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Argus *LNG Daily*

Daily LNG prices, news and analysis

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SUMMARY

Asia Pacific: Prices up on short-covering

Spot prices for LNG deliveries to northeast Asia rose for a second consecutive day amid mounting concerns about the impact of a partial outage at Bintulu LNG

Atlantic: Inter-basin arbitrage widens

LNG prices for delivery into Asia-Pacific markets rose sharply on Friday and significantly expanded their premium to European prices, which followed the Dutch TTF gas hub down

Europe: Des prices fall

LNG prices for delivery to Europe fell as they tracked TTF near-curve contracts lower, as mild weather forecast in the region in the coming days could curb gas demand

Partial Bintulu LNG outage boosts prices

Unplanned shutdowns of three liquefaction trains at Petronas' 30mn t/yr Bintulu facility in Malaysia have boosted spot prices, with expectations of tighter LNG supplies this winter likely to push prices past $7/mn Btu again

Mexico seeks two prompt LNG cargoes

Mexican state-owned utility CFE has issued a tender seeking two cargoes for delivery to its 3.8mn t/yr Manzanillo import facility this month

CNOOC offers December cargo from NWS LNG

Chinese state-owned importer CNOOC is looking to sell a cargo loading from the 16.3mn t/yr North West Shelf (NWS) LNG project in Australia during 29-31 December

Foran Gas and Cheniere sign initial supply deal

China's Foran Energy has signed an initial agreement to purchase 26 LNG cargoes over the next five years from Cheniere

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FEATURED LNG PRICES

Global Front-Month and Index Prices

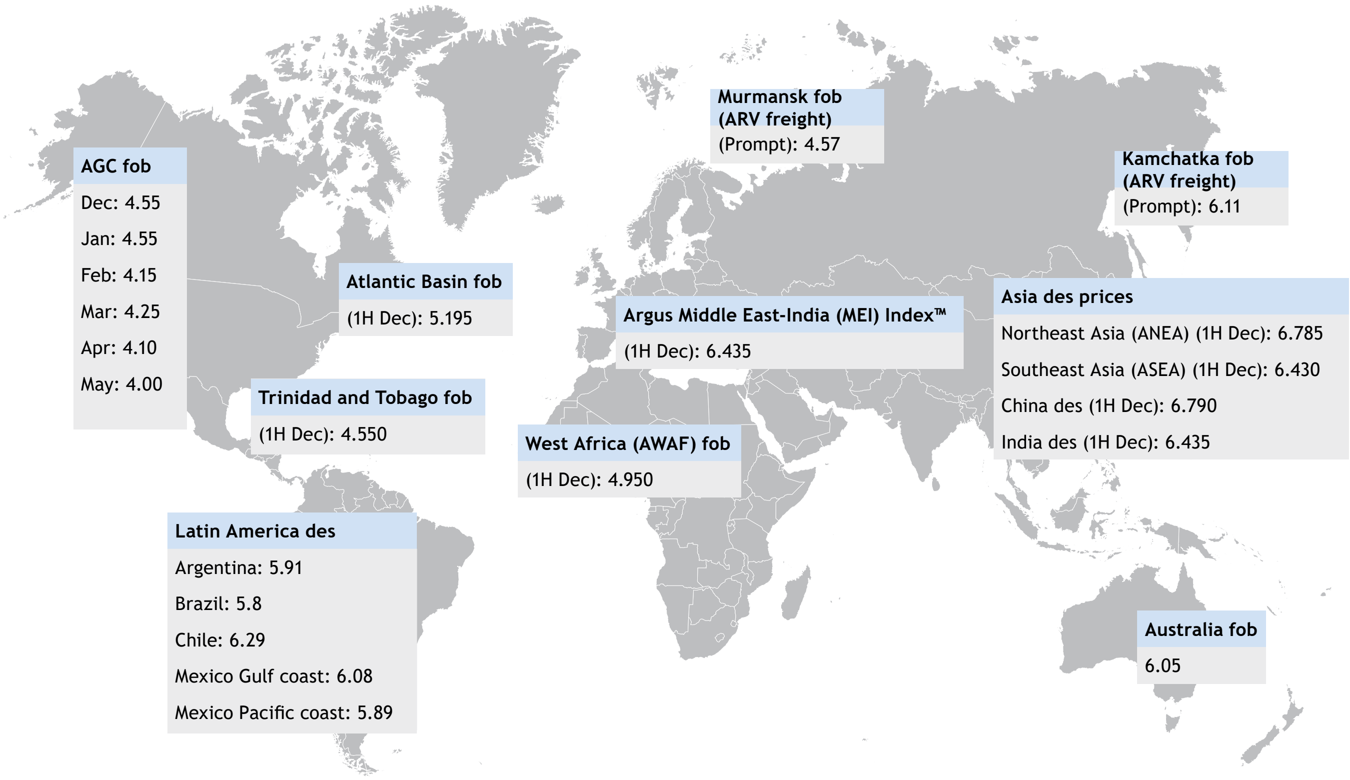
Delivery Point	Midpoint	Change	Trend	Month Index
Argus Gulf Coast fob	4.550	+0.350	▲	4.240
Trinidad & Tobago fob	4.550	+0.350	▲	4.972
Argus West Africa fob	4.838	+0.350	▲	5.053
Mexico des (Pacific) (prompt)	5.890	+0.120	▲	na
Mexico des (Gulf) (prompt)	6.080	+0.230	▲	na
Brazil des (prompt)	5.800	+0.230	▲	na
Argentina des (prompt)	5.910	+0.230	▲	na
Chile des (prompt)	6.290	+0.250	▲	na
Murmansk fob (prompt) (ARV freight)	4.570	-0.060	▼	na
NW Europe fob (reload)	5.275	-0.150	▼	5.583
NW Europe des	4.900	-0.050	▼	5.066
Iberia fob (reload)	5.300	+0.262	▲	5.553
Iberia des	4.950	-0.050	▼	4.919
Italy des	4.950	-0.050	▼	5.122
Greece des	4.950	-0.050	▼	5.130
Turkey des	4.950	-0.050	▼	5.130
Middle east fob (Asia-Pacific bound) (prompt)	5.770	+0.200	▲	na
Middle East fob (Europe bound) (prompt)	3.900	-0.070	▼	na
Middle east des	6.435	+0.270	▲	6.510
India des	6.435	+0.270	▲	6.510
ASEA des	6.435	+0.265	▲	6.498
ANEA des	6.798	+0.330	▲	6.820
China des	6.805	+0.350	▲	6.818
Kamchatka fob (prompt) (ARV freight)	6.110	+0.200	▲	na
Australia fob (prompt)	6.050	+0.200	▲	na

Argus prompt LNG freight day rates *$/day*

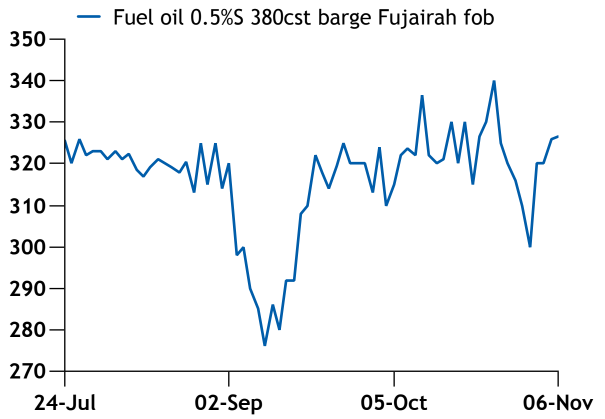
	Price	±	Month index
Steam turbine - west of Suez	72,000	nc	73,200
Steam turbine - east of Suez	67,000	nc	68,200
TFDE - west of Suez	101,000	+3,000	101,800
TFDE - east of Suez	94,500	+1,500	95,300
Two-stroke - west of Suez	113,000	nc	116,200
Two-stroke - east of Suez	108,000	nc	110,000

Argus Round Voyage Rates *$/day*

	Price	+/-	Month index
ARV1: Australia-Northeast Asia	102,432	+1,536	103,251
ARV2: USGC-Northwest Europe	109,539	+3,150	110,379
ARV3: USGC-Northeast Asia	110,958	+3,316	111,719

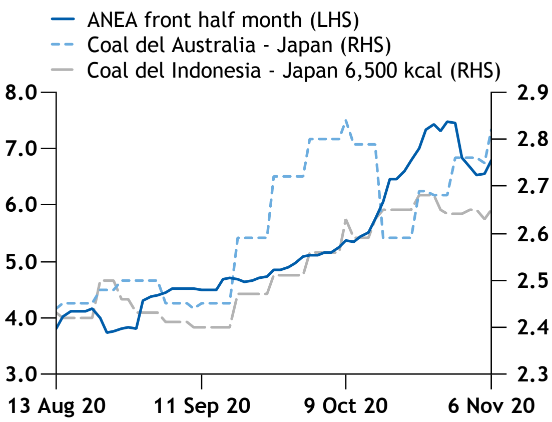


Middle East bunker fuel - Fujairah $/t



Japan oil-linked des LNG (05 Nov 2020)		*$/mn Btu*
Contract	**Price**	**±**
Dec	6.19	nc
Jan	6.59	nc
Feb	6.78	nc
Mar	6.73	-0.010
Apr	6.69	-0.020
May	6.62	-0.030
1Q21	6.70	nc
2Q21	6.65	-0.030
3Q21	6.70	-0.050
4Q21	6.81	-0.060
2021	6.71	-0.040
2022	7.00	-0.050

Japan: Coal vs LNG $/mn Btu



Japan-oil linked	*$/mn Btu*
Jan	6.59

Benchmark price snapshot		*$/mn Btu*
Market	**Delivery**	**Price**
NBP	Dec	5.25
Zeebrugge	Dec	4.82
Peg Nord	Dec	4.78
PSV	Dec	4.71
PVB	Dec	5.01
TTF	Dec	4.84
Nymex Henry Hub (5 Nov)	Dec	2.94
Argus JCC Index (Fixed) (*$/bl*)	Aug	43.4527
Argus JCC Index (Preliminary) (*$/bl*)	Sep	46.1993

MARKET COMMENTARY

Asia Pacific: Prices up on short-covering, tight supply

Spot prices for LNG deliveries to northeast Asia rose across the board for a second consecutive day amid mounting concerns about the impact of a partial outage at the 30mn t/yr Bintulu LNG complex in Malaysia and tightened supply availability.

Prices for deliveries in second-half December rose by a larger margin than for first-half December, flipping the intra-month structure to a contango.

The ANEA price, the *Argus* assessment for spot deliveries to northeast Asia, rose by 43¢/mn Btu to $6.81/mn Btu for second-half December, while first-half December was assessed up by 23¢/mn Btu to $6.785/mn Btu. Second-half December debuted at a 12.5¢/mn Btu premium to first-half December on 1 October but flipped to a discount to first-half December on 26 October as first-half December supplies have tightened.

Purchases of around 5-7 spot cargoes for delivery in November and December by Bintulu plant owner Malaysia's state-owned Petronas due to unplanned shutdowns of the first, third and seventh liquefaction trains at its Bintulu LNG export complex have boosted spot prices and created concerns over supply tightness this winter.

The duration of the shutdowns are unclear, with some market participants expecting that the trains could remain shut until sometime next year. The three trains collectively produce around 10-11 cargoes a month based on nameplate capacity and a 60,000t cargo size. Trains 1 and 3 each have a capacity of 2mn t/yr, while train 7 has a capacity of 3.8mn t/yr.

There is widespread uncertainty about how many cargoes Petronas is seeking, with this dependent on the duration for which the trains will be shut.

Market participants expect prices to continue to strengthen with second-half December prices likely to continue posting the strongest gains. January prices remain at a discount to December but expectations of rising demand and a possible rolling over of demand into first-half January could narrow the differential. The strength of demand for January deliveries depends largely on weather conditions, with most buyers planning to review and firm up their January requirements only two weeks later, based on the updated weather forecasts then.

Petronas is seeking additional December cargoes and deliveries in January, as well, market participants said. And its continued demand is expected to tighten supplies further, particularly for deliveries in December.

There are currently a few December cargoes on offer, including a cargo marketed by a trading firm for a 10 December delivery from Indonesia's 22.6mn t/yr Bontang LNG plant. Australian independent Woodside Petroleum is also offering a cargo for delivery across 15-22 December from Australia's 8.9mn t/yr Wheatstone LNG facility on a bilateral basis.

China's state-owned CNOOC issued a tender today to sell a cargo loading from the 16.3mn t/yr North West Shelf (NWS) LNG project in Australia across 29-31 December, with expected delivery to northeast Asia in first-half January. Bids for the tender are due on 11 November.

There are still a few unfulfilled consumer requirements for December. A few Japanese utilities and second-tier Chinese firms are looking to buy one second-half December cargo each, while a Chinese gas firm is expected to issue a tender soon to buy a cargo for delivery across second-half December and early January.

The latest consumer transaction for second-half December is South Korean Prism Energy's purchase of a 15-18 December delivery at around $6.80-$6.90/mn Btu on 5 November, market participants said.

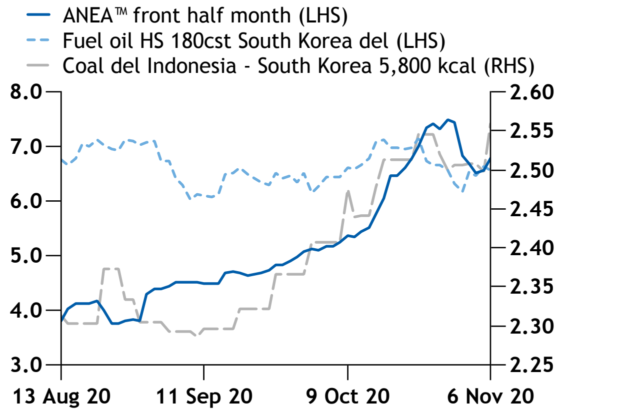
Indicative bids for deliveries in both halves of December ranged between $6.40/mn Btu and $6.80/mn Btu, referencing a purchase at $6.50/mn Btu of a first-half December cargo by Taiwan's state-owned CPC from Qatargas on 4 November. Selling indications for both halves of December were at $6.80-7.15/mn Btu.

