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NATURAL GAS WEEK®

CONTENTS

REGULATION

Operator Fatigue Contributed to 'Severe Damage' at Freeport, Analysis Finds

Employee fatigue and training deficiencies contributed to the fire and explosion that knocked the Freeport LNG terminal off line in early June, according to a root-cause analysis made public this week.

The report by IFO Group, commissioned by Freeport LNG, has shed new light on the scale of destruction to the Texas Gulf Coast facility, adding more uncertainty to when it can restart operations.

IFO concluded that an isolated piping segment ruptured Jun. 8 after the LNG within it warmed and expanded because of exposure to ambient conditions. In the weeks leading up to the incident, 97% of staff worked in excess of their scheduled hours, with 20% of staff working in excess of 130% of their scheduled hours, and 54% of staff working over 120% of their scheduled hours, it found.

Amid 'Excessive Alarms,' a Missed Warning

"During our interviews, operators commented about 'excessive alarms.' Some operators even noted that there were alarms constantly indicating on equipment that had been placed out of service years ago," the report said. "These circumstances apparently resulted in reported alarm fatigue, at least for some of the operators interviewed during the course of the investigation.

"Fatigue can increase errors, delay responses and cloud decision-making. Research also shows that complex task decision-making that requires innovative, flexible thinking and planning are highly sensitive to fatigue."

According to the investigation, two days before the incident one of Freeport's operators noticed a pipe at the facility "had noticeably moved" and alerted supervisors. An engineer was sent to investigate, but he "had very little experience with piping as his expertise was based primarily on rotating equipment such as pumps and compressors."

He prepared a detailed report for senior engineers and the operations management team at the site on Jun. 7, "but none of these more experienced personnel went ... to evaluate the issue for themselves. Regardless, no one at the site recognized the cause of the unusual pipe movement as thermal expansion resulting in increased pipe pressure applying forces to the expansion joints and other components of [the] line ... and events continued unabated until the [rupture]," the report said.

"This initial piping failure and explosion, together with the subsequent displacement of and damage to other process piping, instrumentation, wiring and pipe rack struc-

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KEY WEEKLY SPOT PRICES*

Flow Dates: 11/15-11/21

	$/MMBtu	Chg.	High	Low
Henry Hub	6.05	1.68	6.25	5.66
Transco Z6 - NY	7.46	4.00	8.45	6.00
Algonquin	8.61	5.03	13.00	6.30
Eastern Gas South	5.61	3.03	5.88	5.20
Chicago Citygate	6.03	1.55	6.40	5.65
NNG Ventura	6.14	1.38	6.50	5.77
Waha Hub	5.02	2.21	6.00	4.40
Katy Hub	5.25	1.98	5.70	4.85
SoCal Border	8.04	0.28	8.75	6.80
NW Rockies	7.91	0.48	8.56	5.80
NW Sumas	8.47	-0.08	8.85	7.89
AECO	4.53	0.73	4.76	4.23

>> *Full table on page 2

NATURAL GAS WEEKLY SPOT PRICES

Flow Dates: 11/15-11/21

Price Point	$/MMBtu	Chg.	High	Low	Avg. Daily Vol.	Avg. Daily Deals	Nov Bid Week
GULF COAST							
ANR SE	6.02	1.86	6.13	5.47	76,271	10	5.19
Col. Gulf - Erath	6.02	1.66	6.24	5.70	4,029	1	5.04
Col. Gulf - Rayne	5.72	1.92	5.92	5.40	83,186	11	4.50
Florida Zone 1	5.51	1.99	6.30	5.05	17,929	3	4.69
Florida Zone 2	6.06	1.96	6.38	5.85	2,031	1	5.24
Florida Zone 3	6.31	2.33	6.50	6.00	76,043	15	5.40
Henry Hub	6.05	1.68	6.25	5.66	152,186	17	5.21
NGPL-LA	--	--	--	--	--	--	--
Pine Prairie Hub	5.95	0.00	6.20	5.60	34,657	5	--
Sonat	6.10	1.92	6.45	5.84	129,220	21	5.33
Tenn 500 So LA Z1	5.95	2.19	6.30	5.69	38,629	6	5.02
Tenn 800 So LA Z1	5.63	2.39	6.10	5.45	3,366	1	5.02
Tetco ELA	5.81	2.83	6.10	5.55	41,986	5	4.69
Tetco WLA	5.96	1.99	6.20	5.63	72,943	13	4.93
TGT Zone SL	--	--	--	--	--	--	--
Transco Station 45	6.19	2.26	6.25	5.69	32,800	5	5.17
Transco Station 65	6.20	1.97	6.48	5.86	128,043	19	5.19
Trunkline ELA	--	--	--	--	--	--	--
Trunkline WLA	--	--	--	--	--	--	--
Trunkline Zone 1A	5.73	1.83	6.05	5.44	33,921	4	4.60
Regional Average	*6.02*	*1.91*					*5.10*
TEXAS (SOUTH/EAST)							
Carthage Hub	5.34	1.99	5.75	5.10	19,143	2	4.43
Houston Ship Channel	5.13	2.66	5.50	4.85	44,186	4	4.46
Katy Hub	5.25	1.98	5.70	4.85	129,586	13	4.93
NGPL-South Texas	5.46	1.78	5.75	5.10	95,343	11	--
NGPL-TexOk	5.54	2.24	5.80	5.20	428,105	49	4.52
Tenn Zone 0	5.31	1.99	5.75	5.00	99,900	16	4.43
Tetco-East Texas	5.78	2.03	5.80	5.77	2,000	1	--
Tetco-South Texas	5.44	1.45	5.61	5.10	31,929	5	--
TGT Zone 1	5.73	1.75	5.99	5.40	215,286	21	4.57
Transco Station 30	5.27	1.31	5.60	5.12	15,629	3	--
Tres Palacios Hub	5.38	1.92	5.73	5.01	91,500	13	--
Regional Average	*5.48*	*2.00*					*4.51*
TEXAS (WEST)							
El Paso Permian	5.00	2.13	6.30	4.40	217,171	37	3.22
NNG Custer	--	--	--	--	--	--	--
Transwes E of Thoreau	5.14	2.62	5.70	4.65	31,843	5	3.05
Waha Hub	5.02	2.21	6.00	4.40	132,843	26	3.24
Regional Average	*5.02*	*2.18*					*3.22*
MIDCONTINENT							
ANR SW	5.89	1.58	6.22	5.50	37,314	7	4.69
CenterPoint East	5.62	1.98	5.76	5.34	30,529	4	4.47
CenterPoint West	--	--	--	--	--	--	--
NGPL-MC	5.61	2.17	5.90	5.20	115,071	18	4.51
Oneok	5.68	2.75	5.90	5.15	37,729	7	4.22
Panhandle	5.75	2.18	6.08	5.32	85,889	15	4.49
Southern Star	5.89	2.30	6.20	5.50	18,357	2	4.65
Regional Average	*5.70*	*2.13*					*4.44*
GREAT PLAINS							
Emerson	5.81	1.60	5.97	5.45	28,811	9	4.77
NB Ventura TP	5.97	1.21	6.35	5.80	32,614	4	--
NGPL Amarillo	5.88	1.79	6.30	5.65	5,857	1	--
NNG Demarc	6.12	1.68	6.50	5.82	55,765	9	--
NNG Ventura	6.14	1.38	6.50	5.77	92,614	14	--
Regional Average	*6.06*	*1.59*					*4.77*
UPPER MIDWEST							
Alliance	5.93	1.53	6.23	5.57	183,971	23	--
ANR ML7	6.10	1.60	6.10	6.10	2,857	1	--
Chicago Citygate	6.03	1.55	6.40	5.65	242,486	26	5.05
Consumers	5.83	1.65	6.15	5.48	94,100	15	4.76
MichCon	5.81	1.83	6.15	5.46	197,471	27	4.71
REX Zone 3 Delivered	5.95	1.43	6.30	5.50	200,079	24	4.70
Regional Average	*5.93*	*1.51*					*4.72*

