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Platts

GAS DAILY

Wednesday, August 16, 2017

NEWS HEADLINES

Gas exports open market opportunities: Tenaska

- Company boasts 'strong footprint' in Texas, Gulf Coast
- Questions arise over structure of gas demand from LNG plants

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August power burn down 13% from 2016 on weather

- Gas demand for power averaging 33.3 Bcf/d mid-month
- Midwest and East Coast drive declines

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Whiting Petroleum shedding some Bakken assets

- Company selling some N.D. assets for $500M to RimRock unit
- Transaction expected to close September 1

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Gulf Coast plays benefiting from location

- WildHorse, EOG hold largest positions in Eagle Ford
- Haynesville grows 600 MMcf/d year to date

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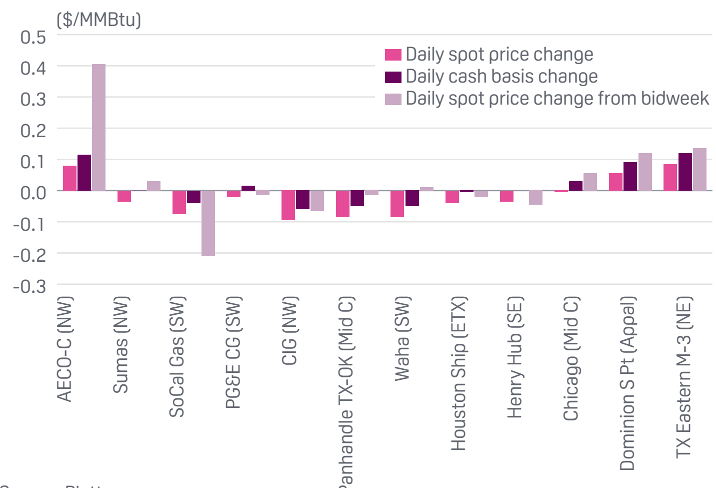
SPOT PRICE AND BASIS CHANGES



Source: Platts

INSIDE THIS ISSUE

DAILY PRICE SURVEY ($/MMBtu)

NATIONAL AVERAGE PRICE: 2.700
Trans. date: 8/15
Flow date(s): 8/16

		Midpoint	+/-	Absolute	Common	Vol.	Deals
Northeast							
Algonquin, city-gates	IGBEE21	2.810	+0.265	2.750-2.880	2.780-2.845	87	20
Algonquin, receipts	IGBDK21	—	—	——	——	—	—
Dracut, Mass.	IGBDW21	—	—	——	——	—	—
Iroquois, receipts	IGBCR21	2.970	+0.050	2.940-2.990	2.960-2.985	40	12
Iroquois, zone 2	IGBEJ21	2.990	-0.045	2.950-3.030	2.970-3.010	37	6
Niagara	IGBCS21	—	—	——	——	—	—
Tennessee, z6 (300 leg) del.	IGBJC21	—	—	——	——	—	—
Tennessee, zone 6 del.	IGBEI21	2.790	+0.325	2.700-2.930	2.735-2.850	158	27
Tx. Eastern, M-3	IGBEK21	1.935	+0.085	1.900-1.955	1.920-1.950	227	39
Transco, zone 5 del.	IGBEN21	3.045	-0.010	3.030-3.065	3.035-3.055	284	30
Transco, zone 5 del. North	IGCGL21	3.045	+0.035	3.030-3.065	3.035-3.055	97	7
Transco, zone 5 del. South	IGCHL21	3.050	-0.020	3.030-3.065	3.040-3.060	177	21
Transco, zone 6 N.Y.	IGBEM21	2.880	+0.050	2.850-2.930	2.860-2.900	101	14
Transco, zone 6 non-N.Y.	IGBEL21	2.915	+0.110	2.750-3.000	2.855-2.980	221	47
Transco, zone 6 non-N.Y. North	IGBJS21	2.915	+0.110	2.750-3.000	2.855-2.980	221	47
Transco, zone 6-non-N.Y. South	IGBJT21	—	—	——	——	—	—
Northeast regional average	IGCAA00	**2.790**					
Appalachia							
Columbia Gas, App.	IGBDE21	2.850	-0.005	2.840-2.865	2.845-2.855	176	43
Columbia Gas, App. non-IPP	IGBJU21	2.850	+1.450	2.850-2.850	2.850-2.850	2	1
Dominion, North Point	IGBDB21	1.855	+0.055	1.830-1.875	1.845-1.865	85	20
Dominion, South Point	IGBDC21	1.850	+0.055	1.820-1.870	1.840-1.865	273	45
Lebanon Hub	IGBFJ21	2.845	+0.000	2.845-2.865	2.845-2.850	14	5
Leidy Hub	IGBDD21	—	—	——	——	—	—
Millennium, East receipts	IGBIW21	1.930	+0.060	1.890-1.955	1.915-1.945	53	14
REX, Clarington Ohio	IGBGO21	—	—	——	——	—	—
Tennessee, zone 4-200 leg	IGBJN21	2.250	+0.105	2.170-2.300	2.220-2.285	230	45
Tennessee, zone 4-300 leg	IGBFL21	1.840	+0.045	1.830-1.850	1.835-1.845	61	15
Tennessee, zone 4-313 pool	IGCFL21	2.230	+0.105	2.170-2.260	2.210-2.255	159	46
Tennessee, zone 4-Ohio	IGBHO21	—	—	——	——	—	—
Texas Eastern, M-2 receipts	IGBJE21	1.780	+0.080	1.750-1.800	1.770-1.795	411	82
Transco, Leidy Line receipts	IGBIS21	1.860	+0.050	1.840-1.875	1.850-1.870	285	29
Appalachia regional average	IGDAA00	**2.195**					
Midcontinent							
ANR, Okla.	IGBBY21	2.595	-0.055	2.580-2.640	2.580-2.610	145	22
Enable Gas, East	IGBCA21	2.680	-0.050	2.680-2.680	2.680-2.680	11	2
NGPL, Amarillo receipt	IGBDR21	2.770	+0.010	2.770-2.770	2.770-2.770	3	1
NGPL, Midcontinent	IGBBZ21	2.655	-0.020	2.640-2.665	2.650-2.660	210	28
Oneok, Okla.	IGBCD21	2.415	+0.010	2.400-2.440	2.405-2.425	47	7
Panhandle, Tx.-Okla.	IGBCE21	2.555	-0.085	2.550-2.590	2.550-2.565	129	28
Southern Star	IGBCF21	2.550	-0.025	2.530-2.575	2.540-2.560	91	13
Tx. Eastern, M-1 24-in.	IGBET21	2.800	-0.010	2.800-2.800	2.800-2.800	2	1
Midcontinent regional average	IGEAA00	**2.630**					
Upper Midwest							
Alliance, into interstates	IGBDP21	2.875	-0.015	2.845-2.880	2.865-2.880	596	74
ANR, ML 7	IGBDQ21	—	—	——	——	—	—
Chicago city-gates	IGBDX21	2.885	-0.005	2.835-2.935	2.860-2.910	577	86
Chicago-Nicor	IGBEX21	2.850	+0.005	2.835-2.860	2.845-2.855	198	28
Chicago-NIPSCO	IGBFX21	2.920	+0.020	2.900-2.935	2.910-2.930	249	37
Chicago-Peoples	IGBGX21	2.860	+0.010	2.845-2.880	2.850-2.870	80	16
Consumers city-gate	IGBDY21	2.910	+0.005	2.890-2.925	2.900-2.920	308	45
Dawn, Ontario	IGBCX21	2.910	-0.005	2.890-2.930	2.900-2.920	508	73
Emerson, Viking GL	IGBCW21	2.635	-0.025	2.610-2.715	2.610-2.660	248	37
Mich Con city-gate	IGBDZ21	2.890	-0.010	2.880-2.900	2.885-2.895	311	50
Northern Bdr., Ventura TP	IGBGH21	2.770	-0.020	2.740-2.790	2.760-2.785	57	8
Northern, demarc	IGBDV21	2.750	-0.040	2.730-2.770	2.740-2.760	127	17
Northern, Ventura	IGBDU21	2.760	-0.015	2.745-2.770	2.755-2.765	32	7
REX, Zone 3 delivered	IGBRO21	2.855	-0.005	2.835-2.870	2.845-2.865	489	66
Upper Midwest regional average	IGFAA00	**2.825**					

Exports open market opportunities: Tenaska

As US exports of natural gas — in the form of LNG and pipeline exports to Mexico — are predicted to increase significantly in coming years, independent gas and power marketer Tenaska is prepared to leverage its physical assets to implement its supply-chain management strategy to take advantage of the accompanying growth in the US gas market, a company executive said this week.

"We think we are prepared. Our platform's very good, very scalable. We've invested a lot into our platform, which includes our people, our systems. Those are very scalable toward continued growth in a growing market," Fred Hunzeker president and CEO of Tenaska Marketing Group, said in an interview.

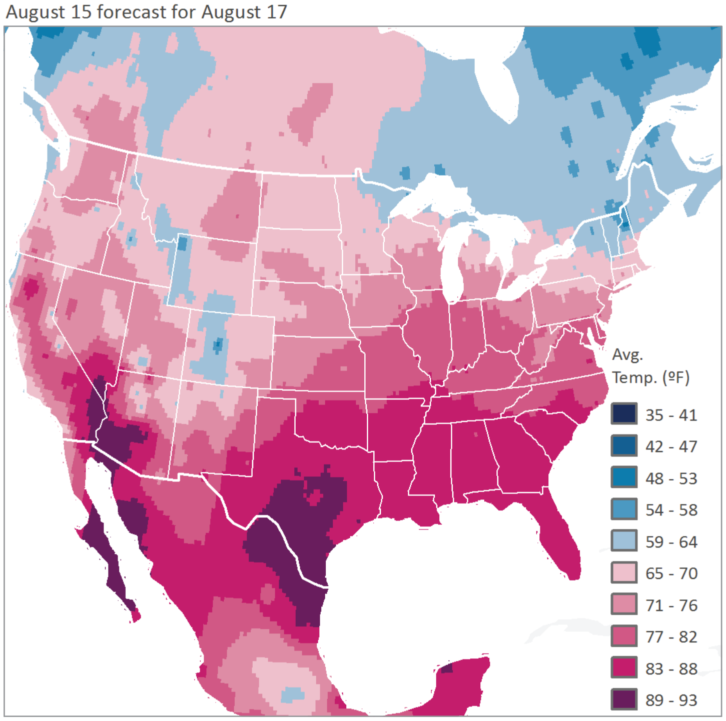
The US is expected to become a net exporter of gas on an average annual basis as early as next year, according to the US Energy Information Administration's recently released Annual Energy Outlook 2017. This development marks a historic reversal from current trends. As recently as last year, the US was a net importer of gas, with net imports of 0.9 Tcf, or 2.6 Bcf/d, EIA said.

LNG exports are expected to make up a growing share of total gas

(continued on page 3)

