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Energy Tidbits

Negative Tone to US NatGas Prices Thru Yr-end **<u>If</u>** Forecasts Are Right for Much Warmer Than Normal December

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Table 1. Summary of natural gas supply and disposition in the United States, 2016-2021
(billion cubic feet)

Year and Month	Gross Withdrawals	Marketed Production	NGPL Production[a]	Dry Gas Production[b]	Supplemental Gaseous Fuels[c]	Net Imports	Net Storage Withdrawals[d]	Balancing Item[e]	Consumption[f]
2016 Total	**32,592**	**28,400**	**1,808**	**26,592**	**57**	**671**	**340**	**-216**	**27,444**
2017 Total	**33,292**	**29,238**	**1,897**	**27,341**	**66**	**-121**	**254**	**-400**	**27,140**
2018 Total	**37,326**	**33,009**	**2,235**	**30,774**	**69**	**-719**	**314**	**-300**	**30,139**
2019									
January	3,377	2,975	208	2,767	5	-74	722	4	3,424
February	3,057	2,705	189	2,516	5	-97	580	16	3,019
March	3,383	3,009	210	2,798	5	-121	253	-8	2,928
April	3,315	2,926	205	2,721	5	-132	-389	7	2,212
May	3,424	3,046	213	2,833	5	-161	-480	-63	2,134
June	3,300	2,956	207	2,750	5	-159	-439	-37	2,119
July	3,396	3,072	215	2,857	5	-163	-260	-45	2,394
August	3,448	3,146	220	2,926	5	-165	-292	-40	2,434
September	3,397	3,057	214	2,843	5	-186	-427	-28	2,206
October	3,552	3,186	223	2,963	5	-215	-353	-94	2,307
November	3,509	3,134	219	2,915	5	-218	156	-74	2,784
December	3,623	3,235	226	3,009	5	-226	428	-45	3,171
Total	**40,780**	**36,447**	**2,548**	**33,899**	**61**	**-1,916**	**-503**	**-408**	**31,132**
2020									
January	3,597	3,194	240	2,954	6	-248	581	8	3,300
February	3,363	2,985	224	2,761	5	-216	545	-53	3,041
March	3,582	3,196	240	2,956	6	-284	53	-24	2,707
April	3,374	3,012	226	2,786	5	-231	-311	-8	2,241
May	3,285	2,927	220	2,707	5	-209	-454	18	2,067
June	3,217	2,873	216	2,657	5	-151	-363	-18	2,131
July	3,374	3,021	227	2,795	5	-139	-165	-7	2,489
August	3,350	3,012	226	2,786	5	-148	-232	-9	2,401
September	3,265	2,918	219	2,699	5	-221	-329	18	2,172
October	3,364	2,992	225	2,767	5	-282	-96	-74	2,320
November	3,352	2,985	224	2,761	5	-316	-6	-8	2,435
December	3,490	3,089	232	2,857	5	-287	597	-5	3,168
Total	**40,614**	**36,202**	**2,717**	**33,485**	**63**	**-2,732**	**-180**	**-164**	**30,472**
2021									
January	[E]3,506	[E]3,110	232	[E]2,878	5	-279	707	-25	3,286
February	[E]2,924	[E]2,586	171	[E]2,416	6	-152	781	-8	3,043
March	[E]3,482	[E]3,092	230	[E]2,862	5	-357	59	38	2,608
April	[E]3,409	[E]3,036	238	[E]2,798	5	-356	-174	[R]-37	[R]2,237
May	[E]3,510	[E]3,130	245	[E]2,885	3	-373	-416	-4	2,094
June	[E]3,391	[E]3,036	238	[E]2,798	5	-331	-248	[R]-11	[R]2,212
July	[RE]3,491	[RE]3,151	245	[RE]2,906	5	-338	-170	[R]-22	[R]2,382
August	[RE]3,535	[RE]3,177	[R]249	[RE]2,928	4	-342	[R]-159	[R]-25	[R]2,406
September	[E]3,418	[E]3,055	240	[E]2,815	4	-315	-390	-5	2,109
2021 9-Month YTD	**[E]30,668**	**[E]27,374**	**2,088**	**[E]25,286**	**43**	**-2,844**	**-10**	**-98**	**22,376**
2020 9-Month YTD	**30,408**	**27,137**	**2,037**	**25,101**	**47**	**-1,847**	**-675**	**-76**	**22,549**
2019 9-Month YTD	**30,096**	**26,892**	**1,880**	**25,012**	**45**	**-1,257**	**-734**	**-195**	**22,871**

[a] Monthly natural gas plant liquid (NGPL) production, gaseous equivalent, is derived from sample data reported by gas processing plants on Form EIA-816, *Monthly Natural Gas Liquids Report*, and Form EIA-64A, *Annual Report of the Origin of Natural Gas Liquids Production*.

[b] Equal to marketed production minus NGPL production.

[c] Supplemental gaseous fuels data are collected only on an annual basis except for the Dakota Gasification Co. coal gasification facility which provides data each month. The ratio of annual supplemental fuels (excluding Dakota Gasification Co.) to the sum of dry gas production, net imports, and net withdrawals from storage is calculated. This ratio is applied to the monthly sum of these three elements. The Dakota Gasification Co. monthly value is added to the result to produce the monthly supplemental fuels estimate.

[d] Monthly and annual data for 2016 through 2020 include underground storage and liquefied natural gas storage. Data for January 2021 forward include underground storage only. See Appendix A, Explanatory Note 5, for discussion of computation procedures.

[e] Represents quantities lost and imbalances in data due to differences among data sources. Net imports and balancing item excludes net intransit deliveries. These net intransit deliveries were (in billion cubic feet): -24 for 2020; -8 for 2019; -12 for 2018; 14 for 2017; and 70 for 2016. See Appendix A, Explanatory Note 7, for full discussion.

[f] Consists of pipeline fuel use, lease and plant fuel use, vehicle fuel, and deliveries to consuming sectors as shown in Table 2.

[R] Revised data.

[E] Estimated data.

[RE] Revised estimated data.

Notes: Data for 2016 through 2019 are final. All other data are preliminary unless otherwise indicated. Geographic coverage is the 50 states and the District of Columbia. Totals may not equal sum of components because of independent rounding.

Sources: 2016-2020: U.S. Energy Information Administration (EIA), *Natural Gas Annual 2020*. January 2021 through current month: Form EIA-914, *Monthly Crude Oil and Lease Condensate, and Natural Gas Production Report*; Form EIA-857, *Monthly Report of Natural Gas Purchases and Deliveries to Consumers*; Form EIA-191, *Monthly Underground Gas Storage Report*; EIA computations and estimates; and Office of Fossil Energy, *Natural Gas Imports and Exports*. See Table 7 for detailed source notes for Marketed Production. See Appendix A, Notes 3 and 4, for discussion of computation and estimation procedures and revision policies.

Table 5. U.S. natural gas exports, 2019-2021

(volumes in million cubic feet; prices in dollars per thousand cubic feet)

	2021 9-Month YTD	2020 9-Month YTD	2019 9-Month YTD	2021 September	August	July	June	May
Exports								
Volume (million cubic feet)								
Pipeline								
Canada	680,956	663,952	693,824	72,023	71,586	68,264	69,528	70,561
Mexico	1,636,486	1,474,297	1,383,853	178,326	193,270	197,141	198,329	192,625
Total Pipeline Exports	**2,317,442**	**2,138,249**	**2,077,676**	**250,349**	**264,857**	**265,405**	**267,857**	**263,186**
LNG								
Exports								
By Vessel								
Antigua and Barbuda	3	0	0	3	0	0	0	0
Argentina	81,371	15,068	39,293	1,950	14,363	22,798	19,312	16,226
Bahamas	380	165	122	43	56	46	48	45
Bangladesh	37,734	10,660	0	3,276	7,085	0	3,493	6,948
Barbados	211	184	147	33	27	31	22	19
Belgium	5,584	25,028	6,794	0	0	0	0	2,100
Brazil	231,985	29,281	47,674	38,282	34,204	39,637	32,293	19,726
Chile	109,623	60,734	73,057	7,929	16,262	19,913	0	17,598
China	340,187	88,677	6,851	48,584	51,662	42,222	42,319	37,731
Colombia	2,247	4,626	6,518	436	919	0	0	0
Croatia	23,600	0	0	0	2,980	3,299	2,923	3,364
Dominican Republic	38,726	10,036	6,906	0	5,901	1,806	4,670	5,283
Egypt	0	0	0	0	0	0	0	0
France	117,534	76,456	61,859	6,578	7,111	0	3,683	11,926
Greece	25,258	41,478	6,891	799	3,607	6,651	0	6,796
Haiti	108	81	18	10	24	8	18	12
India	167,660	86,100	70,498	23,941	20,592	13,090	16,503	28,259
Indonesia	1,118	0	0	1,118	0	0	0	0
Israel	8,906	15,834	0	2,855	0	0	0	0
Italy	34,210	65,370	49,546	0	3,401	6,826	3,425	2,923
Jamaica	22,590	12,164	8,993	2,931	2,907	0	2,927	2,925
Japan	259,037	169,147	137,532	10,290	19,979	24,895	39,783	25,058
Jordan	0	6,872	32,332	0	0	0	0	0
Kuwait	28,283	13,690	10,308	10,333	3,298	0	7,126	0
Lithuania	30,919	12,775	0	3,282	1,677	6,469	3,285	3,049
Malaysia	0	0	0	0	0	0	0	0
Malta	5,427	2,648	413	2,498	0	0	0	0
Mexico	14,112	23,954	123,965	0	0	758	0	0
Netherlands	124,999	71,969	54,401	10,424	7,347	10,597	3,030	26,611
Nicaragua	1	0	0	0	0	1	0	0
Pakistan	40,190	23,489	16,816	9,642	3,319	13,428	3,376	0
Panama	7,526	10,612	9,743	0	1,390	0	0	2,341
Poland	38,824	26,709	24,108	0	0	6,619	10,635	3,581
Portugal	40,396	23,817	40,376	3,696	6,382	3,296	5,538	10,765
Singapore	20,827	17,267	24,602	0	0	3,449	0	3,089
South Korea	350,659	213,268	164,690	31,375	50,101	39,314	55,918	46,033
Spain	124,024	162,358	119,122	31,274	23,068	8,630	7,833	5,234
Taiwan	76,788	42,042	16,865	5,789	6,728	20,653	3,097	10,157
Thailand	14,548	28,917	6,635	0	3,707	0	0	3,453
Turkey	83,713	90,952	19,281	24,176	0	5,591	0	3,017
United Arab Emirates	0	10,110	20,561	0	0	0	0	0
United Kingdom	100,781	86,087	22,391	3,099	0	0	0	10,586
By Truck								
Canada	92	2	10	19	18	16	7	18
Mexico	760	657	787	150	147	97	105	48
Re-Exports								
By Vessel								
Argentina	0	2,164	0	0	0	0	0	0
Brazil	0	0	0	0	0	0	0	0
Japan	0	305	221	0	0	0	0	0
South Korea	0	305	0	0	0	0	0	0
United Kingdom	0	0	0	0	0	0	0	0
Total LNG Exports	**2,610,939**	**1,582,055**	**1,230,325**	**284,813**	**298,262**	**300,143**	**271,368**	**314,922**
CNG								
Canada	211	296	181	NA	14	16	27	25
Total CNG Exports	**211**	**296**	**181**	NA	**14**	**16**	**27**	**25**
Total Exports	**4,928,592**	**3,720,600**	**3,308,182**	**535,162**	**563,133**	**565,564**	**539,252**	**578,132**

See footnotes at end of table.

Table 5. U.S. natural gas exports, 2019-2021

(volumes in million cubic feet; prices in dollars per thousand cubic feet) – continued

	2021				2020			
	April	March	February	January	Total	December	November	October
Exports								
Volume (million cubic feet)								
Pipeline								
Canada	74,567	91,301	78,198	84,927	902,449	84,307	81,358	72,833
Mexico	183,004	183,051	137,381	173,360	1,990,809	164,577	166,135	185,799
Total Pipeline Exports	**257,571**	**274,352**	**215,579**	**258,287**	**2,893,258**	**248,884**	**247,493**	**258,632**
LNG								
Exports								
By Vessel								
Antigua and Barbuda	0	0	0	0	0	0	0	0
Argentina	4,485	2,238	0	0	15,068	0	0	0
Bahamas	46	39	29	28	257	36	31	25
Bangladesh	10,219	3,566	0	3,148	10,660	0	0	0
Barbados	30	14	19	17	241	25	15	17
Belgium	0	3,484	0	0	31,946	0	3,633	3,285
Brazil	11,615	21,977	13,118	21,132	111,826	29,927	30,191	22,427
Chile	10,293	21,320	6,524	9,784	80,615	9,793	3,252	6,836
China	46,837	28,476	3,415	38,940	214,401	45,525	45,083	35,115
Colombia	892	0	0	0	4,626	0	0	0
Croatia	3,666	7,367	0	0	3,275	3,275	0	0
Dominican Republic	2,905	5,577	5,689	6,895	26,050	5,000	5,106	5,909
Egypt	0	0	0	0	0	0	0	0
France	36,120	33,678	14,851	3,587	90,237	3,752	3,390	6,639
Greece	0	6,805	0	600	48,403	3,382	3,543	0
Haiti	3	10	11	12	118	17	11	9
India	13,752	17,381	13,776	20,367	124,402	10,241	10,299	17,762
Indonesia	0	0	0	0	0	0	0	0
Israel	3,225	2,826	0	0	15,834	0	0	0
Italy	6,896	10,739	0	0	68,453	0	3,083	0
Jamaica	2,370	2,458	2,365	3,708	17,052	2,374	0	2,514
Japan	28,756	27,673	18,271	64,331	287,672	54,004	32,967	31,554
Jordan	0	0	0	0	6,872	0	0	0
Kuwait	3,705	3,821	0	0	17,293	0	0	3,603
Lithuania	3,078	3,228	6,851	0	28,879	6,291	3,621	6,191
Malaysia	0	0	0	0	0	0	0	0
Malta	2,928	0	0	0	2,648	0	0	0
Mexico	0	0	13,354	0	34,408	0	3,056	7,398
Netherlands	17,060	24,204	22,777	2,949	85,573	3,316	6,684	3,603
Nicaragua	0	0	0	0	0	0	0	0
Pakistan	3,323	3,421	0	3,682	36,934	0	3,436	10,009
Panama	0	3,279	0	516	12,764	271	1,448	433
Poland	7,382	3,507	7,099	0	36,900	7,033	0	3,157
Portugal	7,358	0	3,360	0	36,922	3,711	5,830	3,564
Singapore	7,297	3,303	0	3,688	28,341	0	7,658	3,416
South Korea	21,683	32,203	18,094	55,936	316,227	39,617	49,103	14,239
Spain	22,974	13,900	3,733	7,377	199,966	13,583	9,907	14,118
Taiwan	6,594	13,450	0	10,319	64,363	12,470	6,216	3,636
Thailand	7,388	0	0	0	32,622	0	3,705	0
Turkey	0	3,619	20,652	26,659	123,957	20,188	12,817	0
United Arab Emirates	0	0	0	0	10,110	0	0	0
United Kingdom	13,877	17,440	34,343	21,436	160,199	30,378	26,544	17,191
By Truck								
Canada	15	0	0	0	10	8	0	0
Mexico	48	19	63	83	822	46	52	68
Re-Exports								
By Vessel								
Argentina	0	0	0	0	2,164	0	0	0
Brazil	0	0	0	0	82	0	0	82
Japan	0	0	0	0	387	0	0	82
South Korea	0	0	0	0	387	0	0	82
United Kingdom	0	0	0	0	0	0	0	0
Total LNG Exports	**306,818**	**321,023**	**208,394**	**305,196**	**2,389,963**	**304,263**	**280,682**	**222,963**
CNG								
Canada	29	36	32	32	386	29	35	26
Total CNG Exports	**29**	**36**	**32**	**32**	**386**	**29**	**35**	**26**
Total Exports	**564,418**	**595,411**	**424,004**	**563,515**	**5,283,607**	**553,176**	**528,210**	**481,621**

See footnotes at end of table.

Table 5. U.S. natural gas exports, 2019-2021

(volumes in million cubic feet; prices in dollars per thousand cubic feet) – continued

								2020
	September	August	July	June	May	April	March	February
Exports								
Volume (million cubic feet)								
Pipeline								
Canada	62,211	60,810	71,778	66,516	67,752	71,722	86,579	77,354
Mexico	182,068	185,867	181,152	162,927	145,242	138,544	166,550	151,071
Total Pipeline Exports	**244,279**	**246,677**	**252,930**	**229,442**	**212,994**	**210,266**	**253,130**	**228,425**
LNG								
Exports								
By Vessel								
Antigua and Barbuda	0	0	0	0	0	0	0	0
Argentina	0	2,249	2,218	2,229	8,372	0	0	0
Bahamas	20	21	15	18	20	23	20	13
Bangladesh	0	0	3,614	0	3,406	0	0	0
Barbados	14	14	15	20	20	15	28	26
Belgium	0	0	0	0	1,348	3,324	3,724	9,872
Brazil	0	3,520	0	0	0	0	6,891	10,433
Chile	3,277	7,428	1,515	3,313	11,068	14,098	3,216	10,731
China	11,245	13,699	10,358	0	14,535	21,140	17,699	0
Colombia	2,548	550	0	0	0	0	0	1,003
Croatia	0	0	0	0	0	0	0	0
Dominican Republic	0	2,772	0	0	2,554	1,838	2,872	0
Egypt	0	0	0	0	0	0	0	0
France	0	0	0	0	9,546	16,336	23,491	20,520
Greece	7,027	0	6,544	1,076	3,430	3,233	8,892	0
Haiti	8	11	8	7	10	8	9	11
India	10,514	10,319	7,404	10,100	10,534	16,674	17,245	0
Indonesia	0	0	0	0	0	0	0	0
Israel	3,041	3,001	3,317	3,277	0	0	3,197	0
Italy	0	6,734	3,232	12,998	6,452	3,135	9,895	16,616
Jamaica	2,610	0	0	0	0	5,770	1	2,914
Japan	6,855	22,541	10,618	21,836	13,729	18,387	21,845	21,360
Jordan	3,578	0	0	0	3,294	0	0	0
Kuwait	3,508	6,886	0	0	0	3,297	0	0
Lithuania	3,308	0	0	3,049	3,473	2,945	0	0
Malaysia	0	0	0	0	0	0	0	0
Malta	0	0	0	0	0	0	0	48
Mexico	3,285	3,701	0	0	0	0	7,037	3,167
Netherlands	6,671	0	6,746	6,870	6,826	10,305	13,772	14,099
Nicaragua	0	0	0	0	0	0	0	0
Pakistan	9,853	3,412	0	0	0	3,334	0	3,567
Panama	3,228	0	0	0	3,070	0	906	3,408
Poland	0	0	0	3,385	6,258	3,523	3,583	6,677
Portugal	6,853	0	0	0	0	10,777	0	6,187
Singapore	0	2,967	3,690	0	0	0	10,610	0
South Korea	32,126	13,814	10,492	28,171	20,921	24,258	28,095	11,071
Spain	15,206	3,222	13,679	9,640	29,360	22,943	23,657	20,240
Taiwan	9,007	0	0	2,953	6,662	0	6,987	7,115
Thailand	0	0	3,254	0	7,397	11,049	3,783	3,435
Turkey	3,611	0	3,222	0	6,661	14,030	6,489	24,303
United Arab Emirates	0	3,359	3,277	0	3,474	0	0	0
United Kingdom	3,664	0	2,908	0	0	0	20,202	28,884
By Truck								
Canada	0	0	0	0	0	0	0	0
Mexico	73	78	72	61	18	23	123	87
Re-Exports								
By Vessel								
Argentina	0	2,164	0	0	0	0	0	0
Brazil	0	0	0	0	0	0	0	0
Japan	0	0	0	0	0	0	0	0
South Korea	0	0	0	0	0	0	0	0
United Kingdom	0	0	0	0	0	0	0	0
Total LNG Exports	**151,128**	**112,462**	**96,200**	**109,002**	**182,438**	**210,466**	**244,269**	**225,786**
CNG								
Canada	17	20	37	43	39	35	38	34
Total CNG Exports	**17**	**20**	**37**	**43**	**39**	**35**	**38**	**34**
Total Exports	**395,424**	**359,159**	**349,167**	**338,486**	**395,472**	**420,767**	**497,437**	**454,245**

See footnotes at end of table.

Table 5. U.S. natural gas exports, 2019-2021

(volumes in million cubic feet; prices in dollars per thousand cubic feet) – continued

	2020	2019						
	January	Total	December	November	October	September	August	July
Exports								
Volume (million cubic feet)								
Pipeline								
Canada	99,231	972,519	109,779	92,671	76,246	71,573	78,302	68,613
Mexico	160,875	1,865,329	151,308	158,633	171,535	162,649	168,089	167,902
Total Pipeline Exports	**260,106**	**2,837,848**	**261,086**	**251,305**	**247,781**	**234,222**	**246,391**	**236,515**
LNG								
Exports								
By Vessel								
Antigua and Barbuda	0	0	0	0	0	0	0	0
Argentina	0	39,293	0	0	0	0	0	13,066
Bahamas	15	156	11	14	8	2	20	11
Bangladesh	3,640	3,419	3,419	0	0	0	0	0
Barbados	33	211	20	20	25	17	17	17
Belgium	6,761	23,897	10,407	3,293	3,402	3,404	0	0
Brazil	8,438	54,298	0	3,279	3,345	6,117	12,868	6,949
Chile	6,087	90,357	7,207	3,484	6,608	9,811	6,297	9,382
China	0	6,851	0	0	0	0	0	0
Colombia	525	6,518	0	0	0	0	649	0
Croatia	0	0	0	0	0	0	0	0
Dominican Republic	0	10,334	501	0	2,927	2,857	0	0
Egypt	0	0	0	0	0	0	0	0
France	6,563	117,791	14,758	26,946	14,228	6,740	3,249	0
Greece	11,276	14,643	7,752	0	0	0	0	0
Haiti	7	42	12	8	4	9	3	2
India	3,309	91,481	7,090	6,933	6,961	14,355	7,294	3,485
Indonesia	0	0	0	0	0	0	0	0
Israel	0	0	0	0	0	0	0	0
Italy	6,308	68,655	12,764	6,345	0	3,230	6,082	9,963
Jamaica	869	13,892	2,435	2,464	0	0	2,946	837
Japan	31,975	200,864	21,226	17,603	24,504	28,084	17,506	21,242
Jordan	0	32,332	0	0	0	3,616	3,277	3,449
Kuwait	0	10,308	0	0	0	0	3,401	3,405
Lithuania	0	3,455	3,455	0	0	0	0	0
Malaysia	0	3,698	0	3,698	0	0	0	0
Malta	2,600	413	0	0	0	0	0	0
Mexico	6,764	143,371	9,696	3,273	6,437	10,442	13,681	24,209
Netherlands	6,681	81,361	13,405	10,099	3,456	3,431	6,688	3,386
Nicaragua	0	0	0	0	0	0	0	0
Pakistan	3,323	26,935	3,400	3,247	3,472	6,512	0	3,656
Panama	0	10,221	0	478	0	0	0	0
Poland	3,282	38,042	7,013	3,432	3,489	0	3,537	3,694
Portugal	0	53,342	6,345	0	6,621	2,924	6,051	6,994
Singapore	0	31,440	3,375	0	3,463	0	0	3,570
South Korea	44,320	270,025	38,139	24,962	42,233	10,818	16,995	32,663
Spain	24,412	166,684	13,874	19,985	13,704	37,938	15,861	3,297
Taiwan	9,317	27,397	3,658	3,736	3,138	0	7,207	0
Thailand	0	6,635	0	0	0	3,234	0	0
Turkey	32,637	30,611	536	7,266	3,528	0	0	0
United Arab Emirates	0	20,561	0	0	0	3,325	3,502	3,487
United Kingdom	30,428	118,357	29,749	39,957	26,260	3,303	1,335	0
By Truck								
Canada	2	25	0	1	14	9	0	0
Mexico	122	1,105	93	86	139	95	113	101
Re-Exports								
By Vessel								
Argentina	0	0	0	0	0	0	0	0
Brazil	0	0	0	0	0	0	0	0
Japan	305	221	0	0	0	0	0	0
South Korea	305	0	0	0	0	0	0	0
United Kingdom	0	305	305	0	0	0	0	0
Total LNG Exports	**250,305**	**1,819,547**	**220,646**	**190,610**	**177,966**	**160,274**	**138,578**	**156,865**
CNG								
Canada	33	263	25	30	28	15	15	20
Total CNG Exports	**33**	**263**	**25**	**30**	**28**	**15**	**15**	**20**
Total Exports	**510,444**	**4,657,657**	**481,757**	**441,944**	**425,775**	**394,511**	**384,983**	**393,400**

See footnotes at end of table.

Table 5

Table 5. U.S. natural gas exports, 2019-2021
(volumes in million cubic feet; prices in dollars per thousand cubic feet) – continued

	2019					
	June	May	April	March	February	January
Exports						
Volume (million cubic feet)						
Pipeline						
Canada	61,809	70,182	71,333	93,182	91,561	87,269
Mexico	156,440	153,452	139,750	149,514	135,514	150,544
Total Pipeline Exports	**218,249**	**223,633**	**211,083**	**242,696**	**227,074**	**237,813**
LNG						
Exports						
By Vessel						
Antigua and Barbuda	0	0	0	0	0	0
Argentina	13,120	8,737	4,369	0	0	0
Bahamas	25	14	14	11	14	11
Bangladesh	0	0	0	0	0	0
Barbados	13	21	17	14	14	17
Belgium	0	0	0	3,390	0	0
Brazil	9,116	4,905	1,201	3,283	3,234	0
Chile	19,012	6,188	9,429	10,005	2,933	0
China	0	0	0	0	3,464	3,387
Colombia	0	0	0	2,935	0	2,934
Croatia	0	0	0	0	0	0
Dominican Republic	1,108	0	0	0	2,942	0
Egypt	0	0	0	0	0	0
France	0	6,621	17,092	20,853	0	7,303
Greece	0	3,497	0	0	3,394	0
Haiti	3	0	2	0	0	0
India	3,215	13,942	6,742	7,446	6,989	7,030
Indonesia	0	0	0	0	0	0
Israel	0	0	0	0	0	0
Italy	3,072	6,560	0	6,684	3,454	10,502
Jamaica	0	2,890	0	2,320	0	0
Japan	14,582	7,149	14,010	7,143	10,320	17,495
Jordan	7,342	7,332	3,622	0	3,695	0
Kuwait	0	3,502	0	0	0	0
Lithuania	0	0	0	0	0	0
Malaysia	0	0	0	0	0	0
Malta	0	0	413	0	0	0
Mexico	16,955	20,244	10,406	7,038	6,681	14,310
Netherlands	3,310	10,734	13,010	10,452	3,390	0
Nicaragua	0	0	0	0	0	0
Pakistan	0	0	0	3,282	3,365	0
Panama	3,282	0	0	3,191	3,269	0
Poland	0	0	3,414	3,701	0	9,762
Portugal	6,908	0	3,489	0	3,720	10,289
Singapore	3,435	3,397	320	6,631	7,249	0
South Korea	20,402	18,069	13,000	18,013	17,750	16,981
Spain	13,506	14,325	10,139	10,678	6,748	6,631
Taiwan	0	3,309	6,349	0	0	0
Thailand	0	3,401	0	0	0	0
Turkey	0	0	2,969	0	6,483	9,829
United Arab Emirates	3,459	0	6,787	0	0	0
United Kingdom	0	0	0	3,669	3,711	10,373
By Truck						
Canada	0	0	0	0	1	0
Mexico	92	75	87	73	48	104
Re-Exports						
By Vessel						
Argentina	0	0	0	0	0	0
Brazil	0	0	0	0	0	0
Japan	0	0	221	0	0	0
South Korea	0	0	0	0	0	0
United Kingdom	0	0	0	0	0	0
Total LNG Exports	**141,956**	**144,913**	**127,102**	**130,814**	**102,866**	**126,957**
CNG						
Canada	20	22	28	29	15	16
Total CNG Exports	**20**	**22**	**28**	**29**	**15**	**16**
Total Exports	**360,226**	**368,568**	**338,213**	**373,539**	**329,954**	**364,787**

See footnotes at end of table.