Price Point	$/MMBtu	Chg.	High	Low	Avg. Daily Vol.	Avg. Daily Deals	Nov Bid Week
SOUTHEAST							
Tetco M1	--	--	--	--	--	--	--
Transco Zone 4	6.24	1.97	8.25	5.95	388,770	53	5.33
Transco Zone 5	7.85	2.87	12.00	6.30	334,800	56	5.68
Regional Average	*6.99*	*2.43*					*5.47*
APPALACHIA							
Col. Gas App. Pool	5.58	2.41	5.83	5.24	67,077	16	4.00
Eastern Gas North	5.74	2.72	5.87	5.30	18,971	1	3.76
Eastern Gas South	5.61	3.03	5.88	5.20	405,962	53	3.74
Lebanon Hub	6.09	1.62	6.60	5.55	22,760	3	4.65
Millennium, East Receipts	5.62	2.88	6.00	5.35	19,994	3	3.91
TENN Z4 200-leg	5.76	2.10	6.00	5.28	76,641	9	4.04
TENN Z4 300 leg, receipts	5.64	3.37	5.80	5.25	12,943	3	3.74
TENN Z4 313 pool	5.60	3.07	5.83	5.31	24,953	4	3.90
Tetco M2	5.68	3.13	5.94	5.25	203,965	30	3.70
Transco Leidy Line	5.64	3.17	5.83	5.31	19,539	4	3.76
Regional Average	*5.65*	*2.76*					*3.90*
EASTERN CANADA							
Dawn	5.91	1.54	6.29	5.49	401,786	51	4.98
Iroquois	6.34	2.23	6.80	5.85	134,466	21	5.09
Niagara	5.92	3.22	6.15	5.70	9,838	2	4.39
Regional Average	*6.02*	*1.66*					*4.96*
NORTHEAST / MIDATLANTIC							
Algonquin	8.61	5.03	13.00	6.30	70,220	11	6.46
Dracut	--	--	--	--	--	--	--
Iroquois Zone 2	8.55	4.08	12.75	6.15	61,001	11	5.78
Tenn Gas Zone 6	8.11	3.96	20.00	6.10	92,757	12	--
Tetco M3	7.08	4.13	8.30	5.55	67,410	13	4.17
Transco Z6 - Non-NY	7.52	4.71	8.75	6.24	28,486	9	4.29
Transco Z6 - NY	7.46	4.00	8.45	6.00	8,401	2	4.49
Regional Average	*8.02*	*4.50*					*4.88*
ROCKIES							
Cheyenne Hub	6.03	1.70	6.50	5.70	90,743	13	5.25
CIG	5.94	1.44	6.46	5.70	45,114	8	4.93
Kern River / Opal	8.15	0.29	8.70	7.80	69,000	16	5.78
NW Rockies	7.91	0.48	8.56	5.80	51,286	10	5.77
Questar	8.06	0.54	8.40	7.62	3,943	1	5.70
White River Hub	6.13	0.85	6.80	5.67	59,743	10	5.30
Regional Average	*6.82*	*1.13*					*5.55*
SAN JUAN BASIN							
El Paso Bondad	6.17	0.54	7.00	5.69	39,886	9	5.34
El Paso San Juan	6.18	0.66	7.55	5.65	91,671	15	5.42
Transwestern, San Juan	6.23	0.69	6.95	5.80	47,871	6	5.61
Regional Average	*6.19*	*0.64*					*5.49*
PACIFIC NORTHWEST/WESTERN CANADA							
AECO	4.53	0.73	4.76	4.23	360,360	60	3.87
Kingsgate	5.27	0.09	5.50	4.65	5,171	1	--
Malin	8.46	0.54	8.65	7.95	20,614	5	5.93
NW Sumas	8.47	-0.08	8.85	7.89	62,888	15	6.07
Stanfield	8.35	0.47	8.70	6.50	69,766	15	--
Westcoast Station 2	2.89	0.76	4.33	1.61	70,260	15	3.51
Regional Average	*5.35*	*1.11*					*4.27*
CALIFORNIA							
El Paso - South Mainline	8.28	0.45	8.75	7.40	44,136	7	--
Kern - Wheeler Ridge	8.38	0.45	8.65	7.96	3,292	1	--
Kern River Delivered	8.43	0.24	8.90	8.10	131,957	28	--
PG&E Citygate	8.77	0.25	9.23	8.21	125,157	19	7.32
PG&E South	7.54	0.11	8.20	5.70	28,543	5	--
SoCal Border	8.04	0.28	8.75	6.80	154,530	33	6.66
SoCal Citygate	8.64	0.36	9.10	8.10	115,529	21	7.25
Regional Average	*8.39*	*0.37*					*7.05*
WEEKLY COMPOSITE SPOT PRICES							
Delivered	7.46	2.13					
Wellhead	5.51	1.75					

