0.01
TX Eastern E Tx	-0.12	-0.11	-0.01	-0.06	-0.15	+0.09	-0.13	-0.13	0.00
TX Eastern S TX	-0.08	-0.09	0.01	0.00	-0.07	+0.07	-0.11	-0.11	0.00

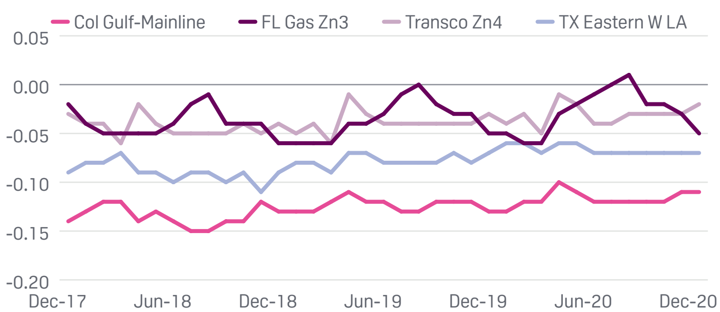
Source: Platts M2M data

SOUTHEAST & TEXAS DEMAND FORECAST (Bcf/d)



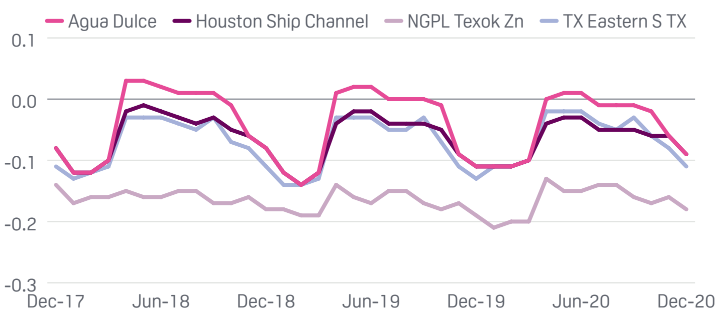
Source: Platts

SOUTHEAST FORWARD BASIS ($/MMBtu)



Source: Platts

EAST AND SOUTH TEXAS FORWARD BASIS ($/MMBtu)



Source: Platts

CENTRAL GAS MARKETS

Midcon prices continue higher as temps fall

Spot gas prices around the Midcontinent continued to move higher Tuesday as lingering unseasonable cold weather kept demand elevated.

Around the Upper Midwest, prices at the Chicago city-gates were up about 3 cents to trade around $3.07/MMBtu.

Prices are likely to face additional upward pressure Wednesday and Thursday and temperatures around the Chicago market are forecast to fall into the 20s. Forecasts from Platts Analytics' Bentek Energy showed total Midcontinent demand climbing to nearly 19.2 Bcf/d on Wednesday, up almost 700 MMcf/d from Tuesday.

Demand is expected to continue rising through midweek, eventually reaching 22.2 Bcf/d on Friday, its highest level of the week and the highest demand has reached since mid-March.

Looking further out, however, the latest eight- to 14-day outlook from the National Weather Service turned increasingly bearish as it now called for a greater likelihood for above-average temperatures across the Midcontinent.

The bearish weather outlook was likely felt in the forward market as Chicago city-gates December basis fell by a half-cent to plus 7 cents/MMBtu. Further out, Chicago January basis moved higher, adding just over a cent to plus 14 cents/MMBtu.

Even with rising demand this week inflows from the Rockies have continued to decline. Platts Analytics data showed inflows from the Rockies fell to just under 2.7 Bcf/d on Tuesday, down more around 420 MMcf/d from Monday. At the same time, inflows from Canada and the Southeast have picked up to more than make up the difference.

Toward upstream Midcontinent markets, spot prices had mixed movements as Panhandle Eastern Pipeline's pricing point added 2 cents to average $2.72/MMBtu. Meantime, NGPL's Midcontinent pricing pool was down about 3 cents to trade around $2.76/MMBtu.