Table 7

Table 7. Marketed production of natural gas in selected states and the Federal Gulf of Mexico, 2016-2021
(million cubic feet)

Year and Month	Alaska	Arkansas	California	Colorado	Kansas	Louisiana	Montana	New Mexico	North Dakota	Ohio
2016 Total	**332,749**	**823,196**	**205,025**	**1,685,755**	**244,795**	**1,784,396**	**47,921**	**1,229,647**	**531,997**	**1,437,285**
2017 Total	**344,385**	**694,676**	**212,458**	**1,706,364**	**219,639**	**2,139,830**	**46,311**	**1,299,732**	**593,998**	**1,791,359**
2018 Total	**341,315**	**589,985**	**202,617**	**1,847,402**	**201,391**	**2,832,404**	**43,530**	**1,493,082**	**706,552**	**2,403,382**
2019										
January	30,503	47,443	16,800	165,594	16,055	259,311	3,773	137,940	67,591	213,280
February	26,728	42,219	15,513	148,543	14,237	242,076	3,095	128,351	58,573	192,640
March	29,346	46,211	16,922	164,062	15,820	266,649	3,508	144,805	68,542	213,280
April	28,816	44,455	16,548	161,046	15,613	259,749	3,552	142,454	67,985	207,990
May	29,028	44,906	16,754	166,110	14,898	270,060	3,817	147,013	70,266	214,923
June	26,889	42,702	16,254	162,072	15,559	265,302	3,757	142,093	65,406	207,990
July	25,348	43,852	16,890	165,821	15,695	277,490	3,783	149,002	70,039	235,476
August	22,876	43,505	16,969	166,581	15,637	276,362	3,739	153,633	75,266	235,476
September	24,494	41,798	16,262	161,977	15,039	266,639	3,675	151,917	72,439	227,880
October	27,409	43,093	16,228	174,304	15,151	275,520	3,617	157,544	78,027	236,778
November	28,256	41,738	15,659	172,088	14,439	270,668	3,559	154,545	77,473	229,140
December	29,669	42,834	16,024	178,720	14,945	282,493	3,660	159,790	79,218	236,778
Total	**329,361**	**524,757**	**196,823**	**1,986,916**	**183,087**	**3,212,318**	**43,534**	**1,769,086**	**850,826**	**2,651,631**
2020										
January	30,018	42,187	15,908	178,066	14,623	274,755	3,527	162,016	78,798	203,701
February	28,537	39,093	14,649	166,620	13,636	255,885	3,340	155,323	77,940	190,559
March	29,219	43,677	15,376	175,202	14,486	276,544	3,527	169,244	83,892	203,701
April	27,513	39,748	14,906	168,438	13,595	264,869	3,148	156,722	72,059	193,050
May	27,076	40,463	15,172	163,768	14,012	281,636	2,692	147,782	52,874	199,485
June	25,545	38,742	14,837	159,601	13,321	264,072	2,667	153,276	52,626	193,050
July	26,779	39,855	15,061	167,105	13,674	264,875	3,322	165,335	64,860	201,686
August	26,846	40,295	13,344	165,091	13,504	260,226	3,248	168,311	74,940	201,686
September	26,978	38,734	12,857	162,531	13,030	255,690	3,009	165,008	78,195	195,180
October	29,080	40,172	13,059	164,462	13,461	263,120	3,204	171,376	82,649	201,097
November	29,575	38,565	12,934	159,409	12,917	267,312	3,143	167,213	80,112	194,610
December	31,161	39,452	12,475	160,168	13,097	277,178	3,135	166,561	83,498	201,097
Total	**338,329**	**480,982**	**170,579**	**1,990,462**	**163,356**	**3,206,163**	**37,963**	**1,948,168**	**882,443**	**2,378,902**
2021										
January	31,632	E39,964	E12,033	E159,820	E12,578	E271,751	E3,214	E179,574	E77,021	E206,660
February	28,365	E30,061	E10,749	E143,416	E9,965	E221,051	E2,790	E151,970	E65,685	E170,668
March	31,481	E39,947	E12,028	E156,534	E12,340	E281,406	E3,144	E187,274	E77,032	E189,405
April	29,514	E37,926	E11,685	E156,009	E12,316	E276,931	E3,096	E184,890	E76,209	E183,444
May	29,005	E38,775	E12,215	E162,200	E12,648	E284,347	E3,226	E196,174	E80,479	E187,668
June	27,715	E37,125	E11,787	E154,405	E12,276	E272,759	E2,932	E190,003	E78,111	E183,602
July	26,280	RE38,273	RE12,014	RE160,065	RE12,780	RE284,504	RE3,151	RE201,572	RE79,150	E189,223
August	27,864	RE37,981	RE11,922	RE158,359	RE12,777	RE288,615	RE3,182	RE205,996	RE81,589	E188,369
September	28,534	E36,711	E11,504	E152,986	E12,403	E286,623	E3,141	E203,126	E80,501	E181,012
2021 9-Month YTD	**260,391**	**E336,764**	**E105,937**	**E1,403,794**	**E110,082**	**E2,467,987**	**E27,878**	**E1,700,580**	**E695,777**	**E1,680,052**
2020 9-Month YTD	**248,513**	**362,793**	**132,110**	**1,506,423**	**123,881**	**2,398,553**	**28,481**	**1,443,018**	**636,185**	**1,782,098**
2019 9-Month YTD	**244,027**	**397,092**	**148,912**	**1,461,805**	**138,553**	**2,383,638**	**32,698**	**1,297,207**	**616,108**	**1,948,935**

See footnotes at end of table.

Table 7. Marketed production of natural gas in selected states and the Federal Gulf of Mexico, 2016-2021

(million cubic feet) – continued

Year and Month	Oklahoma	Pennsylvania	Texas	Utah	West Virginia	Wyoming	Other States	Federal Gulf of Mexico	U.S. Total
2016 Total	**2,468,312**	**5,210,209**	**7,225,472**	**365,268**	**1,384,458**	**1,662,909**	**559,985**	**1,200,669**	**28,400,049**
2017 Total	**2,513,897**	**5,453,638**	**7,223,841**	**315,211**	**1,514,278**	**1,590,059**	**517,698**	**1,060,452**	**29,237,825**
2018 Total	**2,875,787**	**6,264,832**	**8,041,010**	**295,826**	**1,771,698**	**1,637,517**	**485,675**	**974,863**	**33,008,867**
2019									
January	255,006	576,440	737,375	23,148	169,050	125,391	39,987	90,143	2,974,830
February	229,666	519,802	678,066	21,007	154,910	117,653	35,427	76,743	2,705,249
March	250,919	578,820	758,646	23,266	171,516	125,044	39,436	92,017	3,008,808
April	250,314	560,062	727,527	22,751	167,816	123,615	38,348	87,201	2,925,844
May	266,014	571,803	781,002	23,531	171,305	128,320	38,958	87,738	3,046,445
June	243,339	556,708	766,761	22,780	174,784	124,341	37,968	81,599	2,956,304
July	254,709	583,186	804,899	22,987	180,524	116,782	38,381	66,834	3,071,698
August	257,498	585,405	837,459	23,261	181,927	120,984	38,570	91,237	3,146,384
September	256,073	568,646	798,191	22,080	181,334	126,696	37,301	84,094	3,056,535
October	261,454	589,800	828,390	22,559	201,814	130,259	37,566	86,636	3,186,150
November	251,153	597,779	815,089	21,869	196,055	123,894	36,861	83,661	3,133,926
December	259,905	608,342	845,084	22,570	204,178	125,876	37,220	87,441	3,234,746
Total	**3,036,052**	**6,896,792**	**9,378,489**	**271,808**	**2,155,214**	**1,488,854**	**456,024**	**1,015,343**	**36,446,918**
2020									
January	263,734	603,836	843,432	21,944	209,896	124,274	37,391	86,071	3,194,177
February	243,139	569,721	783,094	20,373	198,090	108,722	34,782	81,114	2,984,616
March	257,387	607,689	841,347	21,765	210,559	117,977	36,689	87,955	3,196,236
April	235,642	586,955	783,283	20,379	204,826	111,744	34,389	80,574	3,011,842
May	217,154	592,126	734,176	20,326	212,646	107,288	33,986	64,374	2,927,037
June	222,324	560,390	741,401	19,244	212,831	103,890	32,957	62,227	2,873,001
July	226,843	604,716	775,851	20,312	220,032	108,679	34,568	67,778	3,021,331
August	226,344	607,221	782,436	19,814	223,208	107,320	33,757	43,988	3,011,580
September	222,010	567,029	755,253	19,283	218,893	104,520	30,468	48,900	2,917,569
October	219,403	595,653	773,720	20,042	226,064	104,787	31,775	38,702	2,991,827
November	224,327	605,244	751,562	19,200	223,428	103,236	31,246	60,496	2,984,528
December	228,057	647,714	770,555	19,307	231,845	103,933	32,383	67,085	3,088,701
Total	**2,786,366**	**7,148,295**	**9,336,110**	**241,989**	**2,592,319**	**1,306,368**	**404,391**	**789,262**	**36,202,446**
2021									
January	[E]221,544	[E]657,704	[E]774,497	[E]19,235	[E]234,432	[E]106,649	[E]33,651	[E]68,393	[E]3,110,352
February	[E]163,094	[E]585,221	[E]588,035	[E]17,815	[E]208,571	[E]96,543	[E]30,083	[E]62,325	[E]2,586,408
March	[E]220,130	[E]647,681	[E]771,346	[E]20,356	[E]227,218	[E]107,236	[E]34,338	[E]72,867	[E]3,091,762
April	[E]214,334	[E]618,509	[E]775,796	[E]19,861	[E]229,075	[E]103,470	[E]33,044	[E]69,696	[E]3,035,804
May	[E]223,372	[E]640,431	[E]798,311	[E]20,312	[E]234,118	[E]105,441	[E]33,844	[E]67,642	[E]3,130,208
June	[E]213,314	[E]621,905	[E]781,294	[E]19,587	[E]227,987	[E]100,983	[E]32,490	[E]67,779	[E]3,036,055
July	[RE]221,002	[RE]642,894	[RE]821,587	[RE]20,363	[E]229,376	[RE]104,558	[E]33,626	[RE]70,488	[RE]3,150,909
August	[RE]222,335	[RE]655,365	[RE]824,845	[RE]20,333	[E]241,426	[RE]101,915	[RE]33,126	[RE]61,040	[RE]3,177,040
September	[E]216,884	[E]633,786	[E]802,142	[E]19,838	[E]216,845	[E]101,978	[E]31,830	[E]35,377	[E]3,055,221
2021 9-Month YTD	**[E]1,916,011**	**[E]5,703,496**	**[E]6,937,852**	**[E]177,701**	**[E]2,049,048**	**[E]928,771**	**[E]296,032**	**[E]575,607**	**[E]27,373,759**
2020 9-Month YTD	**2,114,578**	**5,299,684**	**7,040,273**	**183,440**	**1,910,982**	**994,413**	**308,987**	**622,980**	**27,137,389**
2019 9-Month YTD	**2,263,539**	**5,100,872**	**6,889,925**	**204,810**	**1,553,167**	**1,108,825**	**344,377**	**757,605**	**26,892,096**

[E] Estimated data.

[RE] Revised estimated data.

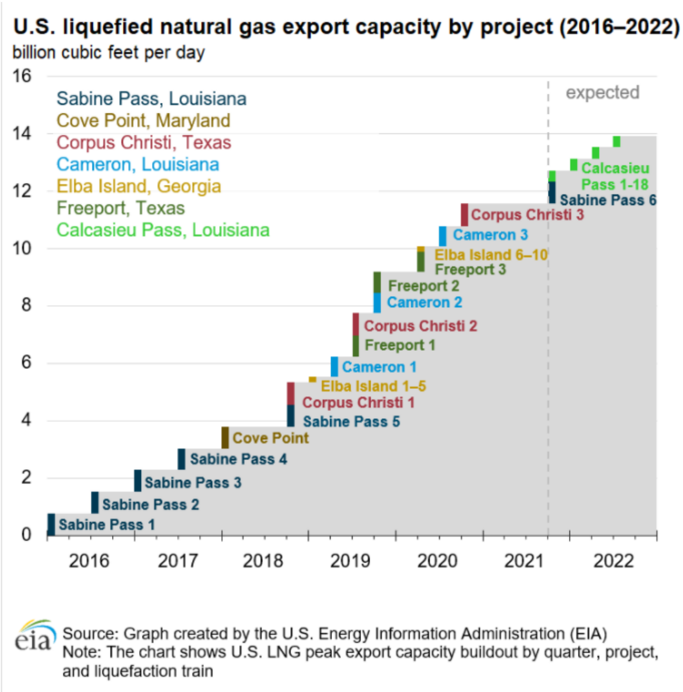
Notes: For 2021 forward, state monthly marketed production is estimated from gross withdrawals using historical relationships between the two. Data for Arkansas, California, Colorado, Kansas, Louisiana, Montana, New Mexico, North Dakota, Ohio, Oklahoma, Pennsylvania, Texas, Utah, West Virginia, Wyoming, and Federal Offshore Gulf of Mexico are individually collected on the EIA-914 report. The "Other States" category comprises states/areas not individually collected on the EIA-914 report (Alabama, Arizona, Federal Offshore Pacific, Florida, Idaho, Illinois, Indiana, Kentucky, Maryland, Michigan, Mississippi, Missouri, Nebraska, Nevada, New York, Oregon, South Dakota, Tennessee, and Virginia). Before 2021, Federal Offshore Pacific is included in California. All data for Alaska are obtained directly from the state. Monthly preliminary state-level data for all states not collected individually on the EIA-914 report are available after the final annual reports for these series are collected and processed. Final annual data are generally available in the third quarter of the following year. The sum of individual states may not equal total U.S. volumes due to independent rounding.

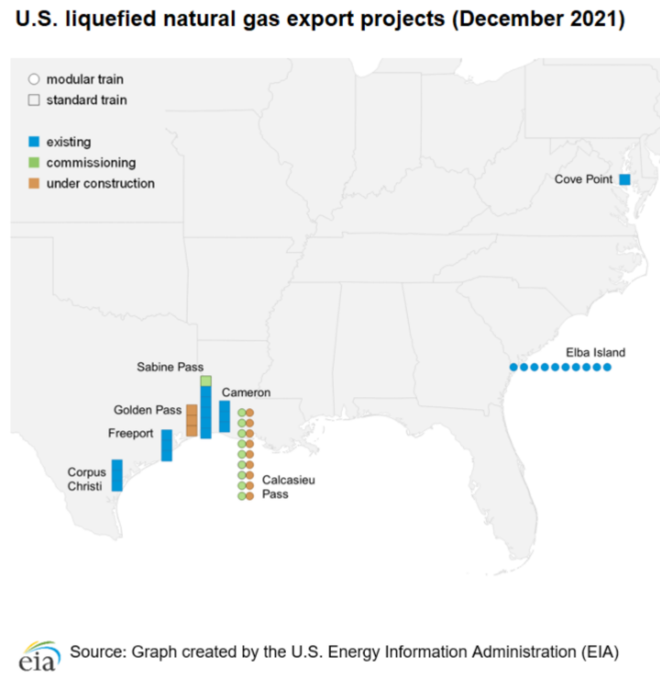
Sources: 2016-2020: U.S. Energy Information Administration (EIA), *Natural Gas Annual 2020*, Bureau of Safety and Environmental Enforcement (BSEE), IHS Markit, Enverus DrillingInfo, and BENTEK Energy. January 2021 through current month: Form EIA-914, *Monthly Crude Oil and Lease Condensate, and Natural Gas Production Report*; and EIA computations.

https://www.eia.gov/naturalgas/weekly/

Natural Gas Weekly Update - On completion of planned projects, U.S. LNG export capacity will be the world's largest in 2022

for week ending December 1, 2021 | **Release date:** December 2, 2021 | **Next release:** December 9, 2021 | Previous weeks





In the News:

On completion of planned projects, U.S. LNG export capacity will be the world's largest in 2022

Since exports of liquefied natural gas (LNG) began from the Lower 48 states in February 2016, U.S. LNG export capacity has grown rapidly. Within four years, the United States became the world's third-largest LNG exporter behind only Australia and Qatar. Once the new LNG liquefaction units (called trains) at Sabine Pass LNG and Calcasieu Pass LNG are placed in service in 2022, U.S. LNG export capacity will become the world's largest.

According to announced project plans, the following U.S. LNG export capacity expansions will occur between December 2021 and fall 2022:

- **Completion of Train 6 at the Sabine Pass LNG export facility.** Train 6 will add up to 0.76 billion cubic feet per day (Bcf/d) of peak export capacity. Train 6 began producing LNG in late November and the first export cargo from this train is expected to be shipped before the end of this year.
- **Increase in LNG production at Sabine Pass and Corpus Christi LNG terminals as a result of optimizing operations.** The U.S. Federal Energy Regulatory Commission (FERC) approved an increase in annual LNG production at these two facilities by a combined 261 billion cubic feet per year (Bcf/y) or 0.7 Bcf/d (11.5%) through uprates and modifications to maintenance. Individually:
  - FERC granted approval to increase LNG production at Sabine Pass LNG from 1,509 Bcf/y to 1,662 Bcf/y across six liquefaction trains, an increase of 10%.
  - FERC approved an LNG production increase at Corpus Christi LNG from 767 Bcf/y to 875 Bcf/y across three trains currently in operation, an increase of 14%.
- **New LNG export facility Calcasieu Pass LNG in Louisiana comes online.** The project consists of 9 blocks, each containing 2 mid-scale modular liquefaction units for a total of 18 liquefaction units with a combined peak capacity of 1.6 Bcf/d. Commissioning activities at Calcasieu Pass LNG started in November 2021, and the first LNG production is expected before the end of this year. All units are expected to be placed in service by the fourth quarter of 2022.

We estimate that as of November 2021, existing U.S. LNG nominal baseload liquefaction capacity was 9.5 Bcf/d and peak capacity was 11.6 Bcf/d (which includes uprates to LNG production capacity at Sabine Pass and Corpus Christi). By the end of 2022, U.S. nominal capacity will increase to 11.4 Bcf/d and peak capacity to 13.9 Bcf/d across 7 LNG export facilities and 44 liquefaction trains, including 16 full-scale, 18 mid-scale, and 10 small-scale trains at Sabine Pass, Cove Point, Corpus Christi, Cameron, Elba Island, Freeport, and Calcasieu Pass. In 2022, U.S. LNG export capacity will exceed that of the two current largest global LNG exporters, Australia (11.4 Bcf/d) and Qatar (10.3 Bcf/d). By 2024, when Golden Pass LNG—the eighth U.S. LNG export facility—completes construction and begins operations, U.S. LNG peak export capacity will further increase to an estimated 16.3 Bcf/d.

In addition, FERC and the U.S. Department of Energy have approved another 10 U.S. LNG export projects and capacity expansions at 3 existing LNG terminals—Cameron, Freeport, and Corpus Christi—totaling 25 Bcf/d of new capacity. Developers of some of these projects announced plans to make a final investment decision (FID) in 2022.

https://www.spglobal.com/platts/en/market-insights/latest-news/lng/111121-cheniere-to-supply-lng-from-texas-export-facility-under-new-deal-with-frances-engie

- **LNG | NATURAL GAS**

- 11 Nov 2021 | 23:52 UTC

Cheniere to supply LNG from Texas export facility under new deal with France's Engie

HIGHLIGHTS

Previously undisclosed 11-year agreement signed in June

Up to 1.2 million mt/year to be delivered FOB: US DOE letter

- Author Harry Weber
- **United States**

Cheniere Energy reached a medium-term supply deal over the summer with French utility Engie tied to the US LNG exporter's Corpus Christi Liquefaction terminal in Texas, according to a recently released letter to the US Department of Energy that was previously filed under seal.

Under the terms of the 11-year sale and purchase agreement, a range of approximately 0.4-1.2 million mt/year of LNG is to be delivered to Engie free on board from the Cheniere terminal.

The transaction, between Cheniere's marketing unit and Engie, was reached June 23, according to the letter, dated July 23. The terms of the contract, beyond its length, volume and delivery basis, were not disclosed in the letter. The contract was to begin in 2021, though the letter did not say exactly when. Cheniere did not publicly announce the transaction at the time it was reached. A spokesperson declined to comment Nov. 11 when reached by phone.

Cheniere also operates an export facility at Sabine Pass in Louisiana. It expects to sanction in 2022 construction of an up to 10 million mt/year midscale liquefaction expansion at the site of its Texas facility.

Fixed-price term commercial activity among several US LNG exporters and developers -- most notably Cheniere and Venture Global LNG -- has picked up in recent months, amid high spot LNG prices in destination markets in Europe and Asia.

Cheniere has also signed supply deals this year with Canada's Tourmaline, a subsidiary of Swiss commodity trader Glencore, China's Sinochem and an affiliate of China's ENN Natural Gas. Each of those deals was announced by Cheniere at the time it was reached.

In 2015, Cheniere announced that its marketing unit had signed a five-year deal with Engie for the delivery of LNG cargoes on an ex-ship basis primarily to the Montoir de Bretagne LNG regasification terminal in France. That SPA covered the delivery of up to 12 cargoes per year from 2018 to 2023, with the volumes linked to Northern European indexes.

In November 2020, Engie said it had halted talks with NextDecade about a supply deal tied to NextDecade's proposed Rio Grande LNG export facility in South Texas, amid pressure that European utilities face from environmental interests to refrain from signing new long-term deals for importing US shale gas.

Asian LNG Buyers Abruptly Change and Lock in Long Term Supply – Validates Supply Gap, Provides Support For Brownfield LNG FIDs

Posted 11am on July 14, 2021

The last 7 days has shown there is a sea change as Asian LNG buyers have made an abrupt change in their LNG contracting and are moving to lock in long term LNG supply. This is the complete opposite of what they were doing pre-Covid when they were trying to renegotiate Qatar LNG long term deals lower and moving away from long term deals to spot/short term sales. Why? We think they did the same math we did in our April 28 blog "*Multiple Brownfield LNG FIDs Now Needed To Fill New LNG Supply Gap From Mozambique Chaos? How About LNG Canada Phase 2?*" and saw a much bigger and sooner LNG supply gap driven by the delay of 5 bcf/d of Mozambique LNG that was built into most, if not all LNG supply forecasts. Asian LNG buyers are committing real dollars to long term LNG deals, which we believe is the best validation for the LNG supply gap. Another validation, Shell, Total and others are aggressively competing to invest long term capital to partner in Qatar Petroleum's massive 4.3 bcf/d LNG expansion despite plans to reduce fossil fuels production in the 2020s. And even more importantly to LNG suppliers, the return to long term LNG contracts provides the financing capacity to commit to brownfield LNG FIDs. The abrupt change by Asian LNG buyers to long term contracts is a game changer for LNG markets and sets the stage for brownfield LNG FIDs likely as soon as before year end 2021. It has to be brownfield LNG FIDs if the gap is coming bigger and sooner. And we return to our April 28 blog point, if brownfield LNG is needed, what about Shell looking at 1.8 bcf/d brownfield LNG Canada Phase 2? LNG Canada Phase 1 at 1.8 bcf/d capacity is already a material positive for Cdn natural gas producers. A FID on LNG Canada Phase 2 would be huge, meaning 3.6 bcf/d of Cdn natural gas will be tied to Asian LNG markets and not competing in the US against Henry Hub. And with a much shorter distance to Asian LNG markets. This is why we focus on global LNG markets for our views on the future value of Canadian natural gas.

<u>Sea change in Asian LNG buyers is also the best validation of the LNG supply gap and big to LNG supply FIDs.</u> Has the data changed or have the market participants changed in how they react to the data? We can't recall exactly who said that on CNBC on July 12, it's a question we always ask ourselves. In the LNG case, the data has changed with Mozambique LNG delays and that has directly resulted in market participants changing and entering into long term contracts. We can't stress enough how important it is to see Asian LNG buyers move to long term LNG deals. (i) Validates the sooner and bigger LNG supply gap. We believe LNG markets should look at the last two weeks of new long term deals for Asian LNG buyers as being the validation of the LNG supply gap that clearly emerged post Total declaring force majeure on its 1.7 bcf/d Mozambique LNG Phase 1 that was under construction and on track for first LNG delivery in 2024. Since then, markets have started to realize the Mozambique delays are much more than 1.7 bcf/d. They have seen major LNG suppliers change their outlook to a more bullish LNG outlook and, most importantly, are now seeing Asian LNG buyers changing from trying to renegotiate long term LNG deals lower to entering into long term LNG deals to have security of supply. Asian LNG buyers are cozying up to Qatar in a prelude to the next wave of Asian buyer long term deals. What better validation is there than companies/countries putting their money where their mouth is. (ii) Provides financial commitment to help push LNG suppliers to FID. We believe these Asian LNG buyers are doing much more than validating a LNG supply gap to markets. The big LNG suppliers can move to FID based on adding more LNG supply to their portfolio, but having more long term deals provides the financial anchor/visibility to long term capital commitment from the buyers. Long term contracts will only help LNG suppliers get to FID.

