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Argus *LNG Daily*

Daily LNG prices, news and analysis

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SUMMARY

Asia-Pacific: Cold weather whets appetite

Prices for spot LNG deliveries to northeast Asia rose across the board, with second-half December posting the greatest rise on expectations that a cold winter will spur demand for deliveries during the peak demand season

Atlantic: Spot charter rates rise further

Prompt spot charter rates rose further on Friday, as demand continued to firm in a market with very little remaining vessel availability

Europe: Des prices fall

LNG prices for delivery into Europe fell on Friday and outstripped losses at the Dutch TTF gas hub, with the region switching to net withdrawals earlier this week

Singapore LNG seeks spot cargoes for first time

Singapore LNG is seeking two LNG cargoes on a spot basis for the first time, following an unprecedented surge in gas prices, made more pressing by the city-state relying mainly on natural gas to generate its electricity

Spain awards additional LNG slots at auction

Spanish gas system operator Enagas has allocated 23 more LNG unloading slots at import terminals in the firm's second "extraordinary" auction in recent months aimed at coping with the ongoing rally in European gas prices

Demand destruction hits European gas market

Gas demand from industry in major European gas-consuming countries has begun to fall as an increasing number of plants that produce steel, chemicals and other products either curtail output or close in response to record-high wholesale prices

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FEATURED LNG PRICES

Global Front-Month and Index Prices

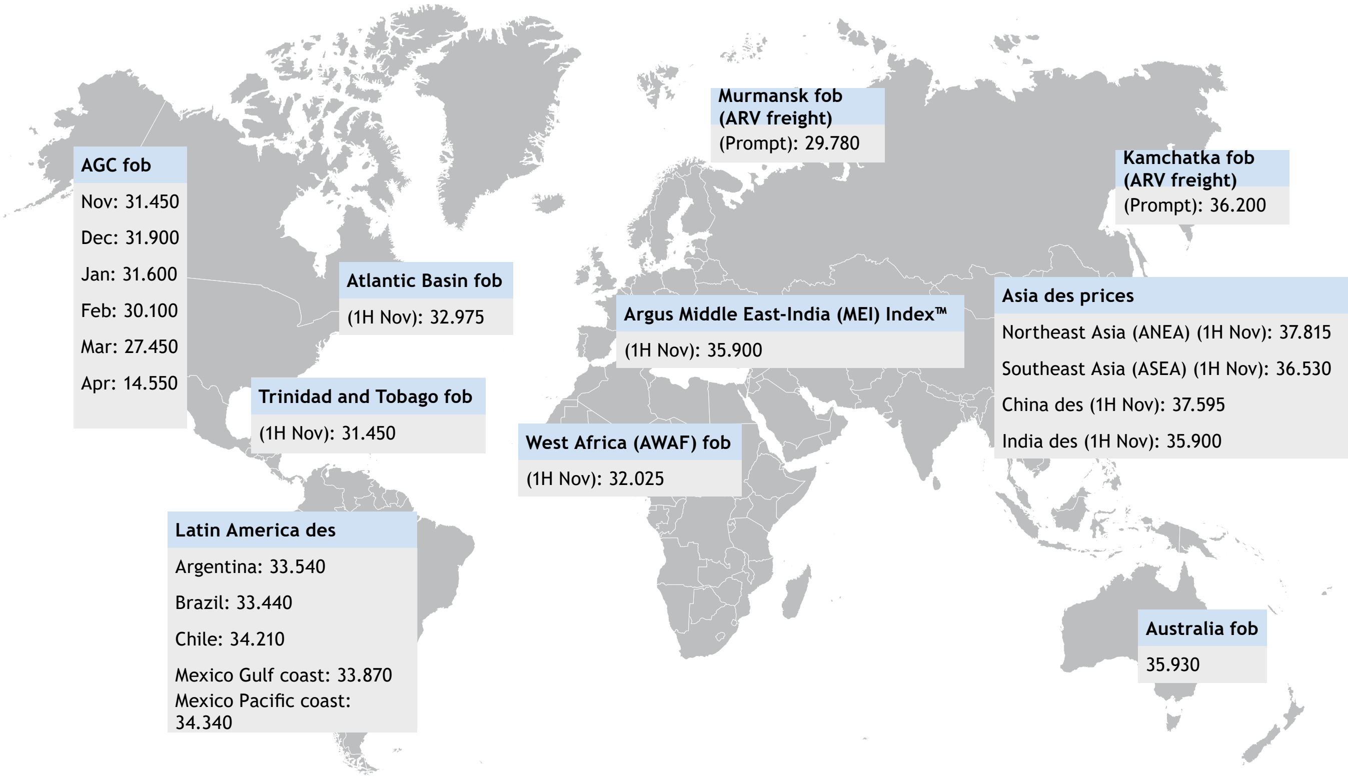
Delivery Point	Midpoint	Change	Trend	Month Index
Argus Gulf Coast fob	31.450	-1.700	▼	32.486
Trinidad & Tobago fob	31.450	-1.700	▼	28.570
Argus West Africa fob	32.075	-1.175	▼	29.729
Mexico des (Pacific) (prompt)	34.340	-0.550	▼	na
Mexico des (Gulf) (prompt)	33.870	-1.460	▼	na
Brazil des (prompt)	33.440	-1.460	▼	na
Argentina des (prompt)	33.540	-1.500	▼	na
Chile des (prompt)	34.210	-1.460	▼	na
Murmansk fob (prompt) (ARV freight)	29.780	-4.380	▼	na
NW Europe fob (reload)	32.100	-1.600	▼	29.862
NW Europe des	30.350	-4.400	▼	29.067
Iberia fob (reload)	34.900	+0.175	▲	30.452
Iberia des	30.325	-4.275	▼	29.077
Italy des	29.913	-4.162	▼	28.817
Greece des	30.625	-4.325	▼	29.222
Turkey des	30.625	-4.325	▼	29.222
Middle east fob (Asia-Pacific bound) (prompt)	35.330	+1.330	▲	na
Middle East fob (Europe bound) (prompt)	28.470	-4.240	▼	na
Middle east des	35.925	+1.477	▲	31.050
India des	35.925	+1.477	▲	31.050
ASEA des	36.565	+1.405	▲	31.296
ANEA des	37.875	+1.590	▲	32.329
China des	37.623	+1.663	▲	32.315
Kamchatka fob (prompt) (ARV freight)	36.200	+1.350	▲	na
Australia fob (prompt)	35.930	+1.360	▲	na

Argus prompt LNG freight day rates *$/day*

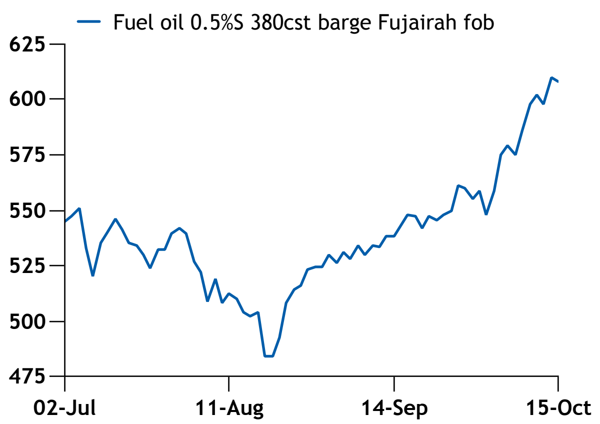
	Price	±	Month index
Steam turbine - west of Suez	87,000	+3,000	81,909
Steam turbine - east of Suez	88,000	+5,000	80,818
TFDE - west of Suez	115,000	+5,000	106,455
TFDE - east of Suez	116,000	+7,000	105,364
Two-stroke - west of Suez	139,000	+7,000	126,273
Two-stroke - east of Suez	140,000	+10,000	124,273

Argus Round Voyage Rates *$/day*

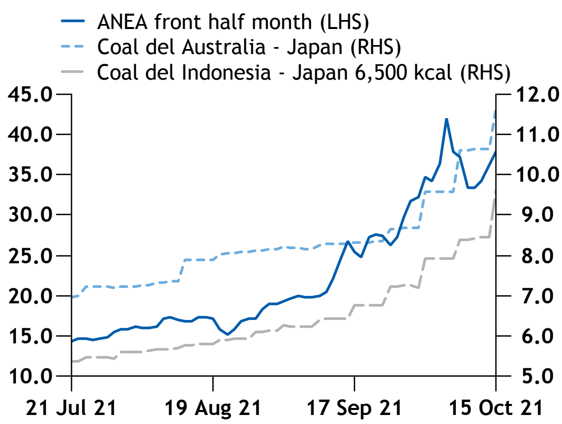
	Price	+/-	Month index
ARV1: Australia-Northeast Asia	145,000	+15,000	119,545
ARV2: USGC-Northwest Europe	142,000	+13,000	116,273
ARV3: USGC-Northeast Asia	148,000	+14,000	126,636



Middle East bunker fuel - Fujairah *$/t*



Japan: Coal vs LNG *$/mn Btu*



Japan oil-linked des LNG (14 Oct 2021)		*$/mn Btu*
Contract	**Price**	**±**
Nov	10.70	nc
Dec	10.92	nc
Jan	11.27	+0.02
Feb	11.54	+0.04
Mar	11.76	+0.06
Apr	11.93	+0.07
1Q22	11.52	+0.04
2Q22	12.14	+0.09
3Q22	12.11	+0.09
4Q22	11.85	+0.08
2022	11.91	+0.08
2023	11.28	+0.06

Japan-oil linked	*$/mn Btu*
Dec	10.92

Benchmark price snapshot		*$/mn Btu*
Market	**Delivery**	**Price**
NBP	Nov	30.551
Zeebrugge	Nov	29.779
Peg Nord	Nov	29.907
PSV	Nov	29.474
PVB	Nov	30.645
TTF	Nov	30.185
Nymex Henry Hub (14 Oct)	Nov	5.687
Argus JCC Index (Fixed) (*$/bl*)	Jul	71.7579
Argus JCC Index (Preliminary) (*$/bl*)	Aug	73.7585

MARKET COMMENTARY

Asia-Pacific: Cold weather whets appetite

Prices for spot LNG deliveries to northeast Asia rose across the board, with second-half December posting the greatest rise on expectations that a cold winter will spur demand for deliveries during the peak demand season.

The ANEA price, the *Argus* assessment for spot LNG deliveries to northeast Asia, rose by $2.210/mn Btu to $38.330/mn Btu for second-half December, putting it at a premium of 39.5-51.5¢/mn Btu to both halves of November and 16¢/mn Btu to first-half December.

South Korea's state-owned importer Kogas may seek more spot cargoes for deliveries across December-February in the coming weeks with forecasts of colder weather, market participants said.

Temperatures in the country's capital city Seoul are expected to fall to 1°C on 17 October compared with 17°C on 15 October, according to the Korea Meteorological Administration. This would mark the lowest temperature recorded during this period in 64 years and could signify increased gas demand to meet heating needs.

Kogas was out of the spot market this week, likely because of sufficient stocks in its inventories following earlier purchases of winter deliveries in the past few weeks.

Market participants had suggested that a likely easing of coal restrictions in South Korea during winter could reduce the call on gas for power generation. The equivalent loss in LNG demand is unclear, but market participants suggest that colder weather could limit the loss of LNG requirements.

Private-sector South Korean buyers have mostly stayed out of the spot market, having been priced out by market levels. Current high spot LNG prices mean that these buyers are uncompetitive against Kogas, which likely has a lower average import cost because of its heavy weighting of term supplies for winter deliveries.

Spot LNG prices may have to fall below $20/mn Btu before it is able to make a spot purchase, according to a private-sector South Korean buyer.

Around two Japanese firms may each buy one cargo for delivery in December or January after monitoring temperatures in the coming weeks.

The US' National Oceanic and Atmospheric Administration said on 14 October that La Nina weather conditions have developed over the past month, with an 87pc probability that they will remain until December-February and up from the 72pc forecast last month. La Nina events have historically been associated with lower temperatures across the northern Pacific basin.

A Japanese buyer on 14 October purchased what was likely its second November delivery in the past week. The firm's recent spot demand is likely because of extremely hot weather in Japan in the first half of October that has drawn down inventories. The firm may also have bought the cargoes as replacement for its cancelled delivery from the 30mn t/yr Petronas-owned Bintulu LNG plant in November because of upstream issues at the Pegaga gas field in Malaysia.

The closure of the 600MW No.8 coal-fired unit at the Nakoso power plant in northeast Japan's Fukushima prefecture on 16 September because of a technical issue has likely also increased the firm's LNG requirements.

Kogas International on 15 October closed a tender to sell a cargo that will be delivered across 19-22 December to northeast Asia from the 3.6mn t/yr Shell-operated Prelude floating LNG export terminal in Australia, although results have yet to emerge.

The 3.7mn t/yr Darwin LNG in Australia sold a cargo to a trading firm that will load across 14-16 November, probably done at a high $36/mn Btu to a low $37/mn Btu on a fob basis through a tender that closed on 14 October. The cargo will arrive in northeast Asia across 21-27 November.

Sakhalin Energy sold on 14 October a cargo that will load on 25 November from the 9.6mn t/yr Sakhalin LNG plant in far east Russia likely at a $38s/mn Btu level.

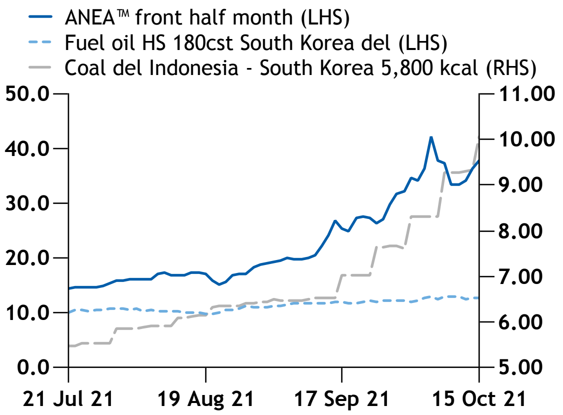
Market participants are eyeing Russian state-owned Gazprom's auction on 18 October for the booking of 15mn m³/d of firm capacity at the Russia-Ukraine border for deliveries in November. Of the offered capacity, 9.8mn m³/d will be available at Sudzha and 5.2mn m³/d at Sokhranovka.