Argus Asia-Pacific des spot LNG					$/mn Btu
	Delivery	Bid	Offer	Midpoint	±
Northeast Asia (ANEA™)	1H Dec	6.60	6.97	6.785	+0.230
	2H Dec	6.63	6.99	6.810	+0.430
	1H Jan	6.36	6.75	6.555	+0.475
	2H Jan	6.22	6.58	6.400	+0.425
China	1H Dec	6.60	6.98	6.790	+0.245
	2H Dec	6.63	7.01	6.820	+0.455
	1H Jan	6.40	6.78	6.590	+0.485
	2H Jan	6.28	6.63	6.455	+0.450
India	1H Dec	6.24	6.63	6.435	+0.200
	2H Dec	6.24	6.63	6.435	+0.340
	1H Jan	5.99	6.41	6.200	+0.355
	2H Jan	5.84	6.24	6.040	+0.330

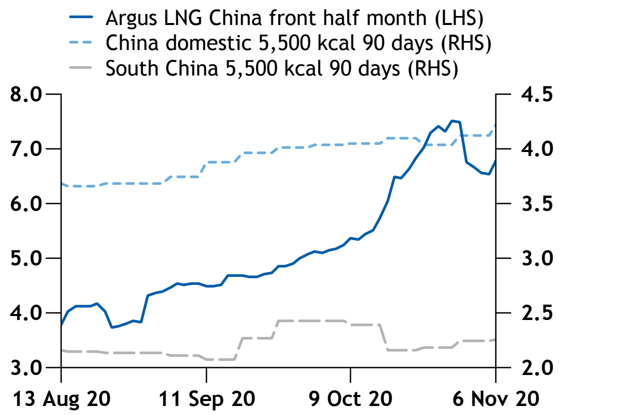
ANEA forward curve		$/mn Btu
Contract	Price	±
Dec	6.798	+0.330
Jan	6.478	+0.450
Feb	6.375	+0.425
Mar	5.625	+0.287
Apr	5.075	+0.225
May	5.030	+0.242
Jun	5.000	+0.275
1Q21	6.159	+0.387
2Q21	5.035	+0.247
3Q21	5.035	+0.247
4Q21	5.650	+0.212

ASIA-PACIFIC COMPETING FUELS

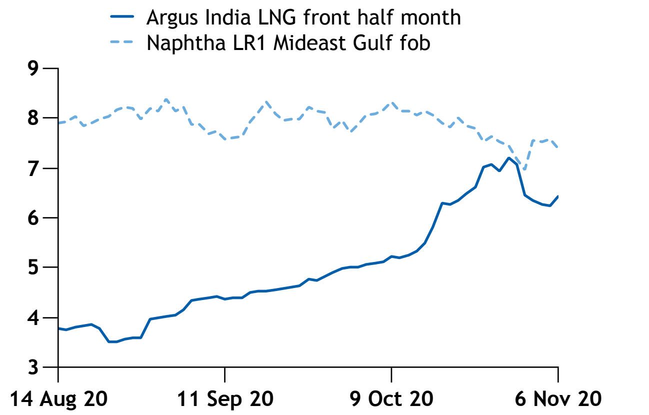
South Korea: Fuel oil, coal vs LNG *$/mn Btu*



China: Coal vs LNG *$/mn Btu*



India: Naphtha vs LNG *$/mn Btu*



ANNOUNCEMENT

The holiday calendar showing which *Argus* reports are not published on which days is now available online https://www.argusmedia.com/en/methodology/publishing-schedule

OTHER ASIA-PACIFIC PRICES

Argus Middle East des spot LNG				*$/mn Btu*
Delivery	**Bid**	**Offer**	**Midpoint**	**±**
1H Dec	6.24	6.63	6.435	+0.200
2H Dec	6.24	6.63	6.435	+0.340
1H Jan	5.99	6.41	6.200	+0.355
2H Jan	5.84	6.24	6.040	+0.330

Argus Middle East-India (MEI) Index				*$/mn Btu*
Delivery	**Bid**	**Offer**	**Mid**	**±**
1H Dec	6.24	6.63	6.435	+0.200
2H Dec	6.24	6.63	6.435	+0.340
1H Jan	5.99	6.41	6.200	+0.355
2H Jan	5.84	6.24	6.040	+0.330

Key netforwards and netbacks			*$/mn Btu*
	Delivery	**Price**	**±**
Southeast Asia (ASEA)	1H Dec	6.43	+0.21
	2H Dec	6.44	+0.32
	1H Jan	6.32	+0.41
	2H Jan	6.14	+0.41
Middle East fob (Asia-Pacific bound)	Prompt	5.77	+0.20
Middle East fob (Europe-bound)	Prompt	3.90	-0.07
Kamchatka fob (ARV freight)	Prompt	6.11	+0.20
Australia Gladstone fob	Prompt	6.03	+0.22
(Unit: A$/GJ)	Prompt	7.85	+0.21
Australia Gladstone oil indexed fob	Prompt	6.19	-0.01
(Unit A$/GJ)	Prompt	8.07	-0.08
Australia fob	Prompt	6.05	+0.20

Snapshot of oil-linked LNG prices (5 Nov 2020)					*$/mn Btu*
Jan	**10pc**	**11pc**	**12pc**	**13pc**	**14pc**
601	4.08	4.49	4.90	5.30	5.71
301	4.29	4.71	5.14	5.57	6.00
311	4.34	4.78	5.21	5.64	6.08
101	4.15	4.57	4.98	5.40	5.81

Contracts defined as: Oil-linked LNG on six-month crude average (601) contract; Oil-linked LNG three-month crude average (301) contract; Oil-linked LNG three-month crude average plus one month lag (311) contract; Oil-linked LNG one-month crude average (101) contract. For more oil-linked LNG forward curve prices, please see the appendix at the back of the LNG Daily report.

AUSTRALIAN GAS PRICES

Argus Wallumbilla Index (AWX) - 20201106					
Delivery	**Units**	**Bid**	**Offer**	**Midpoint**	**±**
Dec	*A$/GJ*	5.58	6.23	5.900	-0.175
Dec	*$/mn Btu*	4.28	4.78	4.530	+0.019

Argus Victoria Index (AVX) - 20201106					
Delivery	**Units**	**Bid**	**Offer**	**Midpoint**	**±**
Dec	*A$/GJ*	5.05	5.70	5.375	-0.075
Dec	*$/mn Btu*	3.88	4.38	4.127	+0.080

The AWX and AVX indexes, the first month-ahead indexes for Australia's east coast Wallumbilla and Victorian natural gas markets, are assessed each Friday and reproduced through the week. The date shown is the date of the assessment. The indexes will also appear in the east coast Australian gas markets page each Friday.

MARKET COMMENTARY

Atlantic: Inter-basin arbitrage widens

LNG prices for delivery into Asia-Pacific markets rose sharply on Friday and significantly expanded their premium to European prices, which followed the Dutch TTF gas hub down.

Delivered prices in northeast Asia rose across the curve, with the ANEA January price posting the largest gains. It rose to $6.48/mn Btu on Friday from $6.03/mn Btu at the previous close, expanding its premium to December prices for delivery into northwest Europe to $1.58/mn Btu from $0.99/mn Btu. The differential between the two markets would again be sufficient to cover the additional shipping costs firms have to bear to ship Atlantic basin cargoes to northeast Asia — which stood at around $1.14/mn Btu on Friday, based on *Argus* Round Trip (ARV) rates.

The inter-basin arbitrage had narrowed significantly in recent days as European hubs had not tracked losses in Asian markets, amid colder weather bolstering residential demand and a surge in power sector gas burn, particularly in the UK. Overnight temperatures in London, Amsterdam and Paris fell more sharply than previously anticipated earlier this week and well below the seasonal norm, but forecasts were revised higher for the coming weeks, with overnight lows expected to stay above the seasonal average throughout most of November.

Asian prices may have been bolstered by further supply issues in the basin. The 30mn t/yr Bintulu project in Malaysia halted production at three of its liquefaction trains, which have a combined capacity of 7.8mn t/yr, with some market participants expecting they could remain offline until early 2021. The outage was likely related to a recent incident involving a vessel that collided with one upstream platform at the Baram field, some said.

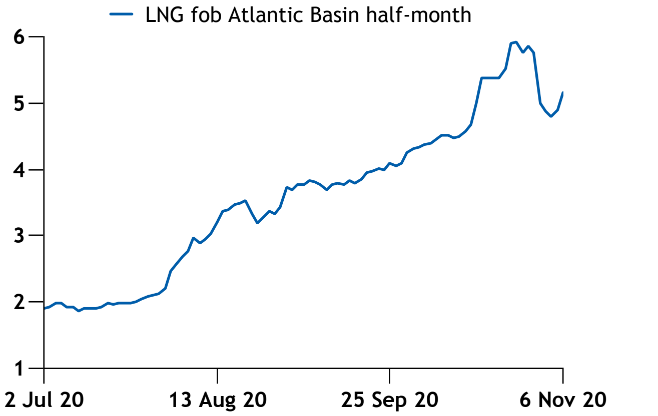
The Bintulu outage adds to a number of other production facilities experiencing issues in both basins, totalling approximately 26mn t/yr of production capacity — or approximately 30 standard-sized cargoes per month. The second train at the 15.6mn t/yr Gorgon LNG project in Western Australia remains offline and was not expected to resume production before the second half of this month. One train at the 22mn t/yr Bonny facility in Nigeria was halted in late October for unplanned maintenance expected to last 2-3 weeks, market participants said. The first train of the 15mn t/yr Freeport LNG terminal in the US Gulf Coast also halted production on 21 October following a fire at the facility, and was expected to resume operations this week. The 4.2mn t/yr Hammerfest facility in Norway was also scheduled to remain offline until October 2021, following a fire at the facility in late September.

Argus Gulf Coast (AGC) fob LNG	Price	± $/mn Btu
Dec	4.55	+0.35
Jan	4.55	+0.25
Feb	4.15	-0.10
Mar	4.25	-0.10
Apr	4.10	-0.05
May	4.00	-0.05

Argus Atlantic Basin fob spot LNG ($/mn Btu)	Loading	Bid	Offer	Midpoint	±
Murmansk fob (ARV freight)	prompt			4.570	na
Iberian peninsula reload	1H Dec	5.00	5.70	5.350	+0.200
	2H Dec	5.05	5.45	5.250	+0.325
	1H Jan	4.90	5.35	5.125	+0.050
Northwest European reload	1H Dec	5.00	5.55	5.275	-0.150
	2H Dec	5.00	5.55	5.275	-0.150
	1H Jan	5.15	5.75	5.450	-0.150
West Africa (AWAF™)	1H Dec	4.75	5.15	4.950	+0.325
	2H Dec	4.50	4.95	4.725	+0.375
	1H Jan	4.35	4.75	4.550	+0.325
Trinidad and Tobago	1H Dec	4.35	4.75	4.550	+0.350
	2H Dec	4.35	4.75	4.550	+0.350
	1H Jan	4.35	4.75	4.550	+0.250

Argus Atlantic Basin fob spot LNG index ($/mn Btu)	Loading	Bid	Offer	Midpoint	±
Atlantic Basin	1H Dec	4.92	5.47	5.195	+0.130
	2H Dec	4.85	5.32	5.085	+0.185
	1H Jan	4.80	5.28	5.040	+0.075

Atlantic Basin fob $/mn Btu



US GULF COAST INDICATIVE FOB PRICE

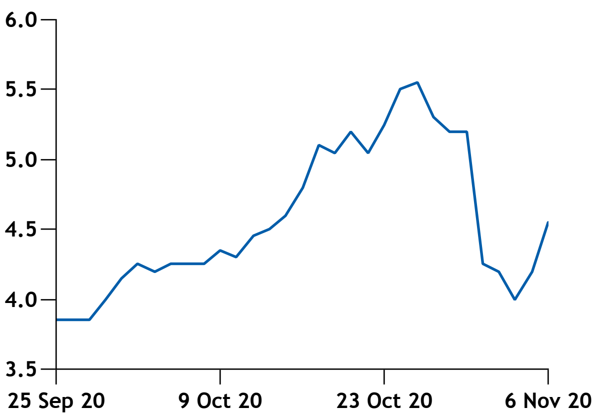
Indicative USGC fob LNG (05 Nov 2020)		*$/mn Btu*
Contract	**Price**	**±**
Dec	6.38	-0.12
Jan	6.54	-0.11
Feb	6.51	-0.09
1Q21	6.49	-0.09
2Q21	6.26	-0.06
3Q21	6.35	-0.05
4Q21	6.51	-0.04
Summer 2021	6.31	-0.05
Winter 2021-22	6.58	-0.03
Summer 2022	5.96	+0.01
Winter 2022-23	6.25	+0.02
2021	6.40	-0.06
2022	6.18	nc
2023	5.93	+0.02

The US Gulf Coast indicative fob price is a derived price series based on the price of Henry Hub gas futures. A subset of these prices is published in the print edition of Argus LNG Daily. The full series is available electronically.

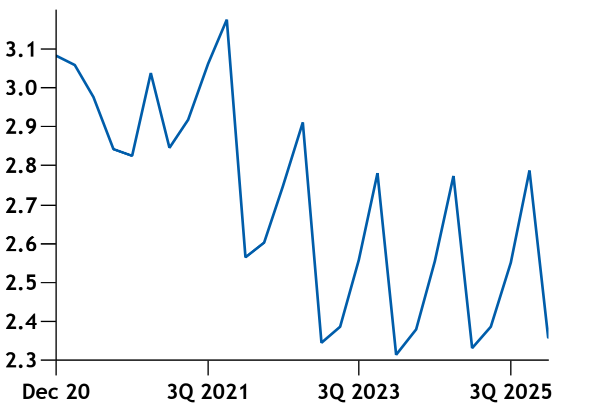
Argus LNG Daily also includes assessments of US Gulf Coast fob LNG prices (see page 1).

For more information, please see the Argus LNG Daily methodology:
http://www.argusmedia.com/methodology-and-reference/

USGC fob LNG Curve *$/mn Btu*



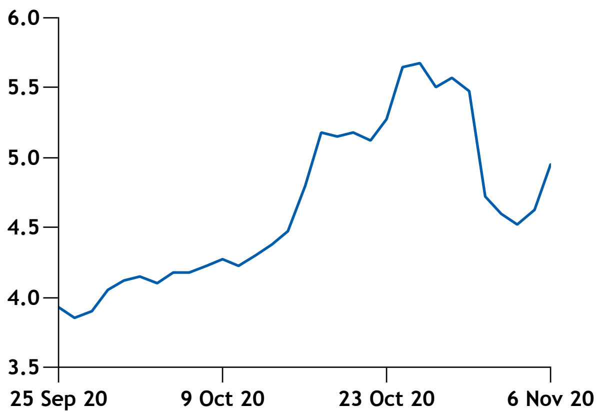
US Nymex gas *$/mn Btu*



OTHER ATLANTIC PRICES

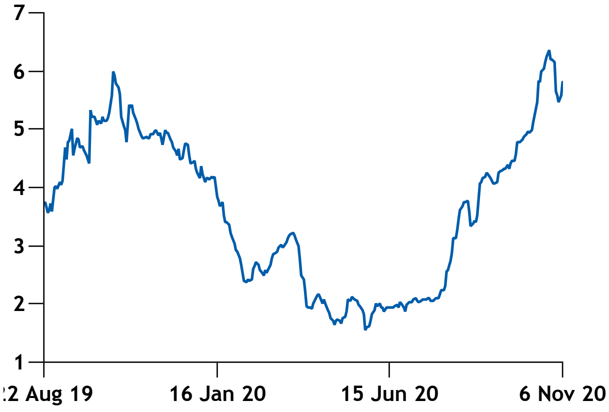
NBP - AGC fob LNG Spread	*$/mn Btu*
Dec 20	0.70
Jan 21	0.89
Feb 21	1.32
Mar 21	0.85
Apr 21	0.70
May 21	0.53

West Africa (AWAF) LNG fob *$/mn Btu*



Argus Latin America des spot LNG			*$/mn Btu*
	Delivery	**Price**	**±**
Argentina	Prompt	5.91	+0.23
Brazil	Prompt	5.80	+0.23
Chile	Prompt	6.29	+0.25
Mexico Gulf coast	Prompt	6.08	+0.23
Mexico Pacific coast	Prompt	5.89	+0.12

Argus Brazil des *$/mn Btu*



MARKET COMMENTARY

Europe: Des prices fall

LNG prices for delivery across Europe fell on Friday as they tracked TTF near-curve contracts lower, as mild weather forecast in the region in the coming days could curb gas demand.

Average temperatures in London, Paris and Essen were expected to hold as much as 4°C above the seasonal norm early next week, while temperatures in major demand centres in southern Europe were forecast to hold closer to the seasonal norm.

A number of European countries, including the UK, Germany, France, and some regions in Italy, had entered into partial lockdowns in recent days to prevent the spread of Covid-19, which may also weigh on gas demand in the region. That said, the new rounds of lockdowns may not result in the same gas demand drop seen between the end of the first quarter and the second quarter, after the first round of restrictive measures was introduced, market participants said.

The first round of restrictions was implemented at the end of the gas winter when temperatures are typically on the rise and heating demand in decline and restrictions on economic activity and movement were also compounded by limited activity around bank holidays, including the Easter bank holiday, market participants said. The new lockdowns, by contrast, are taking place during winter months, with heating demand on the rise, which could be further supported by widespread working from home.