<u>It was always clear that the Mozambique LNG supply delay was 5.0 bcf/d, not just 1.7 bcf/d from Total Phase 1.</u> LNG markets didn't really react to Total's April 26 declaration of force majeure on its 1.7 bcf/d Mozambique LNG Phase 1. This was an under construction project that was on time to deliver first LNG in 2024. It was in all LNG supply forecasts. There was no timeline given but, on the Apr 29 Q1 call, Total said that it expected any restart decision would be least a year away. If so, we believe that puts any actual construction at least 18 months away. There will be work to do just to get back to where they were when they were forced to stop development work on Phase 1. Surprisingly, markets didn't look the broader implications, which is why we posted our 7-pg Apr 28 blog "*Multiple Brownfield LNG FIDs Now Needed To Fill New LNG Supply Gap From Mozambique Chaos? How About LNG Canada Phase 2?*" [LINK] We highlighted that Mozambique LNG delays were actually 5 bcf/d, not 1.7 bcf/d. And this 5 bcf/d of Mozambique LNG supply was built into most, if not all, LNG supply forecasts. The delay in Total Phase 1 would lead to a commensurate delay in its Mozambique LNG Phase 2 of 1.3 bcf/d. Total Phase 2 was to add 1.3 bcf/d. There was no firm in service date, but it was expected to

follow closely behind Phase 1 to maintain services. That would have put it originally in the 2026/2027 period. But if Phase 1 is pushed back at least 2 years, so will the follow on Phase 2, so more likely, it will be at least 2028/2029. The assumption for most, if not all, LNG forecasts was that Phase 2 would follow Phase 1. Exxon Rozuma Phase 1 of 2.0 bcf/d continues to be pushed back in timeline especially following Total Phase 1. Exxon's Mozambique Rozuma Phase 1 LNG will add 2.0 bcf/d and, pre-Covid, was originally expected to be in service in 2025. The project was being delayed and Total's force majeure has added to the delays. Rozuma onshore LNG facilities are right by Total. On June 20, we tweeted [LINK] on the Reuters report "*Exclusive: Galp says it won't invest in Rovuma until Mozambique ensures security*" [LINK]. Galp is one of Exxon's partners in Rozuma. Reuters reported that Galp said they won't invest in Exxon's Rozuma LNG project until the government ensures security, that this may take a while, they won't be considering the project until after Total has reliably resumed work on its Phase 1, which likely puts any Rozuma decision until at least end of 2022 at the earliest. Galp has taken any Rozuma Phase 1 capex out of their new capex plans thru 2025 and will have to take out projects in their capex plan if Rozuma does come back to work. This puts Rozuma more likely 2028 at the earliest as opposed to before the original expectations of before 2025. Pre-pandemic, Exxon's March 6, 2019 Investor Day noted their operated Mozambique Rovuma LNG Phase 1 was to be 2 trains each with 1.0 bcf/d capacity for total initial capacity of 2.0 bf/d with FID expected in 2019 and first LNG deliveries sometime before 2025. LNG forecasts had been assuming Exxon Rozuma would be onstream around 2025. The 2019 FID expectation was later pushed to be expected just before the March 2020 investor day. But the pandemic hit, and on March 21, 2020, we tweeted [LINK] on the Reuters story "*Exclusive: Coronavirus, gas slump put brakes on Exxon's giant Mozambique LNG plan*" [LINK] that noted Exxon was expected to delay the Rovuma FID. There was no timeline, but now, any FID is not expected until late 2022 at the earliest, that would push first LNG likely to at least 2028. What this means is that the Mozambique LNG delays are not 1.7 bcf/d but 5.0 bcf/d of projects that were in all, if not most, LNG supply forecasts. There is much more in our 7-pg blog. But Mozambique is what is driving a much bigger and sooner LNG supply gap starting ~2025 and stronger outlook for LNG prices

<u>One of the reasons why it went under the radar is that major LNG suppliers played stupid on the Mozambique impact.</u> It makes it harder for markets to see a big deal when the major LNG suppliers weren't making a big deal of Mozambique or playing stupid in the case of Cheniere in their May 4 Q1 call. In our May 9, 2021 Energy Tidbits memo, we said we had to chuckle when we saw Cheniere's response in the Q&A to its Q1 call on May 4 that they only know what we know from reading the Total releases on Mozambique and its impact on LNG markets. It's why we tweeted [LINK] "*Hmm! $LNG says only know what we read on #LNG market impact from $TOT $XOM MZ LNG delays*. *Surely #TohokuElectric & other offtake buyers are reaching out to #Cheniere. MZ LNG delays is a game changer to LNG in 2020s, see SAF Group blog. Thx @olympe_mattei @TheTerminal #NatGas".* How could they not be talking to LNG buyers for Total and /or Exxon Mozambique LNG projects. In the Q1 Q&A, mgmt was asked about Mozambique and didn't know any more than what you or I have read. Surely, they were speaking to Asian LNG buyers who had planned to get LNG supply from Total Mozambique or Exxon Rozuma Mozambique or both. Mgmt is asked "*wanted to just kind of touch on the color use talking about for these supply curve. And are you able to kind of provide any thoughts on the Mozambique and a deferral with the project of that size on 13 and TPA being deferred by we see you have you noticed any impact to the market has is there any impact for stage 3 with that capacity? Thanks*." Mgmt replies "*No. Look, I only know about the Mozambique delay with what I read as well as what you read that from total and an Exxon. And it's a sad situation and I hope everybody is safe and healthy that were there to experience that unrest but no I don't think it's, again it's a different business paradigm than what we offer. So, we offer a full value product, the customer doesn't have to invest in equity, customer doesn't have to worry about the E&P side of the business because, we've been able to both the by at our peak almost 7 Dee's a day of US NAT gas from almost a 100 different producers on 26 different pipelines and deliver it to our to facilities. So we take care of a lot of what the customer needs".*

<u>There are other LNG supply delays/interruptions beyond Mozambique.</u> There have been a number of other smaller LNG delay or existing supply interruptions that add to Asian LNG buyers feeling less secure about the reliability of mid to long term LNG supply. Here are just a few examples. (i) Total Papua LNG 0.74 bcf/d. On June 8, we tweeted [LINK] *"Timing update Papua #LNG project. $OSH June 8 update "2022 FEED, 2023 FID targeting 2027 first gas". $TOT May 5 update didn't forecast 1st gas date. Papua is 2 trains w/ total capacity 0.74 bcf/d."* We followed the tweet saying [LINK] *"Bigger #LNG supply gap being created >2025. Papua #LNG originally expected FID in 2020 so 1st LNG is 2 years delayed.*

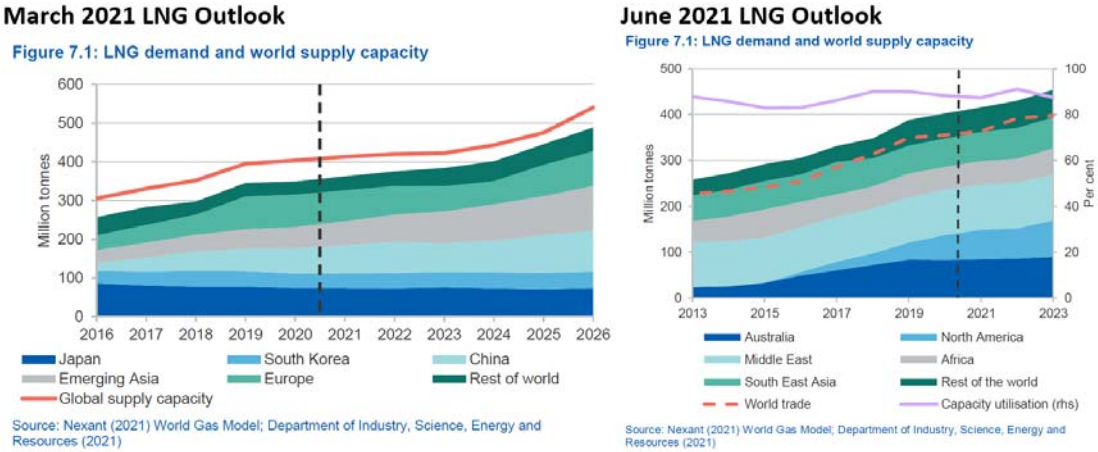
Common theme - new LNG supply is being delayed ie. [Total] Mozambique. Don't forget need capacity>demand due to normal maintenance, etc. Positive for LNG." (ii) Chevron's Gorgon. A big LNG story in H2/20 was the emergence of weld quality issues in the propane heat exchangers at Train 2, which required additional downtime for repair. Train 2 was shut on May 23 with an original restart of July 11, but the repairs to the weld quality issues meant it didn't restart until late Nov. The same issue was found in Train 1 but repairs were completed. However extended downtime for the trains led to lower LNG volumes. Gorgon produced ~2.3 bcf/d in 2019 but was down to 2.0 bcf/d in 2020. (iii) Equinor's Melkoeya 0.63 bcf/d shut down for 18 months due to a fire. A massive fire led to the Sept 28, 2020 shutdown of the 0.63 bcf/d Melkoeya LNG facility in Norway. On April 26, Equinor released "*Revised start-up date for Hammerfest LNG*" [LINK] with regard to the 0.63 bcf/d Melkoeya LNG facility. The original restart date was Oct 1, 2021 (ie. a 12 month shut down), but Equinor said "*Due to the comprehensive scope of work and Covid-19 restrictions, the revised estimated start-up date is set to 31 March 2022*". When we read the release, it seemed like Equinor was almost setting the stage for another potential delay in the restart date. Equinor had two qualifiers to this March 31, 2022 restart date. Equinor said "*there is still some uncertainty related to the scope of the work*" and "*Operational measures to handle the Covid-19 situation have affected the follow-up progress after the fire. The project for planning and carrying out repairs of the Hammerfest LNG plant must always comply with applicable guidelines for handling the infection situation in society. The project has already introduced several measures that allow us to have fewer workers on site at the same time than previously expected. There is still uncertainty related to how the Covid-19 development will impact the project progress."*

<u>Cheniere stopped the game playing the game on June 30</u>. Our July 4, 2021 Energy Tidbits memo noted that it looks like Cheniere has stopped playing stupid with respect to the strengthening LNG market in 2021. We can't believe they thought they were fooling anyone, especially their competitors. Bu that week, they came out talking about how commercial discussions have picked up in 2021 and it's boosted their hope for a Texas (Corpus Christi) LNG expansion. On Wednesday, Platts reported "*Pickup in commercial talks boosts Cheniere's hopes on mid-scale LNG project*" [LINK] Platts wrote "*Cheniere Energy expects to make a "substantial dent" by the end of 2022 in building sufficient buyer support for a proposed mid-scale expansion at the site of its Texas liquefaction facility, Chief Commercial Officer Anatol Feygin said June 30 in an interview." " As a result, he said, " The commercial engagement, I think it is very fair to say, has really picked up steam, and we are quite optimistic over the coming 12-18 months to make a substantial dent in that Stage 3 commercialization."* Platts also reported that Cheniere noted this has been a tightening market all year (ie would have been known by the May 4 Q1 call). Platts wrote "*We obviously find ourselves at the beginning of this year and throughout in a very tight market where prices today into Asia and into Europe are at levels that we frankly haven't seen in a decade-plus," Feygin said. "We've surpassed the economics that the industry saw post the Fukushima tragedy in March 2011, and that's happened in the shoulder period."* It's a public stance as to a more bullish LNG outlook

<u>But we still see major LNG suppliers like Australia hinting but not outright saying that LNG supply gap is coming sooner.</u> We have to believe Australia will be unveiling a sooner LNG supply gap in their September forecast. On June 28, we tweeted [LINK] on Australia's Resources and Energy Quarterly released on Monday [LINK] because there was a major change to their LNG outlook versus their March forecast. We tweeted "*#LNGSupplyGap. AU June fcast now sees #LNG mkt tighten post 2023 vs Mar fcast excess supply thru 2026. Why? $TOT Mozambique delays. See below SAF Apr 28 blog. Means brownfield LNG FID needed ie. like #LNGCanada Phase 2. #OOTT #NatGas"*. Australia no longer sees supply exceeding demand thru 2026. In their March forecast, Australia said "*Nonetheless, given the large scale expansion of global LNG capacity in recent years, demand is expected to remain short of total supply throughout the projection period."* Note this is thru 2026 ie. a LNG supply surplus thru 2026. But on June 28, Australia changed that LNG outlook and now says the LNG market may tighten beyond 2023. Interestingly, the June forecast only goes to 2023 and not to 2026 as in March. Hmmm! On Monday, they said "*Given the large scale expansion of global LNG capacity in recent years, import demand is expected to remain short of export capacity throughout the outlook period. Beyond 2023, the global LNG market may tighten, due to the April 2021 decision to indefinitely suspend the Mozambique LNG project, in response to rising security issues. This project has an annual nameplate capacity of 13 million tonnes, and was previously expected to start exporting LNG in 2024*." 13 million tonnes is 1.7 bcf/d so they are only referring to Total Mozambique LNG Phase 1. So no surprise the change is Mozambique LNG driven but we have to believe the reason why they cut their forecast off this time at 2023 is that they are looking at trying to figure out what to forecast beyond 2023 in addition to Total Phase 1. And, importantly, we believe they will be changing their LNG forecast for more than Mozambique ie. India

demand that we highlight later in the blog. They didn't say anything else specific on Mozambique but, surely they have to also be delaying the follow on Total Phase 2 of 1.3 bcf/d and Exxon Rozuma Phase 1 of 2.0 bcf/d.

Australia's LNG Outlook: March 2021 vs June 2021 Forecasts

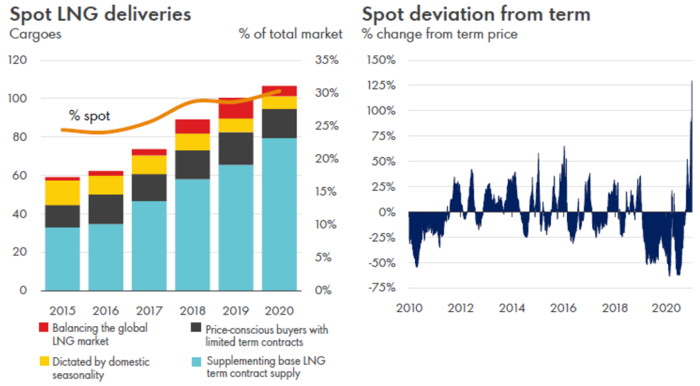


Source: Australia Resources and Energy Quarterly

Clearly Asian LNG buyers did the math, saw the new LNG supply gap and were working the phones in March/April/May trying to lock up long term supply. We wrote extensively on the Total Mozambique LNG situation before the April 26 force majeure as it was obvious that delays were coming to a project counted on for first LNG in 2024. Total had shut down Phase 1 development in December for 3 months due to the violence and security risks. It restarted development on Wed March 24, violence/attacks immediately resumed for 3 consecutive days, and then Total suspended development on Sat March 27. That's why no one should have been surprised by the April 26 force majeure. Asian LNG buyers were also seeing this and could easily do the same math we were doing and saw a bigger and sooner LNG supply gap. They were clearly working the phones with a new priority to lock up long term LNG supply. Major long term deals don't happen overnight, so it makes sense that we started to see these new Asian long term LNG deals start at the end of June.

A big pivot from trying to renegotiate down long term LNG deals or being happy to let long term contracts expire and replace with spot/short term LNG deals. This is a major pivot or abrupt turn on the Asian LNG buyers contracting strategy for the 2020s. There is the natural reduction of long term contracts as contracts reach their term. But with the weakness in LNG prices in 2019 and 2020, Asian LNG buyers weren't trying to extend long term contracts, rather, the push was to try to renegotiate down its long term LNG deals. The reason was clear, as spot prices for LNG were way less than long term contract prices. And this led to their LNG contracting strategy – move to increase the proportion of spot LNG deliveries out of total LNG deliveries. Shell's LNG Outlook 2021 was on Feb 25, 2021 and included the below graphs. The spot LNG price derivation from long term prices in 2019 and 2020 made sense for Asian LNG buyers to try to change their contract mix. Yesterday, Maeil Business News Korea reported on the new Qatar/Kogas long term LNG deal with its report "*Korea may face LNG supply cliff or pay hefty price after long-term supplies run out*" [LINK], which highlighted this very concept – Korea wasn't worried about trying to extend expiring long term LNG contracts. Maeil wrote "*Seoul in 2019 secured a long-term LNG supply contract with the U.S. for annual 15.8 million tons over a 15-year period. But even with the latest two LNG supply contracts, the Korean government needs extra 6 million tons or more of LNG supplies to keep up the current power pipeline. By 2024, Korea's long-term supply contracts for 9 million tons of LNG will expire - 4.92 million tons on contract with Qatar and 4.06 million tons from Oman, according to a government official who asked to be unnamed."*

Spot LNG deliveries and Spot deviation from term price



Source: Shell LNG Outlook 2021 on Feb 25, 2021

Asian LNG buyers moving to long term LNG deals provide financing capacity for brownfield LNG FIDs. We believe this abrupt change and return to long term LNG deals is even more important to LNG suppliers who want to FID new projects. The big LNG players like Shell can FID new LNG supply without new long term contracts as they can build into their supply options to fill their portfolio of LNG contracts. But that doesn't mean the big players don't want long term LNG supply deals, as having long term LNG contracts provide better financing capacity for any LNG supplier. It takes big capex for LNG supply and long term deals make the financing easier.

Four Asian buyer long term LNG deals in the last week. It was pretty hard to miss a busy week for reports of new Asian LNG buyer long term LNG deals. There were two deals from Qatar Petroleum, one from Petronas and one from BP. The timing fits, it's about 3 months after Total Mozambique LNG problems became crystal clear. And as noted later, there are indicators that more Asian buyer LNG deals are coming.

> Petronas/CNOOC is 10 yr supply deal for 0.3 bcf/d. On July 7, we tweeted [LINK] on the confirmation of a big positive to Cdn natural gas with the Petronas announcement [LINK] of a new 10 year LNG supply deal for 0.3 bcf/d with China's CNOOC. The deal also has special significance to Canada. (i) Petronas said "*This long-term supply agreement also includes supply from LNG Canada when the facility commences its operations by middle of the decade*". This is a reminder of the big positive to Cdn natural gas in the next 3 to 4 years – the start up of LNG Canada Phase 1 is ~1.8 bcf/d capacity. This is natural gas that will no longer be moving south to the US or east to eastern Canada, instead it will be going to Asia. This will provide a benefit for all Western Canada natural gas. (ii) First ever AECO linked LNG deal. It's a pretty significant event for a long term Asia LNG deal to now have an AECO link. Petronas wrote "*The deal is for 2.2 million tonnes per annum (MTPA) for a 10-year period, indexed to a combination of the Brent and Alberta Energy Company (AECO) indices. The term deal between PETRONAS and CNOOC is valued at approximately USD 7 billion over ten years.*" 2.2 MTPA is 0.3 bcf/d. (iii) Reminds of LNG Canada's competitive advantage for low greenhouse gas emissions. Petronas said "*Once ready for operations, the LNG Canada project paves the way for PETRONAS to supply low greenhouse gas (GHG) emission LNG to the key demand markets in Asia.*"

> Qatar Petroleum/CPC (Taiwan) is 15 yr supply deal for 0.16 bcf/d. Pre Covid, Qatar was getting pressured to renegotiate lower its long term LNG contract prices. Now, it's signing a 15 year deal. On July 9, they entered in a new small long term LNG sales deal [LINK], a 15-yr LNG Sale and Purchase Agreement with CPC Corporation in Taiwan to supply it ~0.60 bcf/d of LNG. LNG deliveries are set to begin in January 2022. H.E. Minister for Energy Affairs & CEO of Qatar Petroleum Al-Kaabi said *"We are pleased to enter into this long term LNG SPA, which is another milestone in our relationship with CPC, which dates back to almost three decades. We look forward to commencing deliveries under this SPA and to continuing our supplies as a trusted and reliable global LNG provider."* The pricing was reported to be vs a basket of crudes.

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BP/Guangzhou Gas, a 12-yr supply deal for 0.13 bcf/d. On July 9, there was a small long term LNG supply deal with BP and Guangzhou Gas (China). Argus reported [LINK] BP had signed a 12 year LNG supply deal with Guangzhou Gas (GG), a Chinese city's gas distributor, which starts in 2022. The contract prices are to be linked to an index of international crude prices. Although GG typically gets its LNG from the spot market, it used a tender in late April for ~0.13 bcf/d starting in 2022. BP's announcement looks to be for most of the tender, so it's a small deal. But it fit into the trend this week of seeing long term LNG supply deals to Asia. This was intended to secure deliveries to the firm's Xiaohudao import terminal which will become operational in August 2022.

Qatar/Korea Gas is a 20-yr deal to supply 0.25 bcf/d. On Monday, Reuters reported [LINK] "*South Korea's energy ministry said on Monday it had signed a 20-year liquefied natural gas (LNG) supply agreement with Qatar for the next 20 years starting in 2025. South Korea's state-run Korea Gas Corp (036460.KS) will buy 2 million tonnes of LNG annually from Qatar Petroleum".* There was no disclosure of pricing.

More Asian buyer long term LNG deals (ie. India) will be coming. There are going to be more Asian buyer long term LNG deals coming soon. Our July 11, 2021 Energy Tidbits highlighted how India's new petroleum minister Hardeep Singh Puri (appointed July 8) hit the ground running with what looks to be a priority to set the stage for more India long term LNG deals with Qatar. On July 10, we retweeted [LINK] "*New India Petroleum Minister hits ground running. What else w/ Qatar but #LNG. Must be #Puri setting stage for long term LNG supply deal(s). Fits sea change of buyers seeing #LNGSupplyGap (see SAF Apr 28 blog http://safgroup.ca) & wanting to tie up LNG supply. #OOTT".* It's hard to see any other conclusion after seeing what we call a sea change in LNG buyer mentality with a number of long term LNG deals this week. Puri tweeted [LINK] "*Discussed ways of further strengthening mutual cooperation between our two countries in the hydrocarbon sector during a warm courtesy call with Qatar's Minister of State for Energy Affairs who is also the President & CEO of @qatarpetroleum HE Saad Sherida Al-Kaabi".* As noted above, we believe there is a sea change in LNG markets that was driven by the delay in 5 bcf/d of LNG supply from Mozambique (Total Phase 1 & Phase 2, and Exxon Rozuma Phase 1) that was counted on all LNG supply projections for the 2020s. Puri's tweet seems to be him setting the stage for India long term LNG supply deals with Qatar.

Supermajors are aggressively competing to commit 30+ year capital to Qatar's LNG expansion despite stated goal to reduce fossil fuels production. It's not just Asian LNG buyers who are now once again committing long term capital to securing LNG supply, it's also supermajors all bidding to be able to commit big capex to part of Qatar Petroleum's 4.3 bcf/d LNG expansion. Qatar Petroleum received a lot of headlines following the their June 23 announcement on its LNG expansion [LINK] on how they received bids for double the equity being offered. And there were multiple reports that these are on much tougher terms for Qatar's partners. Qatar Petroleum CEO Saad Sherida Al-Kaabi specifically noted that, among the bidders, were Shell, Total and Exxon. Shell and Total have two of the most ambitious plans to reduce fossil fuels production in the 2020's, yet are competing to allocate long term capital to increase fossil fuels production. And Shell and Total are also two of the global LNG supply leaders. It has to be because they are seeing a bigger and sooner LNG supply gap.

Remember Qatar's has a massive expansion but India alone needs 3x the Qatar expansion LNG capacity. In addition to the competition to be Qatar Petroleum's partners, we remind that, while this is a massive 4.3 bcf/d LNG expansion, India alone sees its LNG import growing by ~13 bcf/d to 2030. The Qatar announcement reminded they see a LNG supply gap and continued high LNG prices. We had a 3 part tweet. (i) First, we highlighted [LINK] "*1/3. #LNGSupplyGap coming. big support for @qatarpetroleum expansion to add 4.3 bcf/d LNG. but also say "there is a lack of investments that could cause a significant shortage in gas between 2025-2030" #NatGas #LNG".* This is after QPC accounts for their big LNG expansion. The QPC release said "*However, His Excellency Al-Kaabi voiced concern that during the global discussion on energy transition, there is a lack of investment in oil and gas projects, which could drive energy prices higher by stating that "while gas and LNG are important for the energy transition, there is a lack of investments that could cause a significant shortage in gas between 2025-2030, which in turn could cause a spike in the gas market."* (ii) Second, this is a big 4.3 bcf/d expansion, but India alone has 3x the increase in LNG import demand. We tweeted [LINK] "*2/3. Adding 4.3 bcf/d is big, but dwarfed by items like India. #Petronet gave 1st specific forecast for what it means if #NatGas is to be 15%*

of energy mix by 2030 - India will need to increase #LNG imports by ~13 bcf/d. See SAF Group June 20 Energy Tidbits memo." (iii) Third, Qatar's supply gap warning is driven by the lack of investments in LNG supply. We agree, but note that the lack of investment is in great part due to the delays in both projects under construction and in FIDs that were supposed to be done in 2019. We tweeted [LINK] "*3/3. #LNGSupplyGap is delay driven. $TOT Mozambique Phase 1 delay has chain effect, backs up 5 bcf/d. See SAF Group Apr 28 blog Multiple Brownfield LNG FIDs Now Needed To Fill New #LNG Supply Gap From Mozambique Chaos? How About LNG Canada Phase 2? #NatGas*."

Seems like many missed India's first specific LNG forecast to 2030. Our June 20, 2021 Energy Tidbits memo highlighted the first India forecast that we have seen to estimate the required growth in natural gas consumption and LNG imports if India is to meet its target for natural gas to be 15% of its energy mix by 2030. India will need to increase LNG imports by ~13 bcf/d or 3 times the size of the Qatar LNG expansion. Our June 6, 2021 Energy Tidbits noted the June 4 tweet from India's Energy Minister Dharmendra Pradhan [LINK] reinforcing the 15% goal "*We are rapidly deploying natural gas in our energy mix with the aim to increase the share of natural gas from the current 6% to 15% by 2030."* But last week, Petronet CEO AK Singh gave a specific forecast. Reuters report "*LNG's share of Indian gas demand to rise to 70% by 2030: Petronet CEO"* [LINK] included Petronet's forecast if India is to hit its target for natural gas to be 15% of energy mix by 2030. Singh forecasts India's natural gas consumption would increase from current 5.5 bcf/d to 22.6 bcf/d in 2030. And LNG shares would increase from 50% to 70% of natural gas consumption ie. an increase in LNG imports of ~13 bcf/d from just under 3 bcf/d to 15.8 bcf/d in 2030. Singh did not specifically note his assumption for India's natural gas production, but we can back into the assumption that India natural gas production grows from just under 3 bcf/d to 6.8 bcf/d. It was good to finally see India come out with a specific forecast for 2030 natural gas consumption and LNG imports if India is to get natural gas to 15% of its energy mix in 2030. Petronet's Singh forecasts India natural gas consumption to increase from 5.5 bcf/d to 22.6 bcf/d in 2030. This forecast is pretty close to our forecast in our Oct 23, 2019 blog "*Finally, Some Visibility That India Is Moving Towards Its Target For Natural Gas To Be 15% Of Its Energy Mix By 2030*". Here part of what we wrote in Oct 2019. "*It's taken a year longer than we expected, but we are finally getting visibility that India is taking significant steps towards India's goal to have natural gas be 15% of its energy mix by 2030. On Wednesday, we posted a SAF blog [LINK] "Finally, Some Visibility That India Is Moving Towards Its Target For Natural Gas To Be 15% Of Its Energy Mix By 2030".* Our 2019 blog estimate was for India natural gas demand to be 24.0 bcf/d in 2030 (vs Singh's 22.6 bcf/d) and for LNG import growth of +18.4 bcf/d to 2030 (vs Singh's +13 bcf/d). The difference in LNG would be due to our Oct 2019 forecast higher natural gas consumption by 1.4 bcf/d plus Singh forecasting India natural gas production +4 bcf/d to 2030. Note India production peaked at 4.6 bcf/d in 2010.