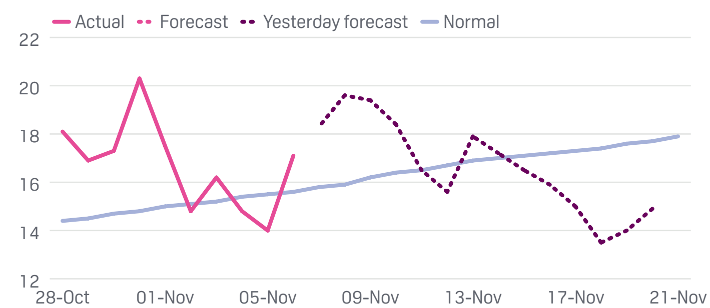
Midcontinent production was shown to have contracted for the second straight day Tuesday as Platts Analytics modeled production data showed volumes fell by 170 MMcf to around 7.9 Bcf/d.

CENTRAL SPOT AND FORWARD BASIS ($/MMBtu)

	Spot basis						Prompt forward basis		
	07-Nov	06-Nov	Chg	MTD Avg.	MTD last year	Chg	07-Nov	06-Nov	Chg
Henry Hub	3.08	3.03	0.05	2.83	2.36	+0.47	3.15	3.13	0.02
Midwest/East Canada									
ANR ML 7	0.02	0.02	0.00	0.02	-0.13	+0.15	0.09	0.09	0.00
Chicago CG	0.00	0.02	—	0.04	-0.13	+0.18	0.08	0.08	0.00
Consumers Energy CG	-0.03	—	-0.03	0.04	-0.12	+0.16	-0.02	-0.02	0.00
Dawn Ontario	0.13	0.09	0.04	0.17	-0.11	+0.28	0.12	0.10	0.01
Mich Con CG	-0.02	-0.01	-0.02	0.05	-0.13	+0.18	0.01	0.01	0.00
Northern Ventura	-0.04	-0.02	-0.02	0.01	-0.18	+0.19	0.03	0.03	0.01
Viking-Emerson	-0.17	-0.12	-0.06	-0.04	-0.27	+0.23	-0.15	-0.15	0.00
Midcontinent									
ANR OK	-0.27	-0.19	-0.08	-0.18	-0.28	+0.10	-0.32	-0.31	-0.01
Enable Gas East	-0.24	-0.27	0.03	-0.27	-0.16	-0.10	-0.22	-0.22	0.00
NGPL Midcontinent	-0.31	-0.24	-0.07	-0.20	-0.26	+0.06	-0.28	-0.26	-0.02
Northern NG Demarc	-0.04	-0.01	-0.03	0.01	-0.18	+0.19	-0.02	-0.03	0.01
Oneok OK	-0.38	-0.29	-0.09	-0.30	-0.24	-0.06	-0.48	-0.47	-0.01
Panhandle TX-OK	-0.35	-0.33	-0.03	-0.28	-0.30	+0.02	-0.36	-0.35	-0.01
Southern Star TxOkKs	-0.28	-0.25	-0.03	-0.23	-0.33	+0.10	-0.37	-0.35	-0.02

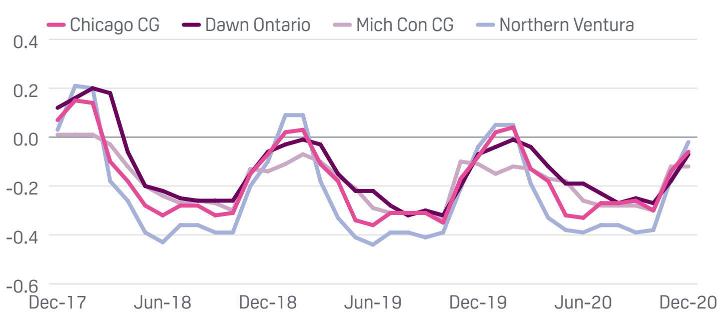
Source: Platts M2M data

MIDWEST & MIDCONTINENT DEMAND FORECAST (Bcf/d)