2-DAY-AHEAD TEMPERATURE FORECAST MAP

August 15 forecast for August 17



Source: Platts, Custom Weather

ASSESSMENT RATIONALE

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

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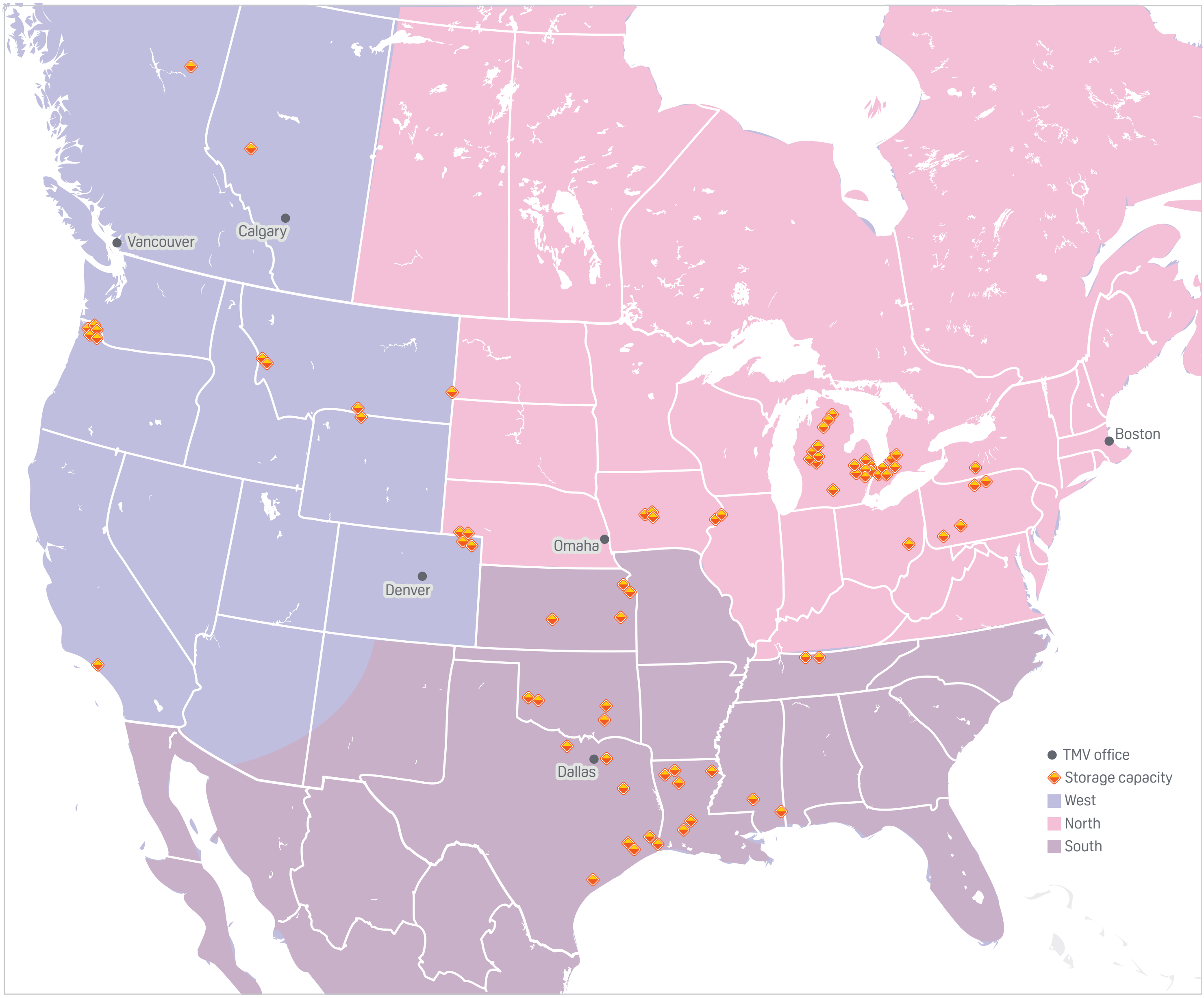
DAILY PRICE SURVEY ($/MMBtu)

Trans. date: 8/15
Flow date(s): 8/16

		Midpoint	+/-	Absolute	Common	Vol.	Deals
East Texas							
Agua Dulce Hub	IGBAV21	—	—	——	——	—	—
Carthage Hub	IGBAF21	2.835	-0.065	2.820-2.860	2.825-2.845	105	17
Florida Gas, zone 1	IGBAW21	2.920	-0.055	2.910-2.930	2.915-2.925	80	7
Houston Ship Channel	IGBAP21	2.900	-0.040	2.900-2.900	2.900-2.900	51	8
Katy	IGBAQ21	2.900	-0.045	2.890-2.940	2.890-2.915	489	62
NGPL, STX	IGBAZ21	2.840	-0.020	2.835-2.850	2.835-2.845	16	5
NGPL, Texok zone	IGBAL21	2.840	+0.000	2.835-2.850	2.835-2.845	47	6
Tennessee, zone 0	IGBBA21	2.835	+0.010	2.835-2.835	2.835-2.835	13	4
Tx. Eastern, ETX	IGBAN21	2.850	-0.080	2.850-2.850	2.850-2.850	12	3
Tx. Eastern, STX	IGBBB21	2.910	-0.055	2.895-2.930	2.900-2.920	38	6
Transco, zone 1	IGBBC21	2.905	-0.010	2.900-2.910	2.905-2.910	57	17
Transco, zone 2	IGBBU21	2.915	+0.000	2.900-2.920	2.910-2.920	11	5
East Texas regional average	IGGAA00	**2.875**					
Louisiana/Southeast							
ANR, La.	IGBBF21	2.885	+0.015	2.875-2.895	2.880-2.890	94	18
Columbia Gulf, La.	IGBBG21	2.920	-0.010	2.890-2.925	2.910-2.925	88	11
Columbia Gulf, mainline	IGBBH21	2.875	-0.005	2.860-2.885	2.870-2.880	161	33
Florida city-gates	IGBED21	3.420	+0.120	3.400-3.530	3.400-3.455	65	5
Florida Gas, zone 2	IGBBJ21	2.925	-0.045	2.920-2.950	2.920-2.935	120	6
Florida Gas, zone 3	IGBBK21	2.975	-0.020	2.950-2.980	2.970-2.980	432	35
Henry Hub	IGBBL21	2.925	-0.035	2.920-2.950	2.920-2.935	176	33
Southern Natural, La.	IGBBO21	2.915	-0.035	2.910-2.920	2.915-2.920	198	28
Tennessee, 500 Leg	IGBBP21	2.900	-0.035	2.900-2.905	2.900-2.900	47	9
Tennessee, 800 Leg	IGBBQ21	2.900	+0.000	2.900-2.900	2.900-2.900	10	1
Tx. Eastern, ELA	IGBBS21	2.885	-0.020	2.885-2.895	2.885-2.890	16	7
Tx. Eastern, M-1 30-in.	IGBDI21	2.930	-0.020	2.930-2.930	2.930-2.930	1	1
Tx. Eastern, WLA	IGBBR21	2.910	+0.040	2.910-2.920	2.910-2.915	35	7
Tx. Gas, zone 1	IGBAO21	2.850	-0.035	2.850-2.865	2.850-2.855	141	12
Tx. Gas, zone SL	IGBBT21	2.830	-0.020	2.830-2.830	2.830-2.830	1	1
Transco, zone 3	IGBBV21	2.915	-0.040	2.900-2.930	2.910-2.925	359	54
Transco, zone 4	IGBDJ21	2.950	-0.030	2.940-2.970	2.945-2.960	740	119
Trunkline, ELA	IGBBX21	2.860	-0.020	2.860-2.860	2.860-2.860	2	1
Trunkline, WLA	IGBBW21	—	—	——	——	—	—
Trunkline, zone 1A	IGBGF21	2.850	-0.020	2.850-2.860	2.850-2.855	147	18
Louisian/Southeast regional average	IGHAA00	**2.925**					
Rockies/Northwest							
Cheyenne Hub	IGBCO21	2.530	-0.085	2.520-2.550	2.525-2.540	111	14
CIG, Rockies	IGBCK21	2.505	-0.095	2.500-2.540	2.500-2.515	77	13
GTN, Kingsgate	IGBCY21	2.445	-0.070	2.440-2.450	2.445-2.450	27	7
Kern River, Opal	IGBCL21	2.585	-0.070	2.565-2.615	2.575-2.600	230	34
NW, Can. bdr. (Sumas)	IGBCT21	2.510	-0.035	2.490-2.520	2.505-2.520	76	20
NW, s. of Green River	IGBCQ21	2.530	-0.050	2.500-2.540	2.520-2.540	35	11
NW, Wyo. Pool	IGBCP21	2.535	-0.065	2.510-2.580	2.520-2.555	30	6
PG&E, Malin	IGBDO21	2.625	-0.075	2.610-2.665	2.610-2.640	95	21
Questar, Rockies	IGBCN21	2.510	-0.080	2.510-2.510	2.510-2.510	1	1
Stanfield, Ore.	IGBCM21	2.515	-0.075	2.500-2.535	2.505-2.525	53	11
TCPL Alberta, AECO-C*	IGBCU21	2.365	+0.080	2.330-2.400	2.350-2.385	848	133
Westcoast, station 2*	IGBCZ21	0.450	-0.135	0.300-0.540	0.390-0.510	153	40
White River Hub	IGBGL21	2.550	-0.050	2.530-2.570	2.540-2.560	48	7
Rockies/Northwest regional average	IGIAA00	**2.530**					
Southwest							
El Paso, Bondad	IGBCG21	2.520	-0.090	2.500-2.550	2.510-2.535	87	15
El Paso, Permian	IGBAB21	2.560	-0.070	2.540-2.620	2.540-2.580	459	62
El Paso, San Juan	IGBCH21	2.570	-0.050	2.540-2.590	2.560-2.585	94	12
El Paso, South Mainline	IGBFR21	2.680	-0.105	2.670-2.680	2.680-2.680	18	5
Kern River, delivered	IGBES21	2.685	-0.085	2.680-2.710	2.680-2.695	179	30
PG&E city-gate	IGBEB21	3.265	-0.020	3.250-3.275	3.260-3.270	275	46
PG&E, South	IGBDM21	2.670	-0.055	2.660-2.675	2.665-2.675	35	5
SoCal Gas	IGBDL21	2.670	-0.075	2.660-2.715	2.660-2.685	208	33
SoCal Gas, city-gate	IGBGG21	2.775	-0.230	2.745-2.810	2.760-2.790	115	20
Transwestern, Permian	IGBAE21	2.550	-0.070	2.550-2.550	2.550-2.550	32	4
Transwestern, San Juan	IGBGK21	2.575	-0.065	2.570-2.580	2.575-2.580	103	21
Waha	IGBAD21	2.610	-0.085	2.570-2.690	2.580-2.640	459	47
Southwest regional average	IGJAA00	**2.680**					

*Price in C$ per gj; C$1=US$0.7840; Volume in 000 MMBtu/day. Symbols represent gas flow date.

TENASKA GAS STORAGE CAPACITY



Source: Tenaska

exports and to surpass pipeline exports of natural gas by 2020, EIA said.

Cheniere Energy's Sabine Pass LNG export terminal became the first export terminal in operation in the Lower 48 States last year. And with four more LNG export facilities slated to come on line over the next several years, the US will have an operational LNG export capacity of 9.2 billion Bcf/d by 2021, according to the Energy Outlook.

Meanwhile, exports of US gas by pipeline to Mexico, which have doubled since 2009, "are projected to continue rising through at least 2020 as pipeline projects currently under construction are completed," the EIA said.

Driven by the growth in demand for LNG and Mexico exports, "the market appears to be poised for continuous growth over the next three years to five years in a significant manner," Hunzeker said.

"LNG and Mexico are just two aspects of this growth we see coming down the road," he said.

Company boasts 'strong footprint' in Texas, Gulf Coast

Hunzeker added that privately owned Tenaska is prepared to accommodate the growth in marketed gas volumes, driven by demand for both forms of exports through its "strong footprint" of assets both in Texas and in the Gulf Coast region.

"We have relationships with all the relevant players in those markets and we hope to be one of the few players able to bring the scale and scope of our physical assets to those areas to help balance those markets," Hunzeker said.

Looking forward, the shifting global LNG market is raising many questions for gas marketers, concerning those proposed US LNG projects that have yet to come on line, as to their timing and even their basic business model, Hunzeker said.

In recent years, global gas prices have begun to converge, with prices in the premium Asian markets falling to parity with Europe as the world has moved from an endemic LNG shortage to global oversupply, according to a recent report by Platts Analytics' Eclipse Energy.

As a result, the price differential between the Platts Japan Korea Marker and the US Henry Hub fell from an average of $12.65/MMBtu in 2013 to $3.02/MMBtu as of November 2016, a $9.63/MMBtu (76%) drop.

Eclipse Energy predicts that new global LNG supply capacity — especially the ramp-up of US export capacity — will outpace nominal demand growth by around 8.5 Bcf/d by 2019, which will likely lead to further global price consolidation over the next five years.

"What is the ultimate timing of those projects coming on line?" Hunzeker asked. He noted that while several projects seem to be getting close to commissioning and start-up, recent announcements indicate that several of those projects might see delays in their timelines.

Questions arise over structure of gas demand from LNG plants

"For the ones that do get built, there's a big question of whether they will all be baseloaded or swinging, maybe on a seasonal basis," Hunzeker said. Demand for US-based gas from LNG terminals that do not operate on a baseload-demand model would likely fluctuate.

"The markets are going to have to be able to handle those demand volume fluctuations just like we have to on the power-gen side," Hunzeker said.

Meanwhile, gas exports to Mexico continue to increase apace. Despite anemic export growth during the first half of the year, exports to Mexico are starting to pick up in the second half, averaging more than 4.4 Bcf/d during the first several days of August, up 250 MMcf/d (6%) from July and up 340 MMcf/d (8%) from last year, according to Platts Analytics' Bentek Energy.

Recently, approximately 3.1 Bcf/d of new West Texas border-crossing capacity has come on line, providing additional opportunities to flow gas into Mexico's gas-hungry markets, Bentek said.

"On the Mexico side, we have a strong footprint in the Texas intrastate market so that gives us a good segue for us to expand into the growing market for exports into Mexico, Hunzeker said.

"We've established an entity to do business in Mexico," he said. "We're also currently active on the US side of the border with our southern team looking for opportunities to do deals ,either on the US or the Mexico side of the border."

— *Jim Magill*

Q2 2017 MARKETER RANKINGS

Platts is currently compiling data for the second-quarter 2017 ranking of North American gas marketers by daily physical wholesale volumes sold.