Bigger, nearer LNG supply gap + Asian buyers moving to long term LNG deals = LNG players forced to at least look at what brownfield LNG projects they could advance and move to FID. All we have seen since our April 28 blog is more validation of the bigger, nearer LNG supply gap. And now market participants (Asian LNG buyers) are reacting to the new data by locking up long term supply. Cheniere noted how the pickup in commercial engagement means they "*are quite optimistic over the coming 12-18 months to make a substantial dent in that Stage 3 commercialization."* Cheniere can't be the only LNG supplier having new commercial discussions. It's why we believe the Mozambique delays + Asian LNG buyers moving to long term deals will effectively force major LNG players to look to see if there are brownfield LNG projects they should look to advance. Prior to March/April, no one would think Shell or other major LNG players would be considering any new LNG FIDs in 2021. Covid forced all the big companies into capital reduction mode and debt reduction mode. But Brent oil is now solidly over $70, and LNG prices are over $13 this summer and the world's economic and oil and gas demand outlook are increasing with vaccinations. And we are starting to see companies move to increasing capex with the higher cash flows. The theme in Q3 reporting is going to be record or near record oil and gas cash flows, reduced debt levels and increasing returns to shareholders. And unless new mutations prevent vaccinations from returning the world to normal, we suspect that major LNG players, like other oil and gas companies, will be looking to increase capex as they approve 2022 budgets. The outlook for the future has changed dramatically in the last 8 months. The question facing major LNG players like Shell is should they look to FID new LNG brownfield projects in the face of an increasing LNG supply gap that is going to hit faster and harder and Asian LNG buyers prepared to do long term deals. We expect these decisions to be looked at before the end of 2021 for 2022 capex budget/releases. One wildcard that could force these decisions sooner is the already stressed out global supply chain. We have to believe that discussion there will be pressure for more Asian LNG buyer long term deals sooner than later.

For Canada, does the increasing LNG supply gap provide the opportunity to at least consider a LNG Canada Phase 2 FID over the next 6 months? Our view on Shell and other LNG players is unchanged since our April 28 blog. Shell is no different than any other major LNG supplier in always knowing the market and that the oil and gas outlook is much stronger than 9 months ago. Even 3 months post our April 28 blog, we haven't heard any significant talks on how major LNG players will be looking at FID for new brownfield LNG projects. We don't have any inside contacts at Shell or LNG Canada, but that is no different than when we looked at the LNG markets in September 2017 and saw the potential for Shell to FID LNG Canada in 2018. We posted a September 20, 2017 blog *"China's Plan To Increase Natural Gas To 10% Of Its Energy Mix Is A Global Game Changer Including For BC LNG"* [LINK]. Last time, it was a demand driven supply gap, this time, it's a supply driven supply gap. We have to believe any major LNG player, including Shell, will be at least looking at their brownfield LNG project list and seeing if they should look to advance FID later in 2021. Shell has LNG Canada Phase 2, which would add 2 additional trains or approx. 1.8 bcf/d. And an advantage to an FID would be that Shell would be able to commit to its existing contractors and fabricators for a continuous construction cycle following on LNG Canada Phase 1 ie. to help keep a lid on capital costs. We believe maintaining a continuous construction cycle is even more important given the stressed global supply chain. No one is talking about the need for these new brownfield LNG projects, but, unless some major change in views happen, we believe its inevitable that these brownfield LNG FID internal discussions will be happening in H2/21. Especially since the oil and gas price outlook is much stronger than it was in the fall and companies will be looking to increase capex in 2022 budgets.

A LNG Canada Phase 2 would be a big plus to Cdn natural gas. LNG Canada Phase 1 is a material natural gas development as its 1.8 bcf/d capacity represents approx. 20 to 25% of Cdn gas export volumes to the US. The EIA data shows US pipeline imports of Cdn natural gas as 6.83 bcf/d in 2020, 7.36 bcf/d in 2019, 7.70 bcf/d in 2018, 8.89 bcf/d in 2017, 7.97 bcf/d in 2016, 7.19 bcf/d in 2015 and 7.22 bcf/d in 2014. A LNG Canada Phase 2 FID would be a huge plus for Cdn natural gas. It would allow another ~1.8 bcf/d of Cdn natural gas to be priced against pricing points other than Henry Hub. And it would provide demand offset versus Trudeau if he moves to make electricity "emissions free" and not his prior "net zero emissions". Mozambique has been a game changer to LNG outlook creating a bigger and sooner LNG supply gap. And with a stronger tone to oil and natural gas prices in 2021, the LNG supply gap will at least provide the opportunity for Shell to consider FID for its brownfield LNG Canada Phase 2 and provide big support to Cdn natural gas for the back half of the 2020s. And perhaps if LNG Canada is exporting 3.6 bcf/d from two phases, it could help flip Cdn natural gas to a premium vs US natural gas especially if Biden is successful in reducing US domestic natural gas consumption for electricity. The next six months will be very interesting to watch for LNG markets and Cdn natural gas valuations. Imagine the future value of Cdn natural gas is there was visibility for 3.6 bcf/d of Western Canada natural gas to be exported to Asia.

Cheniere Moving Faster Than It Expected on Expansions, CCO Says
2021-12-02 12:12:12.506 GMT

By Anna Shiryaevskaya
(Bloomberg) -- Cheniere expects to make final investment decision on the Corpus Christi Stage 3 project by mid-2022 or earlier, Chief Commercial Officer Anatol Feygin said in an interview on the sidelines of the World LNG Summit in Rome.
* Following recent deals, the project still needs to sell 1-2m tons/year of LNG before FID can be reached
* Prices and market volatility have improved dealmaking for long-term contracts
* "What's played out in the market, and specifically with the recent Cheniere successes and our counterparties, we have moved faster than we expected six months ago"
** READ: Nov. 4, Cheniere 'Confident' on LNG Deals Needed for Plant Expansion
* Cheniere is "more and more comfortable" that Sabine Pass Train 6 commissioning cargoes will start before the end of this year
* U.S. to become top LNG supplier in some months next year
** READ: U.S. May Become Top LNG Supplier in 2022: BNEF China Summit
* Cheniere is seeing more interest in linking LNG deals to Henry Hub prices as the benchmark has been "lower and more stable than other indices"

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https://www.mcdermott-investors.com/news/press-release-details/2021/McDermott-Completes-Net-Zero-LNG-Construction-Study-for-Shell/default.aspx

McDermott Completes Net Zero LNG Construction Study for Shell

11/29/2021

Download this Press ReleasePDF Format (opens in new window)

HOUSTON, Nov. 29, 2021 /PRNewswire/ -- McDermott recently completed a liquefied natural gas (LNG) construction study identifying tangible reduction pathways toward net-zero construction emissions on behalf of Shell Global Solutions International B.V.

The results of this study provide a strategic framework for reducing greenhouse gas (GHG) emissions in LNG facilities during the project execution phase.

"Operators continue to seek actionable plans to advance their commitments to net-zero emissions by 2050," said Samik Mukherjee, Executive Vice President and Chief Operating Officer. "Leveraging our unique LNG and modularization expertise, McDermott has developed multiple, innovative pathways to reduce and/or eliminate emissions throughout the life cycle of an LNG facility. We believe, in future scenarios, up to 65 percent of emissions associated with construction can be eliminated through a combination of construction execution efficiency, modularization and targeted investment in construction emissions reduction initiatives."

Study results include emission reduction opportunities, in order of magnitude, based on mapping key sources and the identification of low-carbon alternatives during construction. These include site efficiency improvements, replacing diesel powered equipment with lower GHG intensity alternatives, module fabrication and construction and sourcing lower intensity raw materials. The study also provides more clarity on the associated environmental, social and economic considerations of future projects.

Building on this study, McDermott is also engaging with Shell to identify low-carbon solutions to help reduce GHG emissions in McDermott's operations.

"We are committed to monitoring and managing the carbon footprint on our projects to support our customers in meeting their net zero goals," said Tareq Kawash, Senior Vice President, Europe, Middle East, Africa. "This study is an excellent example of how, through early engagement with Shell, we were able to identify potential low-carbon delivery solutions."

About McDermott

McDermott is a premier, fully-integrated provider of engineering and construction solutions to the energy industry. Our customers trust our technology-driven approach engineered to responsibly harness and transform global energy resources into the products the world needs. From concept to commissioning, McDermott's innovative expertise and capabilities advance the next generation of global energy infrastructure—empowering a brighter, more sustainable future for us all. Operating in over 54 countries, McDermott's locally-focused and globally-integrated resources include more than 30,000 employees, a diversified fleet of specialty marine construction vessels and fabrication facilities around the world. To learn more, visit www.mcdermott.com.

https://www.mcdermott-investors.com/news/press-release-details/2021/McDermott-Collaborates-with-Shell-to-Decarbonize-Construction/default.aspx

McDermott Collaborates with Shell to Decarbonize Construction

11/03/2021

Download this Press ReleasePDF Format (opens in new window)

Collaboration Builds Pathway to Net Zero Carbon Future

HOUSTON, Nov. 3, 2021 /PRNewswire/ -- McDermott has signed a memorandum of understanding (MOU) with Shell Eastern Petroleum Pte Ltd (Shell), a subsidiary of Royal Dutch Shell plc, to collaborate on decarbonizing construction. The agreement enables McDermott and Shell to explore opportunities for reducing, and eliminating, emissions from construction through pathways such as low carbon fuels, renewable power, digital solutions and decarbonizing marine construction vessels.

"Companies such as McDermott and Shell—who have targets to progress towards net-zero emissions by 2050, in step with society—are well positioned to approach the challenges of lowering emissions together," said Samik Mukherjee, McDermott's Executive Vice President and Chief Operating Officer. "A pathway to reduce greenhouse gas emissions from construction operations will make significant strides toward net zero Engineering, Procurement and Construction projects in the future."

McDermott's fabrication yards located in Indonesia, China, the Middle East and Mexico, as well as the marine construction vessels, will be key to identifying opportunities to lower emissions and gain operational efficiencies.

"McDermott's integrated project delivery enables us to look holistically across our operations for opportunities to reduce emissions," said Mahesh Swaminathan, McDermott's Senior Vice President, Asia Pacific. "We are looking forward to working with Shell to explore what's possible and see how our combined expertise delivers more sustainable operations."

11/29/2021

McDermott Completes Net Zero LNG Construction Study for Shell

Description HTML PDF

11/23/2021

Woodfibre LNG awards EPFC contract to McDermott

Description HTML PDF

11/18/2021

McDermott and SBM Offshore to Deliver Fourth FPSO in Guyana

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11/18/2021

McDermott Completes FEED and Wins Ichthys Booster Compression Platform EPC Contract

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11/16/2021

NET Power Delivers Electricity to Grid in Major Technological Breakthrough

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11/03/2021

McDermott Collaborates with Shell to Decarbonize Construction

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11/01/2021

McDermott Completes Its First Sail Away on Tyra Redevelopment Project

Description HTML PDF

10/18/2021

McDermott Selected for Engineering and Procurement Phase of Mega Gas Chemical Complex Project in Russia

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10/13/2021

Shell-Led Consortium Selected by DOE to Demonstrate Feasibility of Large-Scale Liquid Hydrogen Storage

Description HTML PDF

10/04/2021

McDermott Wins Fourth Contract in India This Year

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09/29/2021

McDermott Joins AquaVentus Consortium to Advance Renewable Hydrogen Production

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09/14/2021

McDermott and Saudi Aramco Sign MoU for Feasibility Study of In-Kingdom Onshore Modular Construction

Description HTML PDF

09/13/2021

McDermott's Amazon Tapped for Deepwater Development in Gulf of Mexico

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09/02/2021

McDermott Installs Largest and Heaviest Jacket and CPP Topside in Vietnam

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08/18/2021

McDermott's CB&I Storage Solutions Wins Second EPC Contract for Philippines LNG Import and Regasification Terminal

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08/12/2021

McDermott's CB&I Storage Solutions Completes Conceptual Design for World's Largest Liquid Hydrogen Sphere

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08/05/2021

McDermott Awarded Additional EPCC Project for Barauni Refinery Expansion

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08/04/2021

McDermott Awarded FEED Contract for Waste Tire Recycling Project

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08/03/2021

McDermott Joins H2@Scale in Texas and Beyond

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08/02/2021

McDermott Sustainability Report Spotlights Progress, Anchors Targets in Emission Reductions, Community Engagement, Governance

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07/29/2021
GCGV Mono-Ethylene Glycol Facility Achieves Mechanical Completion
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McDermott Selected for Licensed Modular Unit for Baltic Chemical Plant Polyethylene Project
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LACC Awards McDermott Contract for Seventh Heater Addition
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07/07/2021
McDermott Awarded Contract for Bayu-Undan Gas Field
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06/16/2021
BHP Awards McDermott Marine Installation Contract for Shenzi Subsea Multiphase Pumping Project
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06/14/2021
IOCL Awards McDermott Two EPCC Refinery Contracts
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06/09/2021
McDermott Names Samik Mukherjee Executive Vice President and Chief Operating Officer
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06/09/2021
McDermott receives Conditional Letter of Award for EPCC Contract of Tilenga Project
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06/07/2021
McDermott Announces Leadership Change
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06/02/2021
McDermott Completes KG-D6 Satellite Cluster Project
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05/11/2021
BHP Awards McDermott FEED Contract for Trion FPU
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05/05/2021
McDermott's CB&I Storage Solutions Recognized with Multiple STI/SPFA Safety Awards
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04/28/2021
McDermott Awarded FEED Contract for Plastic Recycling Project
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LNG Supply FIDs Starting to Happen, Does Shell Need to Get LNG Canada Phase 2 FID in the Queue To Protect Its Brownfield Advantages?

Posted 4pm on November 23, 2021

Asian LNG buyers and now LNG suppliers are responding to the abrupt change in LNG supply/demand outlook in April. Unplanned delays to the start up of 5.0 bcf/d of Mozambique LNG put a major hole in all LNG supply plans/forecasts for the 2020s creating a new and larger LNG supply gap. This first drove Asian LNG buyers to abruptly pivot to lock in stable long term LNG supply and now, LNG suppliers are taking FIDs (ie. Woodside on Scarborough yesterday) and looking at the next round of potential FIDs on both brownfield and greenfield LNG projects to fill that gap. This increase is happening at a time of increasing competition/demand for global fabricators, metals, and services that are also being impacted by the general global supply chain stresses. There has been no chatter that Shell will be considering FID on the brownfield LNG Canada Phase 2 (capacity 1.8 bf/d). But, unfortunately for LNG Canada Phase 2 or any major industrial project, these global/domestic stresses reduce the time to think about any FID. We think this means the timing is likely in the next few months for Shell to look at FID on LNG Canada Phase 2 if it wants to get in the queue to ensure it can maintain its brownfield cost advantages. LNG markets have seen the cost and timing advantages of a continuous construction cycle ie. like Cheniere does at Sabine Pass LNG. By now, we mean within the next few months, and not the next year. Any FID is a major undertaking and far from certain especially for a leader in the Energy Transition like Shell. But, we think the answer to the question is more likely a Yes, than a No. And if so, it would be huge for the value of Canadian natural gas.

<u>The reality check at COP26 meant there is no clear phase out of fossil fuels, especially natural gas.</u> COP26 was extended an extra day to end on Saturday but did result in an agreement signed by over 200 countries. The deal was universally viewed as far less than the aspirations leading up to COP26. It seemed that reality won or at least delayed the aspirations. One highly notable item was the watering down of "get rid of coal" to" phase out" of coal to the approved text of a phase down. The best description came from COP26 President Alok Sharma (UK) concluding media statement. He said "*I would say, however, that this is a fragile win. We have kept 1.5 alive. That was our overarching objective when we set off on this journey two years ago, taking on the role of the COP presidency designate. But I would still say that the pulse of 1.5 is weak."* It is important to remember that the actual commitments made by some key countries will be much less than the commitments in the already criticized Glasgow Climate Pact [LINK] because there are always side deals or understandings that aren't public that were made just to get countries to sign on to the Glasgow Climate Pact so there can be a global commitment.

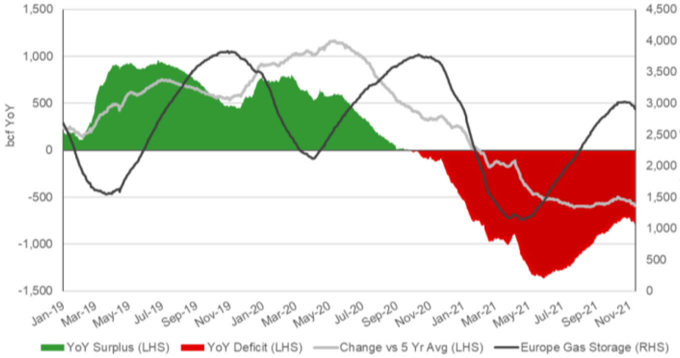
<u>Rather more world Energy Transitiony leaders are either directly or indirectly saying the energy transition plan isn't working</u>. Perhaps the best sign that the energy transition plan isn't working is that the Net Zero leaders are changing their messaging. They want to be able to be on record in the future that they warned people. (i) Its not working and the reality that the plan needs to change. The most vocal is Macron who warns the energy transition aspiration has to be modified/reduced or else there will be years of an energy crisis. Even more importantly, he wants to bring a more pragmatic Energy Transition plan to the EU. On Nov 9, we tweeted [LINK] on Macro's address to the nation [LINK] that closed with his call for a more practical approach to the CO2 emissions and one that will include Europe. Macron said "*But France will not be strong alone. With the European Union: ➜ We will be able to build a credible strategy for reducing our CO2 emissions, compatible with our industrial and technological sovereignty."* The Macron release had at the bottom a reminder "*Next January, it is a new model of investment and growth that the President will defend with the French presidency of the Council of the European Union."* The day before COP26 started, we tweeted [LINK] on Macron's comments to the FT [LINK] that was a clear view on higher fossil fuel prices for the foreseeable future. Macron said, "*on demand for fossil fuels isn't going away for the foreseeable future*." Macron said "*What is happening now is ironic, because we are building a system where in the medium and long term fossil energy will cost more and more, that's what we want [to fight climate change]."* he said," Japan is another calling for a pragmatic time frame. On Nov 9, we tweeted [LINK] on Japan's release [LINK] on its conference with IEA Executive Director Faith Birol. Japan wrote "*The two sides also exchanged views on acceleration of decarbonization efforts following COP26, and shared the importance on measures with pragmatic time frame based on individual circumstances that each countries face including its renewable energy potentials".* (ii) Others just want to be able to say they warned people it would be expensive for years to come. The US is the best example. On Nov 8, we tweeted [LINK] on Energy Secretary Granholm's MSNBC Morning Joe comments. Biden never warned votes that the energy transition will happen but will lead to higher prices on oil, natural gas, and

electricity for years to come. We created a transcript of her saying "*So the long-term strategy is that. and yes we have a short term cost issue because the economy is still coming back on. we have a supply, demand that does not, the supply doesn't meet the demand. that is an issue we are going through. The president is all over this both in the short term and in the long term*."

<u>COP26 did not hurt the outlook for natural gas, rather Europe is helping the financing for natural gas.</u> One of our COP26 themes was that pro Net Zero companies and governments would wait until after COP26 to announce or approve items that wouldn't go over well at COP26. One of the climate change side criticisms of the EU is that the EU is shifting their relaxed position on nuclear and natural gas. On November 4, there was an excellent interview in Belgian news, L'Echo with Frans Timmermans, VP of the European Commission, who they describe as the "Mr. Climate" of the European Executive. Timmermans pointed to the shifting position on nuclear and natural gas so both could be considered as green investments for financing purposes. L'Echo asked "*The Commission must clarify its position on the taxonomy which defines the investments which can be categorized as "green". According to a press leak, nuclear and gas are in the project: will they stay there?"* Timmermans replied "*We have not yet made a decision, we will do so in a few weeks. Nuclear power is by no means green in the sense that it would be sustainable: there is a necessary fuel and waste. The principle of green energy is that it does not need fuel and does not produce waste. As for natural gas, your country is a good example: if you want renewable energies, in the transition you may need natural gas. You need to define its importance as transitional equipment, and you also need to avoid being locked into natural gas forever."*

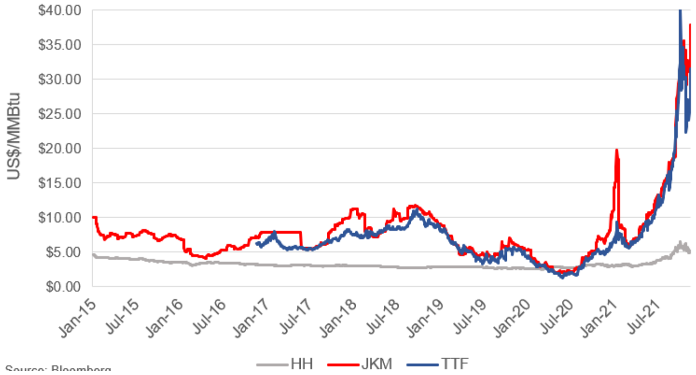
<u>It's been a great year for LNG prices and LNG supply/demand looks strong thru 2030.</u> We feel for the Net Zero fans the Europe energy/natural gas crisis just happened to show up in 2021 ahead of COP26 and Europeans realized that intermittent wind/solar can lead to big electricity and natural gas spikes, and even return to coal. It was also the year that natural gas followers realized the linkage of global natural gas markets and how Europe gas storage is the key indicator for the near-term direction of LNG and natural gas prices. It was a cold winter and Europe gas storage never caught up and still hasn't caught up. We first described this concept back in September 2017 and said Europe is the dumping ground for surplus LNG cargoes. When Europe isn't getting a lot of LNG cargoes, it means those LNG cargoes are wanted/needed in other parts of the world. It was the highest linkage of oil to natural gas markets to electricity markets in a long time. Natural gas and LNG prices hit records and are still exceptionally strong and winter hasn't even started. The outlook for LNG looks strong through the 2030 for the reasons noted later in the memo. Below we pasted Cheniere's current LNG long term supply outlook and most long-term outlooks are similar. LNG markets are very tight thru 2025 and need new supply thereafter. The problem with tight supply is that if anything disrupts supply, there are price spikes. Here is what Cheniere said on its Q3 call "*We now estimate that this tight market could extend well through 2025 and potentially tighter seasonal swings over the midterm period, especially for production from legacy plans remains inelastic and the current constraints on the coal supply cycle persist*."

Europe Gas Storage as of Nov 12, 2021



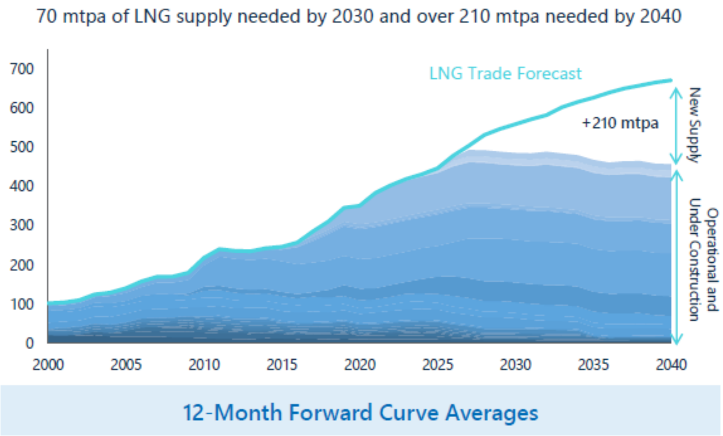
Source: Bloomberg

JKM, TTF and HH Prices



Source: Bloomberg

Global LNG Supply Outlook



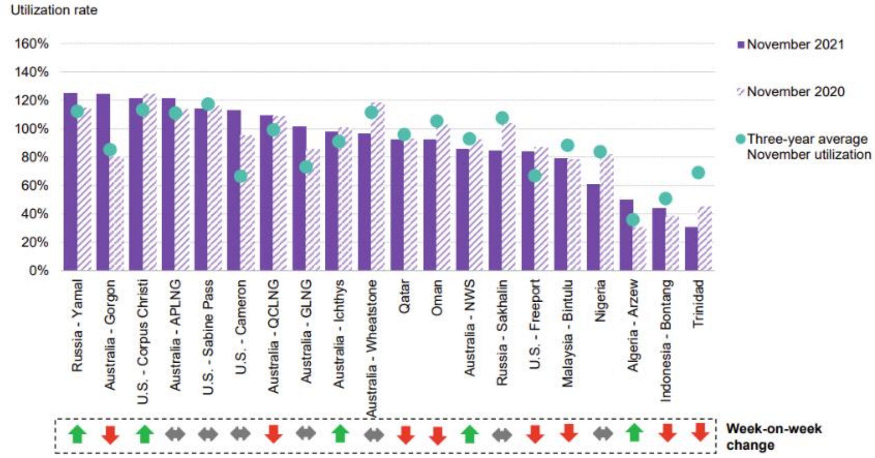
Source: Cheniere Q3/21 Call Investor Presentation

There are no strategic LNG reserves or immediate fix to draw upon if any existing LNG supply goes down, or under construction LNG supply gets delayed. Earlier today, the US and others drew up their strategic oil reserves ie. the oil reserves that are stored away never to be touched unless there is an emergence supply shortage. These strategic reserves are separate from working commercial crude oil inventories. There are no such "strategic" reserves for LNG. The only way to replace a negative LNG supply surprise is to draw on existing LNG commercial storage, existing LNG supply capacity elsewhere or cut back on demand. There is no such thing as having new replacement LNG supply show up in a year or two or three. Rather new replacement LNG supply takes at least 3 or 4 years to hit the market and that is only if there is an existing brownfield expansion that is effectively ready to go like a Cheniere Corpus Christi LNG Phase.