Another difference between the first and second sets of European lockdowns was LNG supply availability. Covid-19 weighing on global gas demand had left ample LNG supply available, leaving Europe to act as the world's balancing market as it absorbed record volumes. Europe's LNG receipts in March were 18pc higher on the year, while April imports rose by 5pc from a year earlier, data from Vortexa shows. By contrast, widespread cancellations of US loadings and an open inter-basin arbitrage resulted in Europe absorbing less supply in recent months. European deliveries fell on the year by 14pc in September and 22pc in October.

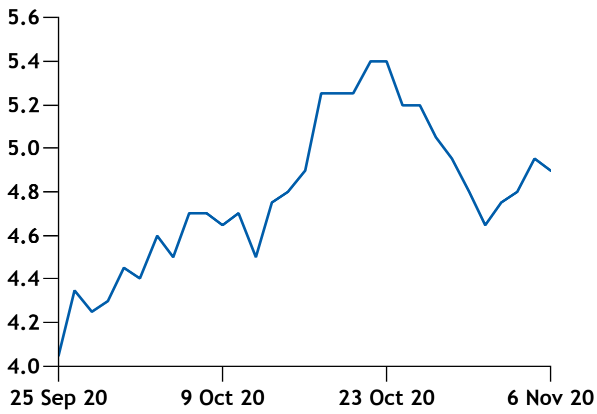
Asian LNG prices holding a premium to European delivered markets could continue to draw some Atlantic volumes into the Pacific this winter, but increasing US loadings, with the country's liquefaction facility 23.8mn t/yr higher on the year at the end of October, would still leave ample supply available for European buyers. Feedgas nominations to US LNG plants rose to an all-time of 9.67bn ft³ on 4 November. That said, a partial outage at Malaysia's 30mn t/yr Bintulu liquefaction facility and additional Chinese demand may draw more Atlantic cargoes to northeast Asia.

UK GAS AND EUROPEAN LNG PRICES

Argus European des spot LNG					*$/mn Btu*
	Delivery	Bid	Offer	Midpoint	±
NW Europe	1H Dec	4.70	5.10	4.900	-0.050
	2H Dec	4.70	5.10	4.900	-0.050
	1H Jan	4.70	5.10	4.900	-0.100
Iberian peninsula	1H Dec	4.75	5.15	4.950	-0.050
	2H Dec	4.75	5.15	4.950	-0.050
	1H Jan	4.75	5.15	4.950	-0.100
Italy	1H Dec	4.75	5.15	4.950	-0.050
	2H Dec	4.75	5.15	4.950	-0.050
	1H Jan	4.75	5.15	4.950	-0.100
Greece	1H Dec	4.75	5.15	4.950	-0.050
	2H Dec	4.75	5.15	4.950	-0.050
	1H Jan	4.75	5.15	4.950	-0.100
Turkey	1H Dec	4.75	5.15	4.950	-0.050
	2H Dec	4.75	5.15	4.950	-0.050
	1H Jan	4.75	5.15	4.950	-0.100

NBP				*$/mn Btu*
Delivery	Bid	Offer	Midpoint	±
Dec	**5.25**	**5.26**	**5.25**	**-0.163**
Jan	5.43	5.44	5.44	-0.146
Feb	5.47	5.47	5.47	-0.153
Mar	5.10	5.10	5.10	-0.150
Apr	4.79	4.81	4.80	-0.131
May	4.52	4.54	4.53	-0.098
1Q21	5.33	5.34	5.33	-0.150
2Q21	4.52	4.55	4.54	-0.089
3Q21	4.33	4.35	4.34	-0.070
4Q21	5.22	5.24	5.23	-0.062
2021	4.85	4.87	4.86	-0.093
2022	5.02	5.05	5.04	-0.033

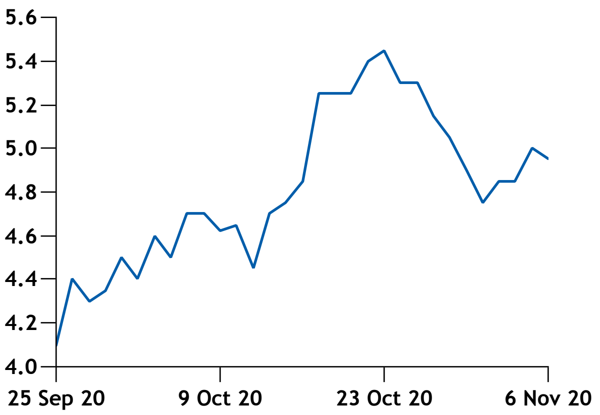
Argus NW Europe LNG des *$/mn Btu*



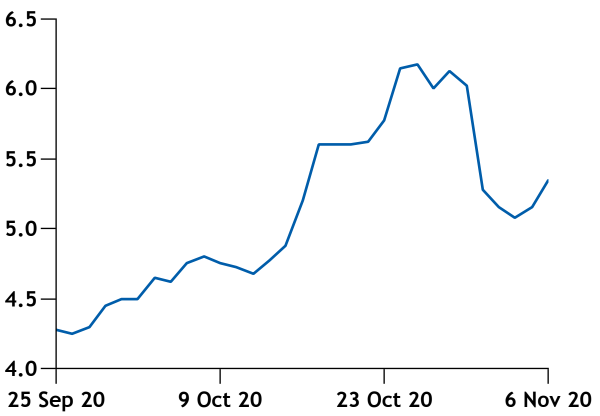
LNG SPREADS AND OIL-LINKED SNAPSHOT

European hubs to LNG price spreads	Northeast Asia		China		India		Middle East		Middle-East-India (MEI) $/mn Btu	
	1H Dec	Dec avg	1H Dec	Dec avg	1H Dec	Dec avg	1H Dec	Dec avg	1H Dec	Dec avg
NBP	1.53	1.54	1.54	1.55	1.18	1.18	1.18	1.18	1.18	1.18
TTF	1.95	1.96	1.95	1.97	1.60	1.60	1.60	1.60	1.60	1.60

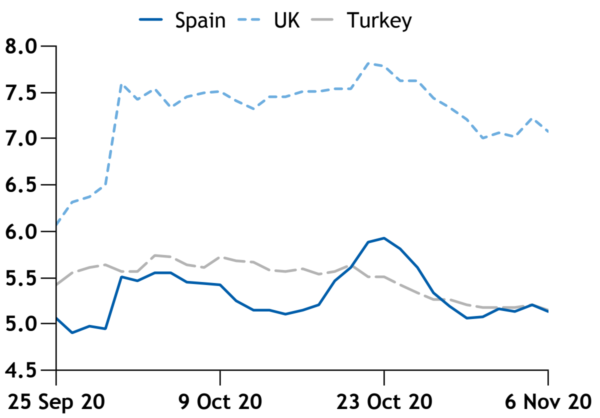
Argus Iberian peninsula des *$/mn Btu*



Iberia peninsula reload fob *$/mn Btu*



Europe: Front month base load break even *$/mn Btu*

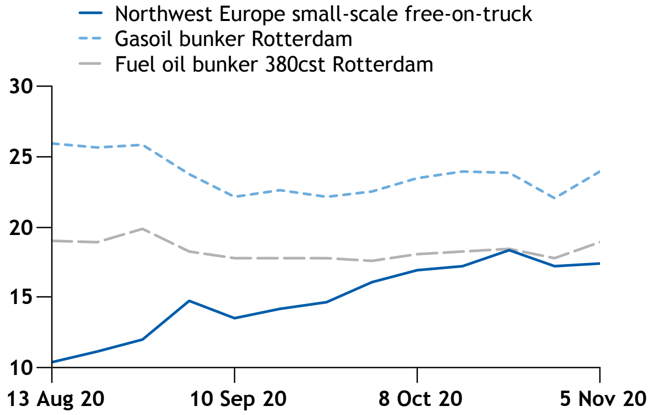


SMALL-SCALE LNG

Small-scale LNG assessments (5 Nov 2020)	€/MWh	+/- 29 Oct	$/t MGOe	+/- 29 Oct
Northwest Europe free on truck front month	17.375	na	243.26	na
Southwest France free on truck front month	18.575	na	260.06	na
Northwest Europe LNG bunker delivered on board	23.150	-0.425	324.11	-1.08

Competing fuels snapshot (5 Nov 2020)				
Gas	€/MWh	± 29 Oct	$/t MGOe	± 29 Oct
TTF	14.375	na	201.258	na
Zeebrugge	14.381	na	201.335	na
Oil products	€/MWh	± 29 Oct	$/t	± 29 Oct
Gasoil bunker Rotterdam prompt	23.947	+1.907	335.250	+31.250
Gasoil diesel 10ppm German NWE barge prompt	0.071	-21.951	1.000	-302.750
Fuel oil bunker 380cst Rotterdam prompt	18.902	+1.145	262.000	+19.500

Small Scale LNG vs. Gasoil and fuel oil *€/MWh*



ANNOUNCEMENT

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LNG OPEN BIDS, OFFERS AND RECENT DEALS

Global Open Bids

Submission date	Validity date	Bid	Period	Note
9-Nov-20	9-Nov-20	2 cargo(es) des to CFE	delivery 13-27 Nov 2020	To Manzanillo. Delivery windows 13-14 Nov, 26-27 Nov
9-Nov-20	9-Nov-20	3 cargo(es) des Pakistan to Pakistan State Oil	delivery 21 Nov 2020 - 22 Jan 2021	For deliveries on 21-22 Nov, 21-22 Dec, 21-22 Jan 2021
9-Nov-20	unknown	1 cargo(es) des Kuwait to KPC	delivery 16-17 Dec 2020	
5-Nov-20	unknown	2 cargo(es) des Taiwan to CPC	delivery 01-31 Jan 2021	
5-Nov-20	unknown	1 cargo(es) des China to Shenzhen Energy	delivery 05-15 Feb 2021	For delivery to Diefu terminal
5-Nov-20	5-Nov-20	7 cargo(es) des Turkey to Botas	delivery 16 Nov 2020 - 28 Feb 2021	One cargo each half-month from the second half of November until the end of February. Submissions either at fixed prices or indexed to hub prices.
3-Nov-20	unknown	1 cargo(es) des to RPGCL	delivery 22-26 Dec 2020	
2-Nov-20	2-Dec-20	1 cargo(es) des to RPGCL	delivery 09-12 Dec 2020	For delivery to either the Excellence FSRU or the Summit LNG FSRU in Bangladesh

Global Open Offers

Submission date	Validity date	Offer	Period	Note
unknown	unknown	1 cargo(es) des from Woodside	delivery 15-22 Dec 2020	From Wheatstone LNG
11-Nov-20	unknown	1 cargo(es) fob Australia from CNOOC	loading 29-31 Dec 2020	From NWS LNG; 155,000m³
5-Nov-20	6-Nov-20	1 cargo(es) des from Sakhalin Energy	loading 02 Jan 2021	On a des or fob basis; 3.3 trillion Btu cargo size
5-Nov-20	5-Nov-20	2 cargo(es) fob from Gail	loading 04 Jan 2021 - 13 Feb 2021	Part of a swap tender. Gail also seeking 2 cargoes for Dabhol on 7-15 Jan and 4-10 Feb. Bids should be premium of 115pc HH, offers at a fixed price.
4-Nov-20	unknown	1 cargo(es) des from Oman LNG	delivery 10-20 Dec 2020	For delivery to northeast Asia in mid-Dec
3-Nov-20	unknown	1 cargo(es) des from Oman LNG	delivery 30 Dec 2020 - 01 Jan 2021	For delivery to northeast Asia
28-Oct-20	unknown	1 cargo(es) des from Ichthys	loading 24-28 Nov 2020	On a des or fob basis; 3.3-4.3 trillion Btu cargo size
27-Oct-20	unknown	1 cargo(es) des from Petronas	delivery 27-31 Dec 2020	From Bintulu LNG

Global Recent Deals

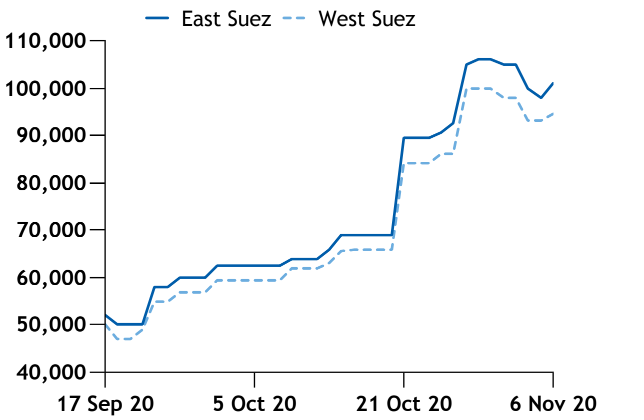
Date	Transaction	Period	Price	Note
5-Nov-20	Total sold to Vitol 1 cargo(es) des China	delivery 26-30 Dec 2020	$6.70/mnBtu	
5-Nov-20	Prism bought from Unknown 1 cargo(es) des South Korea	delivery 15-18 Dec 2020	$6.80-6.90/mnBtu	
4-Nov-20	CPC bought from Qatargas 1 cargo(es) des Taiwan	delivery 01-15 Dec 2020	$6.50/mnBtu	
2-Nov-20	Guangzhou Gas bought from Unknown 1 cargo(es) des China	delivery 20-26 Dec 2020	$6.70-6.80/mnBtu	For delivery to Zhuhai terminal
30-Oct-20	Inpex sold to Unknown 1 cargo(es) des	delivery 23-28 Dec 2020	$6.85-6.90/mnBtu	For delivery to northeast and southeast Asia; from Darwin LNG; 3.5 trillion Btu
28-Oct-20	Ichthys sold to Unknown 1 cargo(es) fob Australia	loading 24-28 Nov 2020	$6.50/mnBtu	3.3-4.3 trillion Btu cargo size; awarded two cargoes instead of one
28-Oct-20	Ichthys sold to Unknown 1 cargo(es) fob Australia	loading 24-28 Nov 2020	$6.50/mnBtu	3.3-4.3 trillion Btu cargo size; awarded two cargoes instead of one
28-Oct-20	Oman LNG sold to Unknown 1 cargo(es) des	delivery 20-22 Dec 2020	$7.30-7.50/mnBtu	For delivery to northeast Asia; 3.2 trillion Btu
28-Oct-20	PNG LNG sold to Unknown 1 cargo(es) des	loading 30 Nov 2020	$7.40/mnBtu	On a des or fob basis; loading on 30 Nov, delivery across 9-14 Dec