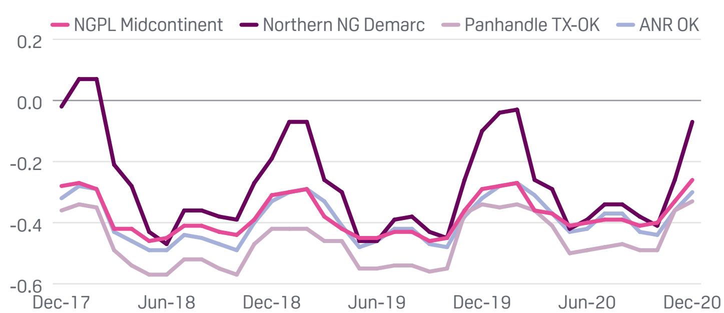
Source: Platts

MIDWEST FORWARD BASIS ($/MMBtu)



Source: Platts

MIDCONTINENT FORWARD BASIS ($/MMBtu)



Source: Platts

WEST GAS MARKETS

West prices down as demand continues to slip

Spot natural gas prices across the western US and Canada were mostly in decline Tuesday as mild weather across the region hampered demand.

In western Canada, spot prices at WestCoast Energy's Station 2 pricing point dropped about 32 Canadian cents to average 87 Canadian cents/Gj.

The fall in Station 2 prices coincides with an uptick in production volumes making their way on to the system. Data from Platts Analytics' Bentek Energy showed total West Coast production receipts have averaged around 1.7 Bcf/d over the last two days. Production receipts had fallen to as low as 11.4 Bcf/d at the start of the month.

At the US-Canadian border cash prices also fell at the Sumas pricing point, which was down just over 12 cents to trade around $2.91/MMBtu.

Spot prices also slipped across upstream Rockies markets as Colorado Interstate Gas' Rockies point slipped almost 5 cents to average $2.85/MMBtu.

Rockies outflows to the Midcontinent were down sharply Tuesday, falling just over 300 MMcf to around 2.1 Bcf/d. In the preceding 30 days, outflows have averaged 2.6 Bcf/d and reached as high as 3.07 Bcf/d, according to data from Platts Analytics. The decline in outflows to the Midcontinent coincide with an uptick in demand from downstream markets in the Northwest, which compete for Rockies supply. Northwest demand is expected to decline Wednesday, however, likely contributing to the downward pressure on Rockies spot prices.

Toward markets in the Southwest cash prices also slipped as the Kern River delivered pricing point shed 5 cents to average $3.06/MMBtu.

Data from Platts Analytics showed total Western demand falling to 10.5 Bcf/d on Wednesday, down more than 200 MMcf from Tuesday. Additional spot price weakness is likely later in the week as regional demand is expected to dip to as low 9.8 Bcf/d by the weekend.

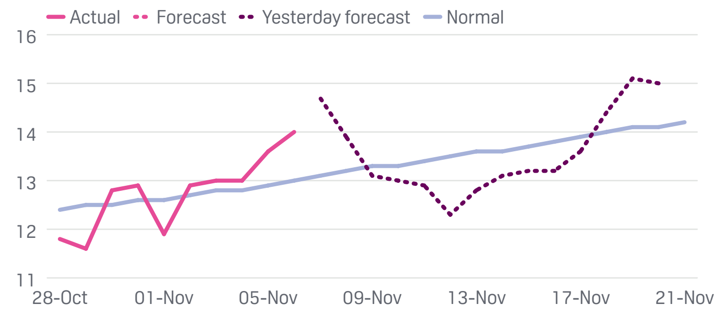
Additional downward pressure came as the latest reactor status report from the US Nuclear Regulatory Commission showed Arizona Public Service's 1,311-MW Palo Verde-1 nuclear generating unit was operating at 11% capacity, up from 2% on Monday. The unit had been shut in early October for refueling.