A number of unplanned supply interruptions from in-service LNG supply projects help create the today's tight LNG market. There have been many interruptions in the past year from existing LNG supply projects. No surprise, it seems to happen to older LNG supply projects. These are temporary so only impact the near term LNG supply/demand balance, but it also reminds that most older LNG supply projects export well below capacity. They also remind Asian LNG buyers that there is risk to existing LNG supply. Lastly, it is important to remember that the issue for all older LNG supply projects is that, unless they are drilling to add more reserves, the natural gas reserves supply the LNG will eventually come to an end. A few examples of interruptions. (i) Equinor's Melkoeya 0.63 bcf/d in Norway was shut down for 18 months due to a fire. A massive fire led to the Sept 28, 2020 shutdown of the 0.63 bcf/d Melkoeya LNG facility in Norway. The original restart date was Oct 1, 2021 but that was revised to March 31, 2022 with the caveat *"there is still uncertainty related to how the*

Covid-19 development will impact the project progress." (ii) Algeria's 0.5 bcf/d Skikda LNG Plant had an unplanned 8-week shut down due to failure of gas turbine control mechanism. Skikda also had an unplanned 6-mnth shut down in 2020. (iii) Petronas Bintulu LNG in Malaysia, there have been multiple reports that Petronas has been seeking approval for the cancellation of some winter cargoes due to upstream natural gas quality issues. (iv) Chevron Gorgon LNG. This was the high profile unplanned outages that caused each of the three trains to have unplanned repairs staring in H1/20. Even another one last week. On Nov 16, Reuters reported ""*Train 1 was shut down due to a small gas leak," the spokesperson said, adding that it was too early to tell how long the unit would be down. "We are preparing plans for investigation and repairs." The leak was detected on piping associated with the dehydration unit on Train 1 and the unit was shut down as a precautionary measure.* As of this morning, still no word on how long it will be down. The three trains have a total capacity of ~2.3 bcf/d. Gorgon produced ~2.3 bcf/d in 2019 but was down to 2.0 bcf/d in 2020. (v) Last November, the 1.03 bcf/d Qatargas LNG Train 1 had a 3-week unplanned shut down for a compressor repair. (vi) There have been many more LNG supply interruptions or reduced LNG cargoes from in-service LNG supply projects, whether it be from hurricanes, or production issues at Chevron Wheatstone or, even yesterday Bloomberg reported that the 0.9 bcf/d capacity Brunei LNG export project "*requested to reduce volumes for winter delivery to long-term buyers due to an upstream natural gas production issue, according to traders with knowledge of the matter."*

LNG Plant Utilization Rates (As of November 14, 2021)



Source: Bloomberg

<u>The game changer for LNG supply was the delay of 5.0 bcf/d of Mozambique LNG that was originally expected to start exporting in 2024.</u> We think the market didn't appreciate the full impact of TotalEnergies April 26 declaration of force majeure on its 1.7 bcf/d Mozambique LNG Phase 1. Surprisingly, markets didn't look to the broader implications, which is why we posted our 7-pg Apr 28 blog "*Multiple Brownfield LNG FIDs Now Needed To Fill New LNG Supply Gap From Mozambique Chaos? How About LNG Canada Phase 2?*" [LINK] We highlighted that Mozambique LNG delays were actually 5 bcf/d, not 1.7 bcf/d. This 5 bcf/d of Mozambique LNG supply was built into all, LNG supply forecasts. The delay in TotalEnergies Phase 1 would lead to a commensurate delay in its Mozambique LNG Phase 2 of 1.3 bcf/d. TotalEnergies Phase 2 was to add 1.3 bcf/d. There was no firm in service date, but it was expected to follow closely behind Phase 1 to maintain services. That would have put it originally in the 2026/2027 period. The original in-service for Phase 1 was 2024, which was then pushed back to 2025. In the Sept investor outlook, TotalEnergies said "*This forecast of upstream production in 2026 includes Mozambique LNG production only in 2026. This relies on the assumption that the project activity will review in 2022.*" In its Oct 28 Q3 call, TotalEnergies seemed to suggest any restart wouldn't be in early 2022. Mgmt said "*we remain fully committed to develop this project, the resource coming from Area 1. But only of course when the condition will allow. We, for obvious reasons, a stable and peaceful environment to be able to mobilize our staff. And its not possible at the present time. We will see if it will be possible next year, in 2022, and if it's the case, production could be there in 2026, exactly what we indicated in September during the investor day. So we are committed to this project. It's there of course, so now we have to be patient and see how the situation will improve in the coming months".* If

Phase 1 is pushed back 2 years to at least 2026 so will the follow up Phase 2, so more likely, it will be at least 2028/2029. The assumption for most, if not all, LNG forecasts was that Phase 2 would follow Phase 1. Exxon Rozuma Phase 1 of 2.0 bcf/d continues to be pushed back in timeline especially following Total Phase 1. Exxon's Mozambique Rozuma Phase 1 LNG will add 2.0 bcf/d and, pre-Covid, was originally expected to be in service in 2025 but was always expected to follow TotalEnergies Phase 1. In the Oct 29 Q3 call, Exxon mgmt gave no indication of any movement on its Rozuma LNG with mgmt saying *"paused simply because of the security situation on the ground, which we will continue to look at and revisit over time".* If we assume the same one-year delay, it would put Exxon Rozuma at 2027/2028 at the earliest instead of its original 2025. What this all means is that the Mozambique LNG delays are not 1.7 bcf/d, but 5.0 bcf/d of projects that were in all, if not most, LNG supply forecasts.

<u>Mozambique force majeure didn't attract the big attention because the major LNG suppliers didn't highlight the Mozambique impact for the first two months.</u> It was difficult for markets to see the bigger issue when the major LNG suppliers weren't making a big deal of Mozambique for the first two months. In our May 9, 2021 Energy Tidbits memo, we said we had to chuckle when we saw Cheniere's response in the Q&A to its Q1 call on May 4, that they only know what we know from reading the Total releases on Mozambique and its impact on LNG markets. It's why we tweeted [LINK] "*Hmm! $LNG says only know what we read on #LNG market impact from $TOT $XOM MZ LNG delays*. *Surely #TohokuElectric & other offtake buyers are reaching out to #Cheniere. MZ LNG delays is a game changer to LNG in 2020s, see SAF Group blog. Thx @olympe_mattei @TheTerminal #NatGas".* We previously wrote how could Cheniere not be talking to LNG buyers for Total and /or Exxon Mozambique LNG projects. In the Q1 Q&A, mgmt was asked about Mozambique and didn't know any more than what you or I have read. Surely, they were speaking to Asian LNG buyers who had planned to get LNG supply from Total Mozambique or Exxon Rozuma Mozambique, or both. Mgmt is asked "*wanted to just kind of touch on the color use talking about for these supply curve. And are you able to kind of provide any thoughts on the Mozambique and a deferral with the project of that size on 13 and TPA being deferred by we see you have you noticed any impact to the market has is there any impact for stage 3 with that capacity? Thanks*." Mgmt replies "*No. Look, I only know about the Mozambique delay with what I read as well as what you read that from total and an Exxon. And it's a sad situation and I hope everybody is safe and healthy that were there to experience that unrest but no I don't think it's, again it's a different business paradigm than what we offer. So, we offer a full value product, the customer doesn't have to invest in equity, customer doesn't have to worry about the E&P side of the business because, we've been able to both the by at our peak almost 7 Dee's a day of US NAT gas from almost a 100 different producers on 26 different pipelines and deliver it to our to facilities. So we take care of a lot of what the customer needs".*

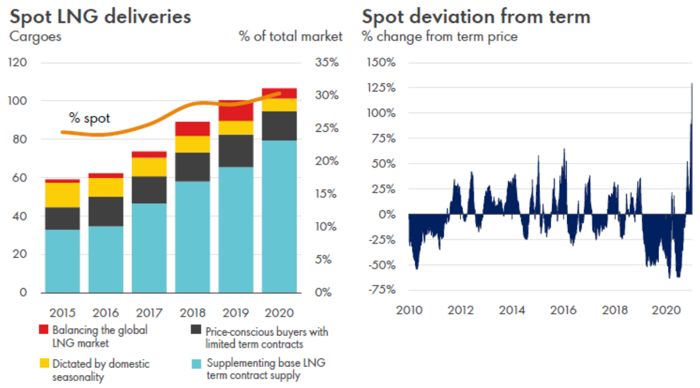
<u>But at the end of June, major LNG suppliers came out with bullish mid/long term talk or action</u>. (i) Our July 4, 2021 Energy Tidbits memo noted that it looks like Cheniere has stopped playing stupid with respect to the strengthening LNG market in 2021. We can't believe they thought they were fooling anyone, especially their competitors. That week, they came out talking about how commercial discussions have picked up in 2021 and it's boosted their hope for a Texas (Corpus Christi) LNG expansion. On Wednesday, Platts reported "*Pickup in commercial talks boosts Cheniere's hopes on mid-scale LNG project*" [LINK] Platts wrote "*Cheniere Energy expects to make a "substantial dent" by the end of 2022 in building sufficient buyer support for a proposed mid-scale expansion at the site of its Texas liquefaction facility, Chief Commercial Officer Anatol Feygin said June 30 in an interview." "As a result, he said, " The commercial engagement, I think it is very fair to say, has really picked up steam, and we are quite optimistic over the coming 12-18 months to make a substantial dent in that Stage 3 commercialization."* Platts also reported that Cheniere noted this has been a tightening market all year (ie would have been known by the May 4 Q1 call). Platts wrote "*We obviously find ourselves at the beginning of this year and throughout in a very tight market where prices today into Asia and into Europe are at levels that we frankly haven't seen in a decade-plus," Feygin said. "We've surpassed the economics that the industry saw post the Fukushima tragedy in March 2011, and that's happened in the shoulder period."* It's a public stance as to a more bullish LNG outlook. (ii) On June 23, Qatar Petroleum was clear that they saw an LNG supply gap. We tweeted [LINK] "*1/3. #LNGSupplyGap coming. big support for @qatarpetroleum expansion to add 4.3 bcf/d LNG. but also say "there is a lack of investments that could cause a significant shortage in gas between 2025-2030" #NatGas #LNG".* And importantly, this is after QPC accounts for their big LNG expansion. The QPC release said "*However, His Excellency Al-Kaabi voiced concern that during the global discussion on energy transition, there is a lack of investment in oil and gas projects, which could drive energy prices higher by stating that "while gas and LNG are important for the energy transition, there is a lack of*

investments that could cause a significant shortage in gas between 2025-2030, which in turn could cause a spike in the gas market."

Markets felt reassured by Qatar's massive expansion without realizing India alone needs 3x the Qatar expansion LNG capacity. Qatar's LNG expansion is huge and plans to add 4.3 bcf/d capacity. However, India alone needs 3x that amount of LNG. On Oct 22, Petronet CEO Singh presented at the India Energy Forum on Friday. As soon as we saw the reports, we tweeted [LINK] "*Bullish for #LNG #NatGas in 2020s. #Petronet CEO fcasts India LNG imports +12.4 bcfd to reach 15.8 bcfd (120 MTPA) in 2030. In line with his June est, see below SAF Group June 20 Energy Tidbits #Petronet sees LNG imports +13 bcfd to 2030. Thx @JournoDebjit @rajeshsing13 #OOTT".* Bloomberg's India energy team reported "*India's import of natural gas is expected to hit 120 million tons/year by 2030 as the nation targets an energy mix goal, Akshay Kumar Singh, CEO of Petronet LNG, said at the India Energy Forum by CERAWeek. NOTE: India aims to boost use to natural gas to 15% of primary energy mix from about 6% now. * India's current annual LNG import is about 26 million tons".* Singh is forecasting India's LNG imports to grow from current 26 MTPA (3.4 bcf/d) to 120 MTPA (15.8 bcf/d) in 2030. That is an increase of 12.4 bcf/d to 2030. This is 3x the massive Qatar expansion capacity.

The late June/early July sea change in Asian LNG buyers contracting is the best validation of the LNG supply gap and gamechanger for LNG supply FIDs. Analysts can make forecasts, but the best evidence of the supply gap is Asian LNG buyers are putting money up to change their contracting moving away from spot/short term to locking in long term LNG supply through 2030. This is an abrupt turn from Asian LNG buyers contracting strategy in 2019 and 2020, when the Asian LNG buyer weren't trying to extend long term contracts, rather, the push was to try to renegotiate down its long-term LNG deals. The reason was clear, as spot prices for LNG were less than long term contract prices. This led to their LNG contracting strategy – move to increase the proportion of spot LNG deliveries out of total LNG deliveries. Shell's LNG Outlook 2021 was on Feb 25, 2021 and showed this pre-Mozambique force majeure trend. But post Mozambique LNG force majeure, clearly Asian LNG buyers did the math, saw a new, sooner and larger LNG supply gap and were working the phones in March/April/May trying to lock up long term supply. They were clearly working the phones with a new priority to lock up long term LNG supply. Major long-term deals don't happen overnight, so it makes sense that we started to see these new Asian long term LNG deals start at the end of June. Its why wrote our 8-pg July 14 blog, "Asian LNG Buyers Abruptly Change and Lock in Long Term Supply – Validates Supply Gap, Provides Support For Brownfield LNG FIDs" that started off "The last 7 days has shown there is a sea change as Asian LNG buyers have made an abrupt change in their LNG contracting and are moving to lock in long term LNG supply. This is the complete opposite of what they were doing pre-Covid, when they were trying to renegotiate Qatar LNG long term deals lower and moving away from long term deals to spot/short term sales. Why? We think they did the same math we did in our April 28 blog "Multiple Brownfield LNG FIDs Now Needed To Fill New LNG Supply Gap From Mozambique Chaos? How About LNG Canada Phase 2?" and saw a much bigger and sooner LNG supply gap driven by the delay of 5 bcf/d of Mozambique LNG that was built into most, if not all LNG supply forecasts. Asian LNG buyers are committing real dollars to long term LNG deals, which we believe is the best validation for the LNG supply gap." Since late June, there have been at least nine Asian LNG buyer long term deals with total volumes of 2.57 bcf/d with an average term of 15 years. In addition, there are reports of Asian LNG buyers about to join this group such as Hokkaido Gas who is looking for 5-10 year LNG supply starting after 2025. Note that in addition to the Asian LNG buyers deals, there have been European long-term deals including PGNiG (Poland) agreement to purchase an additional 2 mtpa (0.26 bcf/d) for 20 years from Venture Global.

Spot LNG deliveries and Spot deviation from term price



Source: Shell LNG Outlook 2021 on Feb 25, 2021

Asian LNG Buyers Long Term Deals Signed Since July 1, 2021

Signed Long-Term Asian LNG Deals Since July 1, 2021					
Date	Buyer	Seller	Country	Volume	Duration
			Buyer / Seller	(bcf/d)	Years
July 7, 2021	CNOOC	Petronas	China / Canada	0.30	10.0
July 9, 2021	CPC	Qatar Petroleum	Taiwan / Qatar	0.16	15.0
July 9, 2021	Guangzhou Gas	BP	China / US	0.13	12.0
July 12, 2021	Korea Gas	Qatar Petroleum	Korea / Qatar	0.25	20.0
September 29, 2021	CNOOC	Qatar Petroleum	China / Qatar	0.50	15.0
October 11, 2021	ENN	Cheniere	China / US	0.12	13.0
November 4, 2021	Unipec	Venture Global LNG	China / US	0.46	20.0
November 4, 2021	Sinopec	Venture Global LNG	China / US	0.53	20.0
November 5, 2021	Sinochem	Cheniere	China / US	0.12	17.5
Total Asian LNG Buyers New Long Term Contracts Since Jul/21				**2.57**	
*Excludes Asian short term/spot deals					
*Excludes non-Asian long term deals ie. Poland's PGNiG new 20-yr deal for 0.26 bcf/d from Venture Global					

Source: Bloomberg

An even stronger validation when the world's largest LNG importer, Japan's JERA, is paying $2.5b to buy 25.7% in Freeport LNG to secure stable LNG supply. Entering into long term supply contracts is a big validator but there was an even bigger validation on last Monday Nov 15, when Japan's JERA announced [LINK] it was spending $2.5b to acquire a 25.7% interest n Freeport LNG "to secure a stable LNG supply". This is an even stronger validation that a long term contract. JERA is the world's largest LNG buyer. JERA announced it "*JERA will not only be involved in the entire existing Freeport LNG project (three trains with an annual production capacity of approximately 15.45 mtpa) but will also work with FLNG to advance new LNG projects including production capacity expansion and the development of Train 4.*" The existing three LNG trains capacity is 2.0 bcf/d.,

Long term LNG supply deals provide the needed anchor for new LNG FIDs. The return of long-term LNG supply deals provides the financing capacity or financial comfort to commit to new LNG supply FIDs. These are critical for the independent LNG supply players who will not FID without a certain minimum long term contract coverage. We recognize supermajors, like Shell, have their own financial capacity and do not need the financing potential of long-term LNG deals to FID a project. Rather the long-term contracts provide the financial comfort to make a FID. Whether is financial comfort or capacity, the abrupt change for Asian LNG buyers to commit to long-term LNG supply deals are a game changer for LNG markets and sets the stage for LNG FIDs.

And it looks like we are seeing the start of FIDs on both brownfield LNG and stalled greenfield LNG - we expect more in the coming months. It looks like LNG supply projects, both brownfield and greenfield, are now moving to FID or are trying to get to FID in the coming months. Yesterday, Woodside Petroleum announced it made FID on its $12.0 billion LNG development at Scarborough/Pluto Trains to add up to 1.05 bcf/d with first LNG cargo in 2026. Woodside highlighted they estimated >13.5% IRR and payback of 6 years. Prior to this FID, over the past few months there were clear comments/signals from other LNG players on the potential for near term FIDs on new LNG supply. In our July 14 blog, we said "*We expect these decisions to be looked at before the end of 2021 for 2022 capex budget/releases. One wildcard that could force these decisions sooner is the already stressed out global supply chain. We have to believe that discussion there will be pressure for more Asian LNG buyer long term deals sooner than later*." More on the supply chain later, but we did not expect to see any major LNG announcements during COP26. Rather we expect the window is for the next few months.

- Cheniere Corpus Christi Stage 3. Cheniere has been publicly calling for FID in 2022 with most expectations being for early in 2022.

- Cheniere Corpus Christi Stage 4. In the Q&A of the Q3 call on Nov 4, Cheniere was asked if they are even thinking about the Corpus Christi Stage 4 at this point. Mgmt replied Yes.

- Woodfibre LNG. We look at Woodfibre LNG as the British Columbia LNG supply project that minds its own business and just keeps advancing to FID. There is one train with capacity of 0.3 bcf/d and is supported by 15-yr sales contracts with BP. Earlier today, Woodfibre announced [LINK] that it signed an EPFC contract with McDermott International. In the release, Woodfibre said "*In addition to the EPFC work, McDermott will also be responsible for commissioning and start-up services. Pre-installation work for the project is planned for early 2022 and will gradually ramp up to September 2023, when major construction is targeted to begin. Major works will continue through to substantial completion, expected in Q3 2027.*"

- Tanzania. Perhaps the best indicator of how Mozambique force majeure changed the LNG outlook. Tanzania LNG went off the radar when Equinor wrote off its investment in 2019. Post Mozambique force majeure Equinor and Shell wrote Tanzania that there was a limited window if Tanzania is to have a change at resurrecting the LNG potential. On Nov 8, Tanzania Energy Minister Makamba tweeted [LINK] he has started negotiations with Shell, Equinor, Pavillion, ExxonMObil and Ophir to work to an LNG FID in the next 6 months. Its not clear if they were working for a broader LNG area but, prior to this year, the Equinor/Shell potential Tanzania project was a potential 1.3 bcf/d LNG export project.

- BP Mauritania FLNG Phase 2. In the Q&A of the BP Q3 call, mgmt replied "*And Tortue, we're going well with Phase one. And we're taking a look at Phase two and trying to come to agreement with partners, government and our own engineers on what is the right thing to do. So stay tuned.*" Mauritania is a 4-phase FLNG, Phase 1 is 0.33 bcf/d capacity.

- Tellurian Driftwood LNG. We have trouble following the public comments and videos from mgmt, but we continued to see reports that FID is now expected to be in H1/22.

- TotalEnergies Papua LNG 0.74 bcf/d is back on track. On June 8, we tweeted [LINK] *"Timing update Papua #LNG project. $OSH June 8 update "2022 FEED, 2023 FID targeting 2027 first gas". $TOT May 5 update didn't forecast 1st gas date. Papua is 2 trains w/ total capacity 0.74 bcf/d."* We followed the tweet saying [LINK] *"Bigger #LNG supply gap being created >2025. Papua #LNG originally expected FID in 2020 so 1st LNG is 2 years delayed. Common theme - new LNG supply is being delayed ie. [Total] Mozambique. Don't forget need capacity>demand due to normal maintenance, etc. Positive for LNG."*

<u>Does the increasing competition/demand for global fabricators, services, etc mean Shell will have to get LNG Canada Phase 2 FID in the queue if they want to protect its brownfield cost and timing advantage.</u> We recognize that LNG Canada Phase 2 FID is not on radars and most North American LNG outlooks don't even mention it as a possibility. But we believe the continuing global supply chain stresses and movement by others to look at new FIDs are likely to have Shell consider FID for LNG Canada Phase 2 in the coming few months and not wait a year. We think the issue for Shell to FID LNG Canada Phase 2 has moved from a market risk to an execution risk ie. how/can they ensure Phase 2 can have the

cost and timing benefit of a brownfield projects. All anyone knows from the outside is that the Asian LNG buyers want security of supply and LNG suppliers are now moving now to add supply to fill the increasing supply gap. Those aren't market guesses; they are simply a reflection of what the people who have to commit capital are doing. Their financial actions/commitments are the best indicator for this increasing supply gap. Plus, the one thing that is clear from LNG supply is that the risk is almost always to downside to unplanned delays or interruptions. The LNG market looks to be there so the key risk factor Shell on LNG Canada Phase 2 is execution risk. The risk to any major construction project has heightened with the pandemic causing global fabricator, global metals, steel, experienced services, and other supply chain issues. The challenges facing major industrial projects is more than the general supply chain issues. The reason why we think Shell is faced with a near-term decision for FID on LNG Canada Phase 2 is that, if they want to have a chance to have the brownfield cost and timing benefits in a world of increasing supply chain issues, we believe they will have to have what we call a continuous construction cycle for Phase 2, ie. retain the spot in the queue for the global fabricators, global and domestic suppliers and trades from Phase 1 and move seamlessly to Phase 2. On Oct 7, LNG Canada announced [LINK] "*Three years after taking a final investment decision (FID) on Canada's first major liquefied natural gas project, the LNG Canada consortium said October 6 the C$40bn (US$31.7bn) project was more than 50% complete. "We're moving swiftly towards commissioning and start-up, and to fulfilling our promise of delivering a world-class LNG facility in Kitimat*." There are different services, trades, people, fabricators, steel, equipment, etc at different phases and LNG Canada would want to retain the options for these services if they want to have the cost advantage of brownfield costs and time to completion. And maintaining a continuous construction cycle is even more important given that there are more global LNG supply projects now moving to FID. We have to believe LNG Canada will want to exercise any options with services and maintain any overseas fabricator slots to keep alive the possibility of a continuous construction cycle. This is the model that Cheniere has used successful in delivering its LNG phases on time and on budget. Its why we believe its now the time for Shell to FID LNG Canada Phase 2. If they are unable to retain any overseas fabricator slots, international service companies and domestic services/trades, it would add to the cost and timeline of LNG Canada Phase 2 vs the costs of a continuous construction cycle. Don't forget they are looking at a much stronger LNG outlook for the 2020s today than a year ago.

<u>LNG Canada Phase 2 will lift the overall project returns.</u> LNG Canada Phase 2 would add two additional trains and capacity of ~1.8 bcf/d and increase the project capacity to ~3.6 bcf/d. We do not know the internal LNG Canada project returns. Phase 1 would have lesser returns as it is burdened with some one-time costs and added costs to set up for the potential of Phase 2. Phase 2 as the brownfield leg would have significantly higher returns and adding Phase 2 would bump the returns of LNG Canada in total.

<u>Sounds like momentum on TC Energy and LNG Canada resolving their cost overrun dispute - If not, then we don't see how there will be a FID on LNG Canada Phase 2.</u> We continue to believe that a key business issue holding back any Shell FID on LNG Canada Phase 2 has been the unresolved cost and timing dispute with TC Energy on the construction of the Coastal GasLink. This is the sole pipeline to deliver natural gas to LNG Canada. The Coastal GasLink pipeline was designed to be able to expand capacity to have enough capacity to support both Phase 1 and 2. But we have believed (and still believe) that LNG Canada would not proceed with Phase 2 until there was a resolve on the cost dispute with TC Energy. There had been no indications pointing to a resolve until the TC Energy Q3 results on Nov 5. In the Q3 report, TC Energy disclosed they had *"committed to provide additional temporary financing to the project, if necessary, of up to $3.3 billion as a bridge to a required increase in project-level financing to fund incremental costs*." In addition, in the Q3 call Q&A mgmt gave the most optimistic comments we have noted on the potential for resolve. Mgmt said "*we can of course discuss the details of any discussions on cost and schedule in the issues between us because they're confidential. But what I can say is that we're very hopeful that ultimately we're going to reach an agreement between us on those issues and that of course will lead to the resolution of some of the temporary financing as well*." There is no guarantee of a resolve, but it seems like there is momentum to get to a resolve. And resolving this cost dispute is needed for any LNG Canada Phase 2 FID. Don't forget, similar to LNG Canada, Coastal GasLink overall economics will get a boost with the full capacity to supply Phase 2 ie. there is economic upside to TC Energy to get the expansion.

<u>Shell has given no formal indications of looking at FID, but it feels like Shell's CEO has been showcasing LNG Canada for some reason</u>. We often find that big companies will drop hints of some things that might come. Shell did this on LNG

Canada Phase 1, we highlighted the hints we saw coming from Shell on our expectations for FID several months ahead of others because of these hints. Shell has given no formal indication that they are considering FID of LNG Canada Phase 2. We believe Shell is one of the leaders in the Energy Transition and Shell CEO van Beurden brings a common-sense view to that leadership. Shell has highlighted how lower emission LNG will be critical to provide long term cash flow to fund the emissions reductions. So, his recent comments seemed to showcase LNG Canada as one of the key long term cash flow sources and we do not believe he would have showcased LNG Canada in this manner if it was only going to be Phase 1. It would seem to us to be disproportional showcasing.

- On Oct 6, Shell CEO van Beurden made a point of showcasing LNG Canada and saying he expected it to still exist in the 50s and later. Phase 1 starts up in the mid 2020s (most assume no later than 2025) and we don't expect he would be showcasing a 30+ year Phase 1 to be operating in the normally big company CEOs showcase a project for a reason. Platts reported [LINK] *"LNG and certainly chemicals and products are going to be relevant for a long time to come — LNG, think of it as a stayer in our portfolio," he said, adding Shell had been "proven right" in its expectation of 4% annual demand growth for LNG. "In the long run — think second half of this century — many of our LNG positions will still be in play. Building LNG Canada at the moment, I don't expect that to be wound down in the '40s, I expect it to still exist in the '50s and later," Van Beurden said. "Whatever we build, we'd better make sure it's carbon competitive, it's first quartile, it can be decarbonized, and therefore it's still relevant in a world that hopefully by then is a net-zero world."*

- In the Q&A of the Q3 call Oct 29, it seemed that CEO van Beurden showcased LNG Canada. He was asked if putting the emissions targets out there has any implications to grow the LNG business or does that imply a shift from equity volumes to be an offtaker for LNG. Van Beurden replied "*But on your other point, the LNG plants, yes, indeed, I do have a -- and sort of quantum of automations. And of course, the ones we operate, which are quite a few actually come onto our account. So we've been very clear that if we want to build new LNG plants, that better come with very competitive carbon footprints on the operational side. And we have to find ways to offset this and offset not with nature based solutions, but offset it with savings elsewhere. So I've been very clear with our organization. If we are to do another energy brands, say for instance in Canada, it needs to come either without emissions or you need to find a way to reduce emissions elsewhere, because we are on a trajectory to bring down our emissions to net zero by 2050".* We don't think van Beurden had to include his *"for instance in Canada*" in his response. It just seemed to be another example of van Buerden showcasing LNG Canada as a place for future growth in equity LNG volumes.