Global shipping highlights

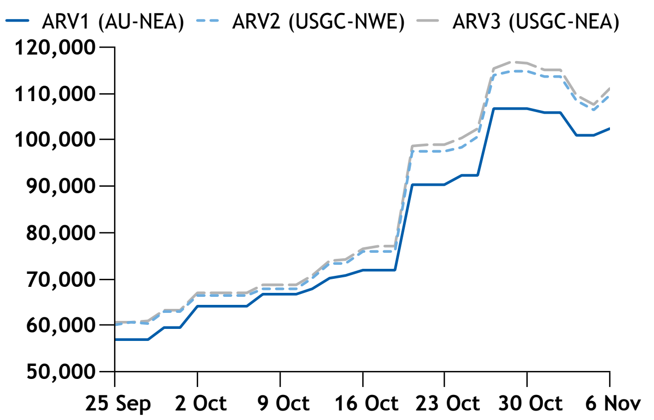
Vessel	Capacity *m³*	From	To	Loading	Arrival	Notes
LNG Unity	154,500	Dunkirk, France	Montego Bay, Jamaica	21 Sep	6 Nov	Reload from Dunkirk
Seri Balhaf	157,000	Sabine Pass, US	Pakistan	6 Oct	7 Nov	Via Cape of Good Hope
Nikolay Yevgenov	172,600	Yamal, Russia	Montoir, France	31 Oct	7 Nov	
Clean Planet	162,000	Yamal, Russia	Zhuhai, China	19 Oct	7 Nov	
Gaslog Houston	174,000	Elba Island, US	India	25 Sep	8 Nov	Via Cape of Good Hope
Excalibur	138,000	Sabine Pass, US	TBC	16 Sep	9 Nov	Via Cape of Good Hope
Corcovado LNG	160,100	Fos-sur-Mer, France	Northeast Asia	5 Oct	9 Nov	Reload, via Suez
Clean Ocean	162,000	Yamal, Russia	Zeebrugge, Belgium	1 Nov	10 Nov	
Christophe de Margerie	172,600	Yamal, Russia	Montoir, France	2 Nov	10 Nov	
La Seine	174,000	Sabine Pass, US	TBC	4 Oct	11 Nov	Via Cape of Good Hope
Elisa Larus	174,000	Freeport, US	Singapore	13 Oct	11 Nov	Via Suez
Maran Gas Andros	173,400	Freeport, US	TBC	3 Oct	11 Nov	Via Panama
SK Resolute	180,000	Freeport, US	Taiwan	17 Oct	12 Nov	Via Panama
Georgiy Brusilov	172,600	Yamal, Russia	Zeebrugge, Belgium	5 Nov	14 Nov	
Clean Vision	162,000	Yamal, Russia	Zhuhai, China	27 Sep	15 Nov	Via Cape of Good Hope
Stena Clear Sky	173,000	Sabine Pass, US	Dahej, India	21 Oct	15 Nov	Via Suez
Golar Penguin	160,000	Freeport, US	TBC	8 Oct	16 Nov	Via Cape of Good Hope
Prism Agility	180,000	Freeport, US	Boryeong, South Korea	19 Oct	16 Nov	Via Panama
Maran Gas Mystras	159,800	Freeport, US	TBC	16 Oct	16 Nov	Via Panama
British Emerald	155,000	Sabine Pass, US	Zeebrugge, Belgium	30 Oct	18 Nov	
Ribera Del Duero Knutsen	173,400	Sabine Pass, US	Montoir, France	5 Nov	18 Nov	
Seri Balqis	152,000	Corpus Christi, US	Himeji, Japan	20 Oct	19 Nov	Via Panama
Gaslog Gibraltar	174,000	Sabine Pass, US	Hazira, India	16 Oct	19 Nov	
LNG Dubhe	174,000	Yamal, Russia	Dapeng, China	14 Oct	19 Nov	Via Suez
Hoegh Gannet	170,000	Freeport, US	TBC	4 Nov	21 Nov	
Flex Endeavour	173,400	Cameron, US	TBC	6 Nov	21 Nov	
BW Pavilion Aranthera	170,800	Sabine Pass, US	TBC	22 Oct	22 Nov	Via Panama
Gaslog Singapore	155,000	Corpus Christi, US	TBC	19 Oct	23 Nov	Via Cape of Good Hope
Kinisis	173,400	Freeport, US	Tianjin, China	21 Oct	23 Nov	Via Panama
Al Ruwais	210,200	Yamal, Russia	TBC	9 Oct	29 Nov	STS from Clean Horizon at Montoir on 16 October
Marvel Pelican	155,000	Sabine Pass, US	Mina Al-Ahmadi, Kuwait	27 Oct	30 Nov	Via Suez
Flex Ranger	174,000	Corpus Christi, US	TBC	4 Nov	30 Nov	
Wilpride	160,000	Cameron, US	Ennore, India	2 Nov	2 Dec	
Yenisei River	155,000	Yamal, Russia	Tianjin, China	26 Oct	2 Dec	STS from Boris Vilkitsky at Zeebrugge on 3 November
Stena Blue Sky	145,700	Sabine Pass, US	TBC	3 Nov	7 Dec	
LNG Saturn	155,700	Cameron, US	Tianjin, China	27 Oct	9 Dec	Via Cape of Good Hope
Meridian Spirit	165,500	Cove Point, US	TBC	21 Oct		Via Suez
Bahrain Spirit	173,000	Cove Point, US	TBC	20 Sep		Offshore Spain since 2 October
Rias Baixas Knutsen	180,000	Corpus Christi, US	Milford Haven, UK	2 Nov		
Maran Gas Pericles	174,000	Sabine Pass, US	TBC	4 Nov		
LNG Merak	174,000	Gate, Netherlands	TBC	2 Nov		Reload, via Suez

FREIGHT RATES

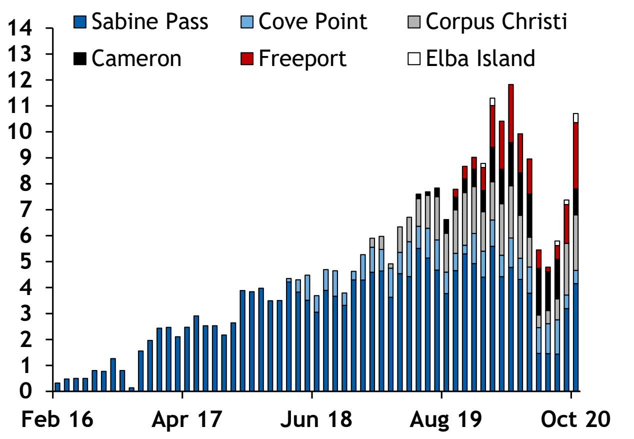
Laden freight rate (prompt - TFDE) *$/day*



Argus Round Voyage rates *$/day*



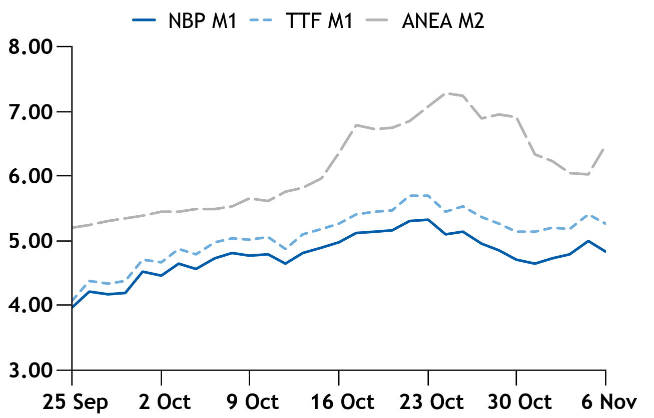
US LNG loadings *mn m³ of LNG*



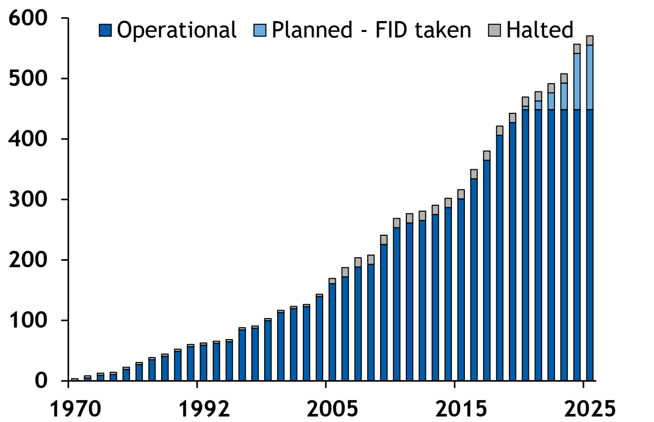
Argus ballast leg TFDE rates (06 Nov 2020)		
	%	+/-(30 Oct)
Day rate - west of Suez	110	nc
Day rate - east of Suez	105	nc
Fuel cost - west of Suez	40	nc
Fuel cost - east of Suez	40	nc

Argus TFDE laden day-rate forward curve (6 Nov)				
	West of Suez		East of Suez	
Month	$/day	+/-(30 Oct)	$/day	+/-(30 Oct)
Dec	100,500	-8,000	95,000	-6,000
Jan	89,000	-3,000	83,000	-2,000
Feb	69,500	nc	62,500	nc
Mar	47,000	nc	44,500	nc
Apr	39,000	nc	36,500	nc
May	39,000	nc	36,500	nc
Jun	39,500	nc	37,000	nc
Jul	40,500	nc	38,000	nc
Aug	48,500	nc	45,500	nc
Sep	57,500	nc	54,500	nc
Oct	69,000	nc	65,000	nc
Nov	77,000	nc	72,500	nc

European gas hubs vs ANEA *$/mn Btu*



Global liquefaction capacity *mn t/yr*



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FREIGHT COSTS AND NETBACKS

Standard round-trip freight costs* *$/mn Btu*

	route via	Ain Sukhna and Aqaba	Aliaga	Altamira	Dahej and Qasim	Escobar	Incheon	Jebel Ali and Mina al-Ahmadi	Manzanillo	Map ta Phut	Milford Haven	Pecem	Quintero	Shenzen and Taipei	Singapore	Tokyo
Angola	-		0.98	1.10	1.16	0.73	1.81	1.25	1.76	1.35	0.84	0.55	1.10	2.15	1.23	1.88
	Suez	1.21														
	Panama								1.40							
Bintulu and Tangguh	-	1.01			0.62	1.61	0.43	0.77	1.42	0.23		1.60	1.76	0.30	0.17	0.50
	Suez		1.22	2.30							1.64					
	Panama			2.13												
Bonny	-		0.91	1.04	1.25	0.76	1.91	1.35	1.79	1.44	0.75	0.52	1.10	1.57	1.35	1.95
	Suez	1.12														
	Panama								1.33							
Bontang	-	1.10			0.75	1.61	0.50	0.88	1.39	0.36		1.67	1.63	0.34	0.27	0.50
	Suez		1.34	2.39							1.73					
	Panama			2.10												
Dampier	-	1.00		1.96	0.67	1.48	0.69	0.79	1.48	0.46		1.52	1.56	0.56	0.36	0.69
	Suez		1.34								1.73					
	Panama			2.13												
Gladstone	-	1.36		1.62	1.00	1.36	0.76	1.12	1.14	0.75		1.73	1.22	0.69	0.64	0.72
	Suez		1.67								2.06					
	Panama			1.79												
Rotterdam	-		0.60	0.86		1.11			2.18			0.71	1.51			
	Suez	0.82			1.22		2.19	1.28		1.75				2.06	1.60	2.26
	Panama								1.28				1.43			
Papua New Guinea	-	1.36		1.62	0.94	1.48	0.69	1.12	1.14	0.62		1.73	1.22	0.56	0.64	0.63
	Suez		1.67								2.06					
	Panama			1.85												
Ras Laffan and UAE	-	0.48			0.23	1.61	1.11	0.12	2.08	0.81			1.91	0.95	0.68	1.17
	Suez		0.82	1.85							1.21	1.56				
Sakhalin	-	1.57			1.10	1.86	0.30	1.25	0.99	0.62		2.13	1.56	0.40	0.62	0.27
	Suez		1.67	2.86							2.10					
	Panama			1.70												
Singapore	-	0.90			0.55	1.58	0.50	0.68	1.52	0.21		1.60	1.76	0.34		0.56
	Suez		1.15	2.20							1.55					
Sagunto	-		0.30	0.89		0.98			2.06		0.33	0.61	1.39			
	Suez	0.57			0.97		1.92	1.00		1.47				1.76	1.35	1.99
	Panama								1.28				1.40			
Trinidad and Tobago	-		0.91	0.39		0.76			1.81	1.94	0.69	0.33	1.16		1.81	
	Suez	1.14			1.54		2.56	1.58						2.40		2.63
	Panama						1.99		0.68				0.80	2.05		1.82
USGC	-		1.11	0.13		1.13	2.83		0.59	2.35	0.84	0.68	1.54		2.22	2.87
	Suez	1.37			1.78			1.85						2.63		
	Panama						2.05		0.76				0.89	2.12		1.85

**Standard freight costs include full charter costs and fuel for the return leg of a delivery fixture*

Netbacks (standard freight costs*) *$/mn Btu (prompt)*

	India	China	Japan	South Korea	Taiwan	Iberian peninsula	Greece	Italy	Turkey	NW Europe	North-east US
Middle East	6.14	5.75	5.54	5.61	5.80	3.80	4.09	3.93	4.06	3.62	3.17
Australia	5.73	6.16	6.06	6.09	6.22	3.28	3.54	3.41	3.54	3.08	2.63
Nigeria	5.12	4.98	4.80	4.87	5.06	4.26	4.04	4.07	4.00	4.08	3.83
Norway	4.91	4.51	4.34	4.44	4.60	4.46	4.17	4.20	4.13	4.50	4.05
Algeria	5.45	5.05	4.92	4.98	5.15	4.74	4.72	4.74	4.68	4.54	4.11
Trinidad and Tobago	4.76	4.44	4.22	4.28	4.61	4.23	4.00	4.04	3.97	4.12	4.37
Russia	5.40	6.45	6.55	6.51	6.44	2.93	3.19	3.06	3.15	2.75	2.48

FREIGHT COSTS AND NETBACKS

Spot (ARV) freight costs* *$/mn Btu*

	route via	Ain Sukhna and Aqaba	Aliaga	Altamira	Dahej and Qasim	Escobar	Incheon	Jebel Ali and Mina al-Ahmadi	Manzanillo	Map ta Phut	Milford Haven	Pecem	Quintero	Shenzen and Taipei	Singapore	Tokyo
Angola	-		0.97	1.10	1.16	0.73	1.78	1.25		1.35	0.84	0.54	1.10	2.12	1.22	1.85
	Suez	1.21														
	Panama								1.39							
Bintulu and Tangguh	-	0.96			0.59	1.55	0.41	0.74	1.38	0.22		1.55	1.69	0.29	0.16	0.47
	Suez		1.19	2.21							1.60					
	Panama			2.05												
Bonny	-		0.91	1.04	1.25	0.76	1.88	1.35		1.44	0.75	0.51	1.10	1.57	1.35	1.92
	Suez	1.12														
	Panama								1.33							
Bontang	-	1.05			0.72	1.55	0.47	0.84	1.35	0.34		1.61	1.56	0.32	0.26	0.47
	Suez		1.30	2.30							1.69					
	Panama			2.02												
Dampier	-	0.96		1.88	0.65	1.43	0.66	0.76	1.44	0.44		1.46	1.50	0.53	0.34	0.66
	Suez		1.30								1.69					
	Panama			2.05												
Gladstone	-	1.30		1.55	0.96	1.31	0.72	1.07	1.11	0.72		1.67	1.17	0.66	0.62	0.69
	Suez		1.63								2.01					
	Panama			1.72												
Rotterdam	-		0.59	0.85		1.10						0.70	1.51			
	Suez	0.81			1.21		2.16	1.27		1.75				2.02	1.59	2.23
	Panama								1.27				1.43			
Papua New Guinea	-	1.30		1.55	0.90	1.43	0.66	1.07	1.11	0.59		1.67	1.17	0.53	0.62	0.60
	Suez		1.63								2.01					
	Panama			1.78												
Ras Laffan and UAE	-	0.47			0.22	1.55	1.06	0.11	2.02	0.78			1.84	0.91	0.65	1.12
	Suez		0.80	1.78							1.18	1.51				
Sakhalin	-	1.51			1.05	1.80	0.29	1.20	0.96	0.59		2.06	1.50	0.38	0.59	0.26
	Suez		1.63	2.75							2.05					
	Panama			1.63												
Singapore	-	0.87			0.53	1.53	0.47	0.65	1.47	0.19		1.55	1.69	0.32		0.53
	Suez		1.13	2.11							1.51					
Sagunto	-		0.29	0.88		0.98					0.33	0.61	1.38			
	Suez	0.56			0.96		1.89	0.99		1.46				1.73	1.34	1.96
	Panama								1.27				1.40			
Trinidad and Tobago	-		0.91	0.39		0.76				1.94	0.68	0.33	1.16		1.82	
	Suez	1.14			1.55		2.53	1.58						2.36		2.59
	Panama						1.95		0.68				0.80	2.02		1.79
USGC	-		1.10	0.12		1.08	2.78			2.27	0.84	0.66	1.49		2.14	2.82
	Suez	1.32			1.72			1.78						2.59		
	Panama						2.02		0.73				0.85	2.09		1.82

**ARV freight costs take into account a varying proportion of return leg fuel and charter costs, in line with Argus' ballast bonus assessments . For more details, consult the Argus Round Voyage methodology.*

Netbacks (ARV freight costs*) *$/mn Btu (prompt)*

	India	China	Japan	South Korea	Taiwan	Iberian peninsula	Greece	Italy	Turkey	NW Europe	North-east US
Middle East	6.15	5.79	5.60	5.66	5.84	3.80	4.09	3.93	4.06	3.63	3.17
Australia	5.75	6.19	6.09	6.12	6.25	3.29	3.54	3.42	3.54	3.08	2.63
Nigeria	5.17	5.05	4.88	4.95	5.13	4.27	4.04	4.07	4.01	4.09	3.83
Norway	4.97	4.60	4.44	4.53	4.69	4.46	4.17	4.20	4.14	4.51	4.05
Algeria	5.49	5.12	4.99	5.05	5.21	4.75	4.72	4.75	4.69	4.54	4.12
Trinidad and Tobago	4.81	4.54	4.31	4.38	4.70	4.24	4.01	4.04	3.98	4.12	4.37
Russia	5.44	6.47	6.56	6.52	6.46	2.93	3.19	3.06	3.16	2.75	2.48

NEWS

Partial Bintulu outage in Malaysia boosts prices

Unplanned shutdowns of three liquefaction trains at Petronas' 30mn t/yr Bintulu LNG facility in Malaysia have led to a rebound in spot prices for LNG deliveries to northeast Asia, with expectations of tighter LNG supplies heading into winter likely to push prices past the $7/mn Btu mark again.