Platts staff intends to compile the rankings from information appearing in reports filed with the Securities and Exchange Commission. For companies that are not publicly traded or do not provide such data to the SEC, staff requests quarterly gas sales data be reported in writing, and verified by executive personnel, no later than Wednesday, August 16, 2017.

Please submit your data by contacting Jim Magill by phone at 713-658-3229, or e-mail at jim.magill@spglobal.com.

Contact Jim Magill with any questions.

August burn down 13% from 2016 on weather

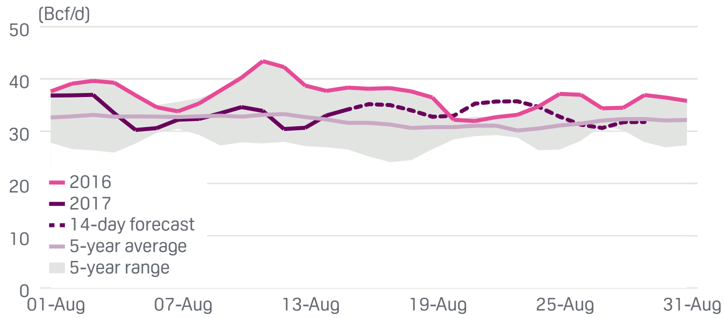
ANALYSIS Midway through August national gas demand for power generation is averaging 33.3 Bcf/d, down over 5 Bcf/d, or 13%, from 2016 on cooler weather and lower loads throughout the Central and Eastern US.

Factoring in near-term forecasts through the end of the month, power burn is currently expected to end August averaging approximately 33.4 Bcf/d, approximately 3.4 Bcf/d, or 9%, below 2016 levels.

With Henry Hub cash prices trending in line with last year, falling power demand on lower temperatures has been the primary driver of lower burns this month as national average temperatures have fallen 4 degrees F from 2016 levels while currently averaging 2 degrees below normal.

National cooling degree days have fallen 26% year over year and are trending 15% below normal which has driven national power demand down 9% from last year to average 12.1 TWh/d, according to data from the Energy Information Administration.

AUGUST US POWER BURN DEMAND



Source: Platts Analytics' Bentek Energy

Midwest and East Coast drive declines

The biggest year-over-year burn declines this month have been in the Northeast, Southeast, and Midcon Market regions which have seen demand slide 1.7 Bcf/d, 1.4 Bcf/d, and 1.2 Bcf/d, respectively, as average temperatures in those regions have fallen 5 degrees, 2 degrees, and 7 degrees year over year.

The Northwest is the only region where temperatures have trended noticeably higher this year, driving stronger burns.

Northwest power burn demand has increased over 0.1 Bcf/d, or 14%, year over year as temperatures have averaged 6 degrees higher than July 2016. Northwest burns have also been supported by hydro generation falling from near record highs earlier in the summer to below 2016 levels so far this month.

Looking forward, the national power burn is expected to hit 35 Bcf/d Wednesday and Thursday as temperatures push higher throughout the country this week before the weekend lull in demand.

Next week power burn demand is expected to top out just below 36 Bcf/d as average national temperatures climbs to just shy of 78 degrees, the hottest level since the first three days of the month when temperatures topped 78 degrees and power burn average 36.8 Bcf/d.

Peak power burn may be in the past

A perfect storm of cheap gas prices, a hotter than normal summer, and massive coal-fired generation retirements pushed US power burn demand to record highs in 2016, highs which may not never be topped again according to a recent report from the International Energy Association.

Henry Hub cash prices averaged $2.49/MMBtu in 2016 — the lowest levels since 1999 — population-weighted summer temperatures averaged between 2-3 degrees above normal, and over 44.3 GW of coal-fired generation had retired between 2012 and the start of summer 2016.

All these factors combined to help gas-fired generators out-compete other conventional power generators and pushing national power burn to annual and summer averages of 27.2 Bcf/d and 30.0 Bcf/d, respectively, beating prior records set in 2015 by 0.9 Bcf/d and 1.6 Bcf/d.

The IEA is forecasting much slower US power burn demand growth over the next six years, according to its Gas 2017 report published in July.

Citing increased renewable generation and reduced coal-to-gas switching potential moving forward, the IEA expects most US growth in gas consumption will be driven by the industrial sector as power sector demand levels off.

— George McGuirk

Whiting shedding some Bakken assets

Independent producer Whiting Petroleum said Tuesday it is selling some largely non-operated assets in North Dakota for $500 million to an affiliate of private equity-backed RimRock Oil & Gas, at a time when drillers and midstream companies are retooling their portfolios to focus on opportunities with lower expenses and higher investment returns.

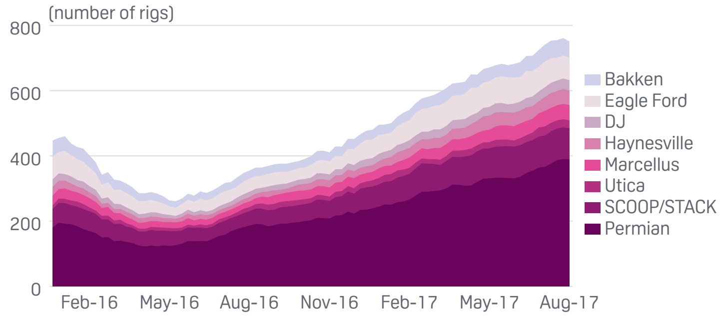
The Bakken shale play, in particular, has been an area where market activity has picked up over the last year, with large swaths of acreage changing hands.

The play encompasses the Williston Basin and spans parts of the upper US Midwest and Canada. Private equity interests have been especially keyed in to the Bakken, with ArcLight Capital Partners saying last month it was buying independent oil and gas producer Halcon Resources' operated assets in the Williston Basin for $1.4 billion. An S&P Global Ratings report issued July 11 said prices and better financing conditions are spurring the M&A moves.

In Whiting's case, the company said it has reached a deal to sell its Fort Berthold Indian Reservation area assets in Dunn and McLean counties, North Dakota, to RimRock Oil & Gas Williston. RimRock, based in Calgary and backed by Warburg Pincus, launched in 2016 with the goal of developing onshore oil and gas assets in North America, according to its website. The transaction is expected to close September 1.

In a statement, Whiting CEO James Volker said the sale will give the company the cash it needs to develop other properties across the Williston Basin where it has identified "4,850 future gross drilling locations."

RIGS IN MAJOR US BASINS



Source: Platts Analytics' Bentek Energy

The properties being sold span 29,637 net acres, 29 non-operated drilling spacing units and 17 operated, Whiting said. Net daily production from the properties averaged 7,785 Boe/d in the second quarter. Lease operating expense for the properties averaged approximately $12.60/Boe for the 12 months ending June 30, compared with $7.50/Boe for Whiting's other operated Bakken production, the company said.

The rig count in the major basins across the US has been steadily growing for more than a year as producers continue to deploy rigs to the field on the back of stronger oil and gas prices. In recent weeks, rig count additions have slowed somewhat as the price of oil fell below $50/b for much of June and July.

For the week ended August 12, 2016, the total rig count in eight major basins across the US stood at 355. A year later, there are now 751 rigs operating in those same eight basins, more than double the active rig count from just one year ago, data compiled by Platts Analytics' Bentek Energy show.

A sizeable portion of the growth in those numbers is being driven by the Permian, which spans parts of Texas and New Mexico. There, total rig counts for the week of August 11 stood at 389, just one rig below the previous week's tally, which was the highest since the 2015 price collapse. Both the Delaware and Midland sub-basins in the Permian have yielded the highest returns in Platts Analytics' internal rate of return analysis for at least the past year. IRRs in the Permian are currently estimated between 28% and 31%.

Not far behind the Permian, IRRs in the Bakken are currently estimated at 23% due to the high oil content of Bakken wells. Those rates of return estimate that a typical well in the Bakken yields higher returns than a typical well in the Marcellus and Utica in the Northeast, and the Haynesville, which spans parts of Louisiana, Arkansas and East Texas.

— Harry Weber, John McManus

Gulf Coast plays benefiting from location

Several producers have increased drilling activity in the Haynesville and Eagle Ford shales to take advantage of low price differentials due to the proximity of those plays to the Gulf Coast.

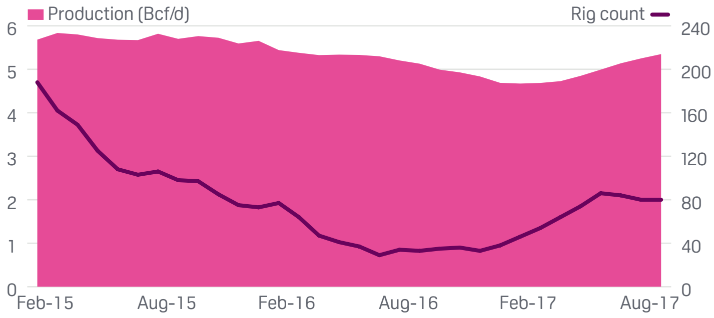
"Differentials in the Eagle Ford are superior to other operating areas," said Drew Crosby, chief financial officer for WildHorse Resource Development, during the Enercom conference in Denver Tuesday. "To use a baseball analogy, it's akin to starting on third base … It's a geographic advantage. We are only 90 miles from the Houston Ship Channel. That provides for low differentials."

WildHorse, EOG hold largest positions in Eagle Ford

After recent acquisitions WildHorse now holds the second-largest acreage position in the Eagle Ford in South Texas with approximately 385,000 net acres. The only operator with a larger footprint is EOG Resources with about 528,000 net acres.

Producers such as WildHorse, SM Energy, Noble Energy and EOG have picked up the pace in the Eagle Ford this year. Rig count has more than doubled since the end of 2016 from 38 to 80, according to Platts Analytics' Bentek Energy, while production has surged by 676 MMcf/d over the same time span.

EAGLE FORD SHALE PRODUCTION AND RIG COUNT



Source: Platts Analytics' Bentek Energy

Noble set a company-best production record in the Eagle Ford of 177 MMcf/d during the second quarter of 2017 as it grew production in the play by 60%, according to its most recent earnings report.

According to the US Energy Information's latest Drilling Productivity Report, Eagle Ford gas production is expected to climb another 63 MMcf/d in September.

Haynesville grows 600 MMcf/d year to date

However, the nearby Haynesville in Louisiana is forecast to grow by 152 MMcf/d in September. This is another play of interest to WildHorse, an operator in the Terryville field, which is located in a layer of rock above the Haynesville in northern Louisiana. Unlike the oily Eagle Ford, the average production mix per well in the Terryville contains about 96% natural gas.

"We have brought 11 wells online so far and expect seven more in the fourth quarter," Crosby said of the Terryville field. "We are currently operating two rigs, and we are also developing midstream infrastructure in the region. The internal rates of return in the Terryville are comparable to other natural gas areas. They are also aided by close proximity to the Gulf Coast."

Black Stone Minerals, which owns and manages acreage in every major play in the US, has also been increasing its activity in the Haynesville.

"Last quarter set a production record for us," said Jeff Wood, senior vice president and chief financial officer. "So this train is not slowing down."

The month-to-date production sample in the Haynesville has reached 3 Bcf/d, nearly 0.6 Bcf/d higher, than what it was at the start of this year, according to Platts Analytics. The new production sample also marks a four-year high as the last time the sample was at or above the 3 Bcf/d mark was in August 2013.

Similarly, the number of active rigs in the play has averaged 33 rigs in August, the highest level since early 2012. Renewed producer interest has breathed life into this play, which has gone largely dormant over the past several years. However, while the drilling activity is at a record high, the completion rate of new wells has stagnated to an extent, which means more of the newly drilled wells are being added to the inventory of drilled but uncompleted wells.

— Brandon Evans

Haynesville activity rises as efficiency improves

Drilling activity in the Haynesville Shale of northern Louisiana and East Texas is continuing to pick up during the second half of the year as producers gain confidence that they can make money in the play at current oil and gas prices.

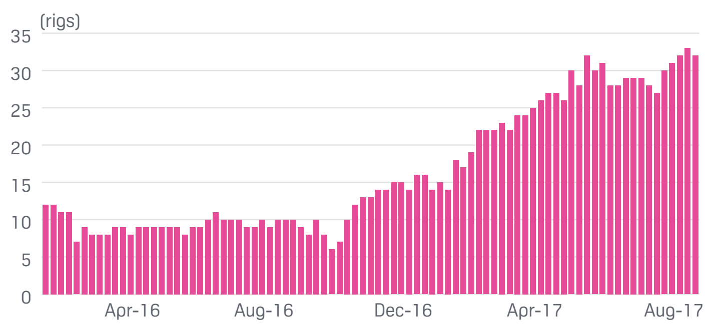
In one example of renewed producer interest, on Monday Rockcliff Energy said it has acquired about 60,000 net acres of Haynesville Shale rights, located primarily in Harrison and Panola counties, Texas. The Houston-based producer did not disclose the seller's name or terms of the transaction.