An LNG Canada Phase 2 would be a huge plus to Cdn natural gas. LNG Canada Phase 1 is a material natural gas development as its 1.8 bcf/d capacity represents approx. 20 to 25% of Cdn gas export volumes to the US. The EIA data showed US pipeline imports of Cdn natural gas as 6.83 bcf/d in 2020, 7.36 bcf/d in 2019, 7.70 bcf/d in 2018, 8.89 bcf/d in 2017, 7.97 bcf/d in 2016, 7.19 bcf/d in 2015 and 7.22 bcf/d in 2014. An LNG Canada Phase 2 FID would be a huge plus for Cdn natural gas. It would allow another ~1.8 bcf/d of Cdn natural gas to be priced against pricing points other than Henry Hub. It would provide demand offset versus Trudeau if he moves to make electricity "emissions free" and not his prior "net zero emissions". Both Asian LNG buyers and LNG suppliers are making big capital commitments to secure long term LNG supply. The LNG outlook has changed and COP26 did not disrupt this outlook. An FID for LNG Canada Phase 2 would provide big support to Cdn natural gas for the back half of the 2020s. And perhaps if LNG Canada is exporting 3.6 bcf/d to Asia from two phases, it could help flip Cdn natural gas to a premium vs US natural gas especially if Biden is successful in reducing US domestic natural gas consumption for electricity. We think the next few months are likely the right time for Shell to look at FID for LNG Canada Phase 2 as, in a world of increasing supply chain shortfalls, they need to make sure they can commit to fabricators, services and trades for a continuous construction cycle to maintain brownfield costs and time to completion ie. a Cheniere type advantage. Who knows what Shell will decide, CEO van Buerden's recent showcasing of LNG Canada reminds us what happened in 2018 ahead of the LNG Canada Phase 1 FID. Just imagine the future value of Cdn natural gas if there is visibility for 3.6 bcf/d of Western Canada natural gas to be exported to Asia.

This is far from an easy decision for Shell, but we think the likely answer is Yes, and not No. We recognize that there has been no chatter that Shell is or will be considering FID on LNG Canada Phase 2 and it may not be the ideal time. Shell is a leader in the Energy Transition but has also been extremely logical/rational in how to accelerate emissions reductions. LNG looks very strong thru 2030 and Asian LNG buyers have abruptly shifted to looking for long term LNG supply. Woodside went FID on its Scarborough/Pluto LNG project yesterday, and other LNG suppliers are pointing to FIDs on multiple brownfield and greenfield FIDs in the coming year. Shell has an advantage that LNG Canada Phase 2 is a large brownfield 1.8 bcf/d phase. The timing may not be ideal, but we believe the world of increasing demand stresses on global fabrications, services, etc mean that it will be important to get LNG Canada Phase 2 in the queue for global and domestic services/fabricators. Everyone in western Canada will hope so because a FID will be a huge game changer to western Canada natural gas valuations. LNG Supply FIDs are starting to happen, does Shell need to get LNG Canada Phase 2 FID in the queue to protect its brownfield advantages? Only Shell knows, but we believe the abrupt positive changes to the LNG market in the face of continuing global supply chain stresses mean the answer is Yes and the timing is the next few months and not the next year. This would be big to Cdn natural gas.

Executive summary

35.2m tons

Projected global LNG imports in December 2021

+3.6%

Projected increase in global LNG supply in December compared to November

$35/MMBtu*

BloombergNEF's estimate for average Japan-Korea Marker price in 1Q 2022

***Disclaimer:** Please note that BNEF does not offer investment advice.*

Outlook for December

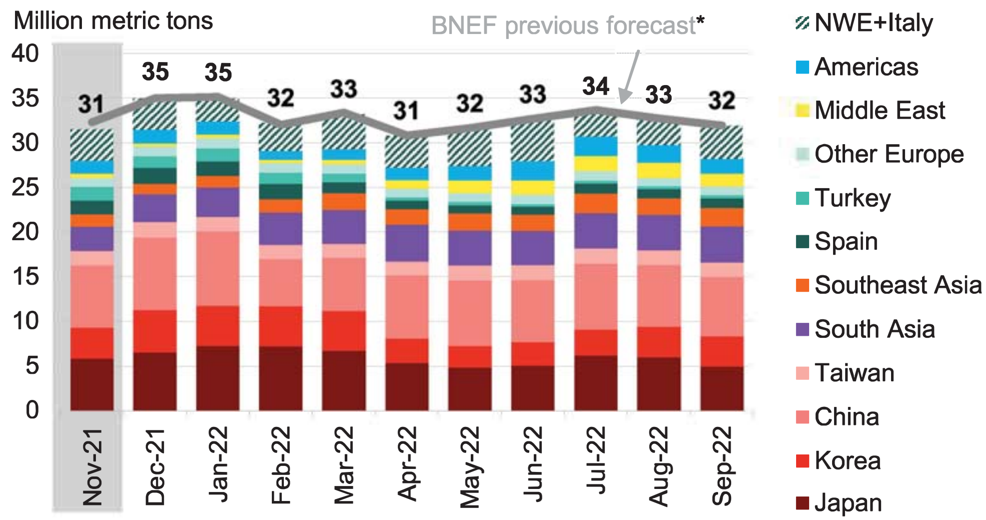
- Global December imports of liquefied natural gas (LNG) are forecast at 35.2 million metric tons, 12% higher than November. North Asia imports are set to grow to meet rising heating demand. Japan's imports will get a boost from coal outages and delays in nuclear restarts. The extent of LNG demand growth in December will depend on how cold Asia gets, as the La Nina weather phenomenon could result in colder-than-normal weather. South Asia LNG imports may be lower than previously forecast with a terminal shutdown in Bangladesh and India seen reducing LNG imports.
- The forecast for Europe's end-of-winter gas storage is cut by more than half from the previous Global LNG Monthly report. While Europe's gas demand has stayed resilient, LNG imports have been lower than expected amid competition with Asia and Russian gas flows remained subdued in November. Turkey's LNG demand is revised up on expectations of higher gas-to-power demand.
- Global LNG supply in December is forecast at 34.4 million tons, 3.6% higher than November. Production issues have surfaced in Indonesia and Brunei, adding to Malaysian supply woes. Supply is expected to be impacted throughout the winter. Overall, however, LNG supply will grow in December as Qatar returns to full-throttle exports after maintenance. U.S. and Australian exports are also forecast to rise on netbacks and seasonality.
- BloombergNEF estimates Japan-Korea Marker (JKM) prices will average $35 per million British thermal units (MMBtu)* for delivery in the first quarter of 2022. Currently, the average price of Asian spot tender cargoes for first quarter delivery reported by Bloomberg News in November is $37.5/MMBtu.

November in review

- Global LNG imports totaled 31.5 million tons in November, up 2.7% from October and 6% higher than the same month last year. China and Japan led the month-on-month growth in imports as heating demand rose, while Korea's LNG imports declined amid storage withdrawals. Europe received more LNG, supported by strong demand from the U.K. and Turkey, but remained unable to offer more attractive netbacks than Asia.
- Total LNG exports reached 33.2 million tons in November, up 0.5% from October and 5.4% higher than last year. Qatar exports fell due to maintenance, but the drop was offset by stable Australian exports and growing U.S. and Russian supply. Indonesia, Brunei and Malaysia exports grew month-on-month despite reported upstream issues.
- JKM prices remained volatile in November, tracking TTF prices while reflecting rising LNG freight rates. Pacific Basin outages and expectation of cold weather brought Asian buyers back to the spot market, pushing up prices. LNG tanker term-charter rates skyrocketed on vessel demand for winter shipments.
- Chinese buyers remained active in signing term contracts with mostly U.S suppliers.

Global LNG demand: North Asia to lead increase in December imports on lower coal and nuclear generation

Global LNG demand forecast



*Source: BloombergNEF, Bloomberg Terminal's AHOY JOURNEY <GO> (historical). *Previous forecast is as per the previous Global LNG Monthly report. Numbers shown are the revised global LNG forecast. Refer to appendix for country breakdown of regions.*

Market (million tons)	Dec. forecast	m/m change	4Q vs 3Q change	Dec. y/y change
Japan	6.5	+0.7	-0.1	-1.1
South Korea	4.8	+1.3	+1.0	+0.7
China	8.1	+1.1	+2.2	+0.1
NWE+Italy	3.7	+0.2	+4.6	+0.9
Global Demand	**35.2**	**+3.7**	**8.3**	**+2.3**

Source: BloombergNEF. Note: m/m is month-on-month, y/y is year-on-year.

Outlook highlights

- **Actuals versus forecasts:** Actual November LNG imports came in 2% (0.8 million tons) below BNEF's forecast, due to lower-than-expected deliveries to South Korea and South Asia. Korean imports fell as higher heating demand was met using LNG storage withdrawals. India saw the biggest decrease among South Asian importers.

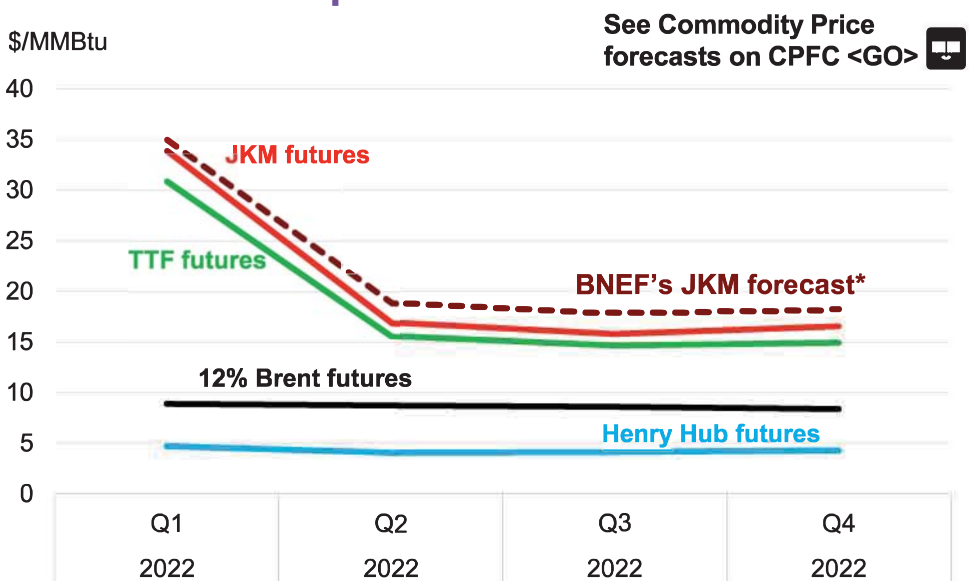
- **Outlook:** Global LNG imports in December could be 12% higher than last month. Total fourth quarter imports are expected to be 9% higher than the third quarter. Besides falling temperatures, lower coal and nuclear generation in Japan and Korea will support December LNG imports. China's gas demand in December will be the highest over the year, underpinning strong monthly growth in LNG imports. Europe will face fierce competition from North Asian buyers to secure scarce spot cargo supply. Mooring line damage in Bangladesh could divert a handful of cargoes to other markets in December.

- **Forecast revisions:** Demand forecasts for December are marginally increased by 0.2 million tons compared to the previous forecast. LNG imports for Japan and Korea are adjusted up due to higher gas demand from the power sector. Kuwait's LNG demand is revised up due to higher-than-expected imports in November. Turkey's forecast is increased on strong demand for spot cargoes from state-owned energy company Botas, likely due to high gas demand for power.

Outlook

LNG spot prices: BNEF forecasts JKM to range between $35.0-18.9/MMBtu over 1Q-2Q 2022

LNG benchmark prices – outlook



$/MMBtu	BNEF JKM forecast	JKM futures	TTF	12% Brent
1Q 2022	35.0	33.9	30.8	8.9
2Q 2022	18.9	16.9	15.6	8.7
3Q 2022	17.8	15.8	14.6	8.6
4Q 2022	18.2	16.5	14.9	8.4

*Source: BloombergNEF, Bloomberg Terminal, NYMEX, ICE. Note: *See forecast methodology in the Appendix.* ***Futures curves are as of Nov. 29, 2021.***

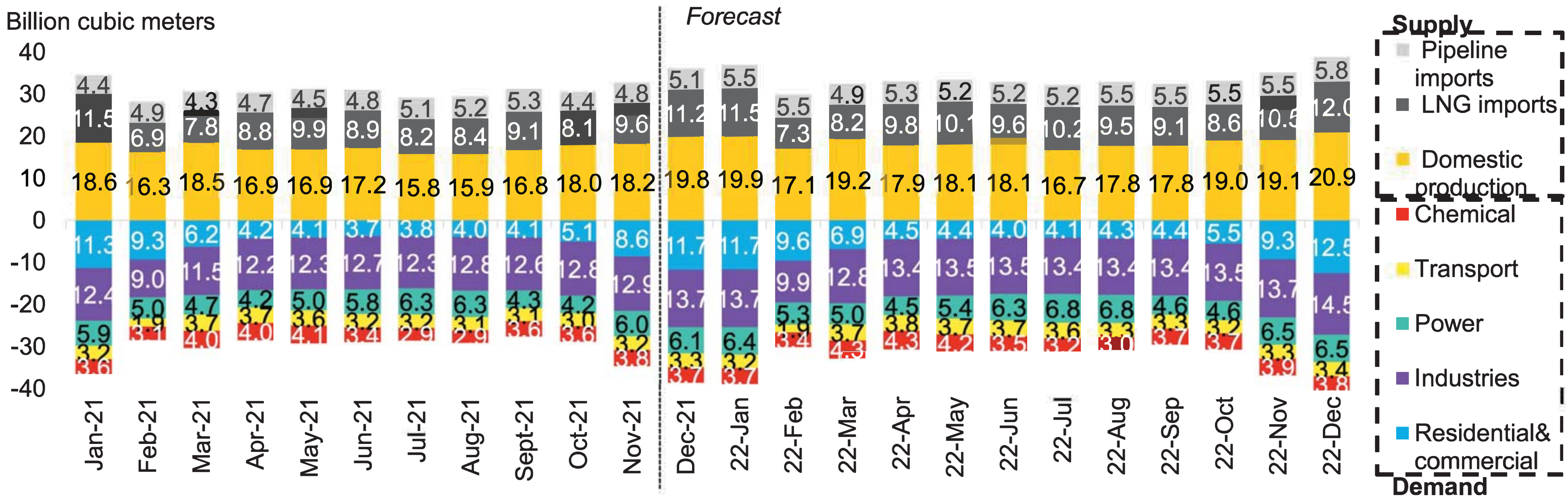
DISCLAIMER: Please note that BNEF does not offer investment advice. Clients must decide for themselves whether current market prices fully reflect the issues discussed in this report and if the methodology encompasses all factors that will impact projected prices.

- Europe's gas market is likely to be tighter in coming months. Lower-than-expected Russian supplies, colder weather and resilient gas demand in Europe means TTF prices will need to rise to lower the spread with JKM and attract more LNG. North Asian buyers are still looking for a few spot cargoes due to higher-than-expected winter demand. This will create upward pressure on JKM prices as Asian buyers compete with gas-starved Europe. BNEF estimates quarterly average JKM prices will be between $35.0-18.9/MMBtu* over 1Q-2Q 2022. The price forecasts are revised up from $27.6-17.1/MMBtu in the November report for the same period.
- Japan and Korea appear to be better prepared for winter than last year, as LNG inventories for December to January are expected to be higher than the previous winter, assuming 10-year normal weather. Japan is likely to have 4.0 million tons of LNG in storage at the start of December, 22% higher than a year earlier. South Korea is estimated to have 3.2 million tons in LNG storage in December, 13% higher than last year. However, there is a risk of inventories coming below last year's level if a colder-than-normal winter arrives, particularly in Korea. See *BNEF analysis*: (web | terminal).
- The probability of an extreme weather event due to the strengthening of the La Nina pattern is rising, which will be an upward risk to JKM prices. Some Japanese utilities re-entered the spot market in November to meet extra gas demand. China's National Climate Center is forecasting a normal or milder weather in December, but is expecting strong cold waves in January.
- European gas inventories could end winter with 6.3 billion cubic meters (Bcm) of gas, which is less than half the previous estimate published in the November Monthly. This is due to lower-than-expected Russian supply and LNG imports, while withdrawals from gas storage facilities in Europe exceeded expectations in November due to resilient gas demand.
- Lower-than-expected LNG supply could further increase JKM prices. BNEF has revised down global supply for December due to reduced output in Malaysia, Indonesia, Brunei, Russia and Trinidad.

China gas balance: Gas imbalance may be more pronounced in January

New ! See BNEF's China Natural Gas & LNG LiveSheet (web | terminal)

China natural gas supply-demand balance



Source: National Development and Reform Commission, Chongqing Oil and Gas Exchange Center, BloombergNEF. Note: Actual consumption is shown instead of apparent consumption in previous versions, see Appendix for description. 'Other' value not shown. Inventory change not included in the chart. Figures rounded.

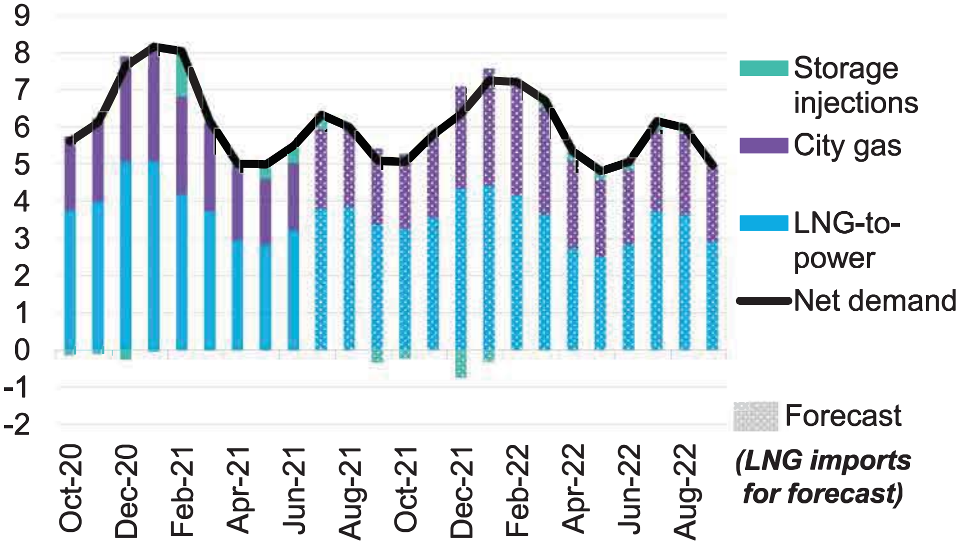
- China's gas consumption is forecast to reach 38.5Bcm in December, an increase of 11.4% from November as the weather gets colder. China may see normal or milder-than-normal weather in December, except for southern and some parts of eastern China, according to China's National Climate Center. January and February 2022 may see stronger cold waves and lower temperatures in central and eastern China. February demand is forecast to drop as the Lunar New Year falls at the beginning of the month and economic activity slows down. Therefore, sporadic gas shortages may occur in January.
- Gas supply in December, excluding storage withdrawals, is expected to grow 11% from November. Domestic gas production is estimated to surge from November to 19.8Bcm as national oil companies (NOCs) raise output from gas fields to full capacity to satisfy peak gas demand. December LNG imports could surge 16% from November to 8.1 million tons. Pipeline imports may also spike to 5.1Bcm as Russian deliveries ramp up.

Outlook

New ! See BNEF's Japan and Korea LNG and Power LiveSheet (web | terminal)

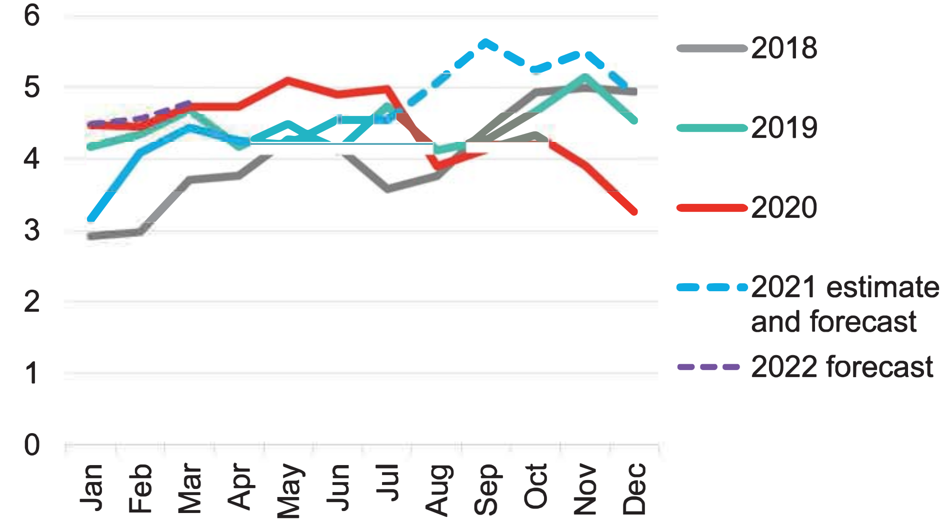
Japan LNG demand: Coal outages and delays in nuclear restart put pressure on existing LNG supply

Japan LNG demand



Source: BloombergNEF, Ministry of Economy, Trade and Industry, Ministry of Finance. Note: Storage injection estimates based on Bloomberg's AHOY JOURNEY import data. Net demand equals LNG imports.

Japan LNG inventories



Source: METI, BloombergNEF. Note: Inventories for city gas companies and electric utilities available through the following tickers: JPJKLNGI Index and JP44INLN Index.

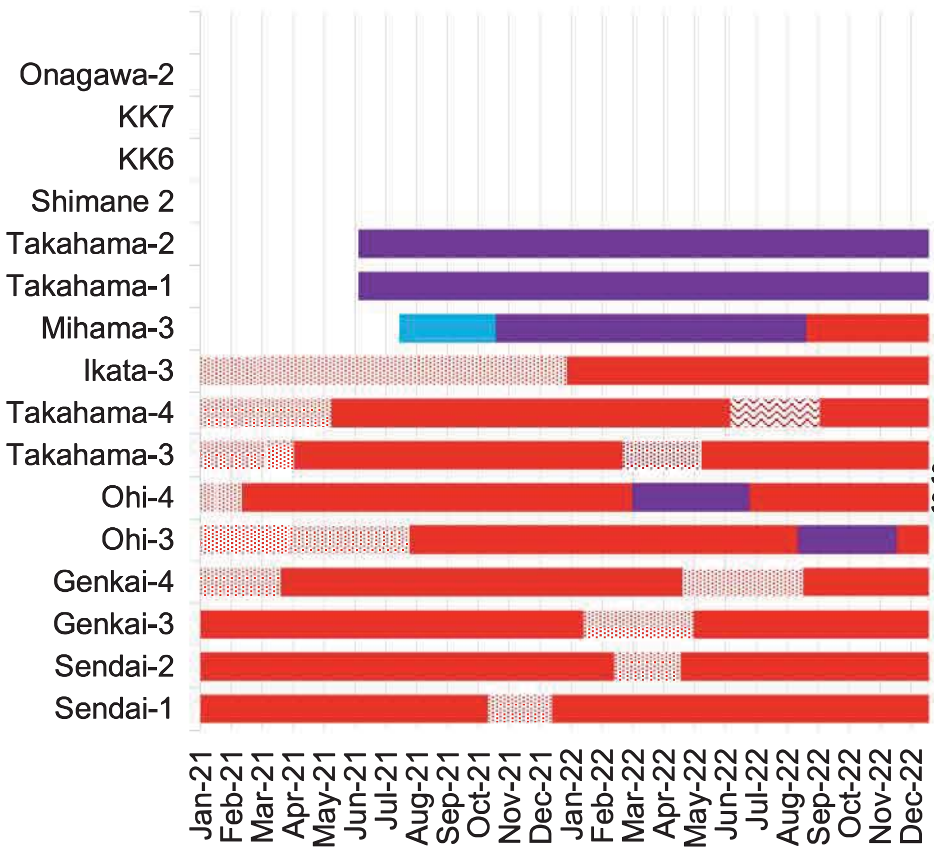
- Japan's LNG imports for December are projected to rise month-on-month, reaching 6.5 million tons as gas demand increases. Gas demand for power generation and city gas is set to go up compared to November, as Japan enters peak winter season and heating demand rises.
- Estimates for LNG inventories remained at a five-year high at the end of November, based on the latest data release from the Ministry of Economy, Trade and Industry (METI). Storage likely experienced a rebound during November. *See BNEF analysis (web | terminal).*
- Coal outages and delays in a restart of a nuclear reactor will likely boost December gas demand. Shikoku Electric's Ikata No. 3 reactor will only begin commercial operations in January 2022, compared to BNEF's previous expectation of November. Unplanned coal outages topping 3 gigawatts over October to November could stretch into December. *See BNEF analysis (terminal).*

Outlook

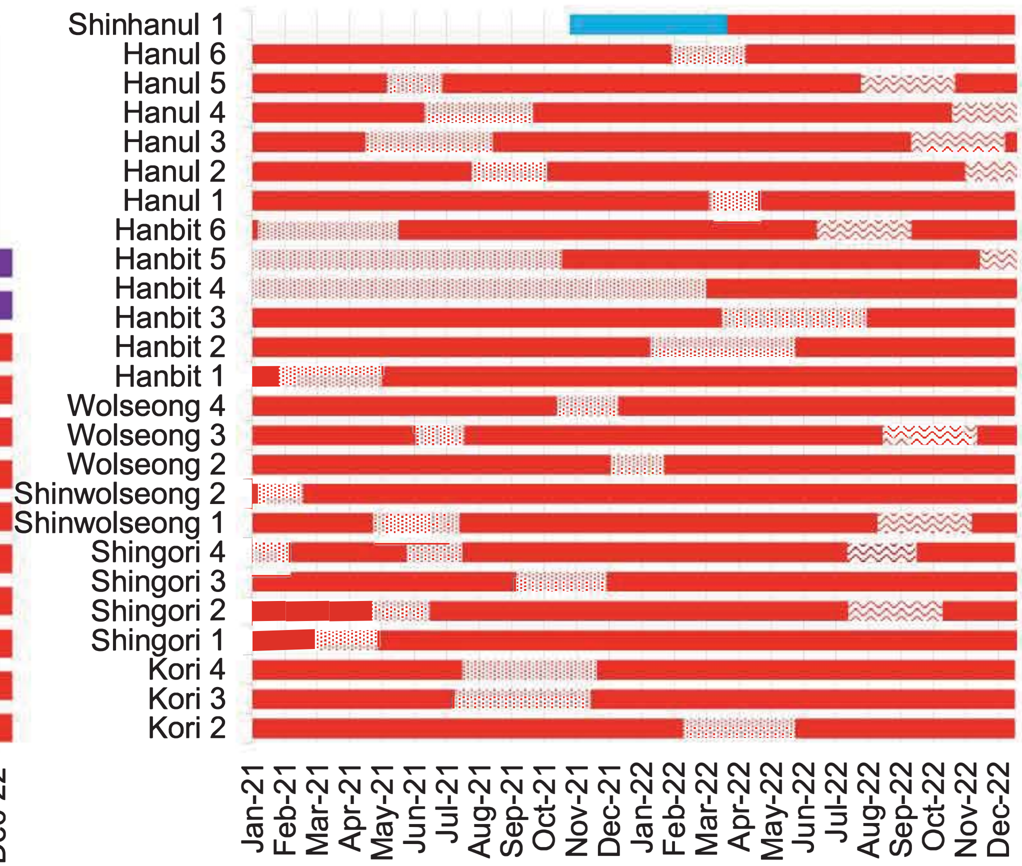
Japan and Korea nuclear plant maintenance schedule

New ! See BNEF's Japan and Korea LNG and Power LiveSheet (web | terminal)

Japan's nuclear maintenance schedule



Korea's nuclear maintenance schedule



Anti-terror outage | Restarts/Commissioning | Active | Under maintenance | BloombergNEF-forecast maintenance

Source: BloombergNEF, HJKS.