Argus Asia-Pacific des spot LNG					$/mn Btu
	Delivery	Bid	Offer	Midpoint	±
Northeast Asia (ANEA™)	1H Nov	37.59	38.04	37.815	+1.545
	2H Nov	37.70	38.17	37.935	+1.635
	1H Dec	37.94	38.40	38.170	+1.940
	2H Dec	38.10	38.56	38.330	+2.210
China	1H Nov	37.36	37.83	37.595	+1.645
	2H Nov	37.42	37.88	37.650	+1.680
	1H Dec	37.67	38.13	37.900	+1.980
	2H Dec	37.73	38.19	37.960	+2.170
India	1H Nov	35.62	36.18	35.900	+1.490
	2H Nov	35.67	36.23	35.950	+1.465
	1H Dec	35.92	36.48	36.200	+1.940
	2H Dec	35.98	36.54	36.260	+2.225

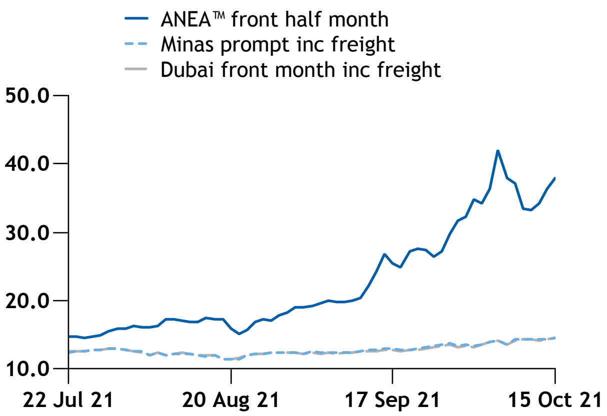
ANEA forward curve		$/mn Btu
Contract	Price	±
Nov	37.875	+1.590
Dec	38.250	+2.075
Jan	39.075	+3.375
Feb	38.250	+2.875
Mar	34.625	+3.050
Apr	20.200	+1.725
May	16.788	+1.263
1Q22	37.317	+3.100
2Q22	17.846	+2.096
3Q22	16.613	+2.013
4Q22	17.575	+1.875

ASIA-PACIFIC COMPETING FUELS

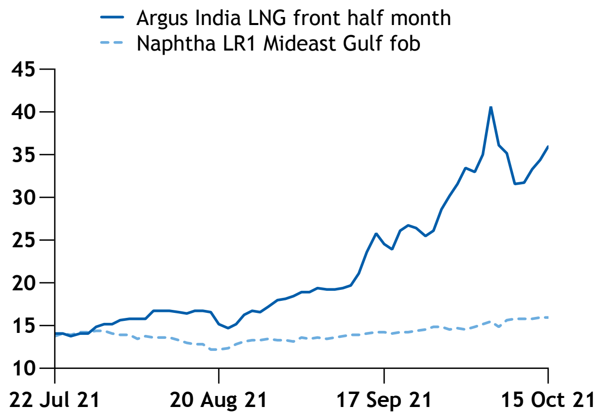
South Korea: Fuel oil, coal vs LNG *$/mn Btu*



Japan:Crude vs LNG *$/mn Btu*



India: Naphtha vs LNG *$/mn Btu*



LNG vs conventional marine fuel	$/mn Btu
weekly avg., week ending 15 Oct	
LNG des southeast Asia (ASEA) half-month net calorific value-adjusted	37.629
Singapore 0.5%S fuel oil delivered	15.414
Singapore 0.1%S MGO delivered	17.490
Singapore 3.5%S fuel oil delivered	13.572

OTHER ASIA-PACIFIC PRICES

Argus Middle East des spot LNG *$/mn Btu*

Delivery	Bid	Offer	Midpoint	±
1H Nov	35.62	36.18	35.900	+1.490
2H Nov	35.67	36.23	35.950	+1.465
1H Dec	35.92	36.48	36.200	+1.940
2H Dec	35.98	36.54	36.260	+2.225

Argus Middle East-India (MEI) Index *$/mn Btu*

Delivery	Bid	Offer	Mid	±
1H Nov	35.62	36.18	35.900	+1.490
2H Nov	35.67	36.23	35.950	+1.465
1H Dec	35.92	36.48	36.200	+1.940
2H Dec	35.98	36.54	36.260	+2.225

Key netforwards and netbacks *$/mn Btu*

	Delivery	Price	±
Southeast Asia (ASEA)	1H Nov	36.530	+1.390
	2H Nov	36.600	+1.420
	1H Dec	36.800	+1.670
	2H Dec	36.960	+1.950
Middle East fob (Asia-Pacific bound)	Prompt	35.330	+1.330
Middle East fob (Europe-bound)	Prompt	28.470	-4.240
Kamchatka fob (ARV freight)	Prompt	36.200	+1.350
Australia Gladstone fob	Prompt	36.180	+1.460
(Unit: A$/GJ)	Prompt	46.240	+1.830
Australia Gladstone oil indexed fob	Prompt	10.160	-0.040
(Unit A$/GJ)	Prompt	12.990	-0.060
Australia fob	Prompt	35.930	+1.360

China carbon emission allowance (CEA) price

15 Oct 21	CNY/t	±	USD/t	±
CEA Closing Price	43.90	-0.06	6.82	nc
Open Trade Volumes, t	8,200	+4,718		

Data source: Shanghai Environment and Energy Exchange

AUSTRALIAN GAS PRICES

Argus Wallumbilla Index (AWX) - Friday 15 Oct 2021

Delivery	Units	Bid	Offer	Midpoint	±
Nov	*A$/GJ*	8.74	9.98	9.360	+0.080
Nov	*$/mn Btu*	6.84	7.81	7.324	+0.178

Argus Victoria Index (AVX) - Friday 15 Oct 2021

Delivery	Units	Bid	Offer	Midpoint	±
Nov	*A$/GJ*	6.82	8.06	7.440	+0.060
Nov	*$/mn Btu*	5.34	6.31	5.822	+0.139

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: Spot charter rates rise further

Prompt spot charter rates rose further on Friday, as demand continued to firm in a market with very little remaining vessel availability.

The ARV3 prompt rate — for US-northeast Asia round trips by dual-/tri-fuel diesel-electric carriers — rose to $148,000/d from $134,000/d a day earlier, and well above $101,000/d at the start of October as activity has shifted away from late October to November.

And the corresponding US-northwest Europe rate — ARV2 — rose to $142,000/d from $129,000/d on Thursday, while the ARV1 rate for Australia-northeast Asia increased to $145,000/d from $130,000/d, widening its premium to the Atlantic intra-basin ARV2 and tightening its discount to the inter-basin ARV3.

The gains took all three prompt rates to above the highest point that forward rates for November had held earlier this year.

Much of the gains by round voyage rates this week have come from increased positioning costs, with laden leg rates rising much slower, as the spot charter market transitions into its usual winter 'three-way economics' incorporating positioning in addition to the empty and laden legs.

Availability in both basins remains particularly thin, market participants said, with the sole form of vessel availability being firms seeking to sublet spare tonnage in many cases. Very few independent owners have carriers that are still unemployed.

And the periods of availability on a number of vessels offered for subletting are limited, with many ships already scheduled to load a cargo later this winter, market participants said.

Several buyers and trading firms have been heard to be seeking vessels in recent days, primarily for loadings from Australian and US Gulf coast liquefaction terminals.

That said, more than a few Atlantic basin sellers have preferred to retain volumes within the basin in recent weeks, even as the near-curve inter-basin arbitrage has opened and closed on the extreme volatility shown by delivered LNG prices. This has trimmed the average journey length west of Suez and curbed gains by charter rates, particularly the ARV2, as the tightening of Atlantic availability has been slower than anticipated. But with vessels that had been set to deliver US and west African volumes to Pacific basin destinations now instead delivering to Europe, availability east of Suez has tightened quicker.

The number of fixtures remains few, market participants noted, with particularly strong short-term chartering activity earlier this year giving many firms winter coverage, but also cutting the amount of tonnage left operating on the spot market through the period. In a market that has historically been relatively illiquid — particularly during winter — this is increasing rate volatility, some added.

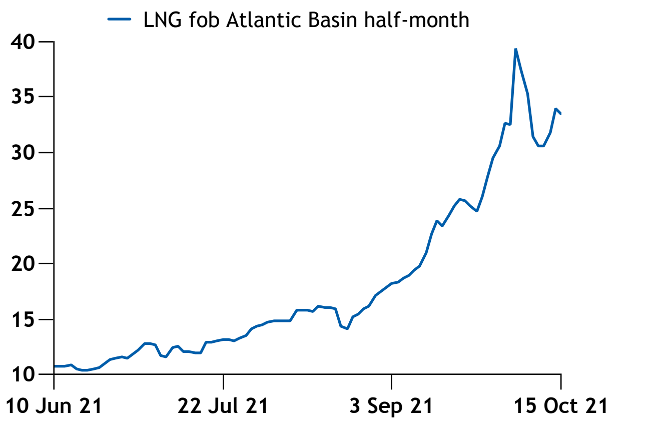
Further along the curve, forward rates for December also rose sharply on Friday, with the tight supply-demand balance in the charter market appearing set to hold through the mid-winter period.

Argus Gulf Coast (AGC) fob LNG		$/mn Btu
	Price	±
Nov	31.450	-1.700
Dec	31.900	-1.200
Jan	31.600	-1.450
Feb	30.100	-3.400
Mar	27.450	-4.350
Apr	14.550	-2.400

Argus Atlantic Basin fob spot LNG					$/mn Btu
	Loading	Bid	Offer	Midpoint	±
Murmansk fob (ARV freight)	prompt			29.780	-4.380
Iberian peninsula reload	1H Nov	34.55	35.15	34.850	+0.125
	2H Nov	34.65	35.25	34.950	+0.225
	1H Dec	34.85	35.45	35.150	+0.225
Northwest European reload	1H Nov	31.50	32.60	32.050	-1.650
	2H Nov	31.60	32.70	32.150	-1.550
	1H Dec	31.75	32.95	32.350	-1.475
West Africa (AWAF™)	1H Nov	31.80	32.25	32.025	-1.225
	2H Nov	31.90	32.35	32.125	-1.125
	1H Dec	32.10	32.55	32.325	-1.125
Trinidad and Tobago	1H Nov	31.25	31.65	31.450	-1.700
	2H Nov	31.25	31.65	31.450	-1.700
	1H Dec	31.70	32.10	31.900	-1.200

Argus Atlantic Basin fob spot LNG index					$/mn Btu
	Loading	Bid	Offer	Midpoint	±
Atlantic Basin	1H Nov	32.62	33.33	32.975	-0.920
	2H Nov	32.72	33.43	33.075	-0.820
	1H Dec	32.90	33.65	33.275	-0.790

Atlantic Basin fob $/mn Btu



US GULF COAST INDICATIVE FOB PRICE

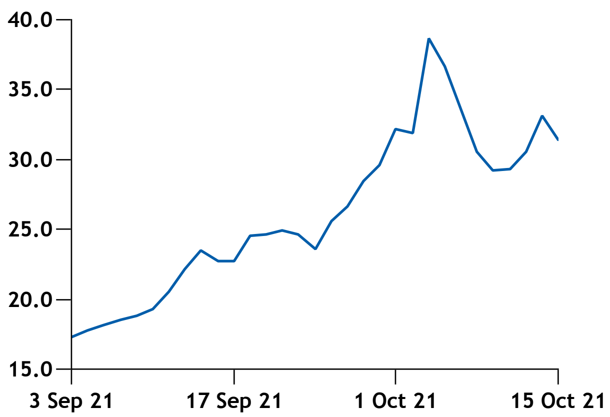
Indicative USGC fob LNG (14 Oct 2021)		*$/mn Btu*
Contract	**Price**	**±**
Nov	9.53	+0.11
Dec	9.71	+0.10
Jan	9.82	+0.10
1Q22	9.62	+0.10
2Q22	7.68	+0.05
3Q22	7.70	+0.05
4Q22	7.86	+0.06
Summer 2022	7.69	+0.05
Winter 22-23	7.90	+0.06
Summer 2023	6.82	+0.04
Winter 23-24	7.13	+0.04
2022	8.22	+0.07
2023	7.15	+0.04
2024	6.79	+0.03

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.

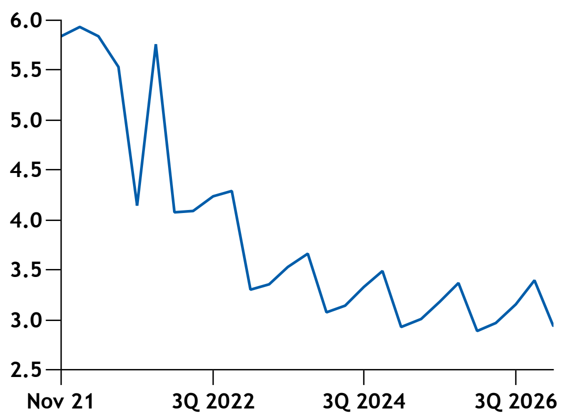
Argus LNG Daily also includes assessments of US Gulf Coast fob LNG prices (see page 1).

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

USGC fob LNG Curve *$/mn Btu*



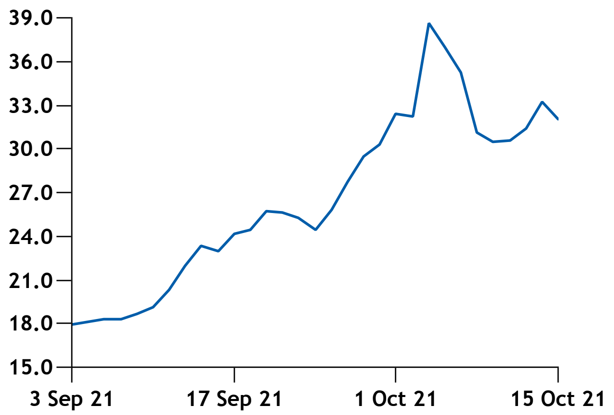
US Nymex gas *$/mn Btu*



OTHER ATLANTIC PRICES

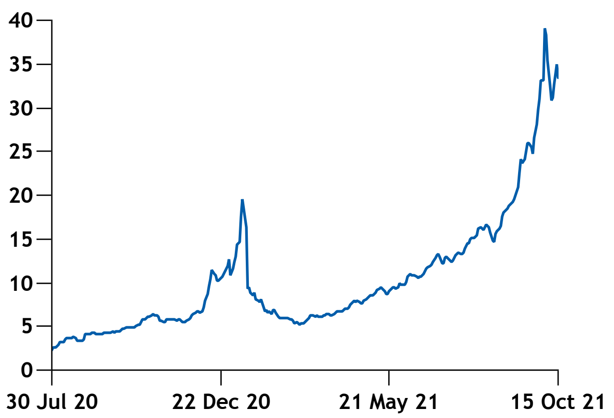
NBP - AGC fob LNG Spread	*$/mn Btu*
Nov 21	-0.90
Dec 21	-0.18
Jan 22	0.86
Feb 22	2.26
Mar 22	1.40
Apr 22	3.24

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



Argus Latin America des spot LNG			*$/mn Btu*
	Delivery	**Price**	**±**
Argentina	Prompt	33.540	-1.500
Brazil	Prompt	33.440	-1.460
Chile	Prompt	34.210	-1.460
Mexico Gulf coast	Prompt	33.870	-1.460
Mexico Pacific coast	Prompt	34.340	-0.550

Argus Brazil des *$/mn Btu*



MARKET COMMENTARY

Europe: Des prices fall

LNG prices for delivery into Europe fell on Friday, outstripping losses at the Dutch TTF gas hub, with the region switching to net withdrawals earlier this week.