Freeport Tugs at Market, But Early Cold Weather Demand Rules

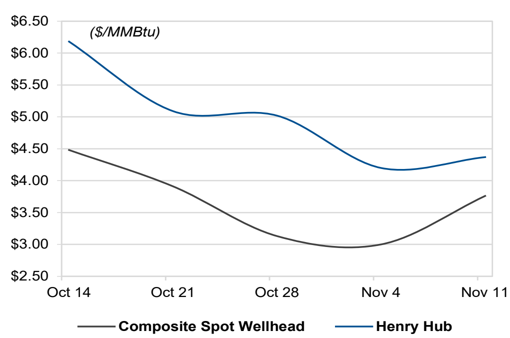
December gas futures recovered from an early plunge, falling just 6.6¢ Friday to $6.303 per million Btu, as the market gained more clarity about when Freeport LNG would resume operations.

Freeport has repeatedly delayed a restart of its facility, originally set for October. The company announced Friday morning that it expects to begin ramping operations in mid-December and reach 2 Bcf/d of production in January, assuming regulatory approvals.

Initially, the market had a knee-jerk reaction to the news and surged as high as $6.475 during the session. But the contract quickly retreated when traders realized the news wasn't all that bullish. The latest timeline means an extra cushion of supply will linger through the end of the year at a time when storage hovers near the five-year average.

The Freeport news comes a day after the US Energy Information Administration reported a 64 Bcf storage build for the week ended Nov. 11, increasing net working gas inventories to 3,644 Bcf. That build compared to a five-year average draw of 5 Bcf and a year-ago build of 23 Bcf, lowering the deficit to the five-year average to 7 Bcf, or 0.2%. The surplus to last year reached 4 Bcf, or 0.1%.

AVERAGE CASH PRICES



But the arrival of cold weather has given bulls reason to be sanguine as attention now shifts to the magnitude of withdrawals over the coming months. The EIA pegged US consumption for the week to Nov. 16 at 90.4 Bcf/d, up 18.2 Bcf/d from last week and up 14.3 Bcf/d from a year ago.

Next week's draw — the first of the winter heating season — is expected to be lofty. Consensus estimates predict a 77 Bcf withdrawal, with some well over 100 Bcf, versus a five-year average of 48 Bcf.

Gelber & Associates (G&A) analysts predict the current storage deficit will widen to around 140 Bcf or more within the next couple of weeks. Even with Friday's price decline, December futures still climbed 42.4¢ on the week, but "there are more bearish catalysts in the market than what market players are recognizing," the analysts warned.

Those include storage inventories topping out above 3.6 trillion cubic feet, the greater certainty of Freeport's resuming full operations early next year, and near-record dry gas production, which the EIA pegged this week at 100.8 Bcf/d, up 5.1 Bcf/d year over year.

Factoring in long-range weather outlooks for warmer-than-average temperatures in January and February in the eastern half of the US, as well as production that could rise toward 103 Bcf/d, storage balances could exit winter at 1.6 Tcf-1.7 Tcf, the analysts predict.

Against this bearish backdrop, there is still the possibility that bullish factors unfold in the coming week, when more than half of rail workers will vote on proposed contracts. A nationwide railroad worker strike could roil gas markets by disrupting coal shipments. "Unless there is a railroad strike announced, I'm leaning toward a lower trending market over the next few days," G&A analyst Alan Lammey told Energy Intelligence. "I wouldn't be surprised to see a settlement of the December contract around $5.50."

Frigid Weather Awakens Cash Markets

The boost in space heating demand shook Northeast and Southeast cash markets out of their shoulder season doldrums this week. Mild weather has kept regional demand centers in the mid- to upper-$3 range just a week ago. Prices for Wednesday flow at Transco Zone 5, which spans Virginia and the Carolinas, averaged $9.57/MMBtu with trades as high as $12/MMBtu. The price for Boston-area Algonquin averaged $7.59/MMBtu, with trades as high as $9. The price action offers a preview of the volatility to come this winter.

The higher prices are occurring as regional supply has been trending lower than expected due to pipeline maintenance and supply chain problems. "Until this week, daily Northeast pipeline samples had been trending opposite our expectations heading into winter," East Daley Analytics said in a note last week lowering its fourth quarter Northeast production forecast by 0.4 Bcf/d to 33.8 Bcf/d. "So far in November, Appalachian Basin pipeline samples have averaged about 0.4 Bcf/d lower than October."

East Daley analysts called the supply chain problems "ominous," pointing to the fact that EQT, the largest US gas producer, had slowed its well completion program. The Appalachian producer now expects full-year production to come in at the low end of guidance. While US storage balances are close to the five-year average, east region storage balances are at 882 Bcf, a 20 Bcf, or 2.2%, deficit to the five-year average.

Everett Wheeler, Washington, and Tom Haywood, Houston

Fatigue >> continued from page 1

tures, caused severe damage to additional process equipment and associated piping in adjacent areas within and near the pipe rack."

Freeport Responds

Freeport said this week that it is implementing IFO's recommendations to address root and contributing causes to the incident, including procedural changes to avoid scenarios where LNG could be "blocked-in" piping segments. It also "revised its control system logic to alert control room operators to valve positions or temperature readings that indicate possible isolation of LNG in any piping segments."

The company is modifying its training program to address causes of the incident so that employees are better able to identify "abnormal operating conditions in the facility."

As it rolls out "an extensive company-wide process safety management initiative," Freeport is also boosting facility staffing by over 30% and creating new departments focused on "training, operational excellence, quality assurance and improved business performance."

Resuming Operations

Freeport said it anticipates resuming operations at its facility in mid-December and ramping up to 2 Bcf/d of production in January, subject to the company meeting regulatory requirements.

"As of Nov. 14, the reconstruction work necessary to commence initial operations, including utilization of all three liquefaction trains, two LNG storage tanks and one dock, was approximately 90% complete, with all reconstruction work anticipated to be completed by the end of November," Freeport said Friday. "Proposed remedial work activities for a safe restart of initial operations have been submitted to the relevant regulatory agencies for review and approval."