WEST SPOT AND FORWARD BASIS ($/MMBtu)

	Spot basis						Prompt forward basis		
	07-Nov	06-Nov	Chg	MTD Avg.	MTD last year	Chg	07-Nov	06-Nov	Chg
Henry Hub	3.08	3.03	0.05	2.83	2.36	+0.47	3.15	—	—
Northwest									
GTN Kingsgate	-0.35	-0.22	-0.13	-0.24	-0.39	+0.15	-0.33	-0.32	-0.01
Northwest Sumas	-0.16	0.01	-0.17	-0.05	-0.51	+0.46	0.24	0.26	-0.02
Northwest Stanfield	-0.20	-0.05	-0.16	-0.10	-0.36	+0.26	-0.17	-0.17	-0.01
Rockies									
Cheyenne Hub	-0.19	-0.14	-0.05	-0.13	-0.35	+0.22	-0.26	-0.25	-0.01
CIG Rockies	-0.22	-0.13	-0.09	-0.17	-0.38	+0.21	-0.26	-0.25	-0.01
Kern River Opal	-0.16	-0.06	-0.10	-0.11	-0.35	+0.24	-0.18	-0.16	-0.01
NW WY Pool	-0.18	-0.06	-0.12	-0.11	-0.36	+0.25	-0.18	-0.16	-0.01
Questar Rky	-0.20	-0.13	-0.07	-0.16	-0.34	+0.18	-0.18	-0.17	-0.01
Southwest									
El Paso Permian	-0.34	-0.32	-0.02	-0.29	-0.37	+0.08	-0.38	-0.36	-0.01
El Paso San Juan	-0.32	-0.31	-0.01	-0.26	-0.35	+0.09	-0.30	-0.29	-0.01
Kern River Dlvd	-0.02	0.08	-0.10	0.02	-0.25	+0.27	0.40	0.41	-0.01
PG&E CG	0.17	0.18	-0.02	0.26	0.21	+0.05	0.12	0.14	-0.02
PG&E Malin	-0.14	-0.02	-0.12	-0.05	-0.29	+0.24	-0.11	-0.10	-0.01
PG&E South	-0.25	-0.26	0.01	-0.18	-0.25	+0.06	0.28	0.28	-0.01
SoCal Gas	-0.01	0.06	-0.07	0.02	-0.27	+0.29	0.37	0.38	-0.01
SoCal Gas Citygate	0.79	0.95	-0.16	0.61	-0.04	+0.66	1.26	1.17	0.09
Transwestern Permian	-0.36	-0.33	-0.03	-0.30	-0.33	+0.03	-0.36	-0.34	-0.01
Waha	-0.29	-0.28	-0.01	-0.25	-0.26	+0.02	-0.32	-0.31	-0.01
West Canada									
AECO-C	-0.49	-0.51	0.02	-0.30	0.12	-0.42	-1.14	-1.08	-0.06

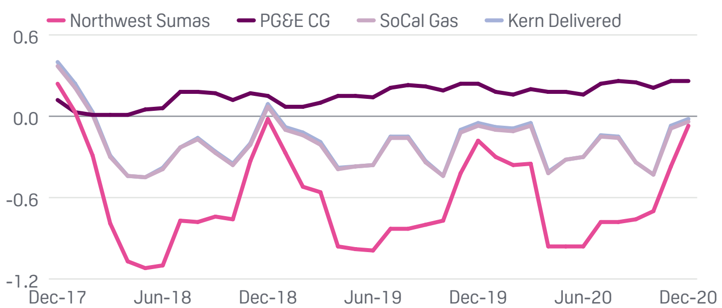
Source: Platts M2M data

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



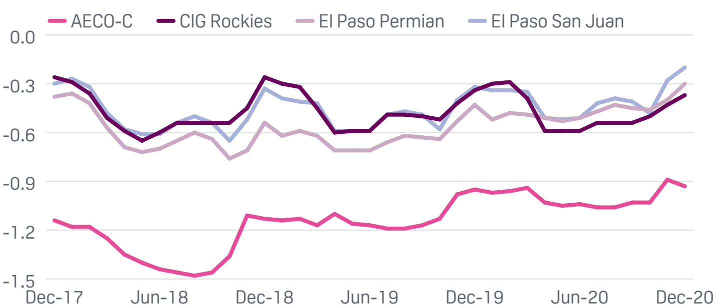
Source: Platts

WEST DEMAND LOCATIONS FORWARD BASIS ($/MMBtu)