The northwest European des price for deliveries in the first half of November fell to $30.35/mn Btu on Friday from $34.75/mn Btu at the previous close, narrowing its premium to the corresponding TTF contract.

A tighter differential between European and Asian prices in recent days may have incentivised Atlantic cargoes to remain within the basin, possibly allowing European buyers to secure cargoes at a smaller premium to the TTF. And Iberian des prices fell to a discount to northwest European prices, with lower gas demand curbing sendout at Spanish terminals, market participants said.

Aggregate Spanish demand averaged 897GWh/d on 1-14 October, down from the previously expected 948GWh/d under system operator Enagas' provisional schedule and the three-year average of 909GWh/d for the same period. And combined LNG inventories at the country's six regasification terminals totalled 2.48mn m^3, up from the three-year average of 2.33mn m^3 and equivalent to around 75pc of total capacity.

Europe switched to net withdrawals from underground storage facilities earlier. Net withdrawals totalled around 560GWh on Wednesday, compared with net injections of 286GWh a day earlier and an average stockbuild of 1.57TWh/d on 1-12 October. Aggregate European underground inventories peaked at 853TWh on Tuesday, well below the 2020 peak of 1,068TWh and three-year average peak stocks of 1,032 TWh. Tight storage spreads likely reduced the incentive to continue injections ahead of the winter, with the TTF balance-of-month contract at a $1.50/mn Btu premium to the March price on Thursday, compared with a 19¢/mn Btu discount a year earlier.

LNG deliveries to Europe have rebounded in recent weeks. The region has already received 3.16mn t so far this month, with additional 1.78mn t loaded on vessels that have already declared for delivery at European terminals, according to Vortexa. This would already bring deliveries broadly in line with the 4.91mn t received in the whole of September and close to the 5.12mn t imported in October 2020.

Slower Latin American demand — particularly from Argentina, which released its Bahia Blanca FSRU last month as demand declines in the southern hemisphere winter and amid a rebound in the country's upstream production — may leave more Atlantic basin volumes available for European buyers. That said, Brazilian demand remained strong, with the country already receiving 534,000t so far this month, on course to exceed the 923,000t it imported in the whole of September.

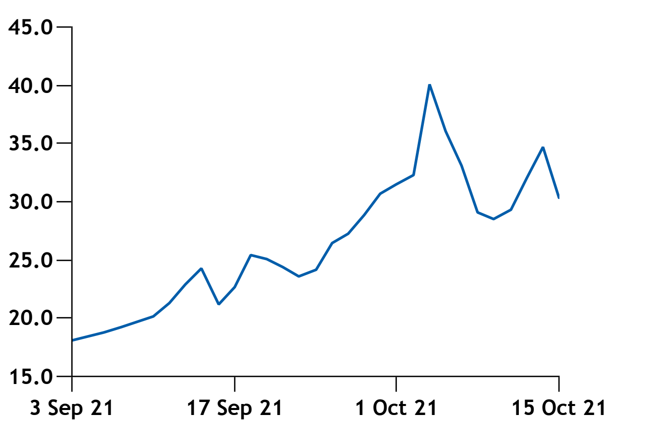
UK GAS AND EUROPEAN LNG PRICES

Argus European des spot LNG					$/mn Btu
	Delivery	Bid	Offer	Midpoint	±
NW Europe	1H Nov	30.15	30.55	30.350	-4.400
	2H Nov	30.15	30.55	30.350	-4.400
	1H Dec	30.45	30.85	30.650	-4.300
Iberian peninsula	1H Nov	30.10	30.50	30.300	-4.300
	2H Nov	30.15	30.55	30.350	-4.250
	1H Dec	30.45	30.85	30.650	-4.150
Italy	1H Nov	29.30	30.50	29.900	-4.175
	2H Nov	29.30	30.55	29.925	-4.150
	1H Dec	30.20	30.85	30.525	-4.025
Greece	1H Nov	30.40	30.80	30.600	-4.350
	2H Nov	30.45	30.85	30.650	-4.300
	1H Dec	30.75	31.15	30.950	-4.200
Turkey	1H Nov	30.40	30.80	30.600	-4.350
	2H Nov	30.45	30.85	30.650	-4.300
	1H Dec	30.75	31.15	30.950	-4.200

NBP				$/mn Btu
Delivery	Bid	Offer	Midpoint	±
Nov	**30.54**	**30.57**	**30.551**	**-4.333**
Dec	31.71	31.73	31.719	-4.297
Jan	32.45	32.48	32.463	-4.294
Feb	32.35	32.37	32.360	-4.168
Mar	28.83	28.86	28.845	-4.118
Apr	17.77	17.80	17.786	-0.789
1Q22	31.21	31.24	31.222	-4.194
2Q22	16.01	16.03	16.020	-0.109
3Q22	14.68	14.71	14.696	-0.048
4Q22	15.85	15.88	15.865	+0.014
2022	19.43	19.46	19.445	-1.082
2023	11.63	11.66	11.641	+0.019

Spain Tanque Virtual de Balance (TVB) LNG hub (15 Oct)		
	€/MWh	Change
Mibgas TVB intraday	92.77	-3.02
Mibgas TVB day-ahead	0.00	-96.02
	MWh	Change
Mibgas TVB volume intraday	310	+140
Mibgas TVB volume day-ahead	0	-120

Argus NW Europe LNG des $/mn Btu



LNG SPREADS AND OIL-LINKED SNAPSHOT

European hubs to LNG price spreads *$/mn Btu*

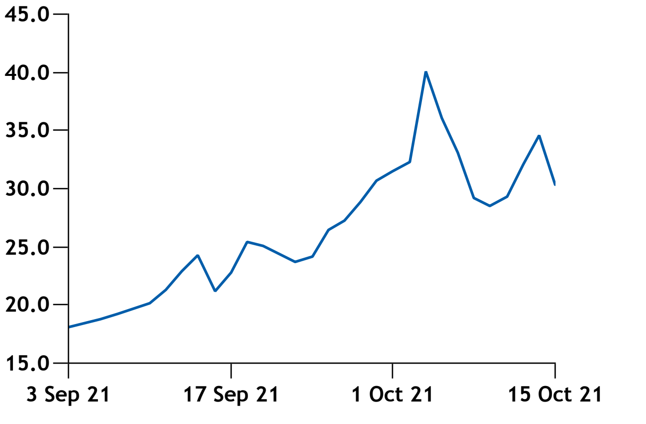
	Northeast Asia		China		India		Middle East		Middle East-India (MEI)	
	1H Nov	Nov avg	1H Nov	Nov avg	1H Nov	Nov avg	1H Nov	Nov avg	1H Nov	Nov avg
NBP	7.26	7.32	7.04	7.07	5.35	5.37	5.35	5.37	5.35	5.37
TTF	7.63	7.69	7.41	7.44	5.72	5.74	5.72	5.74	5.72	5.74

Snapshot of oil-linked LNG prices (14 Oct 2021) *$/mn Btu*

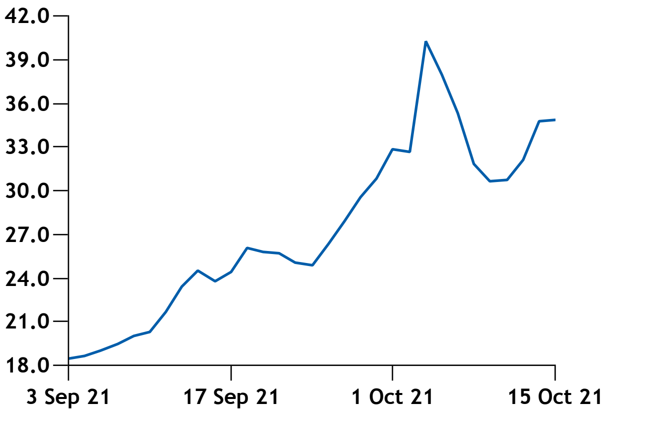
Dec	10pc	11pc	12pc	13pc	14pc
601	7.11	7.82	8.53	9.24	9.95
301	7.32	8.06	8.79	9.52	10.25
311	7.27	7.99	8.72	9.45	10.18
101	7.49	8.24	8.99	9.73	10.48

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.

Argus Iberian peninsula des *$/mn Btu*



Iberia peninsula reload fob *$/mn Btu*



SMALL-SCALE LNG

Small-scale LNG assessments (14 Oct 2021)

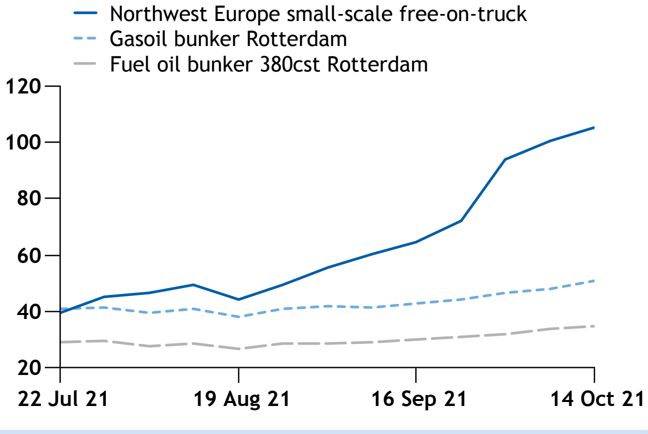
	€/MWh	+/- 07 Oct	$/t MGOe	+/- 07 Oct
Northwest Europe free on truck front month	105.150	+4.800	1,442	+68
Southwest France free on truck front month	106.300	+4.800	1,457	+68
Northwest Europe LNG bunker delivered on board	108.250	+3.400	1,484	+49

Competing fuels snapshot (14 Oct 2021)

Gas	€/MWh	+/- 7 Oct	$/t MGOe	+/- 7 Oct
TTF		+4.795	1,387	+68
Zeebrugge		+4.223	1,377	+60

Oil products	€/MWh	+/- 7 Oct	$/t	+/- 7 Oct
Gasoil bunker Rotterdam prompt	50.755	+2.585	696	+37
Gasoil diesel 10ppm German NWE barge prompt	52.943	+1.613	726	+23
Fuel oil bunker 380cst Rotterdam prompt	34.775	+0.810	472	+12

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



ANNOUNCEMENT

All data change announcements can be viewed online at www.argusmedia.com/announcements.
Alternatively, to be added to the email distribution list for all announcements, please email: datahelp@argusmedia.com.

LNG OPEN BIDS, OFFERS AND RECENT DEALS

Global Open Bids

Submission date	Validity date	Bid	Period	Note
unknown	unknown	1 cargo(es) des China to Beijing Gas	delivery 20-24 Nov 2021	For delivery to Tangshan, China
18-Oct-21	18-Oct-21	19 cargo(es) des to Botas	delivery 01 Nov 2021 - 13 Mar 2022	One delivery per calendar week
08-Oct-21	unknown	1 cargo(es) des India to GSPC	delivery 20 Oct 2021 - 12 Nov 2021	For delivery to Dahej terminal; did not award
05-Oct-21	unknown	1 cargo(es) des India to GSPC	delivery 16 Oct 2021 - 10 Nov 2021	For delivery to Mundra terminal [did not award due to higher-than-expected offers]
05-Oct-21	unknown	4 cargo(es) des Argentina to YPF	delivery 12 Oct 2021 - 20 Dec 2021	To be delivered on 12-17 Oct, 30 Oct-3 Nov, 20-25 Nov and 15-20 Dec to Escobar terminal
29-Sep-21	29-Sep-21	2 cargo(es) des China to Shenzhen Energy	delivery 01 Nov 2021 - 25 Dec 2021	For delivery on 1-3, 9-12 or 23-26 Nov to Diefu terminal; & on 25 Dec to Yuedong terminal [did not award due to higher-than-expected offers]
27-Sep-21	28-Sep-21	20 cargo(es) des Turkey to Botas	delivery 04 Oct 2021 - 20 Feb 2022	

Global Open Offers

Submission date	Validity date	Offer	Period	Note
15-Oct-21	unknown	1 cargo(es) des from Kogas	delivery 19-22 Dec 2021	Offered by Kogas International; loading from Prelude FLNG; for delivery to JKTC
14-Oct-21	unknown	1 cargo(es) des from Angola LNG	delivery 29 Oct 2021 - 16 Nov 2021	May be delivered across 29 October-23 November to Brazil; 30 October-21 November to Europe; 5-16 November to Egypt and Jordan; and 5-16 November to India and Pakistan; on the Sonangol Sambizanga vessel [tender cancelled]
14-Oct-21	unknown	1 cargo(es) fob Australia from BHP Billiton	loading 12-14 Dec 2021	From NWS LNG; on either a des or fob basis
13-Oct-21	unknown	1 cargo(es) fob Egypt from Egas	loading 31 Oct 2021 - 01 Nov 2021	Loading at Damietta
07-Oct-21	unknown	1 cargo(es) des from Angola LNG	delivery 23 Oct 2021 - 05 Nov 2021	To be loaded on the Malanje vessel; DW: 23 Oct-3 Nov (Brazil); 25 Oct-1 Nov (Europe); 31 Oct-5 Nov (Egypt, Jordan, India, Pakistan) [did not award]
28-Sep-21	unknown	1 cargo(es) des from Angola LNG	delivery 18-24 Oct 2021	For delivery to India or Middle East
24-Sep-21	unknown	2 cargo(es) fob from Pertamina	loading 17 Oct 2021 - 15 Nov 2021	Loading from Bontang terminal 17-19 Oct and 5-6, 8-10 or 12-15 Nov