The company anticipates full production utilizing both docks in March 2023.

Freeport has repeatedly delayed a restart of its facility, originally set for October, confining 15 million tons per year (2.1 Bcf/d) of US gas to the domestic market.

Gary Kruse, managing director of research at DC-based consultancy Arbo, who closely follows US energy regulatory matters, told Energy Intelligence the likelihood of further delays has diminished.

"If they have submitted the work plan there should be time" for the Federal Energy Regulatory Commission and the Pipeline and Hazardous Materials Safety Administration "to approve it by maybe the first week of December and then for them to restart the facility as they describe it by early January," he said. "Presuming the restart goes smoothly this looks reasonable."

Everett Wheeler, Washington

Q & A

US-Mexico Gas Market Will Grow, But LNG Is a Challenge

Guillermo Turrent played a key role in implementing the opening of Mexico's natural gas market to the US after the nation's 2013 Hydrocarbon Law took effect, including as Director for Modernization for country's power utility Comision Federal de Electricidad (CFE). In that role Turrent and his team developed more than 5,000 miles of new natural gas pipelines that carry billions of cubic feet per day of US gas to Mexican markets. Turrent, now general manager of consultancy Energy and Infrastructure Advisors, spoke with Energy Intelligence on the sidelines of the US-Mexico Natural Gas Forum held this week in San Antonio on a wide range of issues, including US gas' future role in Mexico's energy sector and the difficulty of creating an LNG export industry south of the US border. The interview has been edited for space and clarity.

Q: Has Mexico's gas sector lived up to the promise it held for US gas producers in 2015?

A: Mexico's gas market has seen exponential growth when it comes to imports of natural gas, from barely nothing in 2010 to up to 6.5 billion cubic feet per day today out of an 8.3 Bcf/d market, or about 75% of the gas market in Mexico. So when you ask whether it has lived up to expectations, I would say yes.

The main reason for that is US natural gas is the cheapest source of supply in the world for generating electricity, in particular, and for producing steel and glass and for general industrial use in Mexico.

The markets started to be deregulated in 1995, but the biggest deregulation was the energy reform in December 2013 There were a series of steps that happened for 18 years between 1995 and 2013 that took us to that point where the energy markets actually opened up. Certain things like private investment in exploration and production opened up for private industry to participate in.

Between 2013 and 2018, a lot of structures were created like CENAGAS, the public independent operator of the original natural gas pipeline system, to break apart the monopoly held by Pemex over gas production, transport and marketing. A market was actually created. Regulated prices of natural gas stopped being important and there was actually some sort of a free market that worked with price arbitrages in the different regions in Mexico.

CFE tendered about 5,000 miles of natural gas pipelines in Mexico, basically increasing the pipeline system from 7,000 to 12,000 miles and I'm anxious to hear how CFE plans to use those natural gas pipelines in an more active way so they bring the benefits to the country and reach even households.

Q: How did this reform specifically benefit the US upstream sector?

A: The previous administration [of Enrique Pena Nieto] tripled the capacity from the US and Mexico. Places like Waha in West Texas were barely connected to Mexico. Now there is 2.8 Bcf/d of capacity from Waha to Mexico, and the same thing happened in South Texas, where our interconnection was about 2.5 Bcf/d and now it's about 5 Bcf/d.

But let's talk about the negatives. Why aren't those pipeline interconnections to Mexico being used 100% even when it can cost zero to bring in natural gas from West Texas? I have my speculations about it. I think non-economic decisions are being made that are not economically driven by the markets.

Mexico has too much [high sulfur 3.5% plus] fuel oil and the only one that can burn that fuel oil in these quantities is CFE, the biggest consumer of natural gas in Mexico. So, if fuel oil is being used instead of natural gas, that slows down the use of natural gas from the US.

Also, some of the [gas-fired] power plants that were supposed to be built were not built and some of the plants that consume fuel oil that were supposed to be converted to gas have not.

How much fuel oil is CFE burning? I'll tell you right now, 120 to 140 thousand barrels a day. You convert that to natural gas and it's more than 800 million cubic feet per day. But there are other issues, such as can the country export all of that fuel oil. If they can't, maybe they have to just burn it.

Q: Do you think natural gas will play a significant role in Mexico's energy market in 2040?

A: My take is natural gas will play a role in Mexico at least as much as it does today, maybe more. One of the main reasons why those pipelines were built by the previous administration was to get rid of the fuel oil and with it decrease emissions. That hasn't happened, but I assume that fuel oil will be gone [in 2040]. Those pipelines were contracted for 25 years until about 2039-40. The previous administration had a comprehensive renewables plan in place to start backing out fossil fuels and the 2040-time frame is the inflection point. But that was the previous administration.

CFE is committed now to the extension of the [Sur de Texas] offshore pipeline. That's going to be at least a 20- to 25-year deal and it's going to be a fixed payments contract. I don't think the Mexican government would commit to a 1.3 Bcf/d, $5 billion investment unless they were planning on using it past 2040.

Also, CFE assigned six or seven power plants over the last few months and they're all combined cycle natural gas plants that are going to burn at least 700-800 MMcf/d. So, do I see natural gas fading in Mexico? I don't see it. Maybe the growth will be slower than increase since the 2010 but I think between now and the next 10 years it's going to go up.

Q: Do you think CFE will re-contract capacity as it rolls off or even take a stake in the pipelines?

A: At the end of those 25 years on the 5,000 miles contracted what ends up happening in theory is the pipeline company has to get a new rate authorization from the Mexican Regulatory Commission for a pipeline that has been amortized 100%. So the rate going forward should be significantly lower. The Hydrocarbon Law prohibits CFE from having a stake outright even when it makes sense from an economic standpoint and from a project financing standpoint. But CFE has said it will ask the regulatory authorities in Mexico to allow it.

I think it would have been the logical thing to have had an option to take a stake in those pipelines and in 25 years assign the option to CENAGAS, but that was denied by regulators at the time.

Q: At the US-Mexico Forum, enthusiasm for developing an LNG export sector in Mexico was lukewarm among many attendees from Mexico, who wondered how the country might benefit from exporting US gas. Why was that?