"Combined with our previously announced Samson acquisition, Rockcliff will have assembled a large, strategic position of approximately 180,000 net acres in the Haynesville Shale play," President and CEO Alan Smith said in a statement Monday.

"We intend to apply the latest technology alongside our team's deep Haynesville experience to successfully develop this premier acreage position."

After bottoming out at 11 rigs in mid-July 2016, the number of rigs in the Arkansas-Louisiana (ARKLA) region — which encompasses the Haynesville play — has begun to increase. Since its low point, 33 rigs have been added, bringing the most recent count to 44 rigs for the week ending August 11, according to Platts' Analytics Bentek Energy.

HAYNESVILLE RIG COUNT



Source: Platts Analytics' Bentek Energy

The majority of this drilling increase has been seen in the Haynesville, Bentek said.

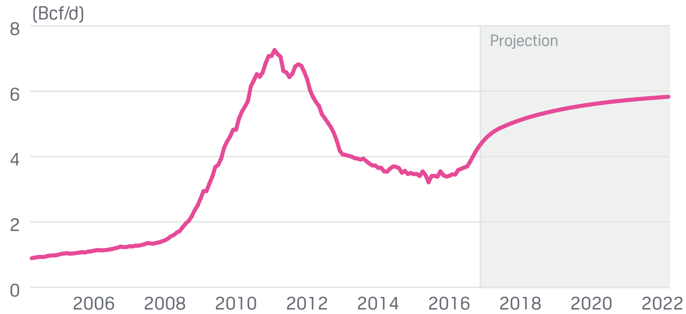
This increase in drilling activity has been accompanied by a corresponding growth in sample production out of the region, according Platts Analytics. Sample production in the Haynesville has seen growth of 0.62 Bcf/d since this time last year.

Together with marginal increases from the non-Haynesville sample, the basin sample growth is up 0.65 Bcf/d over last August, totaling an average 3.4 Bcf/d so far this month — the highest production sample observed there since before 2015.

Projections call for more growth

Platts Bentek production projections suggest that more growth is on the horizon. Projections, which estimate growth potential based on holding current drilling activity constant into the future, suggest that total dry gas production out of the ARKLA-Haynesville and non-Haynesville together could increase 0.57 B/d to 5.1Bcf/d by the end of the year, growing another 0.53 Bcf/d to 5.7 Bcf/d by the end of 2018.

HAYNESVILLE PROJECTED PRODUCTION



Source: Platts Analytics' Bentek Energy

The increase in activity is taking place even as producers are getting better at coaxing more gas out of wells in the play, using cost-effective technology such as drilling longer laterals and employing advanced recompletion techniques.

According to the US Energy Information Administration's monthly drilling productivity report, released Monday, production from an average well in the Haynesville is expected to increase by 38 Mcf/d to 7,578 Mcf/d in September, compared with 7,540 Mcf/d of estimated production in August.

Chesapeake Energy, in its Q2 earnings report, said it is using re-stimulation techniques to get new life out of old wells.

In July, the producer for the first time re-completed a Haynesville well — one of the first wells Chesapeake had drilled in the play — utilizing a new production liner. After installing the new liner, Chesapeake re-stimulated the well and returned it to production at a peak rate of approximately 9,043 Mcf/d, compared with production of 65 Mcf/d before the re-stimulation treatment.

More wells entering production this year

Chesapeake said it expects to place up to 23 wells on production in the Haynesville Shale in the second half of 2017, compared with 17 wells in the first half of 2017.

Haynesville producer Exco Resources, likewise, said it would focus on increasing cost effectiveness and improved efficiencies to drive its drilling operations in the play.

In its second-quarter release, Exco said its drilling program in northern Louisiana — comprising the Haynesville and Bossier shales — will include a combination of drilling wells with standard lateral lengths of 4,500 feet and as well as those with longer lateral lengths up to 10,000 feet.

"The Haynesville projects are among the highest rate-of-return projects in the company's portfolio," Exco said.

The company said that in the second quarter of 2017, it drilled the second- and third-fastest standard lateral-length Haynesville wells in its history with drill times of 22 and 24 days, respectively, from spud to rig release.

Comstock Resources said it plans to more than double the number of Haynesville/Bossier wells it drills this year compared with last year: 27 (17.1 net) wells in 2017 versus 11 (7.8 net) wells in 2016.

Comstock said it has seen Haynesville/Bossier rates of return improve as well costs have declined. "Extended lateral wells have 70% to 100% rates of return at natural gas prices of $2.50 to $3.00/Mcf at current well costs," the company said.

The increase in Haynesville activity has occurred despite a recent softening of gas prices, which further reflects producer confidence in the play. The average 12-month forward curve for Henry Hub has dropped 19 cents/MMBtu to $2.92/MMBtu in early August, compared with early July, according to Platts Analytics.

In the Haynesville, returns have slipped to 7% with a gas breakeven price of $3.14/MMBtu, while some producers are allowing for lower breakeven costs. In its 2Q 2017 earnings statement Chesapeake Energy released a gas breakeven price of $2.50/MMBtu for its Haynesville acreage.

— Jim Magill, Liz McFarland

Court denies second challenge to Freeport LNG

A US federal court on Tuesday denied Sierra Club's effort to block the Department of Energy's approval of LNG exports from the Freeport LNG terminal in Texas, arguing that DOE did its best to determine the environmental impacts of the project.

"We cannot say that the department failed to fulfill its obligations under [the National Environmental Policy Act] by declining to make specific projections about environmental impacts stemming from specific levels of export-induced gas production," the DC Circuit Court of Appeals said.

This is the second time the DC Circuit has upheld Freeport's permits, after the court last year rejected Sierra Club's challenge to the US Federal Energy Regulatory Commission's order approving construction of the terminal. Tuesday's decision is the first time the court has weighed in on a DOE LNG export approval.

At issue in Tuesday's order is DOE's approval of Freeport's 2011 application (FLEX) to export the LNG equivalent of 0.4 Bcf/d of natural gas from its terminal in Brazoria County, Texas, to countries that do not have free-trade agreements with the US.

Sierra Club challenged DOE's NEPA analysis regarding the indirect effects of the Freeport authorization, and the cumulative impacts of its decision when added to other past, present and reasonably foreseeable future actions, the opinion noted.

On both issues, Sierra Club argued that DOE should have tailored its environmental impacts analysis to a particular amount of exports, the court said.

For indirect effects, Sierra Club said DOE should have looked at the impacts that gas production induced by the Freeport project would have on water resources and ozone concentrations, the opinion said.

DOE did not take this approach, arguing that such indirect effects were not reasonably foreseeable, the opinion said. The DC Circuit opinion agreed (Sierra Club v. DOE, 15-1489).

"The Department offered a reasoned explanation as to why it believed the indirect effects pertaining to increased gas production were not reasonably foreseeable," said the opinion, which was penned by Circuit Judge Robert L. Wilkins.

DOE explained that it is hard to predict the amount of gas that might be produced in response to Freeport's exports because that is based on gas prices. DOE said the price competitiveness of US LNG depends on factors that are hard to predict, including technological change, global economic conditions and environmental rules, the opinion noted.

"Even if the department could make reasonable projections about the quantity of export-induced gas production, the department was stumped by where, at the local level, such production might occur," the court said.

Both shale gas and the pipeline grid are spread through the lower 48 states, the opinion noted. DOE argued that nearly all of the environmental issues with shale gas are local in nature, but there is no way to know where induced gas production would occur.

DOE not required to 'foresee the unforeseeable': court

"The department was not required to 'foresee the unforeseeable,'" the court concluded. "Its determination that an economic model estimating localized impacts would be far too speculative to be useful is a product of its expertise in energy markets and is entitled to deference," the opinion said.

"Because the department could not estimate the locale of production, it was in no position to conduct an environmental analysis of corresponding local-level impacts, which inevitably would be 'more misleading than informative.'"

Sierra Club said that even if identifying local impacts is a challenge, DOE should have looked at regional impacts. But DOE said a regional, shale-play-level analysis would not correspond well to the local water resources and ozone attainment areas that could be impacted, DOE said.

The court agreed with DOE's conclusion. "At a certain point, the department's obligation to drill down into increasingly speculative projections about regional environmental impacts is also limited by the fact that it lacks any authority to control the locale or amount of export-induced gas production, much less any of its harmful effects," the opinion said.

For cumulative impacts, Sierra Club said DOE should have considered the environmental impact of the FLEX application as well as other pending and anticipated LNG export approvals.

But the court again agreed with DOE on cumulative effects, noting the department still has a stumbling block in identifying where the export-induced natural gas production might occur and how its impacts might play out, the opinion said.

"Our conclusion is thus no different in the context of cumulative exports as it is for the indirect effects of the FLEX application itself."

The court also rejected Sierra Club's concerns about gas-to-coal switching in the US power sector, noting that the link between exports and fuel switching is too attenuated to be determined.

The opinion similarly denied the group's claim that DOE's greenhouse gas analysis should have considered the potential for LNG to compete with renewables, arguing this complaint is so small that it "falls under the category of 'flyspecking.'"

Sierra Club also failed to prove that DOE should have weighed environmental concerns more heavily before approving the FLEX application under the Natural Gas Act, the opinion said. "Notably, even if the department determined the impacts were significant, it could still find that the public interest weighs in favor of allowing the exports," the DC Circuit concluded.

Sierra Club responded to the court's decision with dismay. "We are disappointed with the Court's refusal to require DOE to use available tools to inform communities of the impact of this additional fracking prior to approving exports," Nathan Matthews, a staff attorney at Sierra Club, said.

"This LNG export approval creates unnecessary risks for the people of Freeport, Texas, and for every community that is saddled with fracking rigs next to their homes, schools, and public spaces," Matthews said in statement Tuesday.

LNG supporters applaud decision

Meanwhile, LNG supporters hailed the decision.

"We are pleased that the DC Circuit Court has upheld the rigorous DOE review process," Charlie Riedl, executive director of the Center for Liquefied Natural Gas, said in a statement.

The court's decision helps pave the way for the US economy to benefit from LNG, Reidl added, arguing that LNG exports can help reduce GHG emissions, balance trade, provide geopolitical stability, and support domestic jobs.

"Judges in the DC Circuit Court of Appeals have, once again, sensibly rejected the specious arguments advanced by the Sierra Club challenging federal authorizations of US LNG exports," said Fred H. Hutchison, the executive director of LNG Allies and Our Energy Moment.

Hutchison noted that the DC Circuit also rejected Sierra Club's challenge to FERC's construction permit for Freeport.

"The court has now fully weighed in on the US LNG regulatory framework and the agencies' detailed environmental review under NEPA, refusing to go along with the Sierra Club's desire to 'fly-speck' (in the court's words) FERC and DOE decision-making," Hutchison said. "This is a most welcome development."

In its decision on FERC's Freeport order, the DC Circuit found that FERC did not need to weigh the environmental impact of upstream gas development because gas production is spurred by the export authorizations granted by DOE, not the construction licenses granted by the commission.

— Kate Winston

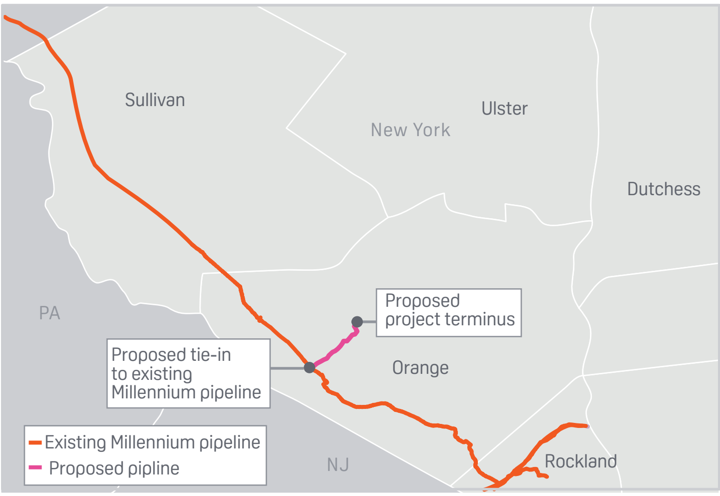
Pipeline delays to impact CPV Valley ramp up

The 650-MW CPV Valley combined-cycle gas plant will begin testing and startup protocols in September, but the 130 MMcf/d pipeline slated to deliver fuel to the plant is awaiting permit approval and has yet to begin construction, Tom Rumsey, Competitive Power Ventures' vice president of external affairs, said Tuesday. The ongoing pipeline delays will likely lead to a one- to two-month period relying on fuel oil, causing low capacity factors and foregone revenue.