Global Recent Deals

Date	Transaction	Period	Price	Note
14-Oct-21	Darwin LNG sold to Unknown 1 cargo(es) fob Australia	loading 14-16 Nov 2021	$36.70-37.30/mnBtu	Sold at a high-$36s/mn Btu or low-$37s/mn Btu on a fob basis
14-Oct-21	Shell sold to Trafigura 1 cargo(es) des China	delivery 25-29 Nov 2021		Sold at a $4.15/mn Btu premium to the December TTF; for delvery to Guangdong Dapeng terminal
14-Oct-21	Sakhalin Energy sold to Unknown 1 cargo(es) des Russia	loading 25 Nov 2021	$38.00-38.99/mnBtu	16-day round-voyage trip
12-Oct-21	Australia Pacific LNG sold to Unknown 1 cargo(es) fob Australia	loading 25-27 Nov 2021		On a des or fob basis
12-Oct-21	PTT bought from Unknown 1 cargo(es) des Thailand	delivery 18-24 Oct 2021		For delivery to Map Ta Phut terminal
12-Oct-21	PTT bought from Unknown 1 cargo(es) des Thailand	delivery 27-29 Oct 2021		For delivery to Map Ta Phut terminal
07-Oct-21	Darwin LNG sold to Unknown 1 cargo(es) fob Australia	loading 05-07 Nov 2021	$30.00-33.00/mnBtu	Sold in the low-$30s/mn Btu; For delivery to northeast Asia, on either a fob or des basis. Cargo size of140,000-170,000m3 if on fob, 135,000-165,000m3 if on des

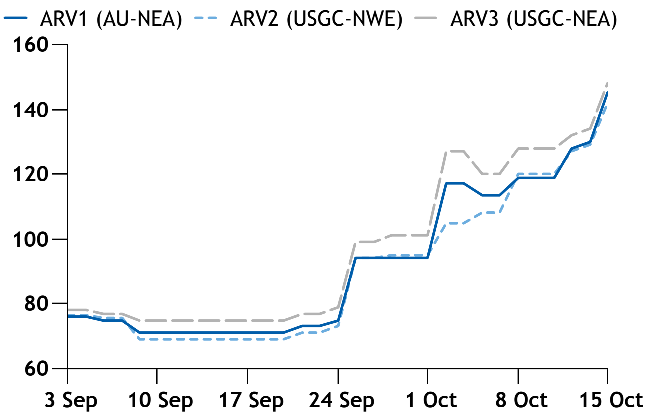
Global shipping highlights

Vessel	Capacity m^3	From	To	Loading	Arrival	Notes
Bilbao Knutsen	138,000	Cove Point, US	Likely Quintero, Chile	29 Aug	15 Oct	
Marvel Falcon	174,000	Cameron, US	Qingdao, China	14 Sep	15 Oct	Via Panama
Nikolay Urvantsev	172,600	Yamal, Russia	TBC	9 Oct	15 Oct	
Neptune	145,000	Fos-sur-Mer, France	Dahej, India	29 Sep	15 Oct	Reload, via Suez
Gaslog Seattle	155,000	Dunkirk, France	Andres, Dominican Republic	29 Sep	15 Oct	Reload
Iberica Knutsen	138,000	Sabine Pass, US	Gate, Netherlands	1 Oct	16 Oct	
Gail Bhuwan	176,523	Cove Point, US	Dahej, India	17 Sep	17 Oct	
Fedor Litke	172,600	Yamal, Russia	Beihai, China	30 Sep	17 Oct	
Boris Vilkitsky	172,600	Yamal, Russia	Sines, Portugal	8 Oct	17 Oct	
Gaslog Galveston	174,000	Sabine Pass, US	South Korea	28 Sep	18 Oct	Via Panama
Golar Tundra	170,000	Sabine Pass, US	TBC	3 Oct	18 Oct	
British Diamond	155,000	Freeport, US	Kisarazu, Japan	12 Sep	18 Oct	Via Panama
Hyundai Peacepia	174,000	Sabine Pass, US	Samcheok, South Korea	21 Sep	18 Oct	Via Panama
Amberjack LNG	174,000	Sabine Pass, US	TBC	5 Oct	18 Oct	
Clean Ocean	162,000	Yamal, Russia	Gate, Netherlands	11 Oct	18 Oct	
Stena Crystal Sky	173,000	Cameron, US	TBC	18 Sep	19 Oct	
Sean Spirit	174,000	Freeport, US	TBC	29 Sep	19 Oct	
Nikolay Zubov	172,600	Yamal, Russia	Yung An, Taiwan	3 Oct	20 Oct	
Arctic Voyager	142,800	Sabine Pass, US	Bilbao, Spain	3 Oct	20 Oct	
Meridian Spirit	165,500	Cameron, US	Cartagena, Spain	6 Oct	20 Oct	
Sohshu Maru	177,000	Freeport, US	Brazil	8 Oct	20 Oct	
Catalunya Spirit	138,200	Sabine Pass, US	Bilbao, Spain	11 Oct	22 Oct	
Diamond Gas Orchid	165,000	Cameron, US	Kawasaki, Japan	22 Sep	23 Oct	Via Panama
Yakov Gakkel	172,600	Yamal, Russia	Beihai, China	4 Oct	23 Oct	
LNG Dubhe	174,000	Yamal, Russia	TBC	8 Oct	23 Oct	
Kinisis	173,400	Freeport, US	TBC	10 Oct	23 Oct	
Yamal Spirit	174,000	Yamal, Russia	Montoir, France	12 Oct	23 Oct	
Valencia Knutsen	173,400	Sabine Pass, US	TBC	19 Sep	24 Oct	
Golar Crystal	160,000	Sabine Pass, US	TBC	22 Sep	24 Oct	Via Suez
Marshal Vasilevskiy	174,000	Yamal, Russia	TBC	23 Sep	24 Oct	
Gaslog Winchester	174,000	Corpus Christi, US	TBC	9 Oct	24 Oct	
Gaslog Hong Kong	174,000	Sabine Pass, US	Fos-su-mer, France	10 Oct	24 Oct	
Flex Endeavour	173,400	Corpus Christi, US	TBC	10 Oct	24 Oct	
Minerva Limnos	173,400	Sabine Pass, US	TBC	9 Oct	25 Oct	Via Suez
Methane Becki Anne	170,000	Elba Island, US	TBC	6 Oct	26 Oct	
Gaslog Singapore	155,000	Corpus Christi, US	Aliaga, Turkey	11 Oct	26 Oct	
BW Pavilion Leeara	162,000	Freeport, US	Paranagua, Brazil	13 Oct	26 Oct	
GDF Suez Point Fortin	154,200	Cameron, US	Mejillones, Chile	25 Sep	27 Oct	Via Panama
British Merchant	138,200	Sabine Pass, US	Sagunto, Spain	14 Oct	27 Oct	
Marvel Crane	177,000	Cameron, US	Tianjin, China	23 Sep	30 Oct	
Flex Resolute	173,400	Sabine Pass, US	TBC	20 Sep	31 Oct	

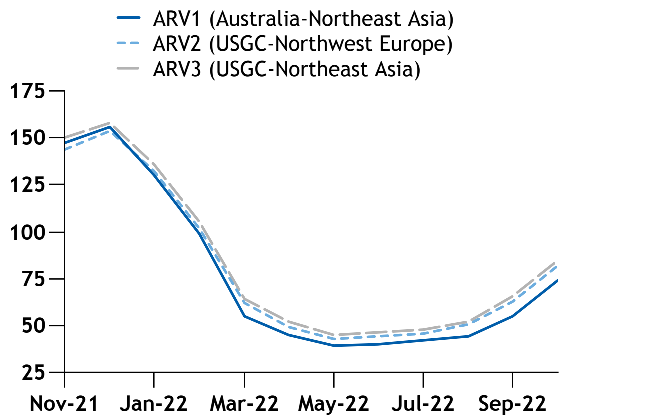
FREIGHT RATES

Argus round voyage forward curves (15 Oct)						
	ARV1: Australia-Northeast Asia		ARV2: USGC-Northwest Europe		ARV3: USGC-Northeast Asia	
Month	$/day	+/- 8 Oct	$/day	+/- 8 Oct	$/day	+/- 8 Oct
Nov	147,000	+24,000	144,000	+23,000	150,000	+20,000
Dec	156,000	+26,000	154,000	+17,000	158,000	+17,000
Jan	130,000	+16,000	132,000	+5,000	136,000	+6,000
Feb	99,000	+13,000	102,000	+3,000	105,000	+3,000
Mar	55,000	nc	62,000	nc	64,000	nc
Apr	45,000	nc	49,000	nc	52,000	nc
May	39,000	nc	42,500	nc	45,000	nc
Jun	40,000	nc	44,500	nc	46,500	nc
Jul	42,000	nc	45,500	nc	47,500	nc
Aug	44,000	nc	50,250	nc	52,250	nc
Sep	55,000	nc	62,500	nc	65,500	nc
Oct	74,000	nc	82,000	nc	85,000	nc

Argus Round Voyage spot rates *$'000/day*



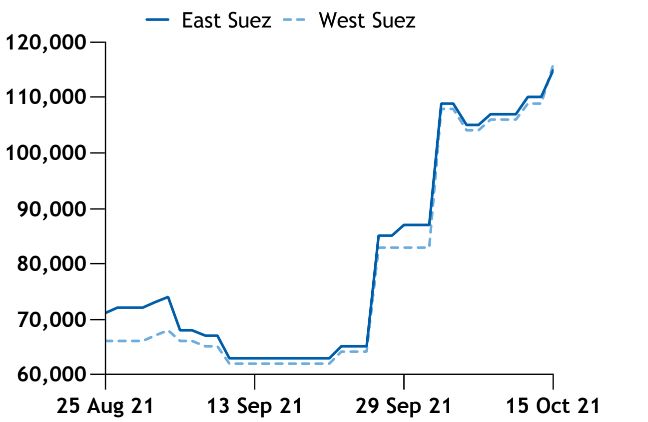
Argus Round Voyage forward curves *$'000/day*



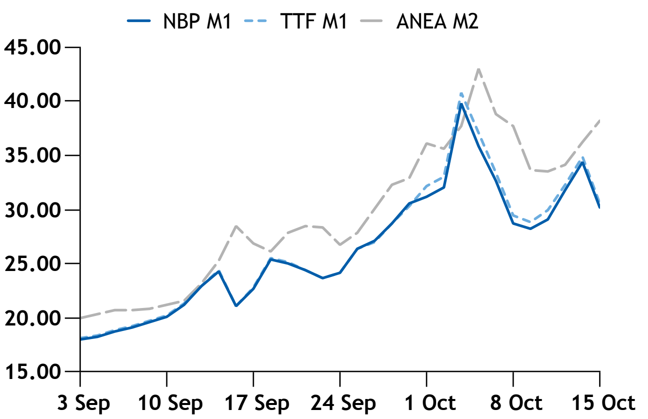
download data on **Argus direct**

Argus ballast leg TFDE rates (15 Oct 2021)		
	%	+/- 08 Oct
Day rate - west of Suez	110	+5
Day rate - east of Suez	110	+5
Fuel cost - west of Suez	35	nc
Fuel cost - east of Suez	35	nc

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



European gas hubs vs ANEA *$/mn Btu*



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	-		1.85	1.73	1.83	1.15	3.61	1.96	2.75	2.13	1.60	0.89	1.73	4.29	1.93	3.74
	Suez	1.84														
	Panama								2.14							
Bintulu and Tangguh	-	2.12			1.32	3.27	0.94	1.62	2.92	0.51		3.27	3.57	0.66	0.38	1.08
	Suez		2.34	4.56							3.19					
	Panama			4.20												
Bonny	-		1.73	1.64	1.96	1.22	3.78	2.13	2.79	2.26	1.45	0.83	1.73	2.46	2.13	3.88
	Suez	1.71														
	Panama								2.04							
Bontang	-	2.29			1.59	3.27	1.08	1.85	2.89	0.79		3.40	3.31	0.77	0.62	1.08
	Suez		2.59	4.72							3.35					
	Panama			4.17												
Dampier	-	1.71		3.97	1.17	3.02	1.49	1.38	3.05	1.03		3.11	3.18	1.22	0.79	1.49
	Suez		2.59								3.35					
	Panama			4.20												
Gladstone	-	2.33		3.29	1.71	2.76	1.63	1.92	2.37	1.60		3.53	2.49	1.49	1.36	1.53
	Suez		3.24								3.99					
	Panama			3.52												
Rotterdam	-		1.18	1.34		1.73			3.39			1.12	2.36			
	Suez	1.23			1.85		4.26	1.94		2.67				3.99	2.44	4.40
	Panama								1.99				2.23			
Papua New Guinea	-	2.33		3.29	1.61	3.02	1.49	1.92	2.37	1.33		3.53	2.49	1.22	1.36	1.36
	Suez		3.24								3.99					
	Panama			3.65												
Ras Laffan and UAE	-	0.80			0.40	3.27	2.35	0.21	4.26	1.74			3.86	2.05	1.47	2.49
	Suez		1.57	3.66							2.33	3.09				
Sakhalin	-	3.26			2.29	3.79	0.66	2.59	2.07	1.33		4.33	3.18	0.91	1.33	0.63
	Suez		3.24	5.65							4.08					
	Panama			3.36												
Singapore	-	1.89			1.19	3.24	1.08	1.45	3.15	0.48		3.27	3.57	0.77		1.22
	Suez		2.22	4.34							2.98					
Sagunto	-		0.59	1.45		1.58			3.28		0.68	0.99	2.22			
	Suez	0.86			1.49		3.72	1.56		2.30				3.41	2.10	3.85
	Panama								1.99				2.20			
Trinidad and Tobago	-		1.73	0.63		1.21			2.84	3.03	1.32	0.54	1.82		2.84	
	Suez	1.74			2.36		4.98	2.42						4.68		5.12
	Panama						3.85		1.03				1.22	3.99		3.55
USGC	-		2.10	0.15		1.33	5.59		0.70	2.76	1.60	0.80	1.81		2.61	5.69
	Suez	1.59			2.07			2.15						5.12		
	Panama						3.99		0.88				1.03	4.12		3.58