A: I believe if there is economic sense in doing something like that it should be done. If you can buy gas from the US for $1 [per million Btu] and bring it to Mexico for 50¢ and sell it for $30 there's an economic reason to do it. I'm all up for that.

I think it's going to be very challenging because there are emerging conditions in the US that could prevent that gas from coming down to Mexico. First of all, if something happens like [Winter Storm] Uri again that gas is not going to flow to Mexico right away. And if Mexico is already committed to selling that gas firm overseas then Mexico's going to have a problem with whoever the developer was or the marketer who sold this forward.

I think there's an issue also if there is an emergency situation in Mexico, which happens often. Is Mexico going to keep exporting that LNG or is Mexico going to keep that gas for its own needs and default on their LNG contracts overseas? I think it's going to be very, very difficult to project finance any of those LNG terminals out of Mexico just for the reason of security of supply.

Tom Haywood, Houston

POLITICS

Pennsylvania, Ohio Emerge as Gas Policy Battlegrounds

Pennsylvania and Ohio, responsible for a combined 35 billion cubic feet per day of natural gas production last year, may well become gas policy battleground over the next several years following two pivotal US Senate and a host of state legislative contests.

The two Senate races in the Nov. 8 midterm elections captured the eyes — and checkbooks — of gas industry interests. Both races were critical for the GOP to have a chance to win back the Senate, which it failed to do, and moreover are seen as setting the tone for energy politics in two of the top 10 gas-producing states.

When it comes to results, the two shale states split the difference. In Ohio, Republican venture capitalist JD Vance won the state's open US Senate seat, while Pennsylvania Lt. Gov. John Fetterman beat out GOP candidate Mehmet Oz for the previously Republican-held Senate seat.

In the US House of Representatives races, Democrats in Pennsylvania captured one more seat than Republicans, while in Ohio GOP candidates won by five seats.

The state results also leaned heavily along party lines: Pennsylvania Democrats appear to have secured control of the state House for the first time in a decade, but the GOP will control the Senate in capital city Harrisburg. Ohio state legislative races saw Republicans maintain a substantial majority. Republican incumbent Mike DeWine won the Ohio gubernatorial election and Democrat Josh Shapiro won in Pennsylvania's race for governor.

Ohio Energy Politics

In a recent blog post, the Utica Energy Alliance, of which the Ohio Gas Association is a member, underscored the importance that the winning candidate support the gas industry. The analysis points to statements made by Vance on the need to "open up Ohio's energy markets and pipelines and that will start to bring these prices under control."

The Affordable Energy Fund, a super-political action committee (PAC) with ties to the natural gas industry, pushed out ads and mailers in Ohio in support of Vance, according to published reports. Chevron reportedly provided $3 million to a super-PAC focused on the GOP candidates Oz and Vance.

Notably, Vance was viewed as the candidate oil and gas interests considered less vetted, given that Democratic challenger US Rep. Tim Ryan had a longstanding and not terribly combative relationship with the industry, Energy Intelligence understands.

But Vance's willingness to go toe-toe-toe with the Biden administration over the role of gas in the energy transition, combined with Ryan's history of votes for policies the industry views as anti-gas — like upholding federal authority to regulate methane from the sector — seem to have been a deciding factor, along with voting to block the Keystone XL pipeline.

It's about more than standing up to Biden on gas production and pipelines, however. There are several political issues in the queue in capital city Columbus relevant to gas interests — most notably a brewing fight over wastewater storage.

In an Oct. 20 letter to US Sen. Rob Portman (R), the Utica Energy Alliance urges lawmakers to push back against greens' calls for the federal US Environmental Protection Agency to take control of the state permitting program that oversees disposal of produced water from gas production.

If Ohio loses oversight authority of the program, it could hinder production in not only Ohio but also Pennsylvania, which has few disposal wells of its own because of its geology and relies on its western neighbor. Losing access to wastewater disposal or slowing tge permitting of disposal wells could mean higher production costs, as water would have to be stored in tanks and trucked elsewhere, to the extent it could not be recycled.

The wastewater issue also has the potential to quickly become a political flashpoint, as it has previously in Pennsylvania, Texas, Oklahoma, and other states where incidents of groundwater pollution or earthquake activity linked to disposal wells have become national news.

Pennsylvania Energy Politics

Pennsylvania's energy policy could prove equally interesting for gas over the next election cycle. The state's renewable portfolio standards, currently set at reaching 18% clean electricity by 2020-2021, have not been revised in years. Shapiro winning the governor's mansion was seen as key to ratcheting up the standards, but a divided state legislature makes that less likely, with state GOP lawmakers reluctant to threaten gas demand.

Given the legislative body split, there will instead be much focus on "what the Shapiro administration can do by executive order," said Mark Szybist, an attorney with the Natural Resources Defense Council who advocates for clean energy in Pennsylvania.

The election comes as Pennsylvania is getting ready to implement a recently passed bill that would create $50 million per year subsidies for "blue" hydrogen and additional subsidies for petrochemical manufacturing facilities. Szybist has called the bill "deeply flawed" and a potential giveaway to shale gas extraction without pollution limits or protections for disproportionately affected communities located near drilling sites.

Bridget DiCosmo, Washington

UTILITIES

Gas Plays Key Role as US Utilities Cut Carbon Emissions

US utilities are slashing carbon intensity as they set loftier climate targets, and natural gas is a part of their success, finds Energy Intelligence's new global ranking of the Top 100 green utilities.

Together with significant shifts away from fossil fuels toward renewables, these factors have resulted in a drop in carbon intensity of 46% among US firms in the ranking since it was first published in 2011. The report uses the most recent data, usually 2021 annual figures, and studies both utilities and independent power producers.

Significantly, many US utilities have set climate goals in line with their European counterparts and are targeting net-zero emissions by 2050 or before. They have added 48 gigawatts of renewables and retired 194 GW of fossil fuel capacity since 2011.

Power Performers

US-based high performers in the first half of the ranking include NextEra Energy, Constellation Energy, Berkshire Hathaway Energy, Dominion Energy, PG&E, Duke Energy and Southern.

The top 10 includes one US firm, NextEra Energy at ninth place, which is the biggest wind developer and operator in the country. Also making the top 10 are five European and three Chinese firms plus one Indian company.