Source: Platts

WEST SUPPLY LOCATIONS FORWARD BASIS ($/MMBtu)



Source: Platts

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

	06-Nov	07-Nov	Change	MTD avg.	MTD last year	Change
Supply regions – net pipeline outflows						
Texas	3,679			7,329	8,200	-871
West Canada	0			7,455	8,073	-618
Rockies	0			5,059	6,389	-1,330
Midcontinent	0			3,141	2,986	155
Northeast	0			7,413	5,751	1,662
Demand regions – net pipeline inflows						
Southwest	0			2,823	4,064	1,241
Southeast	0			7,001	7,441	440
Northwest	0			2,058	1,450	-608
Midwest	0			10,892	10,274	-618
East Canada	0			3,521	3,594	73

* 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, NOV 7

	$/MMBtu	+/-
Gulf Coast ethane fractionation spread	1.098	-0.135
Gulf Coast E/P mix fractionation spread	0.835	-0.172
E/P mix Midcontinent to Rockies fractionation spread	0.002	0.045
E/P mix Midcontinent fractionation spread	0.087	0.020
National raw NGL basket price	8.072	-0.197
National composite fractionation spread	5.072	-0.257

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

PLATTS OIL PRICES, NOV 7

	($/b)	($/MMBtu)
Gulf Coast spot		
1% Resid (1)	58.78-58.80	9.41
HSFO (1)	57.03-57.05	9.13
Crude spot		
WTI (Dec) (2)	57.19-57.21	9.86
New York spot		
No.2 (1)	74.71-74.76	11.96
0.3% Resid LP (3)	65.25-65.27	10.44
0.3% Resid HP (3)	65.25-65.27	10.44
0.7% Resid (3)	60.75-60.77	9.72
1% Resid (3)	58.25-58.27	9.32

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

S&P Global
Platts
GAS DAILY
Volume 34 / Issue 215 / Wednesday, November 8, 2017
ISSN: 0885-5935

Gas Daily Questions? Email:
NAGas&Power@spglobal.com

Managers North America Gas and Power Content
Rocco Canonica, +1-720-264-6626
Matthew Eversman, +1-713-655-2238
Joe Fisher, +1-713-658-3290
Chris Newkumet, +1-202-383-2141
Anne Swedberg, +1-720-264-6728

Editors
Brandon Evans, +1-720-264-6671
Jim Magill, +1-713-658-3229
Jasmin Melvin, +1-202-383-2135
J. Robinson, +1-720-264-6657
Mark Watson, +1-713-658-3214
Harry Weber, +1-713-658-3257
Maya Weber, +1-202-383-2244

Spot Market Editors
Eric Janssen, +1-713-655-2261
Samer Mosis, +1-713-655-2271
Curt Mrowiec, +1-713-658-3271
Ryan Ouwerkerk, +1-713-655-2202

Analysts
Eric Brooks
Richard Frey
John Hilfiker
Luke Jackson
Tyler Jubert
Liz McFarland
George McGuirk
Mason McLean
Ross Wyeno

Director, Americas Generating Fuels and Electric Power Pricing
Mark Callahan

Director, Americas Energy News
James O'Connell

Global Director, Generating Fuels, Electric Power, and Petrochemicals
Simon Thorne

Platts President
Martin Fraenkel

Advertising
Tel: +1-720-264-6618

Manager, Advertisement Sales
Bob Botelho

To reach Platts: E-mail:support@platts.com; North America: Tel:800-PLATTS-8; Latin America: Tel:+54-11-4121-4810; Europe & Middle East: Tel:+44-20-7176-6111; Asia Pacific: Tel:+65-6530-6430

Gas Daily is published daily by Platts, a division of S&P Global, registered office: Two Penn Plaza, 25th Floor, New York, N.Y. 10121-2298.