**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	35.26	35.39	35.11	35.25	35.66	28.22	29.04	28.08	29.01	28.03	6.59
Australia	34.42	36.24	36.21	36.24	36.52	27.24	28.02	27.11	28.02	27.02	5.92
Nigeria	33.18	33.82	33.57	33.71	34.12	28.98	28.87	28.22	28.78	28.78	7.36
Norway	32.83	32.97	32.86	33.03	33.29	29.35	29.12	28.46	29.02	29.55	7.63
Algeria	33.94	34.04	33.90	34.04	34.42	29.87	30.14	29.47	30.04	29.64	7.71
Trinidad and Tobago	32.53	32.84	32.59	32.73	33.28	28.95	28.78	28.19	28.75	28.87	8.03
Russia	33.75	36.83	37.21	37.10	36.97	26.60	27.38	26.47	27.29	26.41	5.71

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	-		1.61	1.41	1.49	0.94	3.06	1.61		1.73	1.39	0.71	1.41	3.64	1.57	3.18
	Suez	1.52														
	Panama								1.76							
Bintulu and Tangguh	-	1.80			1.11	2.81	0.79	1.38	2.54	0.43		2.80	3.04	0.55	0.31	0.90
	Suez		2.04	3.91							2.79					
	Panama			3.61												
Bonny	-		1.50	1.33	1.61	0.98	3.21	1.73		1.85	1.25	0.67	1.41	2.01	1.73	3.29
	Suez	1.41														
	Panama								1.68							
Bontang	-	1.95			1.34	2.81	0.90	1.57	2.51	0.66		2.91	2.82	0.64	0.51	0.90
	Suez		2.26	4.05							2.93					
	Panama			3.58												
Dampier	-	1.37		3.39	0.93	2.59	1.26	1.09	2.66	0.86		2.66	2.71	1.02	0.66	1.26
	Suez		2.26								2.93					
	Panama			3.61												
Gladstone	-	1.86		2.81	1.37	2.37	1.37	1.53	2.05	1.35		3.02	2.12	1.26	1.16	1.29
	Suez		2.83								3.49					
	Panama			3.02												
Rotterdam	-		1.00	1.10		1.41						0.90	1.93			
	Suez	1.01			1.52		3.63	1.60		2.20				3.40	2.01	3.75
	Panama								1.62				1.82			
Papua New Guinea	-	1.86		2.81	1.29	2.59	1.26	1.53	2.05	1.12		3.02	2.12	1.02	1.16	1.14
	Suez		2.83								3.49					
	Panama			3.13												
Ras Laffan and UAE	-	0.66			0.31	2.81	1.99	0.16	3.71	1.47			3.30	1.72	1.24	2.11
	Suez		1.37	3.14							2.04	2.65				
Sakhalin	-	2.78			1.95	3.25	0.55	2.21	1.79	1.12		3.72	2.71	0.75	1.12	0.52
	Suez		2.83	4.86							3.57					
	Panama			2.88												
Singapore	-	1.61			1.01	2.78	0.90	1.23	2.73	0.39		2.80	3.04	0.64		1.02
	Suez		1.94	3.72							2.61					
Sagunto	-		0.50	1.15		1.27					0.57	0.79	1.79			
	Suez	0.70			1.22		3.17	1.26		1.87				2.90	1.70	3.29
	Panama								1.62				1.78			
Trinidad and Tobago	-		1.50	0.51		0.98				2.49	1.14	0.43	1.49		2.33	
	Suez	1.44			1.96		4.25	2.00						3.98		4.37
	Panama						3.28		0.85				1.01	3.40		3.02
USGC	-		1.82	0.14		1.25	4.75			2.61	1.39	0.76	1.71		2.46	4.83
	Suez	1.50			1.96			2.03						4.37		
	Panama						3.40		0.83				0.97	3.51		3.05

**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	35.36	35.72	35.51	35.63	35.98	28.49	29.24	28.31	29.21	28.32	6.64
Australia	34.64	36.46	36.44	36.48	36.71	27.64	28.35	27.46	28.35	27.44	5.98
Nigeria	33.57	34.37	34.20	34.31	34.66	29.16	29.10	28.45	29.03	29.00	7.40
Norway	33.27	33.66	33.59	33.74	33.94	29.48	29.31	28.66	29.24	29.67	7.67
Algeria	34.22	34.57	34.47	34.59	34.90	29.94	30.21	29.54	30.13	29.74	7.74
Trinidad and Tobago	33.01	33.54	33.36	33.48	33.97	29.13	29.03	28.41	28.99	29.07	8.05
Russia	34.06	36.96	37.30	37.22	37.10	27.07	27.79	26.90	27.71	26.91	5.78

NEWS

Singapore LNG seeks spot cargoes for first time

Singapore LNG is seeking two LNG cargoes on a spot basis for the first time, following an unprecedented surge in gas prices, made more pressing by the city-state relying mainly on natural gas to generate its electricity.

The firm is looking to buy two cargoes for delivery in November to the 11mn t/yr Jurong terminal on a bilateral basis, market participants said.

Natural gas has accounted for over 90pc of Singapore's power mix since 2013, according to statistics from power regulator the Energy Market Agency (EMA). While pipeline gas from two of the country's closest neighbours Malaysia and Indonesia traditionally provided most of Singapore's natural gas needs, the opening of the Jurong terminal in 2013 has enabled Singapore to import more LNG from other international providers.

It is unclear why Singapore LNG is seeking spot cargoes with the rally in natural gas prices, especially on a prompt basis. Indonesia is expected to halt piped gas supplies to Singapore via the country's Corridor block in south Sumatra by 2023, the Indonesian energy ministry said last year.

The four LNG importers in Singapore appointed by the EMA are Shell, Pavilion Energy, ExxonMobil and utility provider Sembcorp Power.

Spot prices surge

Spot LNG prices have surged since the beginning of this year as low underground gas storage levels in Europe, coupled with northeast Asian buyers stocking up for the winter season well in advance, have led to increased competition for the same pool of cargoes available.

The ANEA price, the *Argus* assessment for spot prices to northeast Asia, rose to a record high of $42.095/mn Btu for first-half November deliveries on 6 October this year, more than seven times the price over the same period in 2020. It also surpassed the previous record of $39.72/mn Btu set earlier this year.

The *Argus* ASEA price for southeast Asia deliveries, derived via a freight netback from northeast Asia, was last assessed on 14 October at $35.14/mn Btu for first-half November and $35.18/mn Btu for second-half November. This was $3.41/mn Btu and $3.27/mn Btu higher than two weeks ago respectively.

Market participants expect new records to be set in the coming weeks and months as buying activity from within and outside Asia firms ahead of the northern hemisphere winter season. Gas storage inventories in Europe also remain low at only about 78pc full compared to well over 90pc during the same period in previous years, according to statistics from European gas association Gas Infrastructure Europe.

Higher spot LNG prices have created obstacles to independent power retailers in Singapore. Singapore Power supplied electricity to the whole of the city-state until The Open Electricity Market was launched in 2018 by the EMA, in a bid to give Singapore power consumers a larger range of electricity retailers to choose from and to increase competition and efficiency in the industry.

One of Singapore's largest independent electricity retailers iSwitch Energy has announced it will halt electricity retail operations on 11 November.

By Rou Urn Lee and Subethira Ahrumugam

Spain awards additional LNG slots at auction

Spanish gas system operator Enagas has allocated 23 more LNG unloading slots at import terminals in the firm's second "extraordinary" auction in recent months aimed at coping with the ongoing rally in European gas prices.

The additional LNG terminal slots booked on Friday are for use over the next 12 months, alongside 22 unloading slots offered in a separate special auction last month, the system operator said.

"These 45 additional slots are a preventative measure to contribute to security of energy supply in the coming months in a context of great volatility in the international energy markets," Enagas said.

Spanish gas prices at the PVB remain historically high and rank among the most expensive in Europe. November-dated PVB contracts closed at €102.74/MWh on Thursday, slightly higher than at the Dutch TTF and just below the equivalent price at the UK NBP.

The latest auctions give Spanish LNG import terminals a total of 136 booked unloading slots for November 2021-March 2022, sharply higher than the 86 cargoes unloaded last winter.

The auctions, along with other state-backed measures, were designed to give suppliers "maximum capacity" to unload at Spanish regasification plants, the company said.

In the past few months, the Spanish government has announced a raft of measures ahead of this winter, including higher LNG storage requirements and new gas and LNG congestion management tools.

LNG may play a greater role in the Spanish gas market this winter than in recent years.

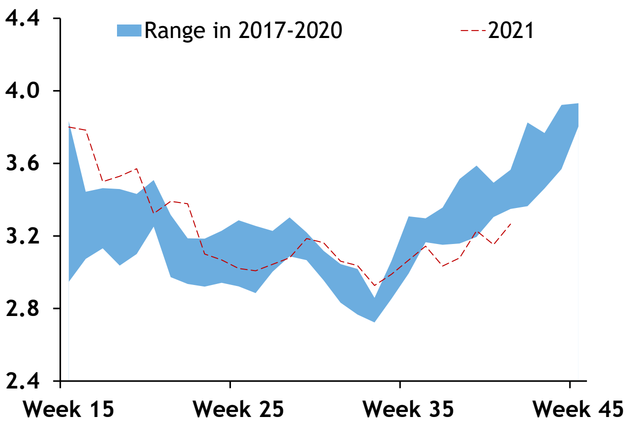
Domestic underground gas storage levels are lower than average and supply from Algeria through Morocco on the Maghreb-Europe pipeline is expected to stop at the end of this month. But Spanish LNG stocks are above the three-year average after several recent deliveries.

Jeff Kuntz

Demand destruction hits European gas market

Gas demand from industry in major European gas-consuming countries has begun to fall as an increasing number of plants

Weekly European industrial gas demand *TWh/d*



that produce steel, chemicals and other products either curtail output or close in response to record-high wholesale prices.

According to *Argus* analysis, industries in Germany, the Netherlands, Spain, Italy, France, Poland, the UK and Portugal consumed a combined 3.27 TWh/d of gas last week — the lowest for calendar week 41 since at least 2017, including during the Covid-19 lockdowns of 2020 and 2021.

That weekly figure is about 8pc lower than the 3.57 TWh/d consumed in the same period last year and 4pc below the three-year average of 3.42 TWh/d.

As of last week, industrial gas demand in these eight economies this year had averaged 3.55 TWh/d, slightly higher than the same period in 2020 and 2017, but shy of the averages of 3.56 TWh/d in pre-Covid 2019 and 3.69 TWh/d in 2018.

In recent months, industrial gas consumption trends in the eight countries — which represent the bulk of that type of European demand — have defied seasonal norms and suggest that a variety of energy-intensive firms will continue cutting operations in the coming weeks and months *(see European, German demand graphs)*.

In a typical calendar year, gas consumption by major European industrial economies follows a U-shape, hitting a post-new year high around February, gradually declining toward an annual low during summer holidays in July and August, then recovering to a second peak before Christmas.

This year, industrial gas use generally followed seasonal trends until mid-September when demand abruptly fell by over 100 GWh/d to low levels unseen in recent years, before continuing on a diminished upward trajectory.

At that time, wholesale gas markets were rallying, with front-month benchmarks at the Dutch TTF and UK NBP hubs steadily rising toward peaks of €117-120/MWh on 5 October, in the face of winter supply concerns, low storage inventories in key markets and rallying LNG prices.

UK weighs on demand

While most countries have experienced lower industrial demand to some degree, the UK emerges as a driving force behind this wave of demand destruction, when established industrial consumers cut or effectively stop using gas *(see UK demand graphs)*.

Rallying gas prices prompted a handful of industrial consumers across the continent to reduce operations last month, including CF Industries, which announced plans in mid-September to temporarily close two UK fertiliser plants.

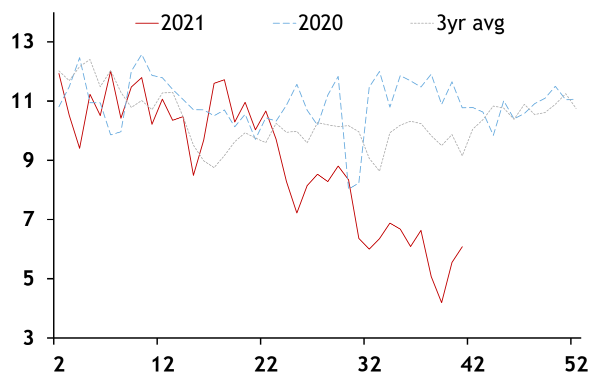
Around the same time, while industries across Europe considered their options, a number of UK steel plants and Spanish silicon producer Ferroglobe either stepped down or idled plants, citing higher power prices, driven in part by costly in-feed from gas-fired plants across Europe.

Front-month gas prices have eased somewhat this week to €85-95/MWh, but remain more than four times higher than at the start of 2021. Accordingly, the spectre of demand destruction looms over the UK and its European neighbours, with Spanish steelmaker Sidenor Group announcing it would temporarily take its Basauri plant off line at the start of this week.

It is unclear how far European demand will fall, as different businesses are coping in different ways.

The UK-based Major Energy Users Council (MEUC), which represents large-scale consumers such as Network Rail and Transport for London, told *Argus* that while long-term energy

Weekly UK industrial gas demand *mn m³/d*



New: Quick access to price history and charts

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In advanced PDF viewers, you can also hover over the price to see the underlying *Argus* PA code.

supply contracts have helped businesses weather the storm, their forward positions are anything but certain.

"I am not aware of any member reducing output or closing, in fact in most cases they cannot contemplate doing so," MEUC technical director Eddie Proffitt said. "In most cases, members take a sensible approach to energy buying, hedging various volumes going forward... the increase is hitting them, but not for the whole of their bill."

But as fixed-price contracts near expiry, some MEUC members shopping for energy have only been able to source quotes from their current suppliers at "massive increases", he said. "There are even requests for deposits or parent-company guarantees," he added.

While certain industries, including glass making, are reportedly considering substituting fuel oil for natural gas in certain processes, sustained high gas prices suggest a combination of further demand destruction and higher retail prices for certain products.
by Jeff Kuntz

Coal restriction easing boosts South Korean coal

Seoul has lifted voluntary restrictions across Kepco coal fleet for the autumn period, boosting the demand outlook for spot coal in South Korea.

Concurrently, one of the state-owned utilities is reportedly affected by a force majeure declared by Russian producer Suek, after a fire hit its Vanino Daltransugol terminal this week, further tightening availability.