Source: BloombergNEF, Korea Power Exchange https://www.spglobal.com/platts/en/market-insights/latest-news/lng/120221-chevron-shuts-australias-gorgon-lng-train-3-for-repairs-after-restart-of-train-1

- **LNG | NATURAL GAS**
- 02 Dec 2021 | 06:57 UTC

Chevron shuts Australia's Gorgon LNG Train 3 for repairs after restart of Train 1

- Author
- Editor
- Commodity

The 5.2 million mt/year Gorgon LNG Train 3 underwent a controlled shutdown late Dec. 1 to address a similar issue to the one that shut the equally sized Train 1 on Nov. 16, a spokesperson for operator Chevron said in a statement Dec. 2.

"Following the successful repair and restart of Gorgon LNG Train 1, we have commenced the controlled shutdown of LNG Train 3 to undertake repairs on piping associated with the dehydration unit," the spokesperson said in the statement.

The work is being guided by information gathered during the repair and restart of Train 1, a source said.

The impacted unit removes water from the gas stream as part of the LNG conversion process.

"We continue to deliver natural gas to our regional customers and the Western Australian domestic market," the spokesperson said, adding that production continues at Trains 1 and 2.

Gorgon, a three-train facility with a total nameplate capacity of 15.6 million mt/year, is a joint venture between the Australian subsidiaries of Chevron at 47.3%, ExxonMobil 25%, Shell 25%, Osaka Gas 1.25%, Tokyo Gas 1%, and JERA 0.417%.

https://www.argusmedia.com/en/news/2279797-shell-halts-prelude-lng-production-after-fire#.YaolNyzqJgo.twitter

Shell halts Prelude LNG production after fire

Published date: 03 December 2021

Share:

Shell has suspended production at the 3.6mn t/yr Prelude floating LNG offshore Western Australia after a fire broke out at the facility on 2 December.

Smoke detected in an electrical utility area triggered the automatic fire detection and management systems on board the Prelude facility in the Browse basin at around 11pm Australian Western Standard Time (03:00 GMT) on 2 December, a Shell spokesperson told *Argus*.

"The incident resulted in the loss of main power and the facility is currently operating on back-up diesel generators," the spokesperson said. "While work is underway to restore main power, production on Prelude has been suspended temporarily."

The spokesperson did not comment on the estimated downtime of the project.

The Prelude facility can produce 69,231t of LNG, or around 1.2 cargoes in a week at nameplate capacity, assuming a 60,000t cargo size.

One cargo from the project may be delayed and another may be cancelled as a result of the shutdown, market participants said, but this could not be confirmed.

Shell operates Prelude LNG with a 67.5pc stake. Japanese upstream firm Inpex has a 17.5pc stake while South Korea's state-controlled import Kogas and Taiwan's state-controlled CPC own 10pc and 5pc, respectively.

Shell, Kogas and CPC receive term volumes from Prelude on a fob basis. Japan's state-controlled Jera and Shizuoka Gas receive Prelude cargoes from Inpex's equity volumes on a des basis.

Prelude has been dogged by production issues since it began shipments in June 2019. Production at the plant was halted in February 2020 due to technical issues and resumed around 11 months later in January this year.

Shell said in February that the project will reach full capacity by summer. Prelude loaded four cargoes in each month across June-September, except August when it loaded three cargoes, according to vessel tracking data from oil analytics firm Vortexa.

This was a slight increase of its two monthly loadings in January and February, three in March, four in April, and none in May. It loaded two cargoes in October, three in November, and none so far this month, Vortexa data showed.

The last loading was on 26 November by the 147,608m^3 *Symphonic Breeze* vessel, which departed the facility a day later and is expected to arrive at the Inpex-operated Naoetsu terminal in Japan's Niigata prefecture on 9 December, according to Vortexa.

This is the second LNG production outage in Australia this week and comes just before the northern hemisphere peak winter demand season. Chevron has suspended operations at the third 5.2mn t/yr liquefaction train at the 15.6mn t/yr Chevron-operated Gorgon LNG in Australia to repair "piping associated with the dehydration unit", the firm told *Argus* on 1 December.

Around 2-3 cargoes are expected to be lost from the Gorgon outage so far, market participants said. The cargoes are likely meant to be delivered at the end of December and first-half January to three of the project's owners, they added, although this could not be confirmed.

The front half-month ANEA price, the *Argus* assessment for spot LNG deliveries to northeast Asia, was last assessed at $36.185/mn Btu for first-half January on 2 December, up slightly from $35.880/mn Btu for second-half December a week earlier and nearly fivefold $8.105/mn Btu on 2 December 2020.

By Joey Chua

The 2017 Prelude to the Future participants.

PRELUDE IN THE COMMUNITY

Prelude FLNG relies on onshore services to support its operations. Most of these services are managed via locations in the Kimberley region and Darwin.

Since 2008, Prelude FLNG has partnered with not-for-profit organisations in both the Kimberley region and Darwin to support the local communities. The Prelude FLNG social investment portfolio aims to build the capabilities of local people who face challenging barriers and improve employment opportunities. Prelude's current Social Investment partners include:

KIMBERLEY LAND COUNCIL BARDI JAWI OORANY (WOMEN) RANGERS

The women rangers undertake activities to support the *Bardi Jawi Healthy Country Plan* on the Dampier Peninsula and skills development is a core component of the project.

KIMBERLEY INSTITUTE

The Kimberley Institute has developed a Collaborative Community Investment framework (known as The Broome Model) that will be taken to corporate and philanthropic investors and potentially underwritten by Government, as a collaborative proposal to address social issues in the region.

NIRRUMBUK ABORIGINAL CORPORATION

Nirrumbuk is leading a strategic partnership of Indigenous organisations to deliver trades based training and employment outcomes to 30 young Indigenous people from the Broome, Dampier Peninsula and Bidyadanga communities.

PRELUDE TO THE FUTURE

Prelude to the Future is a Darwin based program that supports Territorians through a traineeship or apprenticeship and into employment. To date 80% of the 38 participants have maintained ongoing employment. Prelude to the Future is a four-way partnership between Shell Australia, the NT Government, Group Training NT and Charles Darwin University.

NORTHERN REGIONAL TAFE SCHOLARSHIPS

Shell supports a scholarship program with the Northern Regional TAFE, based in Broome. The program provides up to $2,000 for 12 scholarship recipients to encourage Broome residents to undertake vocational training.

WORK INSPIRATIONS BROOME

Shell and INPEX jointly coordinate a Work Inspirations program for Broome high school students which provides awareness of the opportunities in the oil and gas sector, including indirect employment.

FIBRE OPTIC CABLE

The subsea fibre optic cable system, a partnership between Shell, INPEX and Vocus, provides the Ichthys and Prelude FLNG projects with access to reliable and high-speed data and voice communication services for the life of operations.

This capability not only provides a high quality connection to onshore support locations and teams, it also allows those working on the facility to keep in touch with family and friends in real time, via a high-speed internet connection.

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PRELUDE FLNG

AN AUSTRALIAN GAS PROJECT

THE PROJECT

Prelude is a floating liquefied natural gas project located approximately 475km north-north east of Broome in Western Australia. The Prelude project is the first deployment of Shell's Floating Liquefied Natural Gas (FLNG) technology, which will see a giant floating facility extracting, liquefying and storing gas at sea, before it is exported to customers around the globe.

The Prelude FLNG facility has arrived at its location, the Prelude field, 475km North-North East of Broome, where the next phase of the project, hook up and commissioning is underway. The Prelude FLNG facility will produce 3.6 million tonnes per annum (mtpa) of LNG, 1.3 mtpa of condensate and 0.4 mtpa of LPG. The Prelude FLNG facility is 488m long and 74m wide, making it the largest offshore floating facility ever built.

A team of between 120-140 people will work on board Prelude during operations. The project will also be supported by teams and contractors across Perth, Darwin and the Kimberley – providing long-term steady Australian jobs both directly and indirectly. Approximately 100 contracts are required for Prelude's operations and maintenance and a majority of these have been awarded to local companies.

The Prelude FLNG facility will be operated by Shell in joint venture with INPEX (17.5%), KOGAS (10%) and OPIC (5%).

FLOATING LIQUIFIED NATURAL GAS

Floating LNG consolidates the traditional offshore to onshore LNG infrastructure into a single facility that is based over the fields. The FLNG facility gathers, processes, stores and offloads natural gas and condensate products at sea.

FLNG removes the need for pipelines to shore, dredging and onshore works and therefore significantly limits the disturbance to the surrounding environment and in the right conditions, reduces development costs. It is also a competitive solution for fields like Prelude, that are very remote and hard to access.

The Prelude FLNG facility is moored near to the Prelude field location in 250 metres of water, by four groups of mooring chains. Each mooring chain is held to the sea floor by piles. The facility has been designed to withstand severe weather, including up to a '10,000 year' storm, and will remain onsite during all conditions. Seven production wells will feed gas and condensate from the reservoirs via four flexible risers into the facility. All subsea connections join the facility via the turret. The turret's swivel design enables the facility to pivot according to wind and sea conditions while it remains fixed to the sea floor.

The Prelude FLNG facility has thrusters to ensure it remains steady during production and offloading, but it is a fixed facility, with no means of propulsion. The management of subsea wells and manifolds is carried out via umbilicals connected through the turret to the control room on the facility.

The processing of gas and condensate occurs in modules onboard that occupy an area approximately one quarter the size of a typical onshore LNG plant. Shell's Dual Mixed Refrigerant (DMR) process is used to liquefy the gas. Prelude's LNG and LPG will be offloaded via a side by side vessel configuration using specially designed cryogenic loading arms. Ships will load condensate from the rear of the facility using a floating hose arrangement. The products will then be shipped directly to customers around the world.

Safety of the FLNG facility has been paramount during its design, and its safety profile is predicted to be inline with modern offshore oil and gas facilities. The FLNG design has gone through extensive testing programs and simulations to ensure it has the ability to remain connected and moored to the sea floor throughout all weather conditions.


RT Roebuck Bay, Infield Support Vessel


CHC Helicopters


Skandi Darwin, Platform Supply Vessel


Collaborative Work Environment, Perth

PRELUDE LOCATIONS

BROOME

Prelude FLNG is located 475km North-North East of Broome. The town of Broome serves as a base for aviation and marine services for the project. Personnel fly to and from the FLNG facility on helicopters that leave from the Broome International Airport. For the outbound flights, this includes a refuelling stop at the Djarindjin Aiport on the Dampier Peninsula. These helicopters are operated by CHC Helicopters.

During the hook-up and commissioning phase of the project there will be a higher volume of people and helicopters leaving Broome. When Prelude is operating, there will be approximately four helicopter flights from Broome per week.

KT Maritime operate three infield support vessels (ISVs) out of the Broome port. The 42 metre-long vessels will support the berthing and loading of the LNG, LPG and condensate carriers who transport the products to customers. They will also provide emergency response capability. The Prelude ISVs were named; RT Roebuck Bay, RT Kuri Bay and RT Beagle Bay by a St Mary's College, Broome student as part of a community competition.

KT Maritime has contracted the manning, operation and routine maintenance of the ISVs as a partnership model which has created over 50 maritime roles for Australians. Five of these roles are based in Broome.

DARWIN

Prelude's Darwin Onshore Supply Base is now operating, housing equipment and spare parts for the project under the management of contractor ASCO. Equipment from the facility requiring overhaul or repair will either be sent to workshops in Darwin or to specialists interstate and overseas.

A multi-purpose platform supply vessel, the Skandi Darwin, will be based in Darwin and will make weekly trips to the facility. The vessel will deliver supplies to Prelude and will also support Prelude's subsea inspections and maintenance – a critical part of ongoing operations.

Contractor Monadelphous will also provide maintenance, brownfield modifications and turnaround services for Prelude from a fabrication shop based in Darwin.

PERTH

Shell's Perth headquarters houses the Prelude Collaborative Work Environment (CWE), a state-of-the-art operations floor that supports the Prelude facility 24 hours a day.

OFFSHORE

Perth based contractor Sodexo oversees the accommodation management, waste management, house-keeping and laundry services for Prelude FLNG, as well as technical and administration support and the implementation of a wellness program on-board.

Rusca Environmental Solutions is a 100% Indigenous owned business based in the Northern Territory that was awarded the waste management services contract for Prelude FLNG.

Training at the Australian Centre for Energy and Process Training at South Metropolitan TAFE (hosted by ERGT Australia).

PRELUDE PEOPLE

Between 120-140 Shell personnel and contractors will work on the Prelude FLNG facility during normal operations. Offshore staff will work on a fly-in, fly-out roster, meaning there will be a team of about 250 in offshore roles. During heavy maintenance periods, up to 300 people may be required to work on board the facility.

150 Australian production technicians worked on the facility while it was under construction in the Samsung Heavy Industries shipyard in Geoje, South Korea.

PRELUDE PRODUCTION TECHNICIAN TRAINING

Through a partnership with South Metropolitan TAFE in Western Australia, Shell Australia has developed specific FLNG technician training to ensure Prelude personnel have the skills to operate Prelude safely and efficiently.

Via this partnership, the Australian Centre for Energy and Process Training at South Metropolitan TAFE has delivered relevant training to the 150 Prelude technicians across a broad range of critical skills and competencies.

In addition, the Prelude FLNG project is participating in the National Energy Technician Training Scheme (NETTS), which is an industry collaboration across Shell, Woodside, Quadrant and Vermillion with the objective to recruit and train local apprentices. Now in its second year, Shell is sponsoring six apprenticeships including two apprenticeships from Broome.

INTERESTED IN A JOB AT SHELL? VISIT:
SHELL.COM.AU/CAREERS

Executive summary

The European gas market will need a combination of warmer-than-average weather, further price rises or first flows from the Nord Stream 2 pipeline to make it through the upcoming winter, according to BloombergNEF forecasts. Our current estimate, based on 10-year average weather and current prices, and without Nord Stream 2, predicts storage will end the winter season at a critically low 4.4 billion cubic meters. On top of stronger-than-expected November storage withdrawals, we revised our forecasts for Russian gas and LNG supply down while demand is proving surprisingly resilient at current price levels.

- Uncertainty about Nord Stream 2 has returned after the approval process of the pipeline was delayed by a technicality. The process is likely to be suspended for six to eight weeks, making it likely that Europe will have to get through at least the bulk of the winter without the pipeline.
- No monthly Mallnow entry capacity bookings for December means we have had to keep Russian supplies into our perimeter approximately flat month-on-month, further tightening the balance.
- The global LNG market has tightened, given outages and higher-than-expected flows to some regions. The TTF is not regularly pricing high enough relative to JKM to attract the spot cargoes we had previously forecast, and so we have had to revise our LNG imports into Northwest Europe down for the remainder of the winter.
- Demand has been surprisingly resilient, with industrial demand only about 6% below business as usual, and power is demand resilient given low renewables output and limited alternative capacity.
- By the end of February, we forecast gas inventories could be 9.7Bcm, likely driving gas and power prices much higher. In such a scenario, the pressure on European politicians to manufacture some sort of approval for the controversial pipeline would likely reach critical levels.

(Deck has been updated to include North Africa supply on slide 10)

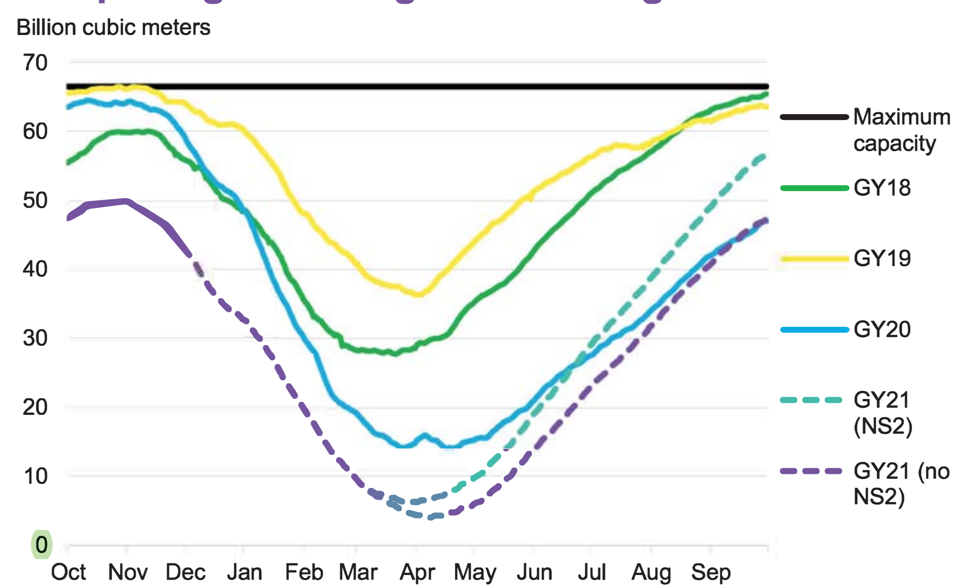
4.4Bcm — **Predicted end-of-winter storage inventories in a 'No NS2' scenario**

11Bcm — **Forecast year-on-year reduction of Russian pipeline flow into Northwest Europe**

29Mcm/d — **Forecast reduction in December through March LNG imports compared to the mean of the previous three years**

Read our Global Gas Winter Outlook (terminal | web)

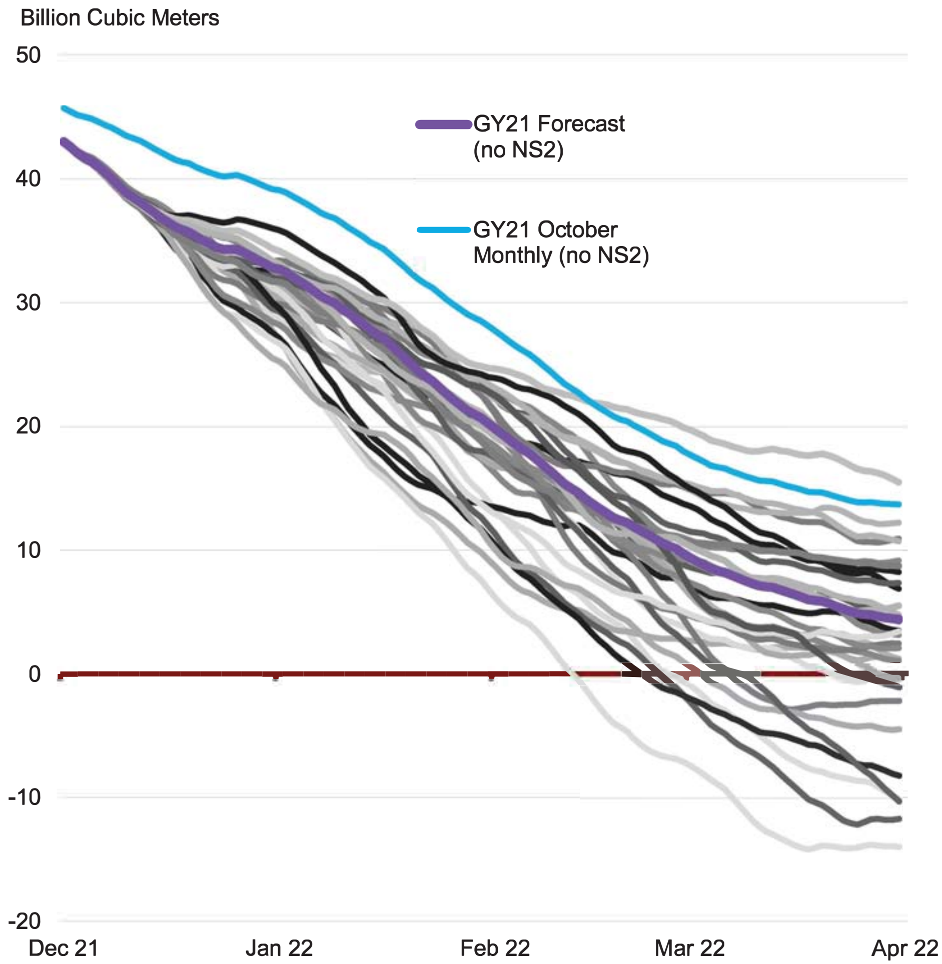
European gas underground storage inventories



Source: BloombergNEF. Note: Gas year is a 12-month period starting from October, for example, gas year 2020 starts from October 1, 2020. NS2 is Nord Stream 2.

NS2 scenarios: The ‘No Nord Stream’ scenario leaves inventories dangerously low

Projected gas storage inventory evolution over winter in ‘No NS2’ scenario by historical weather data

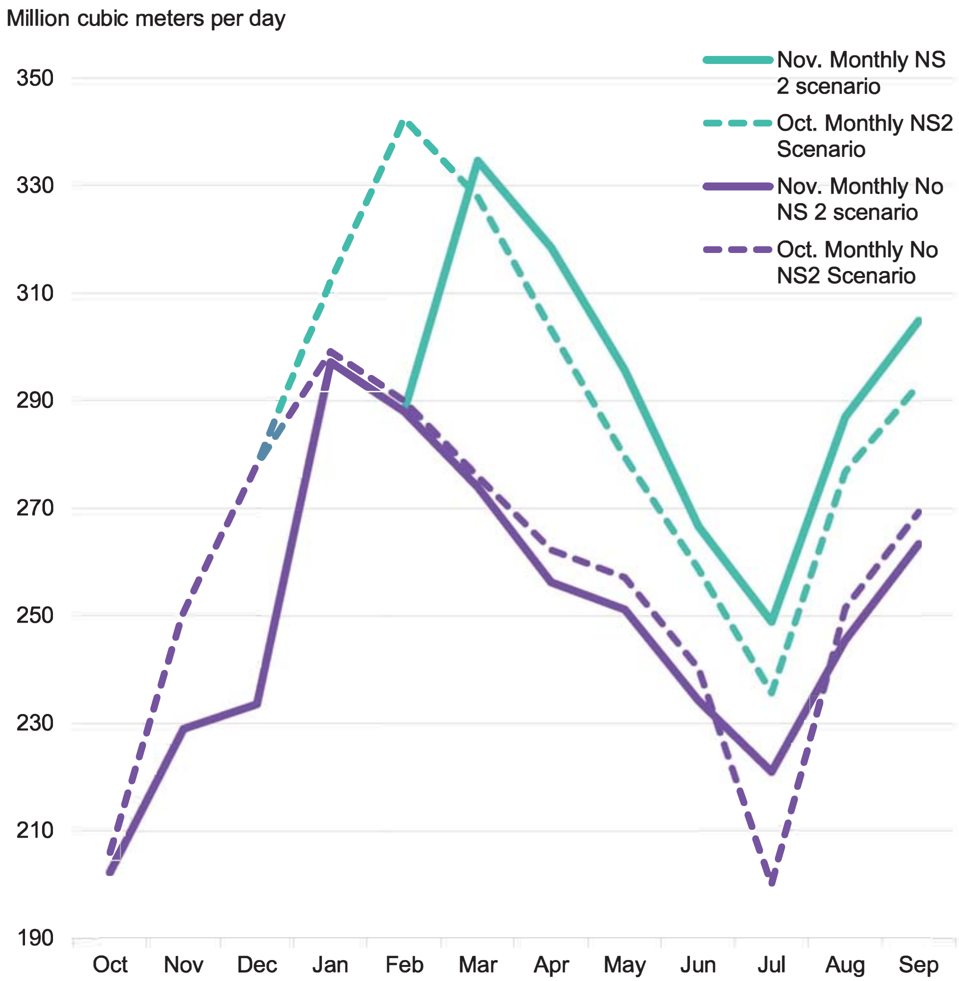


Source: BloombergNEF. Note: Each line represents the evolution of inventory given historical weather data of the last thirty years. Both BNEFs scenarios utilise the average of the last ten years of model runs as input

- We continue to present two Russian flow scenarios into the BNEF perimeter. In the first scenario the Nord Stream 2 pipeline is not approved, and flows remain low; in the other, the pipeline is approved and Russian flows to Northwest Europe increase.
- On October 26, the German Ministry for Economic Affairs and Energy (BMWi) said that in its opinion approval of Nord Stream 2 AG as transmission system operator did not endanger the energy security of the EU. This decision, coming faster than many (including us) had expected, appeared to pave the way for the German Network regulator BNetZA to approve the controversial pipeline.
- However, the announcement on November 16 that the approval process had been suspended while Nord Stream 2 AG set up a regulated German subsidiary to run the pipeline, threw cold water on these hopes. Why BNetzA only then raised a condition as seemingly straightforward as requiring a German registered company remains subject to speculation.
- With the average estimate for how long it might take to set up a German subsidiary being between six and eight weeks, it now looks increasingly likely that Europe will have to get through the winter without the pipeline.
- Anaemic Russian flows at the start of the month, coupled with surprisingly strong demand, led to a total of 6.5Bcm of storage withdrawals in November – around 3Bcm above our forecast. Given no monthly December capacity booked for Mallnow we have revised down our ‘No NS2’ Russian import forecast for that month alone.
- As a result, in our scenario without the pipeline, we now forecast that European storage inventories would reach a paltry 9.7Bcm by the end of February and critically low levels of 4.4Bcm by the end of March. These forecasts are based on the current forward curve and 10-year normal weather.