Officers of the Corporation: Charles E. Haldeman, Jr., Non-Executive Chairman; Doug Peterson, President and Chief Executive Officer; Ewout Steenbergen, Executive Vice President, Chief Financial Officer; Steve Kemps, Executive Vice President, General Counsel

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

Powered by ICE

Trade date: 07-Nov
Flow date(s): 08-Nov

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	3.030	+0.745	2.850	3.250	2.930	3.130	138	38
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	3.335	+0.165	3.270	3.400	3.305	3.370	44	22
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	—	—	—	—	—	—	—	—
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	3.115	+0.075	3.010	3.150	3.080	3.150	372	70
Appalachia									
ICE Clarington Tennessee	JAAFI21	—	—	—	—	—	—	—	—
ICE Columbia Gas, A04 Pool	JAAAU21	—	—	—	—	—	—	—	—
ICE Columbia Gas, A06 Pool	JAAAV21	2.420	+1.290	2.410	2.450	2.410	2.430	25	8
ICE Columbia Gas, Segmentation Pool	JAAAW21	—	—	—	—	—	—	—	—
ICE Millennium Pipeline (buyers' choice delivered)	JAAHA21	—	—	—	—	—	—	—	—
ICE Tennessee, zone 4, station 219 Pool	JAAET21	2.720	+0.295	2.650	2.750	2.695	2.745	139	38
ICE Texas Eastern, M2 Zone (delivered)	JAAEV21	—	—	—	—	—	—	—	—
Midcontinent									
ICE Bennington, Oklahoma	JAAAM21	—	—	—	—	—	—	—	—
ICE Enable Gas, Flex Pool only	JAABE21	2.835	+0.075	2.800	2.860	2.820	2.850	50	16
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	2.960	+0.020	2.960	2.960	2.960	2.960	10	2
ICE NGPL, Mid-Continent Storage PIN	JAACO21	—	—	—	—	—	—	—	—
ICE Northern Natural, Mid 13 - 16A Pool	JAACW21	—	—	—	—	—	—	—	—
ICE Northern Natural, Mid 1-7 Pool	JAACX21	2.755	+0.010	2.740	2.770	2.750	2.765	90	12
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	3.035	+0.015	3.020	3.090	3.020	3.055	1238	148
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	2.970	+0.010	2.950	3.000	2.960	2.985	198	34
ICE NGPL, Amarillo Storage PIN	JAACH21	—	—	—	—	—	—	—	—
ICE NGPL, Iowa-Illinios Pooling PIN	JAACJ21	—	—	—	—	—	—	—	—
ICE NGPL, Iowa-Illinois Storage PIN	JAACK21	—	—	—	—	—	—	—	—
ICE NGPL, Mid-American Citygate	JAACN21	—	—	—	—	—	—	—	—
ICE Northern Border, Harper Transfer Point	JAACS21	—	—	—	—	—	—	—	—
ICE Northern Border, Nicor Interconnect	JAACT21	—	—	—	—	—	—	—	—
ICE Northern Border, Vector Interconnect	JAACU21	3.050	+0.025	3.040	3.065	3.045	3.055	132	22
ICE Northern Border, Will County	JAACV21	3.060	+0.030	3.060	3.060	3.060	3.060	20	2
ICE REX (East), delivered into ANR	JAADK21	3.005	+0.025	2.990	3.020	3.000	3.015	439	80
ICE REX (East), delivered into Lebanon Hub	JAAHC21	—	—	—	—	—	—	—	—
ICE REX (East), delivered into Midwestern Gas	JAADL21	3.005	+0.015	3.000	3.010	3.005	3.010	144	20
ICE REX (East), delivered into NGPL	JAADM21	3.000	+0.015	2.990	3.005	2.995	3.005	337	48
ICE REX (East), delivered into Panhandle	JAADN21	—	—	—	—	—	—	—	—