The South Korean government and Kepco reportedly came to an agreement on 14 October to lift voluntary restrictions across the country's coal-fired fleet, although they will still implement the seasonal fine-dust management measure during December-March, according to sources familiar with the matter.

Although gas remains competitive versus coal in the South Korean power sector currently as a result of the prevalence of oil indexation in Kogas' LNG import costs, firm gas demand has led Kepco utilities to become increasingly exposed to the spot LNG market and associated high prices, which has driven up costs, while the tight restrictions on coal-fired capacity have limited coal-switching flexibility. This has led to mounting pressure to ease the restrictions.

The government has not made an official announcement on the relaxation, but the latest plant maintenance schedule published by the Korea Power Exchange shows that the start date for coal-fired units that are currently under the voluntary restrictions was brought forward this week. Based on the current schedule, no coal units are scheduled to go off line for voluntary restrictions after 17 October, bringing average restrictions across the whole of October to 1.7GW, according to *Argus* analysis. By comparison, based on last week's schedule, around 4.5GW of Kepco's coal-fired capacity was scheduled to be unavailable in October.

October coal availability

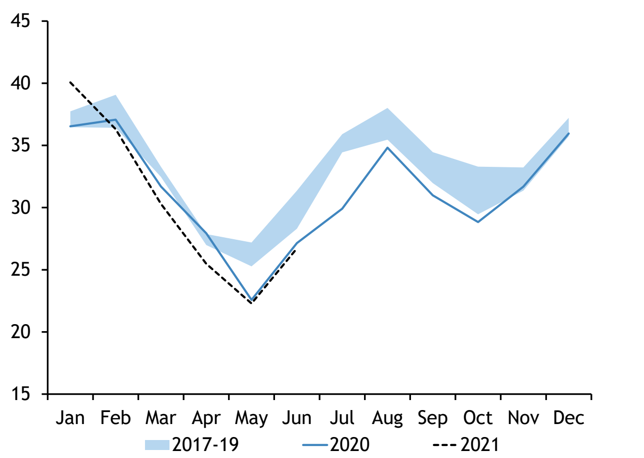
Kepco's coal availability is now scheduled to average around 24GW in October, up from 22.9GW average availability based on last week's schedule.

This 1.1GW rise in coal availability is equivalent to 235,000t more NAR 6,000 kcal/kg coal burnt across the month in 40pc-efficient plants at an 80pc load factor, *Argus* calculations show.

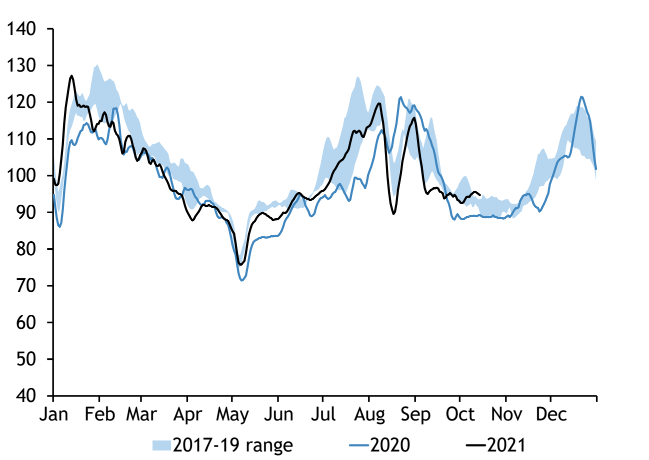
The plant maintenance schedule is updated every week, but it is unlikely that the government will bring back the restrictions as utilities are already facing difficulties procuring coal amid frequent schedule changes, according to a source from the state-owned utilities.

Softer restrictions across Kepco's coal-fired units should lift utility spot coal demand, while one of the utilities was reportedly affected by the force majeure declaration at the Daltransugol terminal, tightening the outlook for spot market availability. The utility was scheduled to receive 155,000t of thermal coal from the Vanino port in October, but only 110,000t were loaded owing to disruption caused by a fire,

Japanese coal-fired generation *GW*



Seven-day avg Japanese power demand *GW*



according to a source familiar with the matter.

Fellow state-owned Korea Western Power (Kowepo) closed a five-year term tender on Friday, procuring a Capesize cargo of NAR 5,800 kcal/kg at around $215/t fob Newcastle on a NAR 6,080 kcal/kg basis for January 2022 loading.

Argus assessed NAR 5,800 kcal/kg coal at $228.64/t cfr South Korea and $208.81/t fob Newcastle, up by $13.66/t and $22.90/t on the week, respectively.

Headwinds for Japanese coal demand outlook

Firmer spot demand expectations across the Asia-Pacific region, a market already buoyed by acute coal shortages in China and India, continued to boost implied landed prices for Japan this week.

Despite the regional strength, firmer nuclear availability and relatively competitive oil-indexed LNG prices are weighing on the demand outlook for coal-fired generation in Japan, although upside risks remain in the event of La Nina weather.

Japanese monthly nuclear availability is scheduled to increase by 4.4GW on the year to 7.8GW on average during October-March, while a 1.5GW year-on-year rise in nuclear availability dented coal-fired power generation by 317GWh in June, despite a 1.3TWh increase in overall power demand.

Combined coal and gas-fired output dropped by 776.3GWh on the year to 43.6TWh in June amid firmer nuclear availability, but oil-fired generation increased by 33pc, or 245.2GWh, on the year to 997.2GWh, as rallies in spot LNG prices incentivised gas-to-oil fuel switching.

Theoretical margins for the most economical 58pc-efficient gas-fired units in Japan averaged minus 11,158 yen/MWh during 8-14 October, based on *Argus*' des northeast Asia spot LNG assessment and the day-ahead system price from the Japan Electric Power Exchange.
By Evelyn Lee

Montoir adds October LNG delivery

France's 7.25mn t/yr Montoir LNG terminal has scheduled a new 165,500m^3 delivery for later this month.

The facility expects the cargo on 26 October, stock movements show.

Nominated regasification from the terminal was revised up as a result to 154 GWh/d for 15-31 October from 149 GWh/d in the previous schedule. This would bring aggregate sendout from France's three regulated terminals to 430 GWh/d for the remainder of this month, still below 527 GWh/d a year earlier.

There were other delivery additions to Fos Cavaou's schedule in recent days, but this would still be insufficient to offset substantial LNG slot cancellations previously, resulting in regasification remaining below average.

French LNG deliveries could slow in the coming months, with northeast Asian LNG prices maintaining large premiums to the French Peg market, indicating little incentive for US-loaded cargoes to head to France this winter instead of Asia.
By Silvia Fernandez Martinez

Ikata nuclear reactor faces extended closure

Japanese utility Shikoku Electric Power is being forced to close its Ikata No.3 nuclear reactor for an extended period, following a safety breach discovered in June. This will boost the firm's demand for replacement thermal power generation fuels, especially with the coming winter peak demand season.

Shikoku has postponed a plan to resume its sole 890MW nuclear reactor in western Japan's Ehime prefecture from the previous restart target of 17 October. It is still unclear when the reactor will be brought back on line, which will depend on approvals from local authorities.

Shikoku on 24 June found the fact that a former employee had left the Ikata nuclear plant without permission five times during March 2017-Febauary 2019, resulting in a failure to meet the required number of personnel at the plant. The company in September submitted its measures to prevent a similar violation of safety rules to the Ehime prefecture and Ikata town that host the nuclear power plant.

The Ehime prefectural government plans to hold another meeting, the date of which is still unknown, to discuss the Ikata issue following its 12 October meeting. Shikoku plans to explain its preventative measures again at the meeting, the company said.

The Ikata No.3 reactor had been closed since December 2019 when regular maintenance at the site started. The reactor was originally scheduled to restart in March 2020. But an injunction shutting down the reactor had been effective from January 2020-March 2021, followed by work need to install counter-terrorism measures.

The delay in restarting the Ikata reactor means Shikoku would continue seeking additional thermal fuels to meet electricity demand, especially ahead of the winter heating season which is forecast to be colder than normal because of a La Nina weather event emerging. The company used around 2.8mn t of coal in the April 2020-March 2021 fiscal year, up by 15pc from a year earlier. LNG consumption also rose by 30pc to 407,000t, while oil use increased by 90.4pc to 2,585 b/d.
By Motoko Hasegawa

Japan's winter power shortage concerns ease

Concerns over possible electric power shortages in Japan for the upcoming winter peak demand season has eased, with the country's 10 service areas expecting to secure more than the minimum 3pc reserve level from December 2021-Februry 2022.

Japan's power agency the Organisation for Cross-Regional Coordination of Transmission Operators (Occto) has updated its winter electricity supply forecast, following efforts by the government and power industry to increase power output capacity. Occto in late March shared a tight power forecast for the 2021-22 winter.

Under the renewed outlook, even the worst-hit Tokyo metropolitan area could have surplus supply of 3.1-3.2pc over January-February, a significant rise from the previous outlook of negative 0.2-0.3pc. Utility Tokyo Electric Power is expected to secure 630MW for winter through a public tender.

Japan's optimal power reserve is more than 8pc, with a minimum of 3pc needed to tackle emergencies such as power plant closures and spikes in peak demand.

Japan's three eastern areas including Tokyo, where the grid runs at 50 hertz (Hz), would have a projected power surplus of an average 3.6pc in February 2022, even if the coldest weather in the past decade hit the country. The outlook reflects a 2.6pc probability of an unexpected shutdown of thermal plants, based on actual closures from April 2014 to March 2017. It also incorporates maximum use of available thermal power capacity and flexible power distribution beyond utilities' service areas.

The country's six western areas that run at 60Hz could have an average 3.9pc reserve in February under the same conditions for east Japan, while grind-independent 60Hz Okinawa region is forecast to secure 33.8pc.

Occto predicts that Japan will secure 117,700MW of thermal power capacity for January, with the possibility of another 1,160MW, although it did not give a breakdown of capacity for fuels such as coal, LNG and oil or availability figures for other months. Japan is also estimated to have 8,320MW of nuclear, 29,740MW of hydro and 4,960MW of renewable power capacity for January.

Occto also showed a different forecast that Japan will have surplus of 17,529GWh at the end of November, based on expected inventory levels of thermal fuels and efficiency of power plants. This is expected to fall to 17,480GWh under normal weather condition and to 9,668GWh with colder-than-usual weather at the end of February 2022.

Japan's meteorological agency has recently raise the possibility of a La Nina for this autumn and winter to 60pc from 30pc. This implies that the country is 38-46pc more likely to experience colder weather in December-February.
By Motoko Hasegawa

Gladstone LNG halves winter maintenance

Australia's 7.8mn t/yr Gladstone LNG (GLNG) export project has shortened maintenance planned for October-November this year, and slightly delayed its start.

The maintenance period has been altered to run over 19 October-4 November, compared with the previously expected 18 October-20 November, halving the planned downtime to 17 days from 34. The maintenance is still expected to impact the equivalent of around half a train of capacity at the two-train facility, unchanged from previous expectations.

The shorter maintenance period should lift available capacity at GLNG over this quarter by around 91,000t — equivalent to around 1-1.5 cargoes of LNG.

APLNG delays, lengthens summer 2022 maintenance

Fellow export terminal 9mn t/yr Australia Pacific LNG (APLNG) has pushed back three summer 2022 maintenance periods, and significantly lengthened one of them.

Brief downtime affecting around half a train at the two-train facility was pushed back to 22-25 March and 26-29 April, having previously been planned for 1-4 March and 1-4 April 2022, respectively. And maintenance affecting a full train is now scheduled for 28 July-26 August, with a later start and longer duration than the previously planned 11 July-7 August.
By Samuel Good

Planned Australian LNG maintenance* *t of LNG*

Project	Start	End	Approx. capacity impact
QCLNG	15 Oct 21	17 Oct 21	11,600
GLNG	19 Oct 21	04 Nov 21	85,400
APLNG	22 Mar 22	25 Mar 22	18,500
Wheatstone	04 Apr 22	09 May 22	533,000
APLNG	26 Apr 22	29 Apr 22	18,500
QCLNG	16 Jun 22	18 Jul 22	279,300
Ichthys	01 Jul 22	05 Aug 22	852,800
APLNG	28 Jul 22	26 Aug 22	357,300
QCLNG	14 Aug 22	28 Aug 22	122,200
APLNG	04 Oct 22	12 Oct 22	49,300
*Excluding Darwin LNG, Prelude FLNG			

— AEMO, Chevron, Inpex, Woodside

ENI eyes investments in LNG as transition looms

Italian energy firm ENI plans to invest more in LNG infrastructure, as it expects gas to retain a crucial role in the energy transition, the firm's deputy chief operating officer for natural resources told *Argus*.

The company plans to invest in new LNG infrastructure to further increase its LNG portfolio, which is already set to grow to 14mn t/yr by 2024 from 10mn t/yr at present, Cristian Signoretto said, adding that priority will be given to "projects integrated with upstream activities, both to maximise value for the group and to ensure a rapid time-to-market". The planned increase is largely the result of its 3.4mn t/yr Coral South floating liquefaction facility in Mozambique, which is scheduled for commissioning in the fourth quarter of 2022.

Eni is betting on gas demand growth being unabated by the energy transition in the coming decades, and expects gas to increasingly dominate its upstream production going forward, reaching more than 90pc of its total output by 2050 as a result of a gradual decline in oil production. But the company is yet to detail plans of a potential reduction in its overall hydrocarbons output, after an expected plateau by the middle of this decade.

"We believe it is right to focus on natural gas, as it facilitates access to energy in developing producing countries. It is the most immediate energy resource for replacing coal and as an energy source complementary to renewables," Signoretto said. This would allow renewable sources to achieve greater diffusion without jeopardising the safety and flexibility of energy systems, he added.

Within the debate on the energy transition, natural gas finds itself "in a rather paradoxical situation", as many stakeholders consider it part of the problem, while producers and "a growing number" of other stakeholders see it as part of the solution, he added.

But an expected peak in oil and coal demand within the next few years supports "a positive vision of gas" in the long term, as the fossil source at the bottom of the merit order, to be replaced last. And even in a scenario of complete decarbonisation, some "incompressible shares of gas consumption in hard-to-abate sectors will remain", Signoretto said.

For gas to remain part of the energy mix in a net zero scenario, its carbon emissions would need to be either captured and stored or offset through the use of "carbon sinks", Signoretto said. Eni is investing in a number of carbon capture and storage (CCS) projects, including the 500mn t Ravenna project, which Signoretto said will be one of the largest CO2 storage hubs in the world. Besides using it to store its own emissions, the firm plans to make the facility available to third-party industrial firms. Eni will also operate the 200mn t Hynet CCS project in the UK.