Term offtakers at Bintulu confirmed that Petronas has shut the nine-train plant's first, third and seventh trains. The exact reason for the shutdowns is unclear, but market participants suggest that they could be due to "unexpected trips" at the facility.

The duration of the outages is still unclear, with some term offtakers expecting that they could last well into early next year.

The three trains collectively produce around 10-11 cargoes/month based on their nameplate capacity and a cargo size of 60,000t. Trains 1 and 3 each have a capacity of 2mn t/yr, while train 7 has a capacity of 3.8mn t/yr.

Petronas has been in the spot market in the last few days to seek December and January deliveries, likely to meet its term obligations. Market participants estimate that Petronas may have already bought around 5-7 cargoes for deliveries across November and early December.

The firm is seeking more December cargoes and deliveries for January as well, they added.

Term offtakers have said they are not seeking replacement cargoes as Petronas will fulfill its contractual commitments, albeit with possible delays of a few days and smaller cargo volumes.

Petronas had asked these firms if they could take delivery of smaller cargo volumes for loadings in November or December, or if they could receive later deliveries. Some firms received both requests. Offtakers said they were also asked if they would agree to receive cargoes from facilities in the US.

It is unclear which of them have agreed to these requests but at least two term offtakers that receive cargoes from the plant have rejected Petronas' requests to delay deliveries and switch cargo sources. They hope Petronas will be able to deliver their cargoes as scheduled.

Term offtakers from Bintulu include Taiwan's CPC, South Korea's Kogas, several Japanese utilities including Jera, Tokyo Gas, Toho Gas, Osaka Gas, Hiroshima Gas, Tohoku Electric and Shikoku Electric, as well as China's CNOOC.

The shutdowns come at a time when demand is at its peak because of increased heating requirements during the northern hemisphere winter. Petronas' purchases on the back of the three-train outages at Bintulu have been a major factor in helping spot prices claw back their losses this week.

The front-half month ANEA price, the *Argus* assessment for spot deliveries to northeast Asia, rose to $6.785/mn Btu for first-half December on Friday, up from $6.555/mn Btu on 5 November, after easing this week on expectations of increased supplies.

The front half-month ANEA price rose by around 24pc to a 22-month high at $7.48/mn Btu on 29 October from $6.05/mn Btu on 16 October on supply disruptions in the US and Australia, several higher-than-expected deal levels and demand from consumers and trading firms. The front-half month during that period was second-half November, while first-half December moved to front-half month position on 2 November.

Rising Dutch TTF gas prices amid cooler weather, forecasts of low wind output, and expectations of a power shortfall, could exacerbate a tight supply situation in Asia if its discount to Asian spot prices narrows sharply.

The TTF December contract inched up by 19.2¢/mn Btu to settle at $4.987/mn Btu on 5 November, narrowing its discount to the ANEA price for both halves of December to $1.39-1.57/mn Btu from $1.98-2.19/mn Btu on 2 November. Market participants suggest a differential of at least $1.20-1.50/mn Btu is required to cover the variable costs in shipping US cargoes to Asia instead of Europe.

Only one LNG vessel is currently berthed at the Bintulu LNG terminal. The 89,800m^3 *Polar Spirit* tanker arrived at Bintulu on 5 November after unloading at the 3mn t/yr Shanghai LNG terminal in China on 31 October, but no destination has been declared for the vessel. Four LNG vessels are scheduled to arrive at Bintulu in the coming days: the 145,000m^3 *Seri Amanah* on 7 November, the 137,100m^3 *Puteri Delima Satu* on 9 November, the 137,585m^3 *Puteri Nilam Satu* on 10 November, and the 18,928m^3 *Aman Sendai* on 14 November, according to vessel tracking data.

Petronas has also been plagued by upstream woes related to high sulphur levels at one of its gas fields that supplies feed gas to Bintulu and supply disruptions due to issues at its 750mn ft^3/d Sabah-Sarawak gas pipeline (SSGP), which supplies Bintulu with feedstock gas for liquefaction. The SSGP suffered a a rupture in the pipeline in mid-January this year, causing a fire. It also suffered leaks in 2018 and 2019 that required extended turnarounds.

By Joey Chua and Camille Klass

Mexico seeks two prompt LNG cargoes

Mexican utility CFE has issued a tender seeking two cargoes for delivery to its 3.8mn t/yr Manzanillo import facility this month.

The deadline for submitting offers is from 06:00-10:00 Mexico City time (12:00-04:00 GMT) on 9 November. CFE is seeking one cargo for delivery on 13-14 November and another for delivery on 26-27 November.

CFE last sought a cargo on the spot market for delivery on 23-24 October, which was likely fulfilled by the 174,000m³ *Maran Gas Hector*. The tanker arrived on 23 October, having loaded at the US' 4mn t/yr Elba Island facility.

Mexico received 209,300t of LNG last month, Vortexa data show, down from 358,100t a year earlier. One of the cargoes was shipped from Indonesia's 7.6mn t/yr Tangguh facility to Mexico's Costa Azul import facility. US firm Sempra has a 20-year flexible offtake agreement with Tangguh for 3.7mn t/yr, which began in 2008. But Sempra also plans to convert the Costa Azul import terminal into a liquefaction facility in the coming years, with a final investment decision on the project expected by the end of this year, having been delayed multiple times.
By Ellie Holbrook

CNOOC offers December cargo from NWS LNG

Chinese importer CNOOC is looking to sell a cargo loading from the 16.3mn t/yr North West Shelf (NWS) LNG project in Australia during 29-31 December. Bids for the tender are due at 5pm Singapore time (09:00 GMT) on 11 November.

The cargo has a volume of 155,000m³ and is expected to arrive in northeast Asia in the first half of January, given a typical sailing time of around 10-12 days from Western Australia to most ports in northeast Asia.

CNOOC's tender comes amid rising spot prices for deliveries to northeast Asia, with unplanned shutdowns at three trains at the 30mn t/yr Bintulu LNG facility in Malaysia pushing plant owner Petronas to seek replacement cargoes from the spot market for deliveries in December-January. The shutdowns and short-covering by Petronas have sparked concerns of tighter supplies for winter and pushed up bids and offers.

Indicative bids for first-half January rose by around 45¢/mn Btu from Thursday, ranging between $6.20/mn Btu and $6.55/mn Btu. Selling indications were up by a similar margin to $6.60-7/mn Btu.

The ANEA price, the *Argus* assessment for spot deliveries to northeast Asia, was assessed at $6.555/mn Btu for the first half of January on Friday, up by 47.5¢/mn Btu from Thursday.

The latest transaction for a first-half January cargo is Japanese utility Chugoku's 22 October purchase of a 4-13 October delivery at around $7-$7.10/mn Btu. Two other firms, South Korea's importer Kogas and Chinese Sinopec's trading arm Unipec, also purchased January cargoes on 21 October and 23 October, respectively, through separate multiple-cargo tenders.

The buying focus among other consumers is gradually shifting to January. But most buyers expect to only firm up their January requirements in about two weeks, when they are likely to get a clearer idea of weather conditions in December and January as well as their inventory levels.
By Joey Chua

Foran Gas and Cheniere sign initial supply deal

Chinese independent utility Foran Energy has signed an initial agreement to purchase a total of 26 LNG cargoes over the next five years from US producer Cheniere Energy to diversify its supply chain and increase its use of LNG.

The two firms signed a heads of agreement in Shanghai on Friday, providing no detail on the contract start date, tenure and price. The agreement is expected to be finalised by 31 December 2021. But the contract price is expected to be indexed to the US Henry Hub natural gas price.

Foran Energy, formerly Foshan Gas, agreed in July to purchase from BP 300,000 t/yr of pipeline gas for delivery to the 6.7mn t/yr CNOOC-operated Dapeng LNG receiving terminal over two years, starting from 1 January 2021.

Foran supplied over 2.2bn m³ of gas to city gas enterprises in Guangdong last year. It intends to develop its midstream and upstream gas businesses, as well as expand its international procurement and diversify its supply sources.

The firm entered the LNG spot market for the first time this year, and bought one spot cargo for delivery over 25-30 June to the 3.5mn t/yr CNOOC-operated Zhuhai terminal in Guangdong. It has bought four spot cargoes this year.
By Tatiana Rosli

China's winter coal switch increases gas demand

China's environment and ecology ministry has released more details of its targets to shut coal-fired boilers and power plants this winter, as part of annual efforts to reduce air pollution in north and east China.

More than 7mn households in north China were due to switch from coal boilers to cleaner energy sources by the end of October, around 4mn of which were to switch to natural gas boilers, the ministry said. It is unclear how many households actually made the switch.

The targets, which are in line with estimates from state-owned PipeChina last week, are expected to increase gas consumption by about 40mn m³/d in the coming winter heating period.

A total of 10.38GW of coal-fired power capacity and 10,032 t/d of coal boilers are earmarked for shutdowns in cities in north China and the Yangtze river delta region by the end of this year. The Chinese government has set a 1,100GW cap on coal-fired power capacity this year. Installed capacity increased 3pc to 1,070GW in January-September.

PipeChina expects total Chinese gas demand to rise by 11.7pc from a year earlier to 150bn m³ in the coming winter period, which typically runs from November to March. The company also expects gas supplies through its nationwide network to exceed 153bn m³ during the period, an increase of 7.7pc from last year that will be sufficient to meet demand.

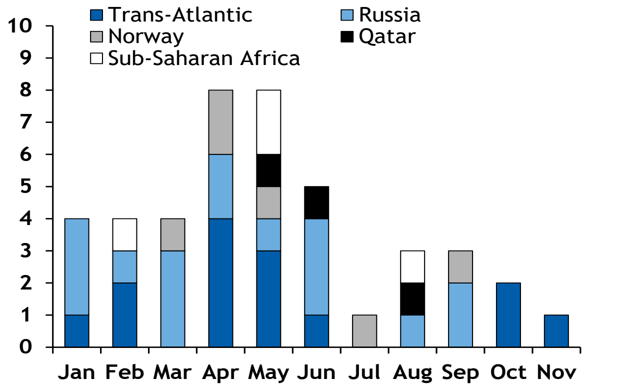
China's authorities are attempting to avoid the widespread gas supply shortages that followed a similar coal-to-gas plan in the winter of 2017-18. The government set aggressive coal-to-gas switching targets in north China over that period, without ensuring there was enough gas available to meet the increased demand.

France's Dunkirk expects Trinidadian LNG

A receipt from Trinidad and Tobago is expected at France's 9.4mn t/yr Dunkirk LNG terminal later this month.

The 155,000m³ *Solaris* is scheduled to arrive on 13 November, according to the Dunkirk port authority schedule. The *Solaris* left the 14.8mn t/yr Atlantic liquefaction complex at Point Fortin on 3 November. The same tanker already delivered to Dunkirk on 19 October, carrying a Peruvian cargo.

Origin of Dunkirk LNG receipts *Number of deliveries*



This could be the terminal's first receipt of the month, with no other receipts scheduled for the rest of November so far. It would also be the first from Trinidad and Tobago since the 135,100m³ *Portovyy* docked at Dunkirk on 3 May.

Dunkirk's most recent receipt was of US origin, with the 174,000m³ *Elisa Larus* delivering a cargo from Freeport, Texas on 25 October.

France has only received LNG from the Atlantic basin so far this winter, with receipts from this destination rising from the third quarter *(see graph)*.

The facility's stocks were 252,740m³ of LNG this morning, approximately 43pc of capacity, leaving ample space for a full cargo from the *Solaris*.

Dunkirk regasification has slowed even further so far this month from October. It was just 10.1GWh/d on 1-5 November, down from 20.9GWh/d in October and 211GWh/d over the period a year earlier.

By Auguste Breteau

Japan's Hokuriku shuts Toyama-Shinko CCGT unit

Japanese utility Hokuriku Electric Power has closed the 424.7MW combined-cycle gas turbine (CCGT) unit at its Toyama-Shinko power generation plant because of a technical problem.

Hokuriku was forced to shut the CCGT unit in Toyama prefecture on Friday while operating at a reduced capacity of 180MW. The company is investigating the cause of the problem and it is unclear when the unit can be brought back on line.

Hokuriku was forced to flare gas through a flare stack, a gas combustion device, following the unscheduled shutdown as the 500MW No.2 oil-fired power unit at Toyama-Shinko is closed for regular maintenance, the company said. The No.2 unit is scheduled to resume operations on 9 November, according to a power plant status notice on the Japan electric power exchange.

Toyama-Shinko has four power units with a combined capacity of 1,665MW — the 240MW No.1 oil-fired, 500MW No.2 oil-fired, 250MW coal 1 and coal 2 units and the CCGT unit. The No.1 oil-fed unit has been mothballed since 1 October.

The CCGT unit is Hokuriku's only gas-fired power facility. It burned 250,000t of LNG in April-September, the first half of its 2020-21 fiscal year, up by 13.6pc compared with the same period in 2019-20.

The company used 2.67mn t of coal in April-September, up by 0.8pc from a year earlier, while oil burning was halved to 344 b/d during the period.

By Motoko Hasegawa

Arid Brazil cranks up thermal generation, imports

Brazil is cranking up thermal power generation and electricity imports to cope with historically dry conditions that have sapped hydroelectric reservoirs.

In a representative single-day snapshot, hydroelectricity supplied just 52pc of domestic demand on 5 November, compared with 24pc for thermoelectric plants, according to the grid operator (ONS). Electricity imports from Argentina reached an average of 1.4GW.

Brazil's Electricity Monitoring Committee (CMSE) decided on 4 November to maintain above-average dispatch of thermoelectric generators and power imports to ease stress on the hydroelectric reservoirs until heavier spring rainfall patterns form. October precipitation plunged to its lowest level in a 90-year historical series.

Rising thermoelectric generation has forced Brazil to increase natural gas imports in recent days.

On 24-30 October, gas imports averaged 88.5mn m^3/d — up from 64.25mn m^3/d on 18-25 September – with more than 40pc directed to thermoelectric plants, according to preliminary data from the mines and energy ministry.

With the rise in thermoelectric generation, domestic gas demand is firmly outstripping domestic production. In September, the most recent month with available data, commercial gas flow averaged 52.9mn m^3/d, according to the hydrocarbons regulator (ANP).

Dependence on imported gas is expected to continue to rise in November. Last week, the mines and energy ministry authorized Brazilian Petrobras to restore pipeline gas imports from Bolivia by 10mn m^3/d through December to meet growing demand.