Construction of the CPV Valley Energy Center in the Town of Wawayanda, New York, is currently about 80% complete, Rumsey said, but "the pipeline is awaiting the [Clean Water Act Section 401] water quality certificate from the NY State Department of Conservation."

Millennium Pipeline is building the 7.8-mile, 16-inch-diameter line, known as the "Valley Lateral Project."

MILLENNIUM PIPELINE VALLEY LATERAL PROJECT



Source: Millennium Pipeline

A NYSDEC spokesman confirmed Tuesday that public comments have been received and the department is in the process of making a decision, which is due August 30.

Meanwhile, Millennium argued in a July 21 Federal Energy Regulatory Commission filing that its application has been pending before NYSDEC for well over 19 months, and as such the state regulator waived its approval rights by not acting within the one-year statutory timeframe.

At this point, either the NYSDEC can issue the permit or FERC can issue the notice to proceed, said Rumsey.

FERC regained its voting quorum August 10 after a third commissioner, Robert Powelson, was sworn in, but it faces a backlog of cases that built up while it lacked a quorum.

Fuel oil would limit run time because of emissions

Should the NYSDEC approve the plant's water quality permit by August 30, pipeline construction could begin in early November. Some preliminary work could commence prior to November, but tree clearing cannot because a portion of the pipeline lateral's route crosses the endangered Indiana bat's seasonal territory.

CPV expects the plant will reach its commercial operational date in February 2018, after which it appears there will be a one- to two-month interim period during which the duel-fuel plant will be configured to run fuel oil before the pipeline is completed, connected and the facility switched over to run gas.

Pipeline construction is expected to take three to four months and it takes roughly 30 days to switch over from oil to gas, Rumsey said. Based on permitted emissions rates, CPV Valley would be limited to 720 hours of operation per year, or about two hours per day, when running fuel oil.

Plant can bid into capacity markets when it reaches COD

Once operational, CPV Valley will begin bidding into the New York Independent System Operator's capacity and energy markets. CPV does not expect its power plant would be dispatched into the energy market unless there were a reliability issue or gas prices spiked considerably, as they did during the 2014 polar vortex that sent Transco Zone 6 spot prices to around $120/MMBtu.

Absent those conditions, natural gas prices would likely remain below fuel oil prices, and CPV Valley would not be dispatched into the NYISO energy market when configured to run fuel oil.

However, the plant will miss out on collecting energy market revenues during that period. Preparing the plant to run fuel oil "will be more expensive in that we won't have energy revenues," Rumsey said.

"Generators that participate in the NYISO-administered markets are required to manage their fuel inventory. A generator is responsible for procuring its own fuel and advising the NYISO what fuel, or fuels, it has available for operation," David Flanagan, NYISO manager of media relations said in an emailed statement Tuesday.

Court system is option of last resort

In the event the NYSDEC does not approve the Valley Lateral Project's water quality permit, then CPV expects FERC to rule in Millennium's favor, waive NYDEC's right to approve the permit based on exceeding the statutory deadline, and issue the notice to proceed with pipeline construction. If that fails, they will go to court, Rumsey said.

Millennium did not respond to requests for comment.

— *Jared Anderson*

Mexico developing underground gas storage

Preliminary government plans for the development of strategic natural gas storage capacity in Mexico will be published by September, Rosanety Barrios, head of the Industrial Transformation Unit at Mexico's Secretary of Energy (SENER), said Tuesday.

Mexico currently lacks underground gas storage, making the country's LNG terminals the only source of buffer supply for system balancing on days when gas demand is elevated.

Currently, Mexico's Secretary of Energy is elaborating legal parameters for the development of underground gas storage capacity. A regulatory regime for gas storage in Mexico will require rules that govern technical aspects — such as reservoir pressure and permissible injection and withdrawal frequency, but also rules that would incentivize the use of the storage, Barrios said Tuesday at the US-Mexico Natural Gas Forum in San Antonio, Texas.

While SENER hopes to establish either an obligation or an incentive to store gas, it also wants to avoid artificially increasing the domestic price of gas in Mexico.

"It's going to be a careful balance," Barrios said.

Responding to questions about the impact of gas storage on Mexico's LNG imports, Barrios said that she expected demand for US LNG to decline significantly following the installation of the South Texas-Tuxpan maritime pipeline — a $3.1 billion project currently under development by Mexico's Comision Federal de Electricidad.

But Barrios said SENER policymakers still see an important strategic use for Mexico's LNG terminals as another means of balancing supply and demand on Mexico's pipeline system. So while future imports will likely decline, Mexico will continue to import LNG for the foreseeable future, Barrios said.

Since exports of LNG from the US Gulf Coast began, Mexico has imported the largest volume of any receiving country, equivalent to more than 130 Bcf of gas, or about 22% of the total, Platts Analytics' data shows.

— J. Robinson

Transco eyes partial Atlantic Sunrise service

Williams' Transcontinental Gas Pipe Line has filed its formal request to begin partial mainline service of its 1.7 Bcf/d Atlantic Sunrise expansion project as early as September 1.

The company said August 3 as it released second-quarter financial results that the 400 MMcf/d of natural gas capacity that will be made available will help bolster supplies of the power plant and home heating fuel into its Southeast markets for the 2017–18 winter heating season.

Friday's filing with the US Federal Energy Regulatory Commission comes even as the major production-takeaway components of the project are not expected to enter service until mid-2018.

In its request, Transco sought approval to place the incremental north-to-south capacity into service, and said that gas would be received at the River Road meter in Lancaster County, Pennsylvania, and would flow as far south as the Station 85 Zone 4 Pooling Point, located in Choctaw County, Alabama. The request specifically seeks authorizations to place certain Mainline A & B replacements into service, alongside upgrades and modifications at Compressor Stations 185 and 190 in Virginia and Maryland, respectively.

The proposed River Road meter is expected to be the interconnect between the existing Transco mainline and the Central Penn Line, a roughly 180-mile greenfield pipeline to be built as part of the Atlantic Sunrise project, which will transport up to 1.7 Bcf/d of northeast Pennsylvania production to Transco's mainline for further southbound flow into the mid-Atlantic and US Southeast regions.

The Atlantic Sunrise expansion has been closely watched in the US gas markets as it represents the first major capacity buildout in several years to target northeastern Pennsylvania, a region that led US Northeast production growth in the earlier part of the decade but which has since stalled out as capacity expansions have focused on the southwestern Appalachian region.

— Harry Weber, Eric Brooks

PIPELINE MAINTENANCE

Start date	End date	Pipeline	Description
04-Jun	15-Oct	Algonquin	Algonquin to begin summer-long maintenance on May 2 limiting flows through Southeast/Oxford Compressor Stations
08-Aug	22-Aug	TC Nova	NGTL's maintenance-loaded schedule for August has seen several adjustments leading up to the start of the month, making the scheduled days and volumes still highly susceptible to changes.
15-Aug	17-Aug	WIC	WIC Planned Service Outage
01-Jun	31-Oct	Westcoast	Westcoast Pipeline maintenance has begun cutting capacity at Station 4B South and Huntingdon that will restrict PNW imports at Sumas. The largest cut to capacity is to begin June 7, lasting five days.

DECISION NOTE

Platts announces trade weighting in daily and monthly North American Natural Gas indices

Following consultation and review of the trade weighting proposal note, originally published on April 18 2017, S&P Global Platts has decided to incorporate Intercontinental Exchange (ICE) trade data with Platts Price Reporter (PR) trade data in its North American natural gas indices as described below.

As previously announced on May 19, Platts will begin publishing preliminary daily indices in parallel with ICE daily indices on trade date August 31 for September 1 gas flow. The daily indices will be published in parallel for a minimum of two months and a maximum of three months. Platts will begin publishing preliminary monthly indices in parallel with ICE monthly indices on trade date September 25 for October bidweek. The monthly indices will be published in parallel for a minimum of two and a maximum of three bidweek periods.

1. Preliminary Daily Indices For Platts And ICE Locations:

The only trade data used in these indices will be ICE trades sourced from ICE. Both the buy and sell side of ICE trades will be counted in the indices, regardless of whether the counterparties are Platts price reporters.

2. Final Daily Indices For Platts Locations:

The trade data used in these indices will be:

a. All Platts PR trades submitted via email or ICE eConfirm

b. All ICE trades sourced from ICE

Duplicates will be removed from the ICE trade data and both the buy and sell side of ICE trades will be counted in the indices. For PR trades not done on ICE, only the buy or sell side reported by the price reporter will be counted in the indices. In addition, Platts will continue to screen for outlying data using existing mechanisms as well as verifying trade data that occurs outside of the transparent trading range observed on ICE.

3. Final Daily Indices For ICE Locations:

The only trade data used in these indices will be ICE trades sourced from ICE. Both the buy and sell side of ICE trades will be counted in the indices, regardless of whether the counterparties are Platts price reporters.

4. Preliminary Monthly Indices For Platts Locations:

The trade data used in these indices will be:

a. All ICE trades which include Platts PR trades sourced from ICE

b. Platts PR trades not done on ICE submitted via email or ICE eConfirm

Any duplicate ICE trade will be removed from the PR data and both the buy and sell side of ICE trades will be counted in the indices, regardless of whether the counterparties are Platts price reporters. For PR trades not done on ICE, only the buy or sell side reported by the PR will be counted in the indices. In addition, Platts will continue to screen for outlying data using existing mechanisms as well as verifying trade data that occurs outside of the transparent trading range observed on ICE.

5. Preliminary Monthly Indices For ICE Locations:

The only trade data used in these indices will be ICE trades sourced from ICE. Both the buy and sell side of ICE trades will be counted in the indices, regardless of whether the counterparties are Platts price reporters.

6. Final Monthly Indices For Platts Locations:

The trade data used in these indices will be:

a. All Platts PR trades submitted via email or ICE eConfirm

b. All ICE trades sourced from ICE

Duplicates will be removed from the ICE trade data and both the buy and sell side of ICE trades will be counted in the indices. For PR trades not done on ICE, only the buy or sell side reported by the price reporter will be counted in the indices. In addition, Platts will continue to screen for outlying data using existing mechanisms as well as verifying trade data that occurs outside of the transparent trading range observed on ICE.

7. Final Monthly Indices For ICE Locations:

The only trade data used in these indices will be ICE trades sourced from ICE. Both the buy and sell side of ICE trades will be counted in the indices, regardless of whether the counterparties are Platts price reporters.

Platts will monitor reported transactions and all indices to ensure they properly reflect market value. Any further need to amend the methodology will be communicated as per editorial standards.

Please send any comments to the above to gas_survey_comments@platts.com and pricemethodology@spglobal.com. For written comments, please provide a clear indication if comments are not intended for publication by Platts for public viewing. Platts will consider all comments received and will make comments not marked as confidential available upon request.

NATURAL GAS FUTURES

NYMEX Sept. gas dips for second straight day

The NYMEX September natural gas futures contract dipped for the second straight day Tuesday as the front-month contract continued to come off from the previous week's gains.

The September contract settled at $2.935/MMBtu, down 2.4 cents from Monday's close. Over the past two days, the market has started to retract, falling 4.8 cents.

David Thompson, executive vice president of brokerage PowerHouse, said the market "had a sharp four-day rally, and now it's running out."

Last week, the September contract saw a 20.9-cent increase, bouncing back from a five-month low.

Thompson said the market "basically stalled out" toward the "uptrend line highs" that were seen in recent months.

Thompson said it is "still a bearish market despite the little rally," adding that the front-month contract would have to close above $3.05/MMBtu to "push things higher." Otherwise, the market will fall back to around $2.85/MMBtu.

Prices may see support as the most recent six- to 10-day outlook from the National Weather Service calls for a likelihood of warmer-than-average temperatures for much of the Northeast and Midcontinent.

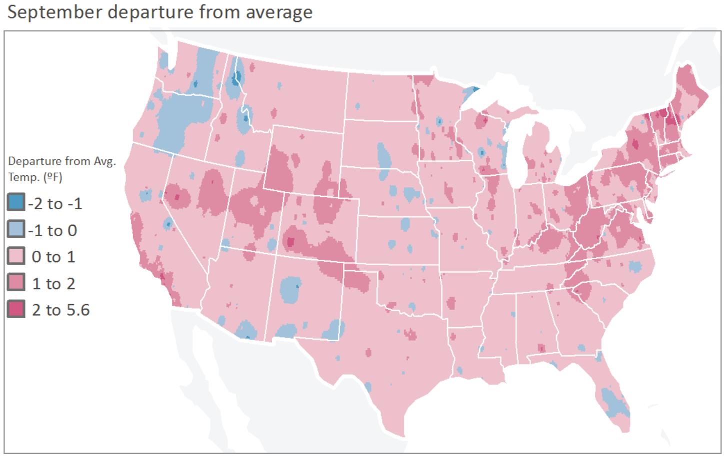
Temperatures in the New York City area are expected to ping-pong from the low 90s to the low 80s back to the mid-80s over the next three days. The average high is 84, according to the weather service.