A wider adoption of carbon price mechanisms around the world may facilitate investments in CCS technologies, as the cost of carbon storage would be in competition with emission allowances. The recent introduction of an emission trading scheme in China is "a step in the right direction", Signoretto said.

But part of the residual emissions would still need to be offset through the use of carbon sinks. Eni recently completed its first sale of a carbon-neutral LNG cargo, where the associated emissions are calculated and offset through the purchase of carbon credits. In the future, however, the company aims to rely more on certificates generated by its own projects, as these will be "better controllable in terms of costs and maintenance of quality standards", Signoretto said.

But the scalability of such system remains challenging, and may largely depend on the "emergence of a single, internationally recognised standard" of certificates, as well as on the evolution of regulation, which in the future may intervene on imports of fossil energy in Europe, Signoretto says.

So far, this system has been entirely based on voluntary choices by customers willing to pay a premium in order to offset the life cycle emissions of their LNG supplies. A large-scale use of such systems may significantly impact demand and prices of such certificates — especially if voluntary and regulated systems should converge. This could see carbon credits prices "gradually diverge from production costs", Signoretto said. Sales of carbon neutral or carbon-offset LNG cargoes have gained traction in recent months, leading several industry participants to voice concerns over the lack of regulation or standardised practices.

By Antonio Peciccia

Taiwan's LNG imports rise in September

Taiwan imported more LNG in September than it did a month earlier following reduced coal imports and despite higher spot LNG prices.

Taiwan imported 1.75mn t of LNG in September, up by around 33.6pc from 1.31mn t in August and also higher by 6pc from 1.65mn t in September 2020.

Australia remained the top exporter in September. Taiwan also imported 74,951t from Oman after not taking any volumes from the country last month.

Australian coal in Taiwan's import mix for September fell below 50pc for the first time in four months, according to Taiwanese customs data. A continued increase in Australian prices over July-August made alternative grades such as Russian and South African material more price competitive. This may have increased the need for Taiwan to buy more LNG to meet its electricity requirements.

CPC bought a cargo for delivery in mid-September to its 6mn t/yr Taichung LNG terminal at $14.50/mn Btu on 21 July. It likely purchased two cargoes to be delivered over 3-7 September to Taichung and 4-13 September to its 10.5mn t/yr Yung An terminal as part of a 10-cargo tender that closed on 28 June.

The ANEA price, the *Argus* assessment for spot prices to northeast Asia, averaged $14.131/mn Btu and $15.450/mn Btu for first- and second-half September this year compared with $2.565/mn Btu and $3.08/mn Btu for the same period a year earlier.

Taiwan paid an average of $11.14/mn Btu for its LNG supplies in September, down from $12.62/mn Btu in August and $4.81/mn Btu in September 2020. Supplies from Oman were the most expensive in September, averaging $15.61/mn Btu. Qatari volumes, which averaged $8.05/mn Btu, were the lowest priced.

By Rou Urn Lee

Toho Gas to supply more 'carbon-neutral' LNG

Japanese gas distributor Toho Gas increased its supply of "carbon-neutral" LNG this month to nine domestic companies across different industries as a part of its decarbonisation efforts.

Toho Gas has agreed to provide a total of 66,000t of "carbon-neutral" city gas. The gas supplier received the LNG last month at the Chita LNG terminal in Aichi prefecture from Japanese upstream firm Inpex's 8.9mn t/yr Ichthys LNG plant. Toho Gas expects to reduce around 200,000t of carbon emissions by helping the nine firms switch to "carbon-neutral" city gas. The company declined to disclose details about the contract periods.

Toho Gas has delivered the "carbon-neutral" gas to metal product supplier Hitachi Metals, auto component producer Aisin, steel product supplier Aichi Steel, vehicle fuel tank manufacturer FTS, ceramics producer KCM, manufacturer of grinding and polishing tools Noritake, construction equipment producer Sumitomo Heavy Industries Construction Cranes, plating chemical supplier Meltex and edible oil producer Miyoshi Oil and Fat.

Toho Gas started supplying the gas in August to six domestic companies, after receiving its first "carbon-neutral" LNG cargo in April.

By Nanami Oki

Taiwan LNG imports *(t)*

	Sep '21	Aug '21	Sep '20
Australia	685,809	428,988	575,667
Qatar	463,952	379,201	473,064
US	115,343	329,455	0
Indonesia	59,492	187,199	113,135
Papua New Guinea	157,170	144,717	149,986
Malaysia	125,168	122,227	0

Source: Taiwan customs

AUSTRALIA WEEKLY - MARKET COMMENTARY

Australia gas: Uncertain weather limits demand

Spot prices for month-ahead gas deliveries to Wallumbilla were little changed as buyers waited on the market sidelines on uncertain weather conditions in November and expectations of ample supplies for deliveries during the month.

The AWX, the *Argus* assessment for month-ahead spot gas deliveries to Wallumbilla, was assessed A8¢/GJ higher from the previous week, slowing gains of A60¢/GJ the previous week.

Mixed weather forecasts for different regions within Queensland have prompted buyers to wait on the sidelines before deciding if they may need to purchase spot gas supplies for November delivery.

Australia's Bureau of Meteorology (BoM) on 7 October forecast a higher than 60pc chance of above median maximum temperatures for the central Queensland coast during November-January, but a higher likelihood of cooler days in southeast Queensland in November.

Buying indications for November deliveries to Wallumbilla fell from A$8.84/GJ last week to A$8.74/GJ this week, widening to an around A$1.30/GJ spread from indicative offers from A$1/GJ last week, reflecting their limited demand for gas supplies in November.

Selling indications for November deliveries to Wallumbilla were up by A25¢/GJ from a week earlier and averaged A$9.98/GJ, as sellers raised their offer levels on the prospects of warmer weather in November.

The BoM's 13 October forecast of low to severe heatwave conditions in parts of northern Queensland across 13-15 October has led to expectations among sellers that the region may experience warmer weather in November instead of December, which is when higher temperatures typically kick in and cooling requirements peak.

Gas supplies for November deliveries to Wallumbilla are ample. Gas flows to the 9mn t/yr Australia Pacific LNG (APLNG), 7.8mn t/yr Gladstone LNG and 8.5mn t/yr Queensland Curtis LNG projects totalled 3.95TJ (105,000 m^3) on 13 October, 130TJ lower than 4.1TJ on 1 October.

The drop in flows to the projects is attributed to a half-train outage at APLNG because of planned maintenance scheduled from 5-13 October. Flows to APLNG were 1.27TJ on 13 October, down from 1.49TJ on 1 October.

APLNG on 11 October issued a tender to sell a 25-27 November loading cargo. It was last in the market on 28 September to offer a cargo for loading over 28-29 October. Market participants suggest an easing of northeast Asian spot LNG prices across 7-12 October may have encouraged the producer to liquefy and export surplus gas supplies it had to maximise profits before any further downside.

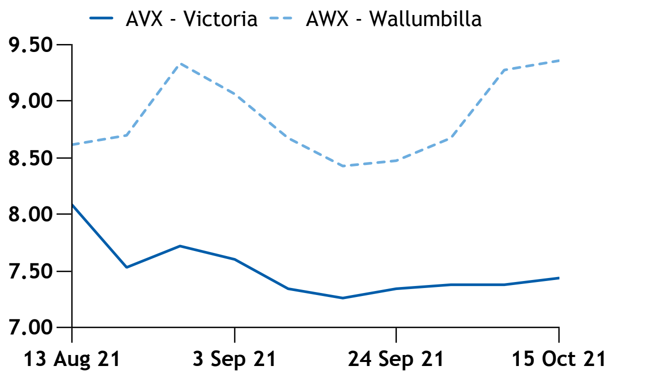
Argus Wallumbilla Index (AWX)					
Delivery	Units	Bid	Offer	Midpoint	±
Nov	*A$/GJ*	8.74	9.98	9.360	+0.080
Nov	*$/mn Btu*	6.84	7.81	7.324	+0.178

Argus Victoria Index (AVX)					
Delivery	Units	Bid	Offer	Midpoint	±
Nov	*A$/GJ*	6.82	8.06	7.440	+0.060
Nov	*$/mn Btu*	5.34	6.31	5.822	+0.139

AEMO weekly average Victoria 6am price			
Delivery	Units	Price	±
Prompt	*A$/GJ*	7.306	-0.016
Prompt	*$/mn Btu*	5.684	+0.066

LNG netbacks weekly average			
	Units	Price	±
Gladstone oil-linked LNG	*A$/GJ*	13.11	-0.22
	$/mn Btu	10.20	-0.02
Gladstone spot LNG	*A$/GJ*	42.99	-3.92
	$/mn Btu	33.46	-2.53

Argus Victoria Index vs Wallumbilla Index *AUD/GJ*



But there are expectations that they may continue their rally with the National Oceanic and Atmospheric Administration announcement on 14 October that there is an 87pc chance of a La Nina developing through the northern hemisphere winter season across December 2021-February 2022. Lower than usual winter temperatures are typically expected during the event.

The front half-month ANEA price, the *Argus* assessment for spot LNG deliveries to northeast Asia, rose by $2.955/mn Btu to $36.27/mn Btu on 14 October after dipping by $8.78/mn Btu from 7-12 October. It had risen to an all-time high of $42.095/mn Btu on 6 October, driven mainly by gains in European gas hub prices.

NEWS

Australian divestment unless more GHGs are cut: RBA

The Reserve Bank of Australia (RBA) has warned that the country's resources sector could face divestment from foreign investors unless there is more action in cutting greenhouse gas (GHG) emissions and accelerating the energy transition to a lower emissions economy.

Australia is dependent on foreign investment as it does not have sufficient capital savings to finance all economic investment activity, so the influences on foreign investment will ultimately impact the Australian economy, RBA deputy governor Guy Debelle said in a speech to the CFA Australian Investment Conference.

"To date, we have only isolated examples of divestment from Australia because of climate risk, but the likelihood of more significant divestment is increasing," Debelle said.

Australia is the world's largest exporter of LNG, iron ore and coking coal and the second-largest thermal coal exporter. Energy-related GHG emissions account for around 78pc of Australia's total emissions.

Discussions about climate change come up more in conversations the RBA has with foreign investors, which is a marked change from a few years ago, Debelle said.

Sweden's central bank the Riksbank discontinued its investment in Queensland and Western Australia (WA) state government bonds a few years ago, Debelle said. Queensland is Australia's largest coal producing state and WA the largest LNG exporting state. "There is a risk we will see more of these divestment decisions sooner rather than later," Debelle said.

Coalition debate

The comments come ahead of a meeting on 17 October by the National party, the junior partner in Australia's coalition government, to debate on whether to agree with its senior partner the Liberal party about deepening GHG cuts by 2030 from the existing target to a 26-28pc reduction below 2005 levels. If there is an agreement, the Liberal-National party coalition may make an announcement next week ahead of the UN Cop 26 climate conference in Glasgow, UK.

"Divestment raises the question as to whether change can be more effective from within, by influencing the approach of the entity you are investing in, or whether divestment is more effective," Debelle said. "If it is the

latter, it begs the question as to how transition will be financed, particularly in the case of governments that will have to deal with both the costs of compensating those adversely affected directly

by climate change as well as structural changes to the economy as it evolves."

Australian states have made far more ambitious GHG emissions cuts than Canberra, which if totalled together equate to a national cut of around 34pc by 2030 from 2005 levels.

Many financiers have pledged to end fossil fuel funding, while investment firms such as the US-based BlackRock and Vanguard are more focused on lowering the emissions intensity in their investment portfolios.

The tighter lending conditions to coal producers operating in Australia prompted Australia's resources minister Keith Pitt an A$250bn ($180bn) lending facility to firms wishing to invest in coal mining in Australia. Pitt's suggestion will require Australian taxpayers to finance coal mines operated by foreign-based firms such as Chinese state-controlled Yancoal and the Switzerland-based commodity trading and mining firm Glencore.

Australia's dependence on foreign capital has already prompted Australian treasurer Josh Frydenberg to call for a net-zero GHG emissions target by 2050, otherwise access to foreign capital markets will tighten and in turn push up borrowing costs that will affect the operating costs of all industries.

By Kevin Morrison

Tasmania targets net-zero emissions by 2030

Australia's Tasmania state has released draft legislation to target net-zero greenhouse gas (GHG) emissions by 2030. It will review the target and accompanying policies every five years, which puts further pressure on the federal government to deepen its 2030 targets ahead of the UN Cop 26 climate conference in Glasgow, UK later this month.

Tasmania has already achieved negative emissions and the target is unlikely to change Australia's overall GHG profile, but it signals the state is positioning itself as a hub for hydrogen produced from renewable sources given its hydropower and wind resources.

"As the world seeks low-emissions products, services and experiences, our plans to double renewable energy generation, export green hydrogen by 2030 and our emissions profile represent our key competitive strengths in the global transition to a low-emissions economy," said Tasmanian premier Peter Gutwein.

A draft bill to strengthen Tasmania's Climate Change Act has been released for public consultation. It will include provisions for a state-wide climate risk assessment every five years and a policy framework to ensure that government policies, plans and strategies consider climate change, Gutwein said.

Tasmania joins four other Australian states with more ambitious GHG emissions reduction targets than the federal government's target of between 26-28pc by 2030 from 2005 levels. Combining these state pledges equate to GHG reductions of 34pc by 2030 from 2005.

Australia's New South Wales (NSW) state last month deepened its target to cut GHG emissions to a 50pc cut by 2030 from 2005 levels compared with its previous 35pc goal. NSW electricity transmission network operator Transgrid this week said as much as 18,000MW of coal-fired power plants across the National Electricity Market (NEM), which covers east Australia, could be withdrawn from the NEM by 2030. This projection is 13,000MW more than current coal-fired retirement plans and is based on decarbonisation objectives aligned to keeping the rise in global average temperatures to 1.5°C and in line with the objectives of the Paris climate agreement, Transgrid said.

Coal-fired plants accounted for around 64pc of electricity supplies in the NEM in the 12 months to 12 October, according to the OpenNEM website.

In all scenarios examined in report about the energy transition in Australia renewable energy supplies the majority of the NEM's electricity needs by 2050, said Transgrid. Renewable energy in five out of the six scenarios modelled in the report supplies more than 70pc of the NEM's annual energy needs by 2035 and more than 90pc by 2050.