Petrobras had already increased gas imports from Bolivia to an average of 21mn m^3/d in October, while its LNG imports reached 15mn m^3/d, compared to a third quarter average of 1mn m^3/d.

Last month, Petrobras received its first LNG cargo at its Guanabara regasification terminal since September 2018. The company is also receiving LNG shipments at its Pecem terminal in Ceara state.

Petrobras said that all of its thermoelectric plants have been dispatched in response to the dry weather.

Two thermoelectric plants that had been operating intermittently in recent years are now back in the market as well. Ambar Energia's 480MW Cuiaba plant has been dispatched since early October using Bolivian gas. And Argentinean energy trading company San Atanasio Energia (Saesa) is expected to restart its newly acquired 640MW Uruguaiana power plant in Rio Grande do Sul state this month using Argentinian gas. Saesa launched a tender offer last month to purchase up to 2.5mn m^3/d of gas from Argentinian producers.

Cheniere confirms Corpus Christi train 3 for 1Q21

The third 5mn t/yr liquefaction train at Texas' Corpus Christi export facility is set to be completed late in the first quarter of next year, operator Cheniere said on Friday.

The completion in January-March 2021 is in line with previous *Argus* estimations based on the commissioning periods for Corpus Christi's first two liquefaction trains, after Cheniere sought to introduce feedgas to the unit in September. The operator received approval from the US' Federal Energy Regulatory Commission to introduce feedgas in early October.

Train 3 — which is around 96.7pc constructed — will have a base-load capacity of 4.5mn t/yr and peak capacity of 5mn t/yr, and is set to produce its first LNG in the "coming weeks", Cheniere said on Friday. Commissioning of the unit is set to lift total US peak liquefaction capacity to 79.8mn t/yr — just less than Australia's 86.5mn t/yr of capacity.

By Samuel Good

Weak interest casts doubt on Wilhelmshaven plans

Little market interest in the planned 7.8mn t/yr Wilhelmshaven LNG terminal in northern Germany has forced the project's developer to re-evaluate its future.

Market participants did not book enough capacity at the terminal to allow the project to proceed, despite ample general interest from numerous firms, LNG Terminal Wilhelmshaven (LTeW) — a subsidiary of German utility Uniper — said. The developer sought binding capacity agreements through an open season procedure ending on 30 October.

Economic uncertainties have played a role in low interest for the terminal, and many companies do not want to make long-term commitments, Uniper said.

The terminal was expected to start operations in 2023, but LTeW suggested it might not become operational until 2025.

The scope and focus of the project will need to be revised to remain attractive to the market, Uniper said. The firm is considering several changes to the project that could allow it to proceed, including the possibility of importing "environmentally friendly gas" or hydrogen in the long term by adapting existing plans.

Environmental group Deutsche Umwelthilfe (DUH) — which has long challenged the project — applauded the changed approach as a "good decision for climate protection" but re-iterated its opposition to the facility's location as too close to nature reserves and unsuitable for industrial infrastructure.

Wilhelmshaven is one of three potential locations for Germany's first LNG import terminal, alongside Stade and Brunsbuttel. The 8bn m^3/yr Brunsbuttel project is not expected to start up before the second half of 2024.

By Jacob Mandel

Colder weather boosts Japan's wholesale power prices

Wholesale electricity prices on the Japan electric power exchange (Jepx) rebounded over the past week, as seasonal falls in temperatures created additional demand for heating purposes. This helped improve theoretical generation economics of the country's thermal power plants, especially gas-fired units that use spot LNG.

The spark spread for a 58pc-efficient plant using spot LNG averaged ¥1,126/MWh ($10.88/MWh) from 30 October to 5 November compared with just ¥481/MWh a week earlier. The ANEA price, the *Argus* assessment for spot deliveries to northeast Asia, fell by 12.4pc on the week to $6.50/mn Btu on 5 November, pressured by weaker European gas hub prices. But the margin was still smaller than ¥1,572/MWh for a 58pc-efficient oil-linked LNG-fed plant.

Spot coal remains price competitive with spot LNG for power generation, with a highly efficient 44pc coal-fired plant more profitable to run than any type of thermal power unit. The dark spread for a 44pc-efficient coal-fired plant averaged ¥2,722/MWh during the week to 5 November.

Day-ahead base-load Jepx prices in Japan's nine service areas, excluding Okinawa, averaged ¥5.50/kWh from 30 October to 5 November, up by 9.5pc from a week earlier. The system-wide prices were cleared at ¥6.34/kWh for Friday and ¥5.42/kWh for Saturday.

The higher prices were despite a 1.4pc week-on-week increase in supplies on the exchange to 6,925GWh. Buying demand edged up by 0.5pc to 6,923GWh, resulting in a 0.2pc drop in transacted volumes to 5,589GWh during the period.

This suggests that sellers' asking prices were too high to attract more buyers.

The higher supplies reflected abundant solar power output from usual sunlight hours, except in Japan's northeastern and Hokkaido areas, and an increase in thermal power generation capacity. Supplies were ample despite the closure of the 1,180MW No.4 reactor at the Ohi nuclear power plant for regular maintenance on 3 November.

Japan's thermal power capacity was set to increase by 568MW in the week to 8 November with a net gain of 648MW in the six western areas, where the grid runs at 60 hertz (Hz), and 24MW in the three eastern regions that run at 50 Hz, outstripping a net loss of 103MW in Okinawa.

Around 3.39GW of coal-fired, 1.42GW of gas-fired and 500MW of oil-fired capacity were supposed to return from regular maintenance, while about 3.43GW of gas-fired, 950MW of oil-fired and 362MW of coal-fired capacity were scheduled to shut during the week.

Power demand in all of Japan's 10 service areas, including Okinawa, averaged 90GW from 30 October to 5 November, up by 1.7pc from a week and year earlier, according to power agency the organisation for cross-regional co-ordination of transmission operators.

Large parts of Japan experienced cold weather over the past week, requiring more electricity to meet heating demand. Temperatures at the country's 10 major cities — Hokkaido, Sendai, Tokyo, Nagoya, Kanazawa, Osaka, Takamatsu, Hiroshima, Fukuoka and Naha — averaged 14.55°C during the week to 5 November, down by 3.4°C compared with the seasonal norm.

Liquidity of electricity futures contracts on the Tokyo commodity exchange (Tocom) fell this week, with transacted volumes dropping to 696MWh over 30 October to 5 November compared with 30,276MW in the previous week. All deals focused on peak-load hours for eastern Japan at off-floor trading, with contract prices for December, January and February 2021 each settled at ¥8.2/kWh.

Deals cleared by the German-based European Energy Exchange (EEX) also fell sharply to 13,800MWh over the past week, down from 56,064MWh on 23-29 October.

Tokyo base-load contracts transacted through EEX at ¥6.95-7/kWh for December, while Tokyo peak-load traded at ¥8.25/kWh for December.

Traded prices for December and January were below levels at which Jepx delivered last year, at ¥9.75/kWh for Tokyo peak-load December, ¥8.71/kWh for Tokyo base-load December and ¥9.27/kWh for Tokyo peak-load January. But prices for February 2021 peak-load delivery were above the ¥8.05/kWh settled on the Jepex platform in February 2020.

Forward prices for oil-linked LNG and coal for the upcoming winter were lower from a year earlier. The most recent oil-linked Japan LNG prices averaged $6.52/mn Btu for December 2020 to February 2021, down by 33.8pc on the year. The *Argus* Newcastle coal 6,000 kcal/kg forward curve is currently averaging $57.77/t for December 2020 to February 2021, while prompt prices for the same period in 2019-20 averaged $66.46/t.

But ANEA LNG delivered prices for December 2020 to February 2021 averaged $6.15/mn Btu, up by 12.6pc from a year earlier.

By Motoko Hasegawa

Pakistan, Bangladesh LNG imports surge

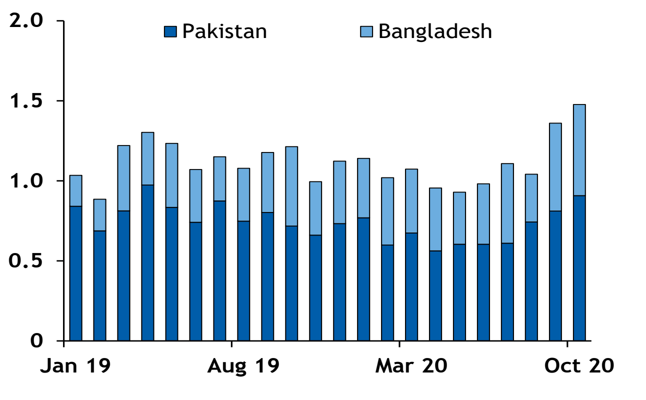
LNG deliveries to Pakistan and Bangladesh rose sharply in September and October from a year earlier, as the countries increased their spot purchases.

Pakistan's LNG imports rose to 907,000t in October from 718,000t a year earlier, with September LNG deliveries also rising to 811,000t from 803,000t, judging by vessel size. Deliveries to Bangladesh rose to a record high of 567,000t in October, from 496,000t a year earlier, with September LNG imports increasing to 550,000t from 375,000t.

Deliveries to Pakistan fell year on year each month in January-August, while Bangladesh's LNG imports fell in March, May and August.

Qatar continued to be the biggest supplier to both Pakistan and Bangladesh in September and October, supplying 22 out of the 36 cargoes the countries received.

Pakistan and Bangladesh LNG imports *mn t*



The 12 Qatari cargoes supplied to Pakistan in September-October were in line with volumes typically delivered under the term supply agreement between firms Qatar Petroleum and Pakistan State Oil (PSO).

Pakistan was also active on the spot market, with Pakistan LNG (PLL) seeking two cargoes for delivery on 12-13 and 25-26 September, followed by another tender seeking a 22-23 September delivery. PLL also issued a tender to buy two cargoes for delivery in October. South Korean firm Posco International and Azeri Socar provided the most competitive offers for the 12-13 and 25-26 September deliveries, respectively, while Swiss trading firm Gunvor was awarded the 22-23 September delivery and the two October deliveries.

Pakistan received a further four cargoes in September-October, which were likely secured under PSO's term contracts with and Gunvor Italy's Eni.

Bangladesh's Rupantarita Prakritik Gas (RPGCL), a subsidiary of state-owned Petrobangla, bought its first spot cargo in August, for delivery between late September and early October.

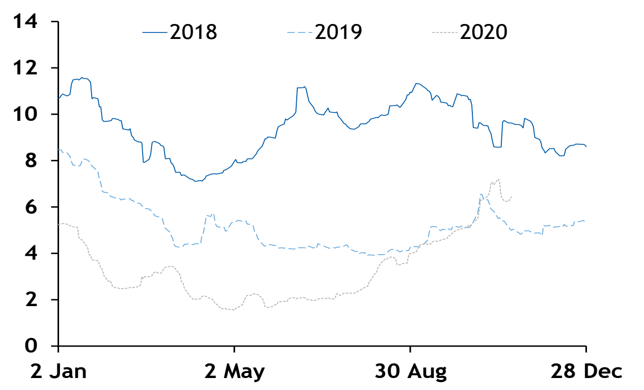
The remaining 13 deliveries to Bangladesh in September-October exceeded volumes typically delivered under Petrobangla's long-term contracts for 2.5mn t/yr with Qatargas and for 1mn t/yr with Dubai-based trading firm Oman Trading International, suggesting the south Asian firm also secured some supply on the spot market.

Pakistan and Bangladesh's spot purchases are set to increase in the coming months. RPGCL issued tenders for one November delivery and two December cargoes. PLL issued tenders to buy three November and six December deliveries, while PSO was seeking three cargoes for delivery across November-January.

The south Asian importers may have increased spot purchases in recent months to take advantage of cheaper LNG prices ahead of winter. Indian prices for delivery in September were assessed at $2.75/mn Btu on average in the preceding two months, down from $4.16/mn Btu a year earlier, while October prices averaged $4.08/mn Btu up from $4.35/mn Btu.

By Livia Gallarati

India des first half-month *$/mn Btu*



Peru's LNG exports fall in October

Loadings from Peru's 4.4mn t/yr Pampa Melchorita liquefaction facility fell last month from a year earlier, while all output was shipped to northeast Asia.

Exports slipped to 294,467t of LNG last month, according to PeruPetro data, from 363,028t a year earlier and 298,148t in September. Loadings were still higher in October than in June when the facility shipped 136,462t — the lowest since August 2018 — but were well below the terminal's monthly nameplate capacity of 370,000t.

Gas supply from fields operated by Argentina's Pluspetrol to Pampa Melchorita fell last month from September, which may have partly driven the drop in LNG exports. Peruvian production fell to 35.5mn m^3/d in October, from 38mn m^3/d in September and 40mn m^3/d a year earlier.

All of October's output was shipped to northeast Asia, with South Korea and China importing 141,577t and 152,980t, respectively. Peru had shipped half of its September output to Europe, the first deliveries to Europe since November last year.

But Europe's LNG imports dropped last month from a year earlier while northeast Asian demand rose, as the region made a stronger economic recovery from the Covid-19 outbreak.

South Korea has accounted for the largest share of Peruvian LNG exports so far this year, taking 40pc of the country's output, up from 33pc a year earlier, Vortexa data shows. And restrictions for the country's coal-fired power fleet this winter could further boost LNG demand, with the South Korean government aiming to suspend as many coal-fired units as possible and impose an 80pc cap on output from any operational units in December-March.

China also increased its share to 32pc across January-October from 19pc a year earlier, and planned shutdowns of around 10.38GW of coal-fired capacity and 10,032 t/d of coal boilers by the end of this year could further increase the scope for quick LNG deliveries to the country.

By Ellie Holbrook

Australia's Gladstone LNG lifts exports in October

LNG shipments from Gladstone in east Australia's Queensland state hit a record 2.01mn t in October from 31 cargoes, up by 1.5pc from the 1.98mn t a year earlier and 9.2pc above the 1.84mn t shipped in September. It marked a firm rebound from the 12-month low of 1.67mn t in July as the Covid-19 pandemic affected global LNG trade.

The record shipments in October were helped by increased shipments to South Korea, Singapore, Malaysia and Japan. This more than offset the slight fall in exports to China that eased to 1.21mn t in October from 1.22mn t in September and down from 1.38mn t in October 2019, according to the October trade data from the Gladstone Ports Corporation (GPC).

The higher shipments last month also reflect the return of LNG plants to higher output following a period of maintenance during a period of weaker demand and lower spot LNG prices.

Australian independent Santos, the operator of the 7.8mn t/yr Gladstone LNG (GLNG), completed maintenance at one of the two production trains on 16 August. The 9mn t/yr Australia Pacific LNG (APLNG) on Curtis island at Gladstone took half a train off line from 4-11 August, which meant the loss of around 39,315t of LNG, or less than one cargo, based on a 60,000t cargo size.

Gladstone LNG shipments (t)

	China	Japan	Malaysia	South Korea	Singa-	Total	Cargoes
Oct '20							31
Sep '20							28
Oct '19							30
Jan-Oct '20							275
Jan-Oct '19							275

Source: GPC

Chinese state-controlled firms have the largest share of sales and purchase agreements (SPAs) with the three LNG projects at Gladstone, which have a combined export capacity of 25.3mn t/yr.

Other companies with SPAs are South Korea's Kogas, which has a 3.5mn t/yr deal with GLNG, in which it owns a 15pc stake. Malaysia's Petronas owns 27.5pc of GLNG and has equity offtake arrangements with the project partners. The only SPA involving a Japanese company is utility Kansai Electric Power's 1mn t/yr deal with APLNG.

By Kevin Morrison

South Korean gas-fired generation rises in September

Gas-fired generation in South Korea rose in September from a year earlier, supported by lower nuclear output and coal-to-gas fuel-switching.

South Korea's gas-fired fleet produced around 12TWh in September, up from 9.98TWh a year earlier, even as total power demand rose only marginally to 44.6TWh from 44.5TWh.