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

Trade date: 07-Nov

Flow date(s): 08-Nov

Location	Symbol	Index	Daily Change	Absolute Low	Absolute High	Common Low	Common High	Volume	Deals
Upper Midwest									
ICE REX (East), delivered into Trunkline	JAADO21	3.005	+0.015	2.990	3.030	2.995	3.015	88	12
ICE REX (West), delivered into ANR	JAADP21	—	—	—	—	—	—	—	—
ICE REX (West), delivered into Northern Natural	JAADQ21	3.020	+0.280	3.020	3.020	3.020	3.020	30	6
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	2.960	+0.025	2.950	2.990	2.950	2.970	122	28
ICE ETC, Maypearl	JAABK21	2.880	+0.330	2.880	2.880	2.880	2.880	20	2
ICE Golden Triangle Storage & Hub	JAABL21	—	—	—	—	—	—	—	—
ICE Gulf South, Pool Area #16	JAABP21	2.970	+0.030	2.965	2.970	2.970	2.970	128	20
ICE HPL, East Texas Pool	JAABR21	—	—	—	—	—	—	—	—
ICE Katy, ENSTOR Pool (excl. Kinder Morgan Texas)	JAABW21	—	—	—	—	—	—	—	—
ICE Katy, Lonestar (warranted as Intrastate)	JAABX21	—	—	—	—	—	—	—	—
ICE Katy, Lonestar Interstate	JAABY21	3.020	+0.220	3.020	3.020	3.020	3.020	20	2
ICE Katy, Oasis Pipeline	JAABZ21	2.995	+0.075	2.985	3.010	2.990	3.000	184	22
ICE Moss Bluff Interconnect (buyers' choice delivered)	JAACD21	3.040	+0.025	3.040	3.040	3.040	3.040	42	4
ICE Moss Bluff Storage (in-ground transfers only)	JAACE21	—	—	—	—	—	—	—	—
ICE NGPL, TXOK East Pool	JAACP21	2.955	+0.025	2.900	2.980	2.935	2.975	314	54
ICE NGPL, TXOK West Pool	JAACQ21	—	—	—	—	—	—	—	—
ICE NorTex, Tolar Hub	JAACR21	2.895	+0.035	2.890	2.900	2.895	2.900	36	10
ICE Tennessee, zone 0 North	JAAEP21	—	—	—	—	—	—	—	—
ICE Tennessee, zone 0 South	JAAEQ21	2.915	+0.095	2.900	2.950	2.905	2.930	90	22
ICE Tres Palacios Hub - Injection	JAAFE21	2.965	+0.095	2.940	2.970	2.960	2.970	62	14
ICE Tres Palacios Hub - Withdrawal	JAAFF21	3.040	+0.040	3.035	3.040	3.040	3.040	60	8
Louisiana/Southeast									
ICE ANR, SE Transmission Pool	JAAAI21	3.010	+0.030	2.990	3.030	3.000	3.020	253	40
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	2.850	+0.300	2.850	2.850	2.850	2.850	10	2
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	3.020	+0.045	2.980	3.030	3.010	3.030	276	40
ICE Sonat, Zone 0	JAAHE21	—	—	—	—	—	—	—	—
ICE Sonat, Zone 0 South Louisiana Pool	JAAEJ21	3.015	+0.030	2.950	3.070	2.985	3.045	740	118
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	2.995	+0.050	2.985	3.000	2.990	3.000	74	8
ICE Texas Gas, Mainline Pool	JAAEX21	2.995	+0.045	2.980	3.010	2.990	3.005	528	78
ICE Texas Gas, North Louisiana Pool	JAAEY21	—	—	—	—	—	—	—	—
Rockies/Northwest									
ICE CIG, Mainline (sellers' choice, non-lateral)	JAAFY21	2.855	-0.045	2.810	2.860	2.845	2.860	103	18
ICE CIG, Mainline Pool	JAAFZ21	—	—	—	—	—	—	—	—
ICE CIG, Mainline South (sellers' choice)	JAAAT21	2.820	+0.285	2.800	2.840	2.810	2.830	23	6
ICE Kern River, on system receipt	JAACA21	2.925	-0.050	2.885	2.960	2.905	2.945	907	114
ICE Opal Plant Tailgate	JAADB21	2.905	-0.080	2.890	2.940	2.895	2.920	122	16
ICE PG&E, Onyx Hill	JAAHB21	—	—	—	—	—	—	—	—
ICE Pioneer Plant Tailgate	JAADG21	2.915	-0.060	2.880	2.920	2.905	2.920	160	24
ICE Questar, North Pool	JAADI21	2.865	-0.035	2.860	2.880	2.860	2.870	10	4
ICE Questar, South Pool	JAADJ21	—	—	—	—	—	—	—	—