Over the next seven days, US demand is projected by Platts Analytics' Bentek Energy to average 66.9 Bcf/d, in line with the 67 Bcf expected for Tuesday, with power burn accounting for 34.4 Bcf/d of that total.

Total supply is projected to drop 1.2 Bcf day on day to 77.2 Bcf/d Wednesday, below the month-to-date average of 78.5 Bcf/d, according to Platts Analytics.

MONTH-AHEAD TEMPERATURE FORECAST MAP

September departure from average



Source: Platts, Custom Weather

NYMEX HENRY HUB GAS FUTURES CONTRACT, AUG 15

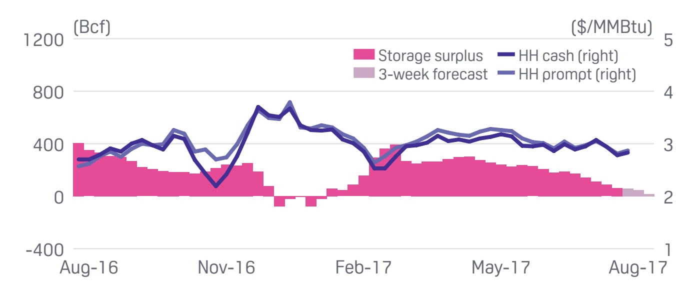
	Settlement	High	Low	+/-	Volume
Sep 2017	2.935	2.972	2.931	-0.024	47507
Oct 2017	2.965	3.000	2.961	-0.024	15132
Nov 2017	3.040	3.069	3.032	-0.019	2775
Dec 2017	3.179	3.204	3.170	-0.018	1074
Jan 2018	3.278	3.303	3.269	-0.020	2519
Feb 2018	3.270	3.294	3.261	-0.019	389
Mar 2018	3.221	3.247	3.213	-0.019	626
Apr 2018	2.892	2.910	2.884	-0.014	1085
May 2018	2.859	2.876	2.851	-0.013	241
Jun 2018	2.884	2.890	2.879	-0.013	50
Jul 2018	2.909	2.920	2.901	-0.014	23
Aug 2018	2.914	2.929	2.911	-0.013	121
Sep 2018	2.890	2.895	2.888	-0.013	34
Oct 2018	2.909	2.915	2.903	-0.013	58
Nov 2018	2.958	2.973	2.954	-0.013	19
Dec 2018	3.087	3.092	3.081	-0.013	18
Jan 2019	3.172	3.180	3.168	-0.013	8
Feb 2019	3.148	3.155	3.143	-0.012	5
Mar 2019	3.080	3.083	3.075	-0.011	3
Apr 2019	2.712	2.720	2.706	-0.014	40
May 2019	2.682	2.682	2.678	-0.014	34
Jun 2019	2.705	2.706	2.700	-0.013	24
Jul 2019	2.728	2.730	2.723	-0.012	2
Aug 2019	2.736	2.738	2.731	-0.012	2
Sep 2019	2.718	2.718	2.718	-0.012	0
Oct 2019	2.740	2.760	2.740	-0.012	0
Nov 2019	2.802	2.802	2.802	-0.014	0
Dec 2019	2.934	2.934	2.934	-0.014	0
Jan 2020	3.038	3.038	3.038	-0.014	0
Feb 2020	3.012	3.012	3.012	-0.015	0
Mar 2020	2.959	2.959	2.959	-0.010	0
Apr 2020	2.647	2.647	2.647	-0.007	0
May 2020	2.627	2.627	2.627	-0.007	0
Jun 2020	2.652	2.652	2.650	-0.008	10
Jul 2020	2.680	3.012	3.012	-0.010	0
Aug 2020	2.701	2.701	2.701	-0.010	0

Contract data for Monday
Volume of contracts traded: 224,911
Front-months open interest:
Sep, 164,417; Oct, 273,549; Nov, 119.044
Total open interest: 1,340,316
Data is provided by a third-party vendor and is accurate as of 5:30 pm Eastern time.

NYMEX PROMPT MONTH FUTURES CONTINUATION

Source: Platts

BENTEK US GAS STORAGE SURPLUS vs ROLLING 5-YEAR AVERAGE



NORTHEAST GAS MARKETS

Northeast prices up on temps, more power burn

A majority of prices in the Northeast and Appalachia saw continued growth Tuesday as warmer temperatures in New York and Boston are expected to support an increase in power burn.

Power burn across the Northeast increased 709 MMcf/d to 8.58 Bcf/d Tuesday, and is expected to stay around the 8 Bcf/d level as warmer temperatures move into the region before dropping off over the weekend. Despite a 9% increase Tuesday, power burn levels are far below the 9.69 Bcf/d averaged in August 2016, according to Platts Analytics' Bentek Energy.

Temperatures in Boston are expected to reach highs in the mid-80s Wednesday, several degrees above the historical seasonal average, as New England power burn is expected to increase, averaging 1.8 Bcf/d over the next two days. Nearby, prices at Algonquin City Gates jumped 26.5 cents to trade at $2.81/MMBtu.

Additionally, New York is projected to see temperatures around 90 on Wednesday, well above the seasonal average high of 84, which will see natural gas demand in the area increase to 2.3 Bcf/d. These factors have seen prices at Tetco-M3 increase 8.5 cents to trade at $1.935/MMBtu.

Decreased natural gas production levels have continued to support upward price movement, as regional production fell 538 MMcf/d Tuesday to 24.1 Bcf/d. This decrease sees regional production matching the 24.1 Bcf/d level last seen July 29, Platts Analytics data shows. Weak production in Pennsylvania has continued to be the main driver of decreased regional production, with Northeast Pennsylvania dry production falling 268 MMcf/d to 8.1 Bcf/d.

Regional production is expected to make gains as the week progresses, climbing to 24.5 Bcf/d by Friday.

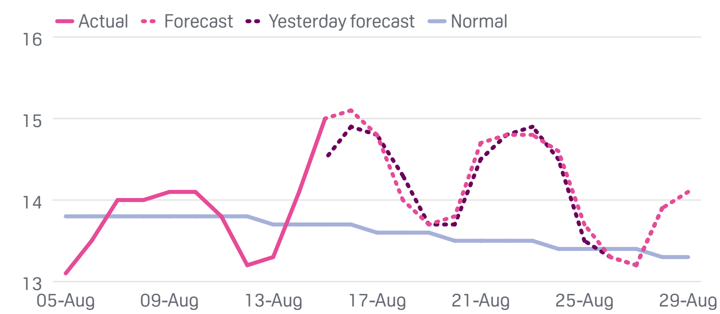
These supply-and-demand dynamics also supported movement in Appalachian prices, with Tetco-M2 receipts trading at $1.78/MMBtu, 8 cents above Monday's close, while TCO saw the only decrease in the region, down 0.5 cent to trade at $2.85/MMBtu.

NORTHEAST SPOT AND FORWARD BASIS ($/MMBtu)

	Spot basis						Prompt forward basis		
	15-Aug	14-Aug	Chg	MTD Avg.	MTD last year	Chg	15-Aug	14-Aug	Chg
Henry Hub	2.93	2.96	-0.04	2.83	2.80	+0.03	2.94	2.96	-0.02
Northeast region									
Algonquin CG	-0.12	-0.42	0.30	-0.41	0.25	-0.66	-0.55	-0.53	-0.02
Iroquois Zn2	0.07	0.08	-0.01	-0.14	0.23	-0.37	-0.21	-0.21	0.00
Tenn Zn6 Dlvd	-0.14	-0.50	0.36	-0.48	0.21	-0.69	-0.52	-0.50	-0.02
Transco Zn 6 NY	-0.05	-0.13	0.09	-0.66	-0.71	+0.05	-0.34	-0.36	0.03
Transco Zn5 Dlvd	0.12	0.10	0.03	0.07	0.00	+0.07	0.10	0.06	0.04
Transco Zn6 Non-NY	-0.01	-0.16	0.15	-0.59	-0.64	+0.04	-0.36	-0.41	0.05
TX Eastern M-3	-0.99	-1.11	0.12	-1.05	-1.44	+0.39	-1.00	-1.01	0.01
Appalachia									
Col Gas Appal	-0.08	-0.11	0.03	-0.11	-0.15	+0.04	-0.18	-0.18	0.00
Dominion N Pt	-1.07	-1.16	0.09	-1.10	-1.52	+0.42	-1.12	-1.12	0.00
Dominion S Pt	-1.08	-1.17	0.09	-1.11	-1.52	+0.40	-1.07	-1.08	0.01
Lebanon Hub	-0.08	-0.12	0.04	-0.08	—	—	-0.12	-0.11	0.00
Millennium East Receipts	-1.00	-1.09	0.10	-1.05	-1.52	+0.47	-1.09	-1.09	0.00
Tenn Zn4-200 Leg	-0.68	-0.82	0.14	-0.89	-1.40	+0.51	-0.92	-0.93	0.01
Tennessee zone 4-300 leg	-1.09	-1.17	0.08	-1.13	-1.56	+0.43	-1.16	-1.17	0.01
Texas Eastern M-2 receipts	-1.15	-1.26	0.12	-1.17	-1.55	+0.39	-1.10	-1.11	0.01
Transco Leidy Line receipts	-1.07	-1.15	0.09	-1.09	-1.49	+0.40	-1.09	-1.10	0.01
Other locations									
Dracut MA	—	—	—	—	—	—	-0.13	-0.12	-0.02
Iroquois Receipts	0.05	-0.04	0.09	-0.13	0.08	-0.21	-0.25	-0.25	0.00
Niagara	—	—	—	—	—	—	-0.62	-0.62	0.00

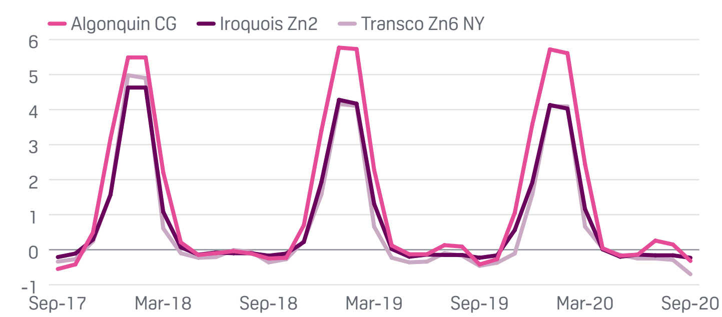
Source: Platts M2M data

NORTHEAST DEMAND FORECAST (Bcf/d)



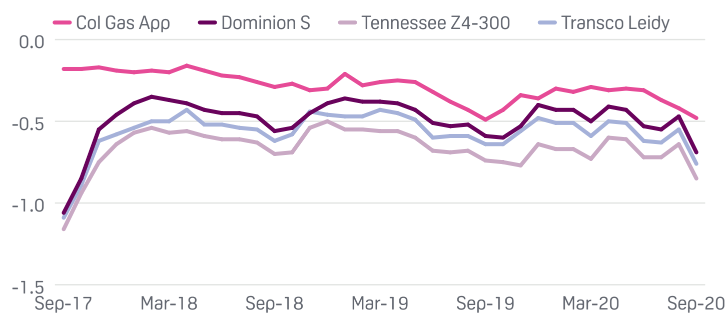
Source: Platts

NORTHEAST FORWARD BASIS ($/MMBtu)



Source: Platts

APPALACHIA FORWARD BASIS ($/MMBtu)



Source: Platts

SOUTHEAST GAS MARKETS

Cash down despite demand nearing 3-week high

Following a strong upward run over much of the last week, Southeast cash prices slipped Tuesday even as demand projections put the market on pace to reach an August high Wednesday, according to Platts Analytics' Bentek Energy data.

Platts Analytics data projects regional demand to edge over the 20 Bcf/d hump on Wednesday, marking the highest level since July 28 and the strongest demand level in August.

Looking ahead, the same data set projects total demand to remain elevated in the 19.6 Bcf/d to 20.1 Bcf/d level through Saturday before tailing off slightly Sunday.

This dovetails with the latest National Weather Service expectations in the six- to 10-day outlook, calling for an increasingly high probability for above-average temperatures.

In the face of this market environment, cash prices largely fell a few cents across the region, with Henry Hub slipping nearly 4 cents to $2.925/MMBtu.

While also falling 2 cents to $2.975/MMBtu Tuesday, Florida Gas Transmission Zone 3 cash basis widened to plus 5 cents/MMBtu as the FGT supply route issued the possibility of an Overage Alert Day as temperatures in the mid-90s persist over Orlando through Thursday.

Since Florida demand has surged above 4.5 Bcf/d a total of eight times in August to date, cash basis has averaged just under plus 3 cents/MMBtu since August 3, a 6-cent strengthening from the July average of minus 3 cents/MMBtu.