Greater gas burn was driven partly by lower nuclear availability, as five nuclear plants totalling 4.6GW went off line in early September following two typhoons making landfall in the country, before restarting from late September-early October. Nuclear generation in September fell to 9.29TWh from 10.3TWh, even as nuclear availability heading into the month had been scheduled to rise to 16.6GW from 13.9GW before the plants halted.

But gas-fired generation appeared to also be supported by greater coal-to-gas fuel-switching, with initial evidence of switching a month earlier. State-controlled gas monopoly Kogas — which supplied around 1.1mn t of gas to South Korea's power sector in September, up from 1.02mn t a year earlier — reduced its raw material supply cost to the sector to 7,430 South Korean won/GJ ($5.94/mn Btu) from $6.86/mn Btu a month earlier, and $8.67/mn Btu a year earlier. This likely drove the increase in Kogas' supply to the power sector. And with rates for October and November holding lower again, the demand for Kogas supply may have held or increased in recent weeks.

Total power-sector gas demand — based on a recent effective efficiency for gas-fired plants of around 51pc, judging by gas demand released by the Korea Energy Statistical Information Statistical System (KESIS) in the 12 months up to September — would be around 1.54mn t in September. This would imply that non-Kogas gas supply was around 440,000t that month.

The firm sold around 907,000t to the country's city gas sector, in which it has a monopoly position, suggesting total September gas demand at around 2.45mn t. But South Korean LNG imports at around 2.95mn t over the month imply that inventories may have been buoyed by around 500,000t. The most recent KESIS data on South Korea's LNG inventories was 4.48mn t in July. But imports in August at 1.96mn t were below the combined assumed power gas demand of 1.7mn t — using the same 51pc efficiency — and city gas demand at 857,000t.

This would suggest a stockdraw of just greater than 500,000t over the month, which would have cleared space in South Korea's import terminals for a stockbuild a month later, once the country's minimal domestic gas supply is accounted for.

By Samuel Good

Klaipeda LNG operator to review pricing

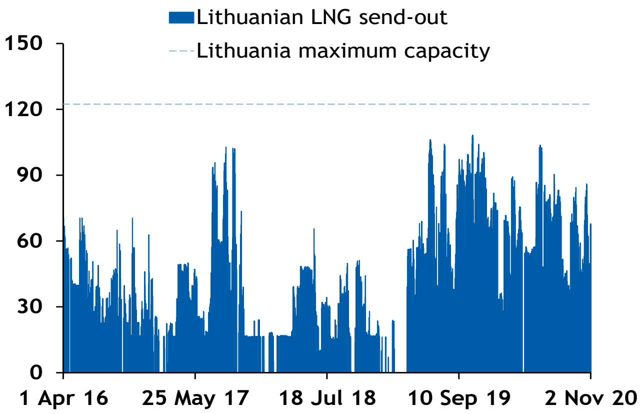
The operator of Lithuania's 2.9mn t/yr Klaipeda LNG terminal will conduct a review of its fees and capacity allocation procedures.

The review will involve consultation with market participants, preceding an externally commissioned study. The firm aims to select consultants by January and prepare the study in late spring 2021. Any changes to terminal rules would be submitted for public consultation after this.

The study aims to identify the most appropriate model for operating the terminal, ensuring maximum long-term capacity utilisation based on a cost-reflective model, Klaipedos Nafta said.

Under the existing pricing methodology, operating costs are partly covered by variable fees paid by terminal users and partly by an additional cost applied to gas grid fees paid by all Lithuanian consumers. The prices are calculated by Lithuania's energy regulator, Vert. The mandatory fee was part of a 2013 agreement with the European Commission that funds Lithuanian state-owned integrated gas and power firm Ignitis' requirement to import and sell 3.8 TWh/yr at the terminal — equivalent to about four standard-sized cargoes.

Klaipeda terminal remains underused *GWh/d*



The existing methodology is based on EU-wide grid pricing principles that aim to ensure equal fees at entry points across a country's grid rather than on actual terminal operating costs. And this results in the firm's operating costs only partly being compensated by the fees, chief executive Darius Silenskis said. Amending the methodology could reduce the supplement paid by grid users. The operator already increased its regasification tariff to €0.35/MWh this year from €0.13/MWh in 2019 in a bid to gather more revenues from terminal users.

One market participant said the firm's operating costs would rise from 2024 once it converts its lease on the terminal from Norwegian shipping company Hoegh into ownership. Klaipedos Nafta will be directly responsible for the hiring of operational and maintenance crew, for example, he said.

The decision to proceed with ownership of the floating storage and regasification unit asset was partly based on reducing operating costs to €43mn/yr from the existing €66mn/yr. Ownership is expected to cut by €6mn the annual costs incurred by local fertiliser producer Achema — the Baltics' biggest gas user — which is responsible for paying about a quarter of terminal operating costs and more than €20mn/yr under the existing structure, a local analyst said.

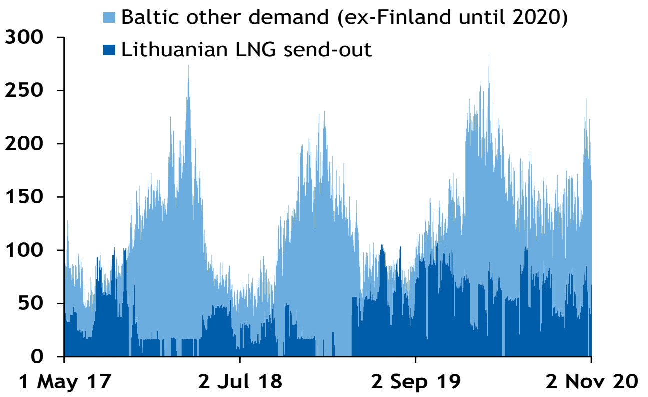
Annual bookings for the 2020-21 gas year at the terminal exceeded those of a year earlier. But the terminal remains underutilised compared with others in the region.

The Gas Interconnection Poland-Lithuania (GIPL), which is expected to begin operations at the start of 2022, will increase Lithuania's supply options (see graphs). The link's expected capacity is 2.4bn m^3/yr, or about 69.6GWh/d, towards Lithuania — a little less than half of Klaipeda's maximum sendout rate.

The Lithuanian and Polish system operators will be gauging interest in capacity on GIPL over the next month.

By Linas Jegelevicius and Paul Martin

LNG more important in Baltic supply mix *GWh/d*



AUSTRALIA WEEKLY - MARKET COMMENTARY

Australia gas: Limited demand for December

Spot prices for gas deliveries in December to Wallumbilla dipped this week as expectations of a mild summer and the return to operations of several coal plants pared demand for gas-powered generation.

But, market participants do not rule out the possibility of some incremental demand emerging or prices rising if Asian spot LNG prices continue to rise or the summer turns out to be hotter than expected.

Prices for month-ahead spot gas deliveries to Wallumbilla have tracked the recent rise and fall of Asian spot LNG prices, with domestic gas offers in the past weeks drawing strength from higher LNG netbacks.

The AWX, the *Argus* assessment for month-ahead spot gas deliveries to Wallumbilla, rose by A57¢/GJ (44¢/mn Btu), or 10pc, from 15 October to 29 October when the front half-month ANEA price gained $1.72/mn Btu or 30pc. The ANEA price is the *Argus* assessment for spot deliveries to northeast Asia.

The AWX was assessed A$5.90/GJ on 6 November, down slightly from A$6.075/GJ a week earlier.

Interest to buy spot gas comes mostly from Queensland's LNG producers, market participants said. Gas flows to the three Queensland LNG plants stood at 4.07PJ on 6 November, up from 3.98PJ on 29 October. Market participants suggest that the LNG producers may have been buying gas from the spot market to top up their gas volumes, with one of the producers enquiring for gas deliveries across November to December on a bilateral basis a few weeks earlier. But this could not be confirmed.

Power utilities are mostly managing their term deliveries at this time of the year, bound by take-or-pay clauses in their contracts and are unlikely to require more gas unless the weather turns out to be unexpectedly hot.

Prompt prices for deliveries to Wallumbilla eased slightly at the end of last week as temperatures eased after unusually warm weather lifted prices at the start of the week. Expectations that the weather will be cooler in the next few weeks are likely to weigh on prompt prices further, market participants said. Trades on the Wallumbilla Gas Supply Hub averaged A$5.35/GJ this week, down from A$5.48/GJ last week.

The return to operations this week of several baseload coal units in Victoria and Sydney following weeks of planned and unplanned outages is expected to pare gas demand in Queensland. Market participants expect coal to be able to meet most of the summer's power requirements, particularly if mild temperatures persist.

December supplies are limited, but there is now more gas flowing from the southern states to meet any potential demand in the north, market participants said. Flows through the South West Queensland Pipeline stood at 120TJ on 6 November, up from 39TJ on 30 October.

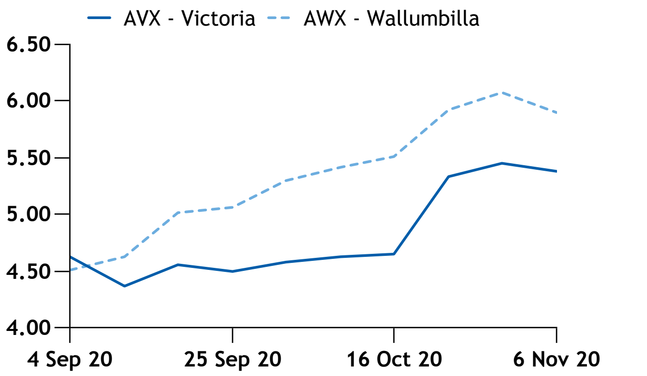
Argus Wallumbilla Index (AWX)					
Delivery	Units	Bid	Offer	Midpoint	±
Dec	*A$/GJ*	5.58	6.23	5.900	-0.175
Dec	*$/mn Btu*	4.28	4.78	4.530	+0.019

Argus Victoria Index (AVX)					
Delivery	Units	Bid	Offer	Midpoint	±
Dec	*A$/GJ*	5.05	5.70	5.375	-0.075
Dec	*$/mn Btu*	3.88	4.38	4.127	+0.080

AEMO weekly average Victoria 6am price			
Delivery	Units	Price	±
Prompt	*A$/GJ*	5.02	-0.29
Prompt	*$/mn Btu*	3.79	-0.18

LNG netbacks weekly average			
	Units	Price	±
Gladstone oil-linked LNG	*A$/GJ*	8.20	+1.15
	$/mn Btu	6.19	+0.92
Gladstone spot LNG	*A$/GJ*	7.84	-1.02
	$/mn Btu	5.91	-0.72

Argus Victoria Index vs Wallumbilla Index *AUD/GJ*



NEWS

Gas flows build through South Australia's Moomba

Pipeline flows from the Moomba gas plant in South Australia (SA) rose to their highest daily rate during January-September since at least 2009, with higher production from the Cooper basin and flows into Moomba from Queensland that in turn flowed south where gas output has been falling.

Total gas flows averaged 349TJ/d (9.32mn m³/d) during January-September compared with an average of 321TJ/d in 2019 and above the 324TJ/d in 2009, according to the latest quarterly data from the Australian Energy Regulator (AER). The AER data started from 1 July 2008.

There are two main pipelines from southern consuming markets connected to the Moomba gas plant, the 241TJ/d Moomba-Adelaide and the Moomba-Sydney pipelines with the link to Adelaide handling the highest daily flows during January-September since the AER data series began.

These increased flows were boosted by higher flows through the QSN Link, which is an extension of the South West Queensland Pipeline to connect the Wallumbilla gas hub to Moomba. There was an average of 117TJ/d of gas flowing from Queensland to Moomba via the QSN Link during January-September compared with 96TJ/d in 2019 and exceeding the previous high of 102TJ/d in 2014.

The increase in gas supplies to Adelaide from Moomba came as SA received less gas from its other usual suppliers through the 314TJ/d Southeastern Australia (SEA) pipeline from Port Campbell in Victoria, the main gas link between the two states. Flows through the SEA pipeline dropped to 60TJ/d during January-September from an average of 90TJ/d in 2019 and were the lowest since the AER data series started.

The lower gas flow through the SEA pipeline reflect reduced gas production in Victoria during January-September.
By Kevin Morrison

East Australia gas-fired power demand tracks lower

Gas consumption for power generation in east Australia is on track to record its lowest daily consumption in more than 11 years based on average daily use for January-September.

The average daily consumption for gas-fired plants in east Australia, which make up the National Electricity Market (NEM), was 380.33TJ/d (10.16mn m³) over the nine-month period compared with an average of 457TJ/d in 2019 and below the average consumption of 500TJ/d between 1 January 2009 and 30 September 2020, according to quarterly gas data from the Australian Energy Regulator (AER).

The AER data series has a start data of 1 July 2008. If the daily gas consumption averages for the sector during January-September are maintained for the rest of this year, South Australia (SA) will be the largest consuming state for electricity generation for the past four years.

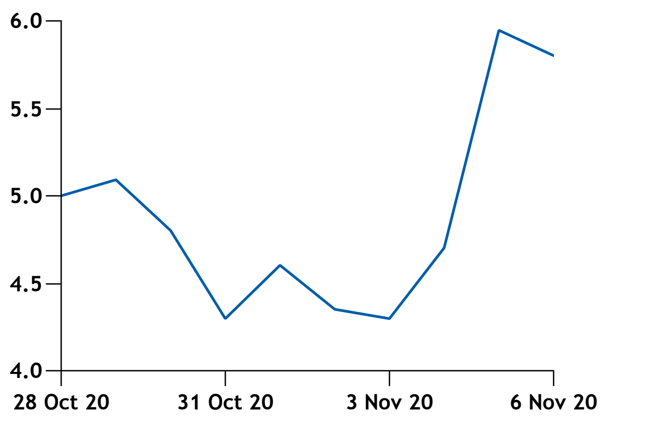
This is despite the average daily gas consumption for gas-fired plants in SA being lower than the average for 2019, the AER data showed.

But daily gas consumption for power generation in Queensland rose during January-September compared with the daily average last year but is well below its daily average over January 2009-30 September 2020.

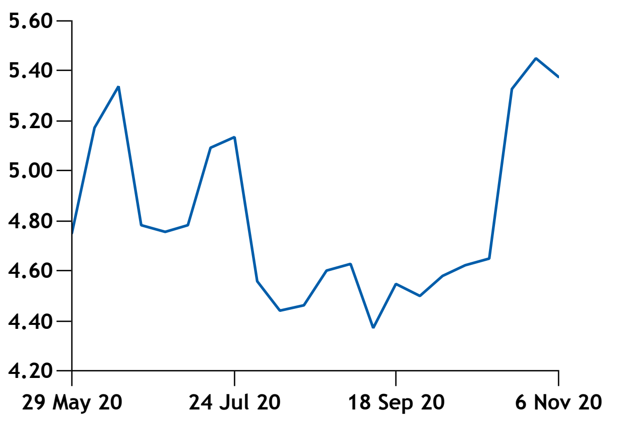
The lower gas use in power generation reflects the fuel's falling share in the NEM where it accounted for around 7.7pc of electricity generation in the region in the 12 months to 1 November 2020, according to data on the OpenNEM website. Coal accounted for 66.6pc of all power generated in the NEM over the same period and renewables accounted for 25.7pc.

Gas over the period 1 April 2005 to the end of October accounted for 9.6pc of the fuel source for power generation in the NEM, while coal accounted for 77.3pc and renewables 13.1pc, based on OpenNEM data.
By Kevin Morrison

AEMO Victoria daily gas price — *AUD/GJ*



Argus Victoria index (AVX) — *A$/GJ*



Senex cuts output guidance after asset sale

Australian independent Senex has cut its production guidance for the 2020-21 fiscal year to 30 June by around 10pc following the sale of its oil and gas interests in the Cooper basin in South Australia earlier this week.