While many of the lowest-ranking companies own little or no renewable capacity, some of them — such as the US' WEC Energy, AEP and DTE Energy — have significant renewable assets but perform poorly in terms of emissions due to substantial coal generation.

Canadian firms generally rank high because of their large carbon-free capacity — including hydropower and, in the case of Ontario Power Generation, nuclear. European oil and gas companies have also started to populate the Top 100 as they diversify into electricity. By contrast, power generation is not a priority for their North American peers. France's TotalEnergies ranks 15 and Italy's Eni 52.

The rankings are calculated using a system in which each company is awarded up to 200 points, 100 of which are based on emissions intensity, or kilograms of CO_2 per megawatt hour generated, while the other 100 is based on non-hydro renewable capacity, in absolute and relative terms.

Big Picture

By comparison, European utilities have seen more dramatic changes. Those in the ranking have added 95 GW of wind and solar capacity in a decade while retiring 143 GW of fossil fuel assets, resulting in a 53% drop in emissions intensity.

The transition's impact on Chinese generators has been equally eye-opening. Companies in the ranking have added a staggering 453 GW of carbon-free capacity since 2011. Overall, companies in the ranking have added almost 100 GW of new renewable capacity last year — more than they ever have.

But the carbon dioxide emissions intensity of their electricity output has not been decreasing as quickly as in previous years. That's because post-Covid-19 recovery caused demand to surge while adverse weather conditions — including low wind and reduced hydro availability — prevented renewable capacity from being fully utilized. This, in turn, caused fossil fuel-fired plants to generate more intensively.

Nevertheless, the ranking's overall average CO_2 intensity has for the first time fallen just below 400 kg/MWh. Carbon intensity stood 399 kg/MWh in 2021 — down from 405 kg/MWh in 2020 and 563 kg/MWh in 2011 when the ranking was first published.

Emissions intensity in the ranking has decreased by 3.4% annually over the past decade. If sustained over the current decade, it would allow companies to slash emissions by 50% over 2010-30 as many have promised.

Philippe Roos, Strasbourg

IN BRIEF

FERC OK's LNG Project

The US Federal Energy Regulatory Commission (FERC) on Thursday approved its first certificate for a major LNG project since 2020, voting unanimously to authorize the Commonwealth LNG facility in Cameron, Louisiana.

Developers of the 8.4 million ton/yr liquefaction project have said they could make a final investment decision in mid-2023 pending a final nod from FERC. The project still needs a separate gas export license from the US Department of Energy, which will analyze whether it is in the public's interest.

Commonwealth has already signed up Australian Woodside to a 20-year deal for 2.5 million tons of LNG from mid-2026, firming up a heads of agreement signed in January.

It has been more than two years since the 3-2 Democratic majority commission certified a major LNG project, and Democratic Chairman Richard Glick reiterated his long-standing concerns that FERC does not conduct full accounting of the climate impacts of such projects. "I still am at a loss as to why we don't assess the significance of greenhouse gas emissions," he said at Thursday's meeting.

Williams, Sempra to Partner

US pipeline giant Williams and LNG developer Sempra Infrastructure are teaming up to deliver additional Haynesville Shale gas to planned LNG export terminals along the US Gulf Coast.

Under a nonbinding heads of agreement (HOA), the companies plan to form a joint venture (JV) to own, expand and operate the Cameron Interstate Pipeline that is expected to ship gas to the proposed Cameron LNG Phase 2 in Hackberry, Louisiana. Additional pipelines are also expected to be owned by the JV, including the Louisiana Connector Pipeline that would deliver gas to Sempra's proposed Port Arthur LNG export terminal in Texas.

The HOA also contemplates a separate gas sales agreement for about 0.5 Bcf/d to be delivered as feed gas for the two LNG projects. And it includes two 20-year sale and purchase agreements for 3 million tons/yr of LNG from the two terminals, although no offtaker was disclosed.

Williams said the transactions complement its recently sanctioned Louisiana Energy Gateway gathering project, which will gather 1.8 Bcf/d of gas produced in the Haynesville starting in late 2024.

LNG Permit Challenged

Three environmental groups have sued the Louisiana Department of Natural Resources for exempting Venture Global LNG from having to obtain a coastal use permit for development of its LNG facility in Plaquemines, 35 miles south of New Orleans.

The Deep South Center for Environmental Justice (DSCEJ), Sierra Club and Healthy Gulf filed a petition last week for judicial review against the Louisiana agency after the regulators decided to exempt Venture Global. It was filed in the 19th district Louisiana State Court.

The groups say the plant's construction will destroy nearly 400 acres of wetlands that serve as a storm buffer for nearby communities. Without sufficient protections, a hurricane would release pollution into homes, businesses, farmland and coastal water, subjecting predominantly black and indigenous communities to the risks, they said.

"Venture Global is not above the law that requires companies to minimize harm in a coastal zone," said Monique Harden, assistant director of law and public policy at DSCEJ.

The Venture Global LNG terminal was sanctioned in May, not long after Venture Global's Calcasieu Pass LNG terminal began operations in February.

Greens Want Leasing Overhaul

Environmentalists are urging the US Department of the Interior to launch a rulemaking to overhaul the federal oil and natural gas leasing program before moving forward with any planned lease sales.

In a letter to Interior Secretary Deb Haaland this week from more than a dozen environmental groups including Earthjustice, Evergreen Action, Public Citizen, and others, the groups call for a "rulemaking to enact common sense reforms to the decades-old federal oil and gas program before any new leasing occurs."

The Inflation Reduction Act, (IRA) signed into law earlier this year, housed a host of regulatory changes that Interior must begin implementing in its leasing program. Those include raising minimum bids from $2 per acre to $10 per acre; higher rental rates for leased, non-producing acreage; first-time royalties on vented, flared or leaked methane; eliminating non-competitive leases; and a new per-acre fee for nominating parcels for sales.

The financial requirements associated with leasing received a significant boost as well. Bonding amounts will increase from the previous value of $10,000 to $150,000 per lease and $25,000 to $500,000 for all leases in a state.