Moving down the Texas Gulf Coast, Natural Gas Pipeline-STX pricing point slipped by 2 cents to $2.84/MMBtu, falling by one of the smaller margins when compared to other South Texas and East Texas pricing points.

NGPL issued a notice Monday afternoon regarding maintenance that will be conducted on Compressor Station 300 in Victoria County, Texas, on Wednesday.

While the notice stated no expected impact to flows during the projected four-hour maintenance episode, NGPL will monitor flows to NET Mexico, possibly impacting all transport services if deliveries flow off-rate.

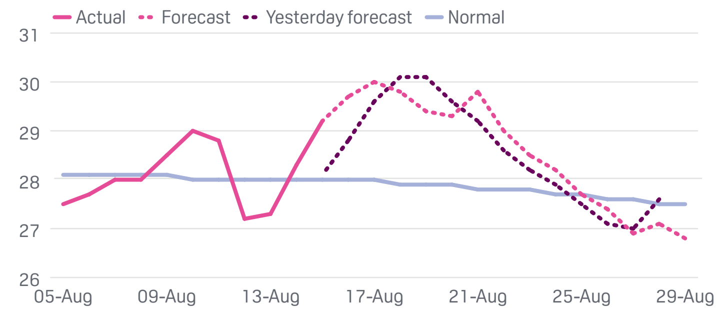
Elsewhere in the region, Texas Eastern, ETX fell by 8 cents to $2.85/MMBtu, the largest downward mover in the East Texas region.

SOUTHEAST SPOT AND FORWARD BASIS ($/MMBtu)

	Spot basis						Prompt forward basis		
	15-Aug	14-Aug	Chg	MTD Avg.	MTD last year	Chg	15-Aug	14-Aug	Chg
Henry Hub	2.93	2.96	-0.04	2.83	2.80	+0.03	2.94	2.96	-0.02
Southeast									
ANR LA	-0.04	-0.09	0.05	-0.05	-0.09	+0.03	-0.10	-0.10	0.00
Col Gulf LA	-0.01	-0.03	0.03	-0.04	-0.09	+0.05	-0.08	-0.08	0.00
Col Gulf-Mainline	-0.05	-0.08	0.03	-0.06	-0.11	+0.04	-0.11	-0.11	0.00
FL Gas Zn1	-0.01	0.02	-0.02	-0.01	-0.08	+0.06	-0.05	-0.05	0.00
FL Gas Zn2	0.00	0.01	—	-0.02	-0.06	+0.04	-0.04	-0.04	0.00
FL Gas Zn3	0.05	0.04	0.02	0.03	-0.02	+0.04	-0.03	-0.03	0.00
Florida CG	0.50	0.34	0.16	0.65	0.51	+0.15	0.26	0.26	0.00
SoNat LA	-0.01	-0.01	0.00	-0.02	-0.07	+0.05	-0.09	-0.08	0.00
Tenn LA 500 Leg	-0.03	-0.03	0.00	-0.03	-0.08	+0.05	-0.09	-0.10	0.01
Tenn LA 800 Leg	-0.03	-0.06	0.04	-0.05	-0.08	+0.03	-0.08	-0.08	0.00
TETCO-M1	0.01	0.04	-0.04	-0.01	-0.08	+0.07	-0.08	-0.08	0.00
Texas Gas Zn SL	-0.10	-0.06	-0.04	-0.08	-0.12	+0.03	-0.12	-0.12	0.00
Texas Gas Zn1	-0.08	-0.08	0.00	-0.06	-0.11	+0.05	-0.12	-0.12	0.00
Transco Zn2	-0.01	-0.05	0.04	-0.02	-0.09	+0.06	-0.14	-0.13	-0.01
Transco Zn3	-0.01	-0.01	-0.01	-0.02	-0.06	+0.05	-0.05	-0.05	0.00
Transco Zn4	0.03	0.02	0.01	0.01	-0.04	+0.05	-0.04	-0.04	0.00
Trunkline E LA	-0.07	-0.08	0.02	-0.09	-0.13	+0.04	-0.09	-0.09	0.00
Trunkline WLA	—	—	—	—	-0.11	—	-0.08	-0.09	0.01
Tx Eastern E LA	-0.04	-0.06	0.02	-0.04	-0.09	+0.04	-0.09	-0.09	0.00
TX Eastern W LA	-0.02	-0.09	0.08	-0.03	-0.08	+0.05	-0.08	-0.08	0.00
East & South Texas									
Agua Dulce	—	—	—	—	0.10	—	0.00	0.00	0.00
Carthage Hub	-0.09	-0.06	-0.03	-0.05	-0.08	+0.03	-0.09	-0.09	0.00
Houston Ship Channel	-0.03	-0.02	-0.01	-0.01	-0.05	+0.04	-0.04	-0.04	0.00
Katy	-0.03	-0.02	-0.01	-0.01	-0.06	+0.05	-0.04	-0.04	0.00
NGPL S TX	-0.09	-0.10	0.02	-0.03	-0.10	+0.07	-0.08	-0.08	0.00
NGPL Texok Zn	-0.09	-0.12	0.04	-0.08	-0.11	+0.03	-0.13	-0.13	0.00
Tenn Zn0	-0.09	-0.14	0.05	-0.11	-0.16	+0.05	-0.15	-0.15	0.00
Transco Zn1	-0.02	-0.05	0.03	-0.04	-0.07	+0.03	-0.08	-0.08	0.00
TX Eastern E Tx	-0.08	-0.03	-0.05	-0.06	-0.11	+0.05	-0.08	-0.08	0.00
TX Eastern S TX	-0.02	0.01	-0.02	-0.01	-0.06	+0.05	-0.06	-0.06	0.00

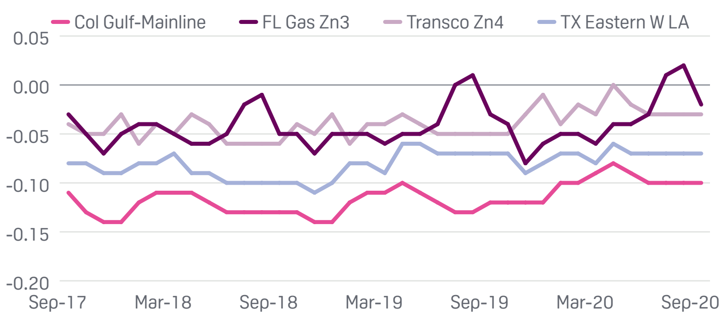
Source: Platts M2M data

SOUTHEAST & TEXAS DEMAND FORECAST (Bcf/d)



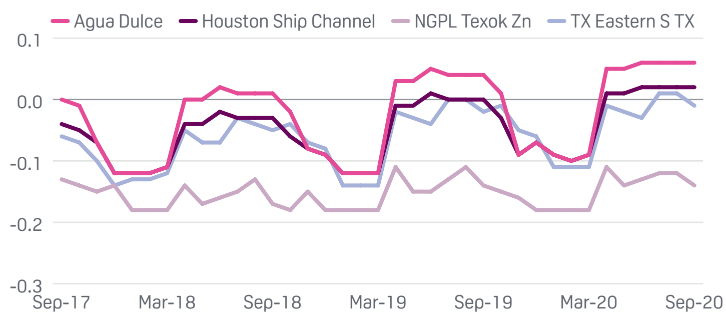
Source: Platts

SOUTHEAST FORWARD BASIS ($/MMBtu)



Source: Platts

EAST AND SOUTH TEXAS FORWARD BASIS ($/MMBtu)



Source: Platts

CENTRAL GAS MARKETS

Prices move sideways in demand areas

US Central natural gas next-day cash prices fell in producing areas Tuesday, as demand area prices moved sideways on the day, with temperatures expected to be average.

Next-day cash prices for Carthage dropped 6.5 cents day-on-day to $2.835/MMBtu, weakening its cash basis against the Henry Hub spot price to around minus 9 cents/MMBtu. The Henry Hub prompt price dropped 3.5 cents to $2.925/MMBtu.

Chicago city-gates spot prices notched 0.5 cent downward on the day to $2.885/MMBtu, strengthening its cash basis to minus 4 cents/MMBtu.

The relative stability of demand prices comes as temperatures in the Windy City are projected to hover around the low 80s over the next five days, in line with the average of 82 degrees Fahrenheit seen in the Chicago area during that time, according to the National Weather Service.

Total demand in the Midcontinent is projected by Platts Analytics' Bentek Energy data to average 11.64 Bcf/d over the next 2 days, above the 11.33 Bcf/d averaged month to date.

Month to date, total demand in the Midcontinent is down 6% from the 12.04 Bcf/d averaged this time last August, according to Platts Analytics.

Looking ahead, the most recent six- to 10-day weather outlook from the weather service calls for a high likelihood of warmer-than-average temperatures in the Detroit and Chicago areas. The warmer outlook could push prices upward if supply doesn't keep pace with the uptick in demand.

The bullish weather outlook will also likely continue to put pressure on storage stocks in the Midwest. Storage builds in the region have been under the five-year-average for nine straight weeks, depleting total stocks in the Midwest to only a 2.8% surplus over the five-year average, according to US Energy Information Administration data.

Platts Analytics data shows production in the Midcontinent has averaged 7.64 Bcf/d month to date, up from the 7.35 Bcf/d seen this time last August.

Total inflows to the Midcon are expected to increase 89 MMcf day on day, with the largest on day increasing coming from Canada-West, according to Platts Analytics.

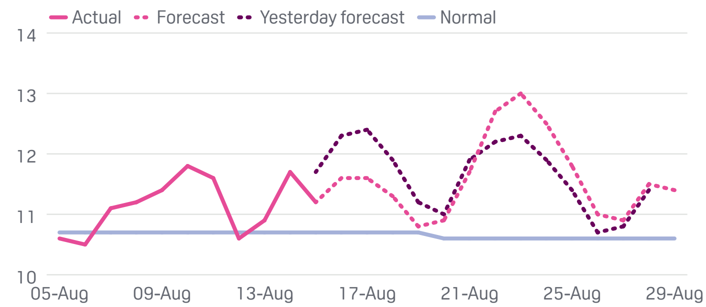
Year to date, Platts Analytics data shows inflows from Canada-West have averaged 4.15 Bcf/d, up 14% from the 3.63 Bcf/d averaged this time last year.

CENTRAL SPOT AND FORWARD BASIS ($/MMBtu)

	Spot basis						Prompt forward basis		
	15-Aug	14-Aug	Chg	MTD Avg.	MTD last year	Chg	15-Aug	14-Aug	Chg
Henry Hub	2.93	2.96	-0.04	2.83	2.80	+0.03	2.94	2.96	-0.02
Midwest/East Canada									
ANR ML 7	—	—	—	-0.06	-0.07	+0.01	-0.03	-0.04	0.01
Chicago CG	-0.04	-0.07	0.03	-0.04	-0.05	+0.01	-0.11	-0.12	0.01
Consumers Energy CG	-0.02	-0.06	0.04	-0.01	-0.04	+0.03	-0.14	-0.14	0.00
Dawn Ontario	-0.02	-0.05	0.03	-0.01	-0.05	+0.04	-0.06	-0.06	0.00
Mich Con CG	-0.04	-0.06	0.03	-0.03	-0.08	+0.05	-0.09	-0.09	0.00
Northern Ventura	-0.17	-0.19	0.02	-0.15	-0.09	-0.05	-0.19	-0.19	0.00
Viking-Emerson	-0.29	-0.30	0.01	-0.30	-0.17	-0.12	-0.36	-0.36	0.00
Midcontinent									
ANR OK	-0.33	-0.31	-0.02	-0.26	-0.23	-0.03	-0.33	-0.33	0.00
Enable Gas East	-0.25	-0.23	-0.02	-0.17	-0.17	+0.00	-0.19	-0.19	0.00
NGPL Midcontinent	-0.27	-0.29	0.02	-0.25	-0.14	-0.10	-0.31	-0.31	0.00
Northern NG Demarc	-0.18	-0.17	-0.01	-0.14	-0.09	-0.05	-0.20	-0.19	-0.01
Oneok OK	-0.51	-0.55	0.04	-0.52	-0.25	-0.26	-0.54	-0.54	0.00
Panhandle TX-OK	-0.37	-0.32	-0.05	-0.33	-0.22	-0.11	-0.37	-0.37	0.00
Southern Star TxOkKs	-0.38	-0.39	0.01	-0.35	-0.23	-0.12	-0.39	-0.39	0.00

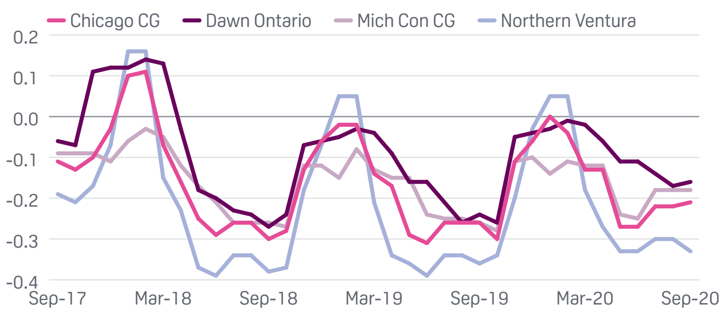
Source: Platts M2M data

MIDWEST & MIDCONTINENT DEMAND FORECAST (Bcf/d)



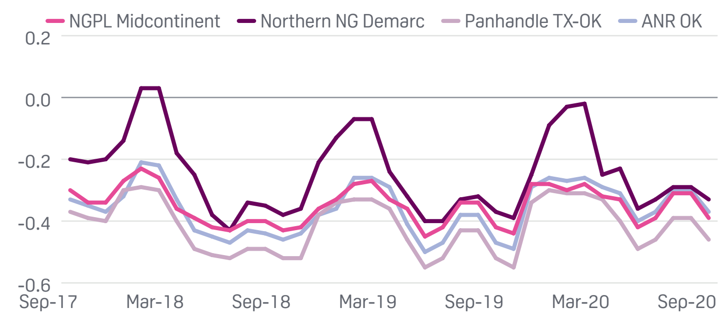
Source: Platts

MIDWEST FORWARD BASIS ($/MMBtu)



Source: Platts

MIDCONTINENT FORWARD BASIS ($/MMBtu)



Source: Platts

WEST GAS MARKETS

Gas lower as inflows grow despite weak demand

Cash prices across the West were markedly lower Tuesday as temperatures failed to drive expectations for significant demand and inflows continued to show strength despite bearish demand and outflow trends.