Senex's production guidance for 2020-21 is 2.8mn-3.2mn bl of oil equivalent (boe), or around 7,700-8,800 boe/d, compared with the previous guidance of 8,800-9,800 boe/d. This is still at least 33pc above the 5,800 boe/d produced in 2019-20.

The rise in production in 2020-21 is because of expectations of higher output from its gas fields in the onshore Surat basin of Queensland where it owns and operates the Atlas and Roma North fields. Senex also provided a guidance for its key assets to reach 9,600 boe/d within the next two years, as part of its medium-term plan to reach 27,400 boe/d by 2024-25.

The Atlas and Roma North fields are earmarked to contribute to 60pc of the 2024-25 target, with the remainder coming from undeveloped projects in its portfolio. These include the Roma North West project and the Artemis gas project, which is also in the Surat basin and is near the Condabri coal-bed methane project operated by the 9mn t/yr Australia Pacific LNG partners.

Senex plans to spend between A$30mn-40mn ($21.5mn-28.7mn) on capital expenditure in 2020-21, down by 75-80pc from the A$155mn spent in 2019-20. Most of that spending was associated with developing the Atlas and Roma North gas projects.

By Kevin Morrison

Central, Incitec restart Range gas project

Australian independent Central Petroleum plans to restart Queensland's Range gas project with its 50:50 partner domestic fertilizer, explosives and industrial chemicals group Incitec Pivot, supplying Incitec's Gibson Island fertilizer plant in Brisbane.

Central and Incitec deferred the Range project in the onshore Surat basin in March because of the impact of the Covid-19 pandemic on energy and fertilizer markets. But the outlook for energy markets has since stabilised and forecasts indicate continuing strong demand for new domestic term gas supplies, said Central.

Pre-final investment decision (FID) activity will be restarted, including a three-well appraisal pilot programme planned for the first half of 2021, as well as obtaining the necessary approvals and permits for project development. A FID is planned after the appraisal drilling and will take place by the end of next year with first gas to be delivered in 2023, Central said.

There will also be gas available for sale to the east Australia gas market beyond the sales agreement with Incitec, Central said. Range is seeking to develop and produce 270PJ (7.21bn m^3) of gas resources, which it intends to convert to proven and probable gas reserves before a FID.

Range plans to deliver gas to its customers through a new pipeline to be connected to the Roma-Brisbane pipeline or a tie-in to other nearby pipeline infrastructure, Central said.

Incitec's gas supply agreement with Central ended in December 2019, with it currently buying from the 9mn t/yr Australia Pacific LNG to meet Gibson Island's needs from 1 April 2020 through to 31 December 2022.

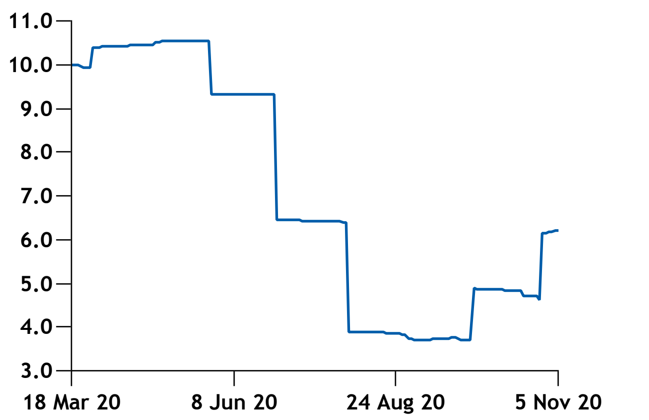
By Kevin Morrison

Beach buys Senex's Cooper basin assets

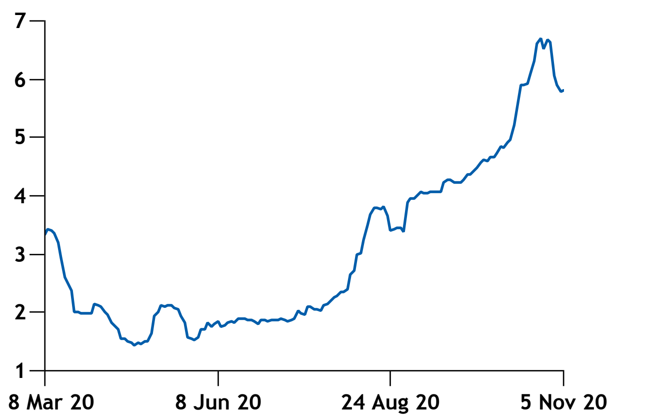
Beach Energy has bought oil and gas interests in the onshore Cooper basin in South Australia (SA) from fellow Australian independent Senex Energy for A$87.5mn ($62mn).

The assets include 6.8mn bl of oil equivalent (boe) of proven and probable reserves and estimated production of 600,000 boe (1,650 boe/d) in the 2020-21 fiscal year to 30 June, Beach said. Oil accounted for 4.6mn boe of the proven

Gladstone oil-indexed netback *USD/mn Btu*



Gladstone spot netback *USD/mn Btu*



and probable reserves, while gas and gas liquids accounted for 2.2mn boe.

The transaction will allow Senex to use the sale proceeds to fund the development of the firm's gas assets in the onshore Surat basin in Queensland where it operates the North Roma and Atlas gas fields, it said.

The transaction is expected to be settled in next year's January-March quarter, with the settlement adjusted to 1 July 2020 so that the contribution of the acquired output will be for the full 2020-21 fiscal year.

The assets include Senex's 60pc operated interest in the Growler, Snatcher and Spitfire oil fields and associated infrastructure, which will see Beach's interests increase to 100pc for each field, along with a 100pc stake in the Gemba gas field and 70pc in the Worrier oil field.

Senex will update its 2020-21 production guidance at its investor day briefing on 5 November.

Gas production in the Cooper basin contributes the highest share of east Australia gas output to Beach, which also has gas interests offshore Victoria and SA. Beach owns around a third of the South Australia Cooper Basin venture, which is operated by fellow Australian independent Santos that owns the remainder.

By Kevin Morrison

Queensland re-elects Labor party

Australia's largest coal exporting state of Queensland on 31 October re-elected the ruling Labor party in state elections. The party won with a larger majority that has governed on a pro-resource policy platform and also a commitment to lower the state's greenhouse gas (GHG) emissions by 30pc by 2030 from 2005 levels and to source half of the state's power generation from renewable energy plants by 2030.

The Labor party won 50 seats of the 93-seat single chamber parliament with around two-thirds of the total votes counted and is projected to win a total of 52 seats, a net gain of four seats from the previous state election in 2017. All of Labor's net gained seats come at the expense of its rival the Liberal National Party (LNP), which has won 31 seats so far and is projected to win a total of 34 seats or five below the 39 it held prior to Saturday's election. Labor also lost one seat to the Greens party, which now has two seats in the state parliament. An independent and two minor parties will hold the remaining five seats.

Queensland is Australia's second largest resource-exporting state after Western Australia. It is also Australia's largest exporter of coking coal and the second largest state exporter of LNG, as well as a previous shipper of base metals including copper, zinc, lead and a producer of aluminium. Coal exports from Queensland totalled A$27.34bn ($19.32bn) in the 12 months to 31 August, which accounted for 38pc of all exports by value from the state over the same period.

Labor will be able to rule for the next four years, which will give them time to implement their 2030 renewable energy target. Queensland is known as the sunshine state but it derived around 11pc of its electricity supply from solar photovoltaics and account for the largest share of renewable generation in the state, which amounted to around 15pc in the past 12 months, according to data from the OpenNEM website. Coal remains the dominant source commanding around three quarters of power supply in the past 12 months with the balance coming from gas. A move to 50pc renewables over the next 10 years would result in the closure of some coal plants over that period.

Queensland consumed around 26.27mn t of coal in the 2018-19 fiscal year to 30 June, with nearly all of the coal consumed by power generators. The only coal-fired power plant to close by 2030 is the 700MW Callide power plant is scheduled to shut in 2029, according to the Australian Energy Market Operator. The next coal plant in Queensland to close is the 1,400MW Tarong power station by 2036. The timeline for these closures may change if Queensland meets its renewable energy target.

Queensland's GHG emissions are around 150mn t now and were around 180mn t in 2005. A 30pc reduction from 2005 levels would be 126mn t. Around half of Queensland's GHG emissions come from power generation plants. The combination of an emissions reduction target and a renewable energy target will have to impact coal-fired generation if these targets are to be met.

Queensland will also seek a new energy and mines minister after former minister Anthony Lynham retired at the state election.

By Kevin Morrison

APPENDIX

Full methodology of oil-linked LNG prices available at *http://www.argusmedia.com/methodology-and-reference/*. A subset of the oil-linked LNG prices are published in the print edition of *Argus* LNG Daily. The full series is available electronically.

Oil-linked LNG on six-month crude average (601) contract (5 Nov 2020)										*$/mn Btu*
Delivery	**10pc**	**10.5pc**	**11pc**	**11.5pc**	**12pc**	**12.5pc**	**13pc**	**13.5pc**	**14pc**	**14.5pc**
Dec	3.83	4.02	4.22	4.41	4.60	4.79	4.98	5.17	5.36	5.56
Jan	4.08	4.28	4.49	4.69	4.90	5.10	5.30	5.51	5.71	5.92
Feb	4.23	4.44	4.65	4.86	5.07	5.28	5.49	5.70	5.92	6.13
Mar	4.23	4.44	4.66	4.87	5.08	5.29	5.50	5.71	5.93	6.14
Apr	4.21	4.42	4.63	4.84	5.05	5.26	5.47	5.68	5.89	6.10
May	4.16	4.37	4.57	4.78	4.99	5.20	5.41	5.61	5.82	6.03
1Q21	4.18	4.39	4.60	4.81	5.02	5.22	5.43	5.64	5.85	6.06
2Q21	4.18	4.39	4.59	4.80	5.01	5.22	5.43	5.64	5.85	6.06
3Q21	4.21	4.42	4.64	4.85	5.06	5.27	5.48	5.69	5.90	6.11
4Q21	4.30	4.51	4.73	4.94	5.16	5.37	5.58	5.80	6.01	6.23
2021	4.22	4.43	4.64	4.85	5.06	5.27	5.48	5.69	5.90	6.11
2022	4.43	4.65	4.87	5.09	5.32	5.54	5.76	5.98	6.20	6.42

Oil-linked LNG on three-month crude average (301) contract (5 Nov 2020)										*$/mn Btu*
Delivery	**10pc**	**10.5pc**	**11pc**	**11.5pc**	**12pc**	**12.5pc**	**13pc**	**13.5pc**	**14pc**	**14.5pc**
Dec	4.34	4.56	4.78	4.99	5.21	5.43	5.64	5.86	6.08	6.30
Jan	4.29	4.50	4.71	4.93	5.14	5.36	5.57	5.78	6.00	6.21
Feb	4.15	4.36	4.56	4.77	4.98	5.19	5.39	5.60	5.81	6.02
Mar	4.13	4.33	4.54	4.74	4.95	5.16	5.36	5.57	5.78	5.98
Apr	4.13	4.34	4.54	4.75	4.96	5.16	5.37	5.58	5.78	5.99
May	4.17	4.37	4.58	4.79	5.00	5.21	5.42	5.62	5.83	6.04
1Q21	4.19	4.40	4.60	4.81	5.02	5.24	5.44	5.65	5.86	6.07
2Q21	4.17	4.37	4.58	4.79	5.00	5.21	5.42	5.62	5.83	6.04
3Q21	4.26	4.48	4.69	4.90	5.12	5.33	5.54	5.76	5.97	6.18
4Q21	4.33	4.55	4.76	4.98	5.20	5.41	5.63	5.85	6.06	6.28
2021	4.24	4.45	4.66	4.87	5.08	5.30	5.51	5.72	5.93	6.14
2022	4.45	4.68	4.90	5.12	5.35	5.57	5.79	6.01	6.24	6.46

Oil-linked LNG on three-month crude average with one month lag (311) contract (5 Nov 2020)										*$/mn Btu*
Delivery	**10pc**	**10.5pc**	**11pc**	**11.5pc**	**12pc**	**12.5pc**	**13pc**	**13.5pc**	**14pc**	**14.5pc**
Dec	4.30	4.52	4.73	4.95	5.16	5.38	5.59	5.81	6.02	6.24
Jan	4.34	4.56	4.78	4.99	5.21	5.43	5.64	5.86	6.08	6.30
Feb	4.29	4.50	4.71	4.93	5.14	5.36	5.57	5.78	6.00	6.21
Mar	4.15	4.36	4.56	4.77	4.98	5.19	5.39	5.60	5.81	6.02
Apr	4.13	4.33	4.54	4.74	4.95	5.16	5.36	5.57	5.78	5.98
May	4.13	4.34	4.54	4.75	4.96	5.16	5.37	5.58	5.78	5.99
1Q21	4.26	4.47	4.68	4.90	5.11	5.33	5.53	5.75	5.96	6.18
2Q21	4.14	4.35	4.55	4.76	4.97	5.18	5.38	5.59	5.80	6.00
3Q21	4.23	4.45	4.66	4.87	5.08	5.29	5.50	5.72	5.93	6.14
4Q21	4.31	4.53	4.74	4.96	5.17	5.39	5.60	5.82	6.03	6.25
2021	4.24	4.45	4.66	4.87	5.08	5.30	5.50	5.72	5.93	6.14
2022	4.44	4.66	4.88	5.10	5.33	5.55	5.77	5.99	6.21	6.44

Oil-linked LNG on previous-month crude average (101) contract (5 Nov 2020)										$/mn Btu
Delivery	10pc	10.5pc	11pc	11.5pc	12pc	12.5pc	13pc	13.5pc	14pc	14.5pc
Dec	4.20	4.41	4.62	4.83	5.04	5.25	5.46	5.67	5.88	6.09
Jan	4.15	4.36	4.57	4.77	4.98	5.19	5.40	5.61	5.81	6.02
Feb	4.09	4.30	4.50	4.71	4.91	5.12	5.32	5.53	5.73	5.93
Mar	4.13	4.34	4.54	4.75	4.96	5.16	5.37	5.58	5.78	5.99
Apr	4.17	4.37	4.58	4.79	5.00	5.21	5.42	5.62	5.83	6.04
May	4.20	4.41	4.62	4.83	5.04	5.25	5.46	5.67	5.88	6.09
1Q21	4.12	4.33	4.54	4.74	4.95	5.16	5.36	5.57	5.77	5.98
2Q21	4.20	4.41	4.62	4.83	5.04	5.25	5.46	5.67	5.88	6.09
3Q21	4.29	4.50	4.72	4.93	5.15	5.36	5.57	5.79	6.00	6.22
4Q21	4.35	4.57	4.79	5.00	5.22	5.44	5.66	5.87	6.09	6.31
2021	4.24	4.45	4.67	4.88	5.09	5.30	5.51	5.73	5.94	6.15
2022	4.47	4.69	4.91	5.14	5.36	5.59	5.81	6.03	6.26	6.48

Crude oil forward prices												$/bl
	Jan 2021	Feb 2021	Mar 2021	Apr 2021	May 2021	Jun 2021	Jul 2021	Aug 2021	Sep 2021	Oct 2021	Nov 2021	Dec 2021
Argus Calculated Japanese Crude Cocktail	41.380	42.230	42.500	42.790	43.080	43.340	43.580	43.810	43.990	44.160	44.310	44.450
Ice Brent (Singapore close)	40.52	40.90	41.26	41.61								
Months 13-24 available to LNG Daily data subscribers. Months 25-47 available to Asia Crude Oil Forward Curves subscribers.												

JAPAN, KOREA AND TAIWAN LNG PRICES

Argus Japan, South Korea, Taiwan des spot LNG					$/mn Btu
	Delivery	Bid	Offer	Mid	±
Japan, South Korea, Taiwan	1H Dec	6.59	6.97	6.780	+0.205
	2H Dec	6.61	6.99	6.800	+0.420
	1H Jan	6.34	6.74	6.540	+0.475
	2H Jan	6.19	6.56	6.375	+0.425

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