NATURAL GAS WEEK DATA ROUNDUP

NATURAL GAS FUTURES - Trading Dates: Nov 14-Nov 18

New York Mercantile Exchange (NYMEX) Henry Hub

	Monday		Tuesday		Wednesday		Thursday		Friday		Week's	Open
	Nov 14	Vol.	Nov 15	Vol.	Nov 16	Vol.	Nov 17	Vol.	Nov 18	Vol.	Low-High	Interest
Dec '22	5.933	110,910	6.034	76,925	6.200	112,921	6.369	106,768	6.303	--	5.727-6.547	40,049
Jan '23	6.299	55,522	6.395	42,664	6.607	68,551	6.744	72,237	6.716	--	6.132-6.912	170,177
Feb '23	6.050	33,523	6.143	17,326	6.353	32,597	6.491	28,488	6.483	--	5.895-6.650	64,627
Mar '23	5.410	27,556	5.457	16,622	5.590	28,747	5.706	33,448	5.703	--	5.249-5.789	102,512
Apr '23	4.726	21,315	4.765	17,039	4.799	30,656	4.838	29,181	4.814	--	4.610-4.891	90,726
May '23	4.706	11,695	4.750	12,719	4.774	13,937	4.803	12,395	4.786	--	4.590-4.856	91,078
Jun '23	4.784	7,176	4.833	7,756	4.858	7,935	4.883	7,973	4.875	--	4.683-4.932	26,643
Jul '23	4.868	6,965	4.924	7,285	4.947	8,751	4.968	6,589	4.968	--	4.777-5.009	32,433
Aug '23	4.877	4,944	4.933	4,554	4.958	5,559	4.981	5,381	4.985	--	4.790-5.014	27,287
Sep '23	4.817	5,479	4.870	4,717	4.896	6,337	4.920	5,481	4.931	--	4.723-4.959	33,505
Oct '23	4.870	8,937	4.918	8,643	4.944	12,900	4.965	11,390	4.979	--	4.774-5.015	50,578
Nov '23	5.175	3,945	5.229	2,968	5.256	4,519	5.268	3,341	5.287	--	5.105-5.313	20,143
Dec '23	5.503	2,537	5.565	2,120	5.587	3,673	5.601	2,759	5.637	--	5.448-5.664	27,888
12 Month Strip	**5.210**		**5.271**		**5.349**		**5.411**		**5.403**			
2022 Strip	6.579		6.587		6.601		6.615		6.610			
Total Volume		**300,504**		**221,338**		**337,083**		**325,431**		**--**		

GAS PRICE REPORT

($/MMBtu) The Week of	11/14/2022	APPA-LACHIA	CALIFORNIA North	CALIFORNIA South	LOUISIANA Gulf Coast Offshore	LOUISIANA Gulf Coast Onshore	LOUISIANA North	MID-CONT	MID-WEST	NEW ENG-LAND	NEW MEXICO	ROCKIES	SOUTH-EAST	TEXAS Central Onshore	TEXAS Gulf Coast Offshore	TEXAS West
Delivered to Pipeline	This Week	5.65	7.93	8.04	5.83	6.05	5.73	5.81	6.04	6.70	6.18	7.13	6.25	5.46	5.39	5.02
	Bid Week	3.94	5.93	6.66	4.54	5.16	4.57	4.44	5.05	4.27	5.42	5.56	5.37	4.65	4.69	3.22
Delivered to Utility	This Week	5.73	8.77	8.64	--	6.16	5.87	6.06	6.03	8.28	6.33	7.46	6.57	5.61	--	5.10
	Bid Week	4.03	7.32	7.25	--	5.31	4.71	4.55	5.05	6.04	5.57	5.89	5.82	4.80	--	3.30
Interstate Wellhead	This Week	5.54	--	--	5.76	5.98	5.66	5.71	--	--	6.01	7.01	6.10	5.38	5.32	4.95
	Bid Week	3.83	--	--	4.47	5.09	4.50	4.34	--	--	5.25	5.44	5.22	4.57	4.62	3.15
Intrastate Wellhead	This Week	--	--	8.03	5.76	5.98	5.65	5.69	--	--	--	6.98	--	5.40	5.33	4.95
	Bid Week	--	--	6.64	4.47	5.09	4.49	4.32	--	--	--	5.41	--	4.59	4.63	3.15

INTRASTATE WEEKLY SPOT PRICES - Trade Dates 11/14-11/18

Price Point	$/MMBtu	Chg.	High	Low	Avg. Daily Vol.	Avg. Daily Deals	Nov Bid Week
Oklahoma Intras	5.68	2.75	5.90	5.15	37,729	7	4.22
West Texas Intras	--	--	--	--	--	--	4.93

PRICE OUTLOOK

	Composite Wellhead	Delivered to Pipeline	12-Month Strip Nymex
Nov 21, 2022	5.51	7.46	
2022 Outlook	5.46	6.99	--

CANADIAN PRICE REPORT

($US/MMBtu and $Can/MMBtu)	ALBERTA AECO Hub	ALBERTA Empress Border	BRITISH COLUMBIA Total Province	BRITISH COLUMBIA Kingsgate Border	BRITISH COLUMBIA NW Sumas Border	MANITOBA Emerson Border	ONTARIO Dawn Hub	ONTARIO Niagara
November 18, 2022								
Delivered to Pipeline (US$)	4.53	4.65	8.22	5.27	8.47	5.81	5.91	5.92
Delivered to Pipeline (C$)	6.04	6.20	10.96	7.01	11.28	7.75	7.88	7.90
Wellhead (US$)	--	--	8.08	--	--	--	--	--
Wellhead (C$)	--	--	10.77	--	--	--	--	--
Oct 2022 Avg.								
Delivered to Pipeline (US$)	2.28	4.02	5.03	3.65	5.32	4.94	5.30	5.10
Delivered to Pipeline (C$)	3.12	5.51	6.88	5.01	7.29	6.77	7.27	6.98
Wellhead (US$)	--	--	4.89	--	--	--	--	--
Wellhead (C$)	--	--	6.69	--	--	--	--	--
2021 Avg.								
Delivered to Pipeline (US$)	2.78	2.95	3.96	3.12	4.05	3.50	3.64	3.40
Delivered to Pipeline (C$)	3.48	3.71	4.98	3.91	5.09	4.40	4.56	4.27
Wellhead (US$)	--	--	3.82	--	--	--	--	--
Wellhead (C$)	--	--	4.81	--	--	--	--	--

Note: Monetary conversions are done weekly. All prices represent volume-weighted averages for the most recent Monday-Sunday trading week.