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

Trade date: 07-Nov
Flow date(s): 08-Nov

Location	Symbol	Index	Daily Change	Absolute Low	Absolute High	Common Low	Common High	Volume	Deals
Rockies/Northwest									
ICE Ruby, Onyx Hill	JAADS21	2.950	-0.040	2.920	2.970	2.940	2.965	155	22
ICE Ruby, Receipt Pool	JAADT21	2.890	—	2.885	2.895	2.890	2.895	30	4
ICE Ryckman Creek Gas Storage	JAADU21	—	—	—	—	—	—	—	—
ICE WIC, Pool	JAAFH21	—	—	—	—	—	—	—	—
Southwest									
ICE El Paso, Keystone Pool	JAABB21	2.725	+0.030	2.700	2.750	2.715	2.740	486	74
ICE El Paso, Plains Pool	JAABC21	—	—	—	—	—	—	—	—
ICE El Paso, Waha Pool	JAABD21	2.775	+0.025	2.775	2.775	2.775	2.775	5	2
ICE Oasis, Waha Pool	JAACZ21	2.765	+0.025	2.750	2.780	2.760	2.775	98	18
ICE ONEOK, Westex Pool	JAADA21	2.790	+0.040	2.780	2.800	2.785	2.795	128	28
ICE PG&E, Daggett	JAADC21	—	—	—	—	—	—	—	—
ICE PG&E, Kern River Station	JAADD21	—	—	—	—	—	—	—	—
ICE PG&E, Topock	JAADE21	2.825	+0.050	2.810	2.850	2.815	2.835	76	20
ICE Socal, Blythe	JAADX21	—	—	—	—	—	—	—	—
ICE Socal, Ehrenberg (delivered)	JAADY21	3.070	+0.000	2.980	3.080	3.045	3.080	101	18
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	3.000	+0.260	3.000	3.000	3.000	3.000	8	2
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	3.070	-0.060	3.070	3.070	3.070	3.070	56	6
ICE Transwestern, Central Pool	JAAFB21	2.720	+0.045	2.720	2.720	2.720	2.720	3	2
ICE Transwestern, Panhandle Pool	JAAFC21	—	—	—	—	—	—	—	—
ICE Transwestern, West Texas Pool	JAAFD21	—	—	—	—	—	—	—	—
ICE Waha Hub, West Texas (buyer's choice delivered)	JAAFG21	2.830	+0.040	2.800	2.840	2.820	2.840	47	18

ICE GAS DAILY ASSESSMENT RATIONALE

The daily indices for ICE locations are a volume weighted average of ICE Exchange trades submitted to Platts by ICE. No other sources of data are used. Platts editors do not screen the data for outliers or assess prices if there are no transactions. Questions may be directed to Curt Mrowiec at 713-658-3271 or Curt.Mrowiec@spglobal.com