Cooler-than-normal temperatures are expected to keep total demand below the 10 Bcf/d mark through the rest of the week, Platts Analytics data shows, in turn taking the monthly average below the comparable period last year for the first time this month.

These weaker expectations weighed on California gas markets, with SoCal city-gates cash basis trading over 15 cents lower at minus 15 cents/MMBtu.

Simultaneous with the weakening demand, regional outflows have diminished 21% in August compared with last year, with most of the decline attributable to Southwest-to-Texas flows on El Paso, which have fallen over 500 MMcf/d year on year, Platts Analytics data shows.

Despite this flat year-on-year demand and falling outflows, inflows from Texas to the Southwest have remained strong during the first half of August, rising 40% above the same period last year, currently averaging 1.3 Bcf/d, Platts Analytics' Bentek Energy data shows.

This build in inflows largely originates in the Permian, where production has averaged 6.2 Bcf/d August to date, 1.1 Bcf stronger than a year prior. A good portion of this new production is then moving westward on existing infrastructure, including El Paso Pipeline, which has seen westward flows average 1.8 Bcf/d this month, up nearly 200 MMcf/d year on year.

These increased flows, without the demand to match it, has put downward pressure on Southwest cash basis, including Waha hub, which has averaged plus 8 cents/MMBtu this month, 4 cents, or over 30%, lower than last year.

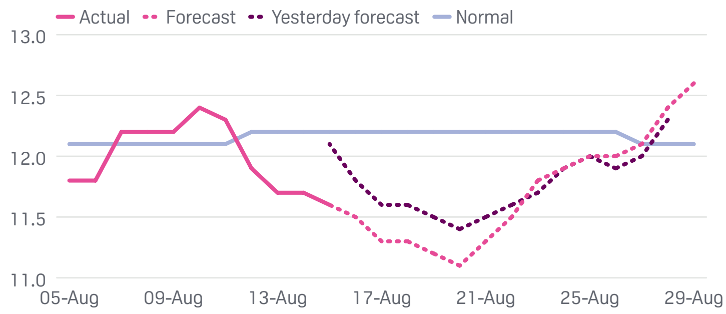
On Tuesday, Waha cash basis extended recent losses into a four-session slump, shedding an additional 14 cents to trade at minus 31 cents/MMBtu. Tuesday's drop brings the total decline since August 9 to over 35 cents.

WEST SPOT AND FORWARD BASIS ($/MMBtu)

	Spot basis						Prompt forward basis		
	15-Aug	14-Aug	Chg	MTD Avg.	MTD last year	Chg	15-Aug	14-Aug	Chg
Henry Hub	2.93	2.96	-0.04	2.83	2.80	+0.03	2.94	2.96	-0.02
Northwest									
GTN Kingsgate	-0.48	-0.45	-0.04	-0.42	-0.34	-0.08	-0.51	-0.50	-0.01
Northwest Sumas	-0.42	-0.42	0.00	-0.32	-0.29	-0.03	-0.51	-0.50	-0.02
Northwest Stanfield	-0.41	-0.37	-0.04	-0.31	-0.21	-0.10	-0.34	-0.33	-0.01
Rockies									
Cheyenne Hub	-0.40	-0.35	-0.05	-0.31	-0.23	-0.08	-0.37	-0.37	0.00
CIG Rockies	-0.42	-0.36	-0.06	-0.33	-0.24	-0.09	-0.37	-0.36	-0.01
Kern River Opal	-0.34	-0.31	-0.04	-0.26	-0.17	-0.09	-0.34	-0.33	-0.01
NW WY Pool	-0.39	-0.36	-0.03	-0.31	-0.22	-0.09	-0.34	-0.33	-0.01
Questar Rky	-0.42	-0.37	-0.05	-0.32	-0.21	-0.11	-0.33	-0.33	-0.01
Southwest									
El Paso Permian	-0.37	-0.33	-0.04	-0.26	-0.17	-0.09	-0.36	-0.36	0.00
El Paso San Juan	-0.36	-0.34	-0.02	-0.26	-0.16	-0.09	-0.32	-0.31	-0.01
Kern River Dlvd	-0.24	-0.19	-0.05	0.05	0.05	+0.00	-0.16	-0.14	-0.01
PG&E CG	0.34	0.33	0.02	0.42	0.37	+0.05	0.36	0.36	-0.01
PG&E Malin	-0.30	-0.26	-0.04	-0.20	-0.12	-0.08	-0.25	-0.24	-0.01
PG&E South	-0.26	-0.24	-0.02	-0.13	-0.07	-0.07	-0.16	-0.15	-0.01
SoCal Gas	-0.26	-0.22	-0.04	-0.04	0.00	-0.04	-0.17	-0.15	-0.01
SoCal Gas Citygate	-0.15	0.05	-0.20	0.34	0.06	+0.29	0.15	0.16	-0.01
Transwestern Permian	-0.38	-0.34	-0.04	-0.27	-0.16	-0.11	-0.35	-0.35	0.00
Waha	-0.32	-0.27	-0.05	-0.20	-0.14	-0.06	-0.29	-0.29	0.00
West Canada									
AECO-C	-0.56	-0.68	0.12	-1.16	-0.75	-0.41	-1.33	-1.31	-0.02

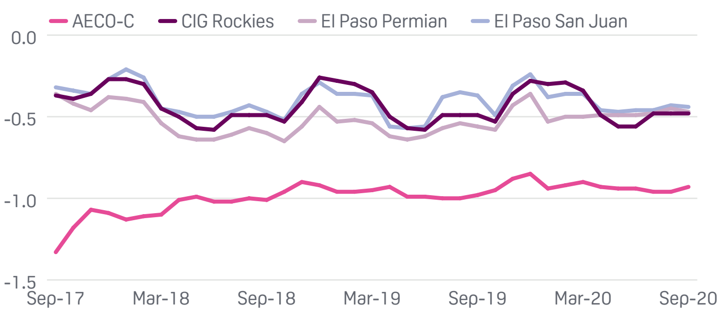
Source: Platts M2M data

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



Source: Platts

WEST SUPPLY LOCATIONS FORWARD BASIS ($/MMBtu)



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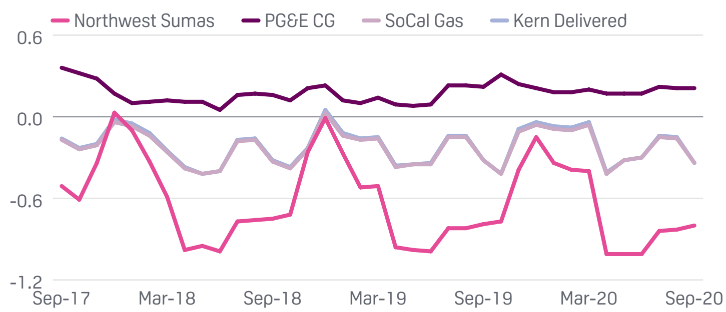
WEST DEMAND LOCATIONS FORWARD BASIS ($/MMBtu)



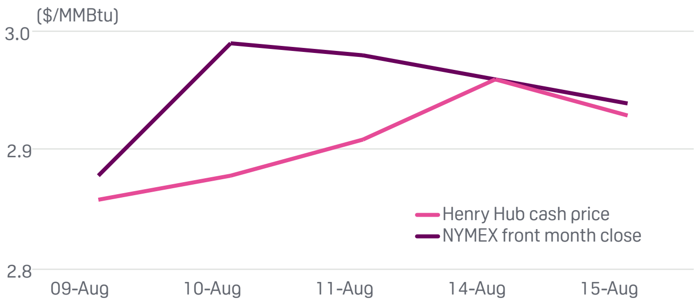
Source: Platts

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

	14-Aug	15-Aug	Change	MTD avg.	MTD last year	Change
Supply regions – net pipeline outflows						
Texas	7,833	7,925	-92	7,900	8,064	-164
West Canada	8,174	8,175	-1	8,351	8,896	-545
Rockies	6,780	6,414	366	6,617	6,741	-124
Midcontinent	3,263	3,318	-55	3,212	2,643	569
Northeast	6,181	5,988	193	5,661	3,980	1,681
Demand regions – net pipeline inflows						
Southwest	4,940	4,328	-612	4,992	4,995	3
Southeast	6,836	6,937	101	6,554	6,601	47
Northwest	1,734	1,720	-14	1,782	1,719	-63
Midwest	11,123	11,192	69	10,889	10,359	-530
East Canada	3,277	3,185	-92	3,168	2,631	-537

* 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



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SHALE VALUE CHAIN ASSESSMENTS, AUG 15

	$/MMBtu	+/-
Gulf Coast ethane fractionation spread	1.123	0.040
Gulf Coast E/P mix fractionation spread	1.085	0.040
E/P mix Midcontinent to Rockies fractionation spread	0.916	0.133
E/P mix Midcontinent fractionation spread	0.766	0.058
National raw NGL basket price	6.868	-0.029
National composite fractionation spread	3.968	0.011

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

PLATTS OIL PRICES, AUG 15

	($/b)	($/MMBtu)
Gulf Coast spot		
1% Resid (1)	46.59-46.61	7.46
HSFO (1)	44.84-44.86	7.18
Crude spot		
WTI (Sep) (2)	47.54-47.56	8.20
New York spot		
No.2 (1)	58.24-58.28	9.32
0.3% Resid LP (3)	51.21-51.23	8.20
0.3% Resid HP (3)	51.21-51.23	8.20
0.7% Resid (3)	47.46-47.48	7.60
1% Resid (3)	46.21-46.23	7.40

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

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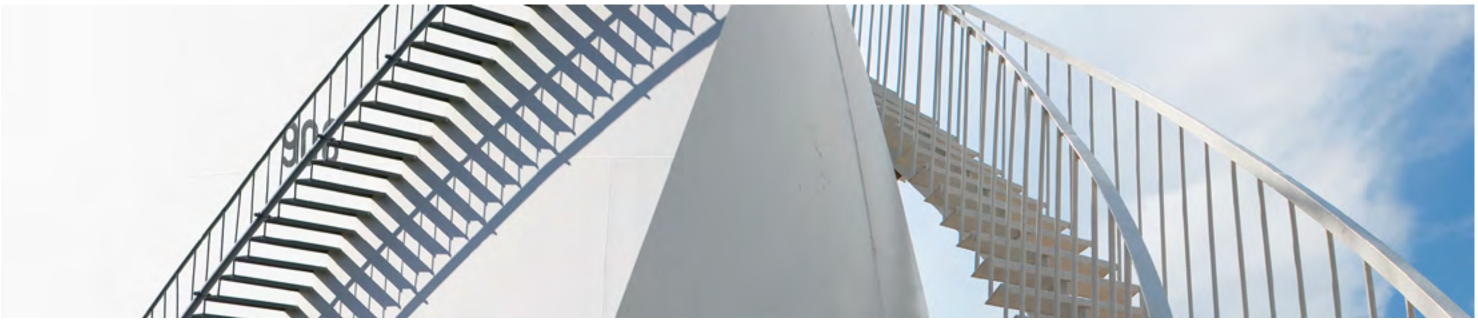

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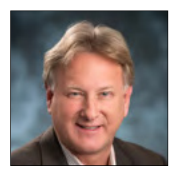
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