NATURAL GAS WEEK DATA ROUNDUP

NORTH AMERICAN WEEKLY GAS STORAGE

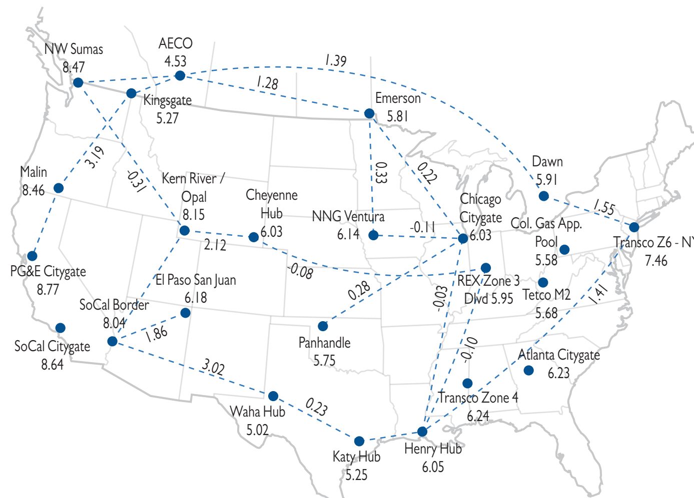
(Billion Cubic Feet)

Region	Week Ending Nov 11	Week Ending Nov 4	% Full	1 Week Chg.	Year Ago	1 Yr Chg.	5 Yr Avg.	5 Yr Chg.
US								
East	882	865	80.3	17	900	(18)	902	(20)
Midwest	1,084	1,068	88.6	16	1,078	6	1,078	6
Mountain	208	208	44.1	-	212	(4)	212	(4)
Pacific	241	247	65.4	(6)	261	(20)	290	(49)
South Central	1,228	1,193	78.5	35	1,189	39	1,169	59
Total Lower 48	**3,644**	**3,580**	**77.1**	**64**	**3,640**	**4**	**3,651**	**(7)**
Canada								
East	279	277	99.2	2	278	2	272	7
West	459	455	93.8	3	463	(5)	441	18
Total Canada	**738**	**733**	**95.8**	**6**	**741**	**(3)**	**713**	**25**
Lower 48 & Canada								
Total North America	**4,382**	**4,313**	**79.7**	**70**	**4,382**	**1**	**4,364**	**18**

Sources: US-EIA. Canada-RBN Energy. Values in Bcf unless otherwise noted.

PRICES AND DIFFERENTIALS FOR MAJOR HUBS AND SELECTED CITY GATES

Nov 18, 2022 — (US$/MMBtu, Volume-Weighted)



Selected Daily Differentials

Differential	Nov 14	Nov 15	Nov 16	Nov 17	Nov 18
NY-HH	0.16	--	1.88	1.10	2.06
Chicago-HH	0.10	0.04	-0.04	0.11	-0.09
CHIC-AECO	1.88	1.48	1.43	1.63	1.36
PG&E-AECO	4.37	4.61	4.03	4.02	4.08

COMPARATIVE FUEL PRICES

(Cash Market) Nov 18, 2022

Natural Gas	$/MMBtu	Comparative Fuel	Fuel Price	MMBtu equivalent
Appalachia				
App Pool Dvld (util)	5.61	McCloskey CSX Coal	$169.00/ton	7.03
East Coast				
New York City Gate	7.76	Heating Oil No. 2*	392.17¢/gal	28.28
	--	Residual 0.30%	$91.66/bbl	14.58
	--	Residual 1.00%	$82.40/bbl	13.11
Gulf Coast				
TX Central Onshore	5.46	Heating Oil No. 2*	308.57¢/gal	22.25
	--	Residual 0.70%	$80.65/bbl	12.83
LA Gulf Coast Onshore	6.05	Residual 3.00%	$63.39/bbl	10.08
	--	WTI Cushing	$84.02/bbl	14.49

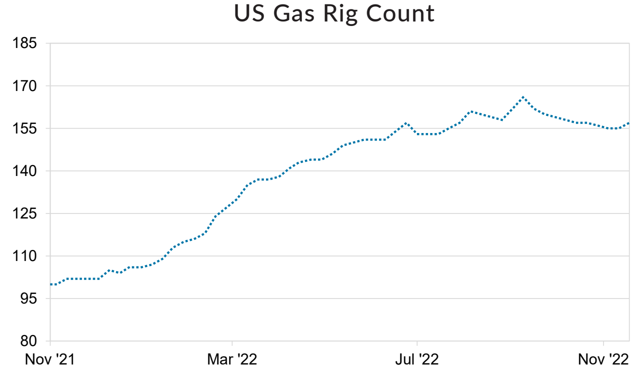
Notes: (1) Residual=Residual Fuel Oil, priced exclusive of taxes; (2) WTI=West Texas Intermediate crude oil; (3) % = % of sulfur content. *Average sulfur content = 0.2%-0.5%. *Sources: Gas: Natural Gas Week; all prices volume-weighted. Oil: The weekly average of The Oil Daily's cash price postings.*

BAKER HUGHES RIG COUNT

Week Ended Nov 18, 2022

Region	Current Week	Previous Week	Year Ago
Total US	782	779	563
Land	762	758	546
Inland Waters	3	4	2
Offshore	17	17	15
Gulf of Mexico	16	16	15
Total Canada	201	200	167
US Rigs Exploring for			
Oil	623	622	461
Gas	157	155	102
Unspecified	2	2	0

US Gas Rig Count



SPOT ELECTRICITY TRADING

Trading Dates: 11/14-11/17, 2022

POINT	Avg. Price This Week	Avg. Price Last Week	Change	Year Ago	Month Ago
COB	$102.50	$111.83	-$9.33	$58.00	$81.05
ERCOT	$60.77	$62.24	-$1.47	$47.17	$58.13
Mid-Columbia	$97.84	$94.63	$3.22	$54.87	$78.30
NEPOOL	$72.44	$42.44	$30.00	$51.88	$51.18
Palo Verde	$83.50	$67.31	$16.19	$44.10	$69.60
PJM-West	$82.06	$54.96	$27.11	$43.80	$72.05

Notes: (1) Prices in $/MWh. (2) Prices are for next day peak delivery.
Sources: Energy Intelligence and wire reports.