Renewables accounted for 30pc of electricity generation in the 12 months to 12 October, according to OpenNem. "The economic viability of Australia's coal generators is being challenged by the influx of renewables," said Transgrid, which operates the largest state transmission network based on power generation capacity within the NEM and one of the most coal-fired intensive with coal accounting for 68pc of electricity supplies to the state in the past 12 months.
By Kevin Morrison

NSW unveils hydrogen production hub plan

Australia's New South Wales (NSW) state plans to be a significant producer of hydrogen for domestic use and export, through a A$3bn ($2.2bn) state-funded investment plan for the expansion of renewable energy to produce hydrogen rather than for alternative methods of producing hydrogen from coal or gas.

The NSW state government plans to create hydrogen production hubs in traditional coal producing regions of the Hunter Valley, which is the country's largest thermal coal producing and exporting area, and the Illawarra region which produces metallurgical coal, as well as build hydrogen hubs around planned renewable energy zones (REZ) in regional NSW.

The NSW state government has targeted a hydrogen price made from renewable energy, otherwise known as green hydrogen, at A$2.80/kg ($2.05/kg) by 2030 from around A$8.60/kg at present with much of the cost reductions coming from electricity network concessions as well as through economies of scale.

The state government also aims to install 700MW of electrolyser capacity backed by around 12,000MW of renewable energy, producing 110,000 t/yr of green hydrogen by 2030 as well as blending its gas pipeline network with up to 10pc hydrogen and to have more than 10,000 hydrogen vehicles on the road by the end of the decade.

"We want to be a significant hydrogen producer, not just in Australia but around the world," NSW premier Dominic Perrottet told reporters at a news conference on 13 October.

The NSW hydrogen plan follows the announcement last month that the state will deepen its greenhouse gas (GHG) emissions reduction by 50pc by 2030 from 2005 levels compared with its previous plan of a 35pc cut.

The hydrogen plan will also signal a significant shift in energy production and use, as coal-fired plants produced almost 70pc of the state's electricity in the 12 months to 17 October according to the Open NEM website. Renewables accounted for 21pc of NSW electricity supply over the same period, electricity imported from neighbouring states made up a further 7.8pc of NSW power supply and the remainder came from gas.

"Hydrogen is going to be the fuel that powers the low carbon economy. The A$3bn investment will be focused on the Hunter and the Illawarra, which futureproofs those regions," NSW treasurer and energy minister Matt Kean said at the press conference. The treasurer hopes that the government funding will stimulate private investment of between A$80bn-270bn in hydrogen related businesses by 2050.

The focus on the coal region address once of the coal industry's concerns about the energy transition. Both regions are connected to ports as well as hosts to significant power transmission infrastructure. Australia is the world's second largest thermal coal exporter, with most of these shipments from NSW. Australia is also the world's largest metallurgical coal exporter with mines in the Bowen basin region of Queensland producing the majority of the country's hard coking coal.

"The size of the hydrogen industry here in NSW will be as big by 2050 as the coal industry is now," Kean said. The NSW government hydrogen strategy announcement was also accompanied by mining entrepreneur Andrew Forrest, chairman and the largest shareholder in Australia's third biggest iron ore exporter Fortescue Metals Group.

"There will be no bigger industry than green hydrogen, green ammonia and green electricity. It will be bigger than iron ore, it will dwarf the scale of coal in our country, and to capture it here in NSW reflects that we have plenty of solar and wind resources to produce hydrogen," Forrest told reporters.

"The fossil fuel sector has had a magnificent day. The fossil fuel sector will still play an important role in years to come," he said.

NSW already has plans to expand its renewable energy supply through at least five REZs in regional areas of the state and has only released plans for two of those REZs, which will host a combined 11,000MW of installed capacity.

NSW is the latest Australian jurisdiction to unveil hydrogen plans. Fortescue Future Industries, the sustainable energy arm of Fortescue Metals, plans to build a 2,000 MW/yr hydrogen electrolyser production plant at Gladstone in Queensland, which would be the largest plant of its kind in Australia.

The Queensland state government has established a A$2bn fund to finance renewable energy and hydrogen projects in the state.

Last week, Australia's Northern Territory government released plans for an export-oriented hydrogen production hub fuelled by solar photovoltaic (PV) and battery storage.

The Australian government has already nominated the Hunter valley region as one of six national hydrogen hubs.

The NSW hydrogen plan is also an update on the state's energy plan released in November when it targeted the construction of 12,000MW of new renewable energy capacity by 2030, with most of this from wind and solar PV sources and a further 2,000MT of power storage.

By Kevin Morrison

Fortescue invests in green hydrogen, ammonia

Fortescue Future Industries (FFI), the green energy arm of Australia's third-largest iron ore producer Fortescue Metals, plans to build a hydrogen electrolyser production plant at Gladstone in Queensland and convert an ammonia production facility near Brisbane to green hydrogen.

The two major Queensland projects will reduce the carbon emissions of a state that is heavily reliant on coking and thermal coal exports for royalty income.

FFI plans to build a facility capable of producing 2GW/yr of hydrogen electrolysers at Gladstone, with first production scheduled for 2023. FFI, which is underpinned by a strong Fortescue Metals balance sheet, will make an initial investment of A$114mn ($83.5mn) with construction set to begin in February, pending final approvals. The 2GW/yr capacity facility at Gladstone will more than double current global electrolyser production, according to FFI.

Fortescue plans to use hydrogen and ammonia produced from renewable sources to allow its core iron ore business to achieve net-zero greenhouse gas emissions from customer use of its iron ore by 2040. It has committed to generating 15mn t/yr of green hydrogen by 2030, rising to 50mn t/yr by 2040.

As part of this plan it is working with Australian fertilizer and chemicals firm Incitec Pivot to study converting the 50,000 t/yr Gibson Island ammonia production facility to green hydrogen from natural gas as a feedstock. Incitec is developing the Range gas project in Queensland to supply natural gas to the fertilizer plant at Gibson Island, with the pilot beginning production at Range in June. It also has a contract to buy gas from the 9mn t/yr Australia Pacific LNG plant to meet Gibson Island's needs from 1 April 2020 through to 31 December 2022.

Incitec has struggled with volatile gas prices and threatened to close Gibson Island in May 2019 if it were unable to secure gas at an economical rate beyond December 2019. The Australian domestic gas price has not spiked in line with the ANEA LNG price and European gas prices, but it has returned to levels seen in May 2019 when Incitec threatened to close Gibson Island. The ANEA is the *Argus* assessment for spot deliveries to northeast Asia.

Argus last assessed the Wallumbilla domestic gas index in Queensland at A$9.27/GJ on 8 October, up from A$6.47/GJ six months ago but close to the A$9.44/GJ seen on 17 May 2019. The domestic price is far below the Gladstone LNG export price, which *Argus* last assessed at A$46.31/GJ, up from A$8.76/GJ six months ago.

"FFI's goal is to become the world's leading, integrated, fully renewable energy and green products company, powering the Australian economy and creating jobs for Australia as we transition away from fossil fuels. Our manufacturing arm, starting with electrolysers and expanding to all other required green industry products, will herald great potential for green manufacturing and employment in regional Australia," chief executive Julie Shuttleworth said.

Shuttleworth envisages five more stages beyond the 2GW/yr electrolyser factory at Gladstone, which will include production of wind turbines, long-range electrical cable, photovoltaic cells and associated infrastructure on the site near the key Queensland port of Gladstone.

By Jo Clarke

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 (14 Oct 2021)										*$/mn Btu*
Delivery	**10pc**	**10.5pc**	**11pc**	**11.5pc**	**12pc**	**12.5pc**	**13pc**	**13.5pc**	**14pc**	**14.5pc**
Nov	6.96	7.30	7.65	8.00	8.35	8.69	9.04	9.39	9.74	10.08
Dec	7.11	7.46	7.82	8.17	8.53	8.89	9.24	9.60	9.95	10.31
Jan	7.42	7.79	8.16	8.53	8.90	9.28	9.65	10.02	10.39	10.76
Feb	7.67	8.05	8.44	8.82	9.21	9.59	9.97	10.36	10.74	11.12
Mar	7.83	8.22	8.61	9.00	9.39	9.78	10.17	10.57	10.96	11.35
Apr	7.95	8.35	8.75	9.14	9.54	9.94	10.34	10.73	11.13	11.53
1Q22	7.64	8.02	8.40	8.78	9.17	9.55	9.93	10.32	10.69	11.08
2Q22	8.10	8.50	8.91	9.31	9.72	10.13	10.53	10.93	11.34	11.74
3Q22	8.08	8.49	8.89	9.29	9.70	10.10	10.51	10.91	11.31	11.72
4Q22	7.89	8.28	8.68	9.07	9.47	9.86	10.26	10.65	11.05	11.44
2022	7.93	8.32	8.72	9.12	9.51	9.91	10.31	10.70	11.10	11.50
2023	7.49	7.86	8.23	8.61	8.98	9.36	9.73	10.11	10.48	10.85

Oil-linked LNG on three-month crude average (301) contract (14 Oct 2021)										*$/mn Btu*
Delivery	**10pc**	**10.5pc**	**11pc**	**11.5pc**	**12pc**	**12.5pc**	**13pc**	**13.5pc**	**14pc**	**14.5pc**
Nov	7.27	7.63	7.99	8.36	8.72	9.09	9.45	9.81	10.18	10.54
Dec	7.32	7.69	8.06	8.42	8.79	9.15	9.52	9.89	10.25	10.62
Jan	7.65	8.03	8.41	8.79	9.18	9.56	9.94	10.32	10.70	11.09
Feb	8.07	8.48	8.88	9.29	9.69	10.09	10.50	10.90	11.30	11.71
Mar	8.33	8.75	9.16	9.58	10.00	10.41	10.83	11.25	11.66	12.08
Apr	8.26	8.67	9.08	9.49	9.91	10.32	10.73	11.15	11.56	11.97
1Q22	8.02	8.42	8.82	9.22	9.62	10.02	10.42	10.82	11.22	11.63
2Q22	8.18	8.59	9.00	9.41	9.82	10.23	10.63	11.05	11.45	11.86
3Q22	7.98	8.38	8.78	9.18	9.58	9.98	10.38	10.77	11.17	11.57
4Q22	7.80	8.19	8.58	8.97	9.36	9.75	10.14	10.53	10.92	11.31
2022	8.00	8.40	8.79	9.20	9.60	10.00	10.39	10.79	11.19	11.59
2023	7.41	7.78	8.15	8.52	8.89	9.27	9.63	10.00	10.38	10.75

Oil-linked LNG on three-month crude average with one month lag (311) contract (14 Oct 2021)										*$/mn Btu*
Delivery	**10pc**	**10.5pc**	**11pc**	**11.5pc**	**12pc**	**12.5pc**	**13pc**	**13.5pc**	**14pc**	**14.5pc**
Nov	7.19	7.55	7.91	8.27	8.63	8.99	9.35	9.71	10.07	10.43
Dec	7.27	7.63	7.99	8.36	8.72	9.09	9.45	9.81	10.18	10.54
Jan	7.32	7.69	8.06	8.42	8.79	9.15	9.52	9.89	10.25	10.62
Feb	7.65	8.03	8.41	8.79	9.18	9.56	9.94	10.32	10.70	11.09
Mar	8.07	8.48	8.88	9.29	9.69	10.09	10.50	10.90	11.30	11.71
Apr	8.33	8.75	9.16	9.58	10.00	10.41	10.83	11.25	11.66	12.08
1Q22	7.68	8.07	8.45	8.83	9.22	9.60	9.99	10.37	10.75	11.14
2Q22	8.26	8.67	9.08	9.49	9.91	10.32	10.73	11.15	11.56	11.97
3Q22	8.04	8.45	8.85	9.25	9.65	10.06	10.46	10.86	11.26	11.66
4Q22	7.86	8.25	8.64	9.04	9.43	9.82	10.22	10.61	11.00	11.40
2022	7.96	8.36	8.76	9.16	9.55	9.95	10.35	10.75	11.14	11.54
2023	7.46	7.83	8.21	8.58	8.95	9.33	9.70	10.07	10.44	10.82

Oil-linked LNG on previous-month crude average (101) contract (14 Oct 2021)										$/mn Btu
Delivery	10pc	10.5pc	11pc	11.5pc	12pc	12.5pc	13pc	13.5pc	14pc	14.5pc
Nov	7.05	7.40	7.76	8.11	8.46	8.81	9.17	9.52	9.87	10.22
Dec	7.49	7.86	8.24	8.61	8.99	9.36	9.73	10.11	10.48	10.86
Jan	8.40	8.82	9.24	9.66	10.08	10.50	10.92	11.34	11.76	12.18
Feb	8.33	8.75	9.17	9.58	10.00	10.42	10.83	11.25	11.67	12.08
Mar	8.26	8.67	9.08	9.49	9.91	10.32	10.73	11.15	11.56	11.97
Apr	8.18	8.59	9.00	9.40	9.81	10.22	10.63	11.04	11.45	11.86
1Q22	8.33	8.75	9.16	9.58	10.00	10.41	10.83	11.25	11.66	12.08
2Q22	8.11	8.52	8.92	9.32	9.73	10.13	10.54	10.95	11.35	11.76
3Q22	7.92	8.31	8.71	9.11	9.50	9.90	10.30	10.69	11.09	11.48
4Q22	7.74	8.13	8.52	8.90	9.29	9.68	10.06	10.45	10.84	11.22
2022	8.03	8.43	8.83	9.23	9.63	10.03	10.43	10.83	11.24	11.64
2023	7.36	7.73	8.10	8.47	8.84	9.21	9.57	9.94	10.31	10.68

Crude oil forward prices												$/bl
	Dec 2021	Jan 2022	Feb 2022	Mar 2022	Apr 2022	May 2022	Jun 2022	Jul 2022	Aug 2022	Sep 2022	Oct 2022	Nov 2022
Argus Calculated Japanese Crude Cocktail	85.49	84.44	83.58	82.87	82.23	81.61	80.99	80.40	79.82	79.25	78.68	78.13
Ice Brent (Singapore close)	84.82	84.10	83.28	82.46								
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 Nov	37.51	37.96	37.735	+1.330
	2H Nov	37.63	38.09	37.860	+1.390
	1H Dec	37.89	38.34	38.115	+1.715
	2H Dec	38.05	38.50	38.275	+2.000

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