NS2 scenarios: Deal for NS2 looking increasingly necessary

BNEF Perimeter Russian imports for different Nord Stream 2 scenarios



*Source: BloombergNEF. Note: *Gas year is a 12-month period starting every October 1. The BNEF perimeter includes Northwest Europe, Italy and Austria. October and the majority of November are actual data in the November monthly lines.*

- Low Russian flows in October have reinforced our view that Russia is using low flows as a bargaining chip to force through approval of Nord Stream 2. In our note *Unpacking Putin's statements* (web | terminal), we concluded that it was unlikely Europe would see increased flows from Russia, or any certainty about how much gas it would receive, unless the pipeline was approved.
- What is becoming increasingly clear is that unless the pipeline is approved, the European gas market is currently relying on warmer-than-average temperatures to make it through winter.
- In both our scenarios, storage inventories reach an unusually low level of 9.7Bcm by the end of February . As we have long highlighted, diminishing European gas inventories and rising prices will force European politicians to consider approving the pipeline in the hope of more Russian supply.
- An eight-week pause for Nord Stream 2 AG to set up a German subsidiary takes us to a deadline of March 5 for BNetzA to submit a preliminary decision. Thus, early March seems to us to be the point at which the issue is likely to reach a critical juncture.
- We have previously highlighted the complexities around the approvals process and that it is an assumption that flows on the pipeline could begin without completion of the full European approvals process. However, given how low European inventories might be then it seems increasingly likely that some sort of approval, likely partial and with conditions, might have to be manufactured.
- Accordingly, in our Nord Stream 2 scenario, we have one string of the pipeline ramping up to full capacity from the start of March. Although the second string is also likely to be ready to operate by then, we do not expect full flows on both strings or, more importantly for the balance, a return to previous high levels of Russian imports, until full and permanent approval is given to the pipeline.

European gas balance: Without changes gas inventories will likely reach critically low levels

Update on European gas market supply-and-demand balance sheet for winter in gas year* 2021

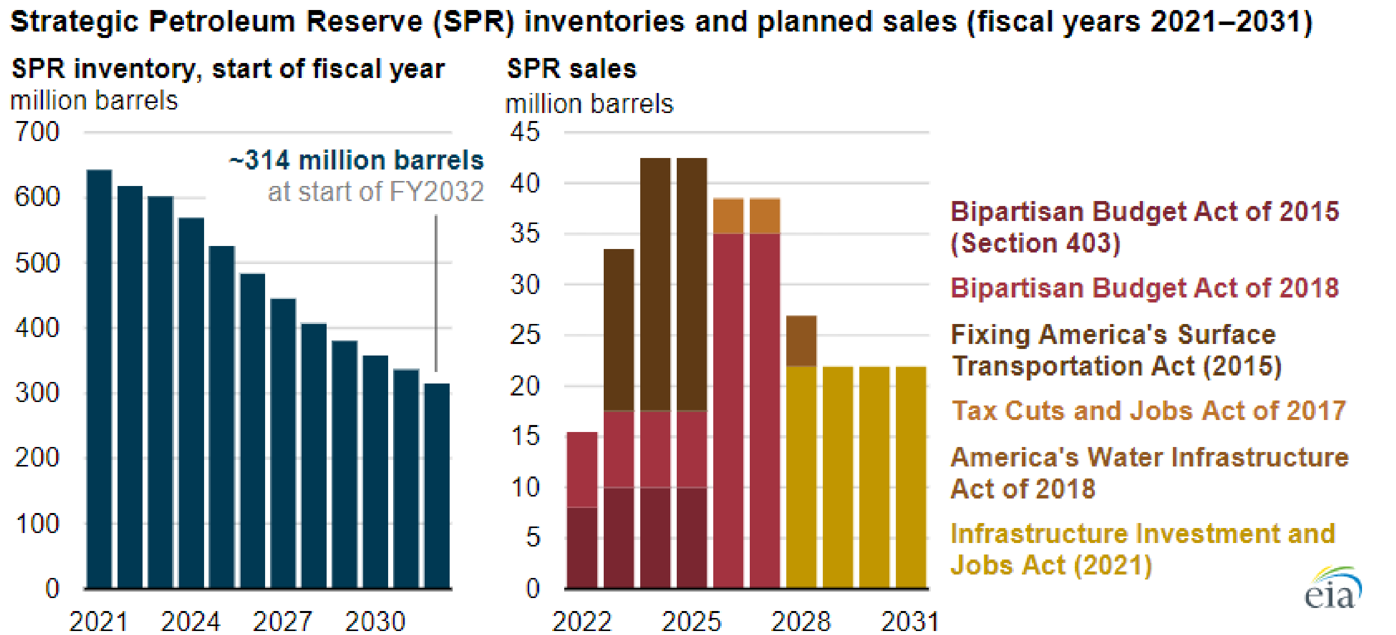
Rest of Winter (December 1 to March 31)	Nov. 1 – Nov. 28, 2021			No NS2 Scenario (Dec. 1, 2021 – Mar. 31, 2022)			NS2 Scenario (Dec. 1, 2021 – Mar. 31, 2022)		
Million cubic meters per day (Mcm/d)	**October monthly forecast**	**Actuals**	**Difference**	**October monthly forecast**	**Forecast as of Nov. 30**	**Difference**	**October monthly forecast**	**Forecast as of Nov. 30**	**Difference**
LDZ (commercial and residential demand)	713	706	-7	888	897	9	888	897	8.5
Gas-to-power (BE, DE, FR, GB, IT)	182	207	24	175	187	12	173	187	14
Industrial	256	277	21	275	284	9	275	284	9
Total demand	**1151**	**1189**	**38**	**1336**	**1368**	**32**	**1336**	**1368**	**32**
Russian imports	250	227	-23	286	273	-13	315	288	-26
Norwegian imports	336	334	-2	329	336	7	329	336	7
Dutch production**	72	67	-5	85	87	2	85	87	2
U.K. production	94	106	12	98	106	8	98	106	8
LNG imports	187	150	-37	169	150	-18	169	150	-18
North Africa imports	80	71	-9	79	75	-4	79	75	-4
Other border flows (+TAP)	3	2	0	-1	-4	-3	-1	-4	-3
Other production	24	22	-2	24	24	0	24	24	0
Total supply	**1045**	**980**	**-66**	**1068**	**1046**	**-22**	**1068**	**1062**	**-6**
Call on storage	**105**	**209**	**103**	**268**	**322**	**54**	**268**	**307**	**38**
Days	28	28		121	121	121	121	121	
Call on storage (Bcm)	2.9	5.8	2.9	32.45	39.0		32.4	37.1	4.65
Starting inventory Nov 1 (Bcm)					43.4			43.4	
Finishing inventory Mar 31 (Bcm)					**4.4**			**6.3**	
Maximum storage capacity (Bcm)					66.5			66.5	

*Source: BloombergNEF. Note: *Gas year is a 12-month period that starts on Oct 1. **In our framework, the Dutch production is a sum of gas production flowing into the Dutch network and the net withdrawal from Norg. Values may not add up due to rounding errors.*

https://www.eia.gov/todayinenergy/detail.php?id=50476

NOVEMBER 29, 2021

Recent legislation would reduce the U.S. Strategic Petroleum Reserve



Source: U.S. Energy Information Administration, *Petroleum Supply Monthly* and Congressional legislation

Reposted at 10:30 a.m. on November 30, 2021 to include an exchange agreement after Hurricane Ida in 2021.

On Tuesday, November 23, the White House announced plans to make 50 million barrels of crude oil available to the market through a combination of exchanges and accelerating previously announced sales. With these sales and several other legislated drawdowns, SPR inventories could decline from 618 million barrels (as of October 1, 2021) to about 314 million barrels by the start of the 2032 fiscal year, the lowest level since March 1983. The Infrastructure Investment and Jobs Act, passed earlier this month, includes a provision to draw down 87.6 million barrels of crude oil from the U.S. Strategic Petroleum Reserve (SPR) in fiscal years (FY) 2028 through 2031.

The SPR was established in the 1970s to alleviate the effects of unexpected oil supply reductions. The reserve was designed to hold up to 714 million barrels of crude oil across four storage sites along the Gulf of Mexico, where much of the U.S. petroleum refining capacity is located.

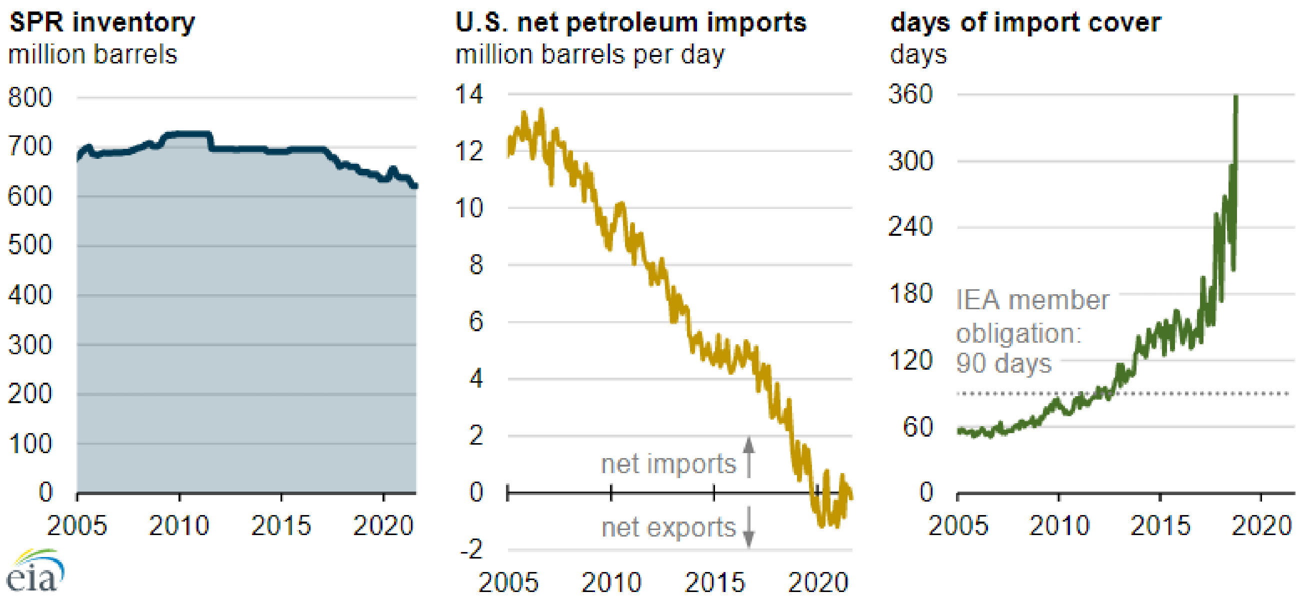
Crude oil can be released from the SPR under four conditions: emergency drawdowns, test sales, exchange agreements, and nonemergency sales. Emergency drawdowns and test sales are relatively rare. The most recent emergency drawdown occurred in 2011 in response to production disruptions in Libya, and the most recent test sale occurred in 2014. The SPR has released crude oil under exchange agreements 13 times since 1996, most recently after Hurricane Ida earlier this year. In these exchange agreements, crude oil is released to private companies and repaid in kind by specified dates with additional barrels, similar to monetary interest on a loan.

Congress has also authorized nonemergency sales of SPR crude oil to respond to lesser supply disruptions or to raise revenue for the U.S. Treasury. For example, the Fixing America's Surface Transportation Act, passed in 2015, and The Bipartisan Budget Act of 2018 collectively call for the sale of more than 160 million barrels of crude oil from the SPR in FYs 2022 through 2027.

One of the SPR's core missions is to hold enough oil stocks to fulfill U.S. obligations under the International Energy Program, the 1974 treaty that established the International Energy Agency (IEA). As a member of the IEA, the United States is obligated to maintain stocks of crude oil and petroleum products, both public and private, to provide at least 90 days of U.S. net import protection. The U.S. Department of Energy calculates this value by dividing the SPR inventory level by EIA's sum for net crude oil and petroleum product imports.

As net imports of crude oil and petroleum products into the United States declined in recent years, the volume needed to meet the 90-day import coverage also fell. In October 2019, the United States [exported more crude oil and petroleum products than it imported], becoming a net exporter for the first time in EIA data, which dates back to 1977. IEA members who are net petroleum exporters [do not have stockholding obligations]. Although the United States has occasionally imported more petroleum than it exported in some months since late 2019, SPR inventory levels have continued to provide sufficient coverage for net import protection.

Strategic Petroleum Reserve inventories and net petroleum imports (Jan 2005–Aug 2021)



Source: U.S. Energy Information Administration, *Petroleum Supply Monthly*
Note: IEA is the International Energy Agency. Days of cover increase as net imports decrease or switch to net exports. Only months with less than 360 days of cover are shown. On a monthly basis, days of cover have exceeded 360 days 18 times since 2018, and the United States was a net exporter in 17 months.

More information about the role of the SPR is available on the U.S. Department of Energy's [SPR website].

Principal contributor: Owen Comstock https://www.enbridge.com/media-center/news/details?id=123699&lang=en

Enbridge Responds to Canada Energy Regulator Decision to Deny Mainline Contracting

November 28, 2021

CALGARY, AB, Nov. 28, 2021 /CNW/ - Enbridge Inc. (Enbridge or the Company) (TSX: ENB) (NYSE: ENB) today responded to the Canada Energy Regulator's (CER) November 26, 2021 decision to deny the implementation of contracting for firm service on the Enbridge Canadian Mainline system.

Enbridge has completed its review of the decision and identified next steps that include re-engaging all stakeholders, including shippers and non-shippers on the Mainline system.

The Enbridge Mainline is a critical conduit connecting western Canadian crude oil and product supply with Canadian and U.S. Midwest markets, and ultimately the U.S. Gulf Coast. For decades, the system has provided its customers with unparalleled market access, crude oil quality management, system reliability and long-term expansion potential at the most competitive toll. Since inception of the Enbridge system in 1950, the commercial underpinning of the Mainline has evolved, from a contested cost-of-service (COS) framework to incentive rate making. Enbridge pioneered the first incentive tolling agreement with our customers in 1995, which aligned industry and Enbridge interests, and supported significant investment and expansion of the Mainline.

The most recent incentive agreement, called the Competitive Tolling Settlement (CTS Agreement), expired in June 2021; therefore, the Mainline is currently under interim tolls (subject to refund) and which will stay in effect until new tolls are approved by the CER. In 2018, in preparation for the upcoming expiry of the CTS Agreement, Enbridge initiated consultations with industry participants to determine their goals for the next Mainline tolling arrangement. Among other feedback, the Company heard significant concerns from industry over continuing Mainline apportionment, due to growing western Canadian production and lack of sufficient egress. A large portion of existing shippers expressed desire for continued toll certainty, and to contract for firm service to ensure access to the system.

However, it was also evident from extensive industry input that there was no consensus on what a new commercial structure should look like – some favoured contracting, while others opposed it altogether, preferring to maintain the status-quo, a monthly nominations process and a fixed toll. After significant negotiation with industry on a comprehensive set of terms, Enbridge applied to the CER to contract the Canadian Mainline.

In reaching its decision, the CER determined that providing firm service on the Canadian Mainline is not contrary to the CER Act. The CER also found that elements of the application provided strong justification for some proportion of firm service on the Canadian Mainline. However, the CER denied the application on the basis that, among other things, contracting as proposed would result in a significant change to access the Canadian Mainline and potentially inequitable outcomes to some shippers and non-shippers without a compelling justification. The CER confirmed Enbridge's existing process for downstream verification and that interim tolls would stay in effect.

Based on its review of the CER decision, Enbridge will initiate, in consultation with its stakeholders, a process to negotiate toward a go-forward Mainline commercial framework. Elements of the process will include:

- Enbridge will re-engage with stakeholders, to receive input on key objectives and variables that are important in considering the future commercial framework, the current industry outlook and desire for future expansion of the Mainline; and
- Enbridge will explore, with stakeholders, alternatives that may include: a modified and extended CTS agreement, a new incentive rate-making agreement, or a COS rate-making structure. Any negotiated settlement would require CER approval before implementation.

In parallel with negotiations of a potential negotiated settlement, Enbridge will prepare a COS application for the Canadian Mainline, which will be filed with the CER if Enbridge, after consultation with stakeholders, concludes that an agreement to continue with incentive rate making is not achievable.

Enbridge expects the preceding steps to begin in the coming weeks, although the negotiating process may take through 2022. We expect the subsequent CER review and decision process to conclude in 2023.

From a financial perspective, Mainline throughput is expected to be strong over the next several years and the Company's outlook is positive. Based on our review of the CER decision and other factors, the Company anticipates that the range of financial outcomes associated with an alternative commercial model will be manageable and is not expected to materially impact Enbridge's financial results.

Enbridge will provide its 2022 guidance, longer term outlook and strategic priorities at Enbridge Day on December 7th, 2021, in Toronto.

FORWARD-LOOKING INFORMATION

https://www.transmountain.com/news/2021/ensuring-safety-during-bc-and-wa-storm-impacts

Trans Mountain Pipeline Plans to Safely Restart Tomorrow

Home › News

Dec 4, 2021

December 4, 2021, 12:00 pm PDT

Following the precautionary shutdown of the Trans Mountain Pipeline as a result of heavy rains and flooding, Trans Mountain plans to restart the pipeline tomorrow.

Throughout the shutdown period, the pipeline remained safely in a static condition and there was no indication of any product release or serious damage to the pipe. Trans Mountain completed detailed investigations of the pipe's integrity and geotechnical assessments of the surrounding landscape to confirm readiness to restart the line. Restarting the pipeline has required a significant, sustained effort to re-instate access lost due to damaged roads, changes in river flows, and adverse weather. Crews worked around the clock to clear highways, build bridges and manage watercourses to allow for access and repairs to the pipeline.

We expect that all assessments, repairs and protective earthworks necessary for a safe restart will be completed by tomorrow and plans have been developed and shared with the Canada Energy Regulator.

Subject to CER concurrence and final repair work, the restart will take place during daylight hours tomorrow and the pipe will be closely monitored by our teams in the field and technology systems operated by our Control Centre. Emergency management teams and equipment remain staged in key areas with booms proactively deployed in the unlikely event of a release.

Over the coming weeks Trans Mountain will continue with additional emergency work. Some of this work includes conducting additional inline inspection, armouring of riverbanks and adding ground cover or relocating sections of the pipeline.

https://www.transmountain.com/news/2021/ensuring-safety-during-bc-and-wa-storm-impacts

Trans Mountain Braced for Continued Rain and Snowfall; Additional Resources Deployed to Manage Water Accumulation and Allow for Necessary Work

Home › News

Dec 1, 2021

December 1, 2021, 11:30 am PDT

With continued storms bringing heavy rain causing water accumulation, crews are continually monitoring and assessing the pipeline and so far, there are no new areas of concern caused by the weather conditions. Where work has been done to shore-up banks, we are making improvements such as berm fortification to ensure the work already done is holding.

Trans Mountain has brought-in more than 44,000 cubic metres of rock and gravel at critical sites and deployed several hundred sandbags to assist with shoring-up banks in flooded areas to allow the required assessment and repair work to continue. Crews are utilizing 30 sets of pumps and hoses to manage water accumulation and have set up 15 separate light-stands with generators to allow monitoring and work to continue around the clock.

We are continually assessing conditions in the region and are deploying additional resources where necessary. More than 470 people, six helicopters and some 100 pieces of heavy equipment, including three pieces of snow maintenance equipment and three sidebooms are in the Coquihalla and Coldwater regions to support getting the pipeline restarted.

We have natural hazard assessments ongoing and are focused on supporting our field teams who are working day and night in dynamic wet weather conditions near high-energy river flows. Safety of our crews and protection of the pipeline system remain our top priorities and despite the adverse conditions we are moving forward with work necessary to safely restart the pipeline.

Provided there are no additional setbacks from the latest round of rainstorms, Trans Mountain will soon complete work that needs to be done before a restart can take place. Based on current conditions and the amount of progress we have been able to make, we are only a few days away from restarting the pipeline at a reduced capacity.

Trans Mountain Continues With Reinforcement of Berms and Improvements to Ground Access; Weather Continues to Impact Progress Towards Restart

Nov 29, 2021

November 29, 2021, 2:45 pm PDT

This past weekend, progress continued towards a safe restart of the pipeline. However heavy rains impacted air and ground access and caused substantial accumulation of water in some areas where work is underway. Work was interrupted at some sites on Sunday November 28, 2021 due to high water or lack of access. Assessments of the impacts of the latest storm are being undertaken today with a focus on the Coldwater and Coquihalla regions. While early reports indicate much of the work to protect the worksites held up well, crews continue to reinforce berms and are continuing to improve ground access.

Based on current conditions and the amount of progress we have been able to make in the face of continued challenges with weather and access, we are still days away from restarting the pipeline at a reduced capacity. Once restarted, delivery of oil and refined products currently in the line will continue as they progress to their delivery points at either Kamloops, Sumas, or Burnaby. After initial start-up, a sustained effort will continue to return the system to its full capacity as soon as possible.

The Trans Mountain Pipeline is a critical piece of infrastructure for British Columbia and Washington state and every effort is being made to safely restart the pipeline as promptly as possible. Trans Mountain does not own the product transported in the pipeline. We are the only pipeline in North America that carries both refined products and crude oil. Depending on the needs of Trans Mountain's customers, the amount of product shipped to four general destinations: Kamloops Terminal, Burnaby Terminal, Westridge Marine Terminal or Washington State refineries, varies from week to week.

Google Translate of https://www.minenergia.gov.co/en/web/10180/historico-de-noticias?idNoticia=24321463

Gas production in Colombia registered an increase of 4.16% during October 2021

Minenergy. Bogotá, DC, December 2, 2021. Commercialized gas production in Colombia was 1,127 million cubic feet per day (mcfd) in October 2021, which represents an increase of 4.16% compared to September past (1,082 mpcd). Compared to October 2020 (1,091 mpcd), production had a 3.3% recovery.

The increase in commercialized gas was recorded mainly in the Cupiagua (Aguazul, Casanare), Mamey (Ovejas, Sucre), Ballena (Manaure, La Guajira), Cañahuate, Aguas Vivas (Sahagún, Córdoba), Níspero (San Marcos, Sucre) and Sucumbíos (Ipiales, Nariño), due to the restoration of production after the scheduled maintenance of the Cupiagua gas plant and the increase in gas demand during the month.

During the first ten months of 2021, the average production of commercialized gas in Colombia registered an increase of 5.12%, reaching 1,082 million cubic feet per day (mpcpd) compared to the 1,029 mpcpd reported in the same period of 2020.

Regarding oil production, in October 2021 it was 740,265 barrels a day, a slight decrease of 0.5% compared to the data reported during September 2021 (744,173 bpd). With respect to the production of October 2020 (751,374 bpd), a drop of 1.48% was registered.

The decrease in production occurred mainly in the Rubiales (Puerto Gaitán, Meta), Yariguí-Cantagallo (Cantagallo, Bolívar), Platanillo, Cohembí (Puerto Asís, Putumayo), Chichimene (Acacías, Meta), Floreña Mirador, Pauto Sur fields (Yopal, Casanare) and Cicuco (Cicuco, Bolívar), due to electrical, mechanical and public order failures.

In the first ten months of 2021, the average oil production reached 734,318 barrels per day, which shows a reduction of 6.52% compared to the same period in 2020, when there was a production of 785,526 barrels per day.

Finally, during October 2021, the drilling of 5 exploratory wells and 47 development wells began in Colombia, for a total of 29 exploratory wells and 334 development wells so far this year. In addition, 29.2 kilometers of equivalent 2D seismic were acquired during this month, for a total of 1,192 kilometers in the year.

https://www.gov.br/anp/pt-br/canais_atendimento/imprensa/noticias-comunicados/anp-divulga-dados-consolidados-da-producao-nacional-de-petroleo-e-gas-em-outubro

ANP releases consolidated data on national oil and gas production in October

Published on 12/02/2021 08:37 am Updated on 12/02/2021 09:19 am
The national production of oil and natural gas in October totaled 3,606 MMboe/d (million barrels of oil equivalent per day), with 2,777 MMbbl/d (million barrels daily) of oil and 132 MMm ^{3} /d (million cubic meters) of natural gas. There was a 7.4% reduction in oil production compared to the previous month and 3.3% compared to October 2020. In natural gas there was a 1.3% reduction compared to the previous month and an increase in 1.3% compared to October 2020.
The main reasons for the drop in production in the month were scheduled maintenance stoppages in Stationary Production Units (UEPs), in particular, platforms P-76 and P-75, in the Búzios field, and the FPSO Cidade de Mangaratiba, in the Tupi field.
Consolidated information on domestic production for the month is available in the Monthly Oil and Natural Gas Production Bulletin for October 2021 , published today (12/2) on the ANP website. They are also available, interactively, on the Oil and Natural Gas Production Dynamic Panels .

Pre-salt
Pre-salt production in October totaled 2,640 MMboe/d (million barrels of oil equivalent), of which 2,088 MMbbl/d (million barrels per day) were oil and 87.6 MMm³/d (million cubic meters) daily) of natural gas.
There was a 7.2% reduction compared to the previous month and an increase of 4.1% compared to the same month in 2020. Pre-salt production originated from 128 wells and corresponded to 73.2% of the total produced in Brazil .

Use of natural gas
In October, the use of natural gas was 96.7%. 57.1 MMm³/day were made available to the market. Gas flaring in the month was 4.3 MMm³/d, an increase of 9% compared to the previous month and 43.5% compared to the same month in 2020.

Origin of production
This October, the offshore fields produced 97% of the oil and 81% of the natural gas. The fields operated by Petrobras were responsible for 93% of the oil and natural gas produced in Brazil.

Highlights
In October, the Tupi field, in the Santos Basin pre-salt, was the largest producer of oil and natural gas, recording 899 Mbbl/d of oil and 41.3 MMm3/d of natural gas.
The Petrobras 77 platform, producing in the Búzios field through five wells connected to it, was the installation with the highest oil production, with 160.652 Mbbl/d.
The FPSO Cidade de Itaguaí installation, producing in the Tupi field, through 7 wells connected to it, was the installation with the highest production of natural gas, producing 7.197 MMm³/d.
Estreito, in the Potiguar Basin, had the highest number of onshore producing wells: 943.

Tupi, in the Santos Basin, was the offshore field with the highest number of producing wells: 61.

Marginal accumulations fields

These fields produced 330.5 boe/d, of which 114.8 bbl/d of oil and 34.3 Mm^3/d of natural gas. The Iraí field, operated by Petroborn, was the largest producer, with 205.8 boe/d.

Other information

In October 2021, 267 areas granted, four for transfer of rights and five for sharing, operated by 36 companies, were responsible for national production. Of these, 60 are offshore and 216 on land, 12 of which are related to contracts for areas containing marginal accumulations. Production took place in 6,160 wells, 474 offshore and 5,686 onshore.

The average API degree of oil extracted in Brazil was 28, with 2.4% of production considered as light oil (>=31°API), 92.3% medium oil (>=22 API and <31 API) and 5.3 % heavy oil (<22 API).

The mature onshore basins (fields/long-term tests in the Espírito Santo, Potiguar, Recôncavo, Sergipe and Alagoas basins) produced 90.770 Mboe/d, with 70.542 thousand bbl/d of oil and 3.2 MMm^3/d of natural gas. Of this total, 66,900 boe/d were produced by Petrobras and 23,800 boe/d were produced by concessions not operated by Petrobras, of which: 15,779 boe/d in Rio Grande do Norte, 7,867 boe/d in Bahia , 472 boe/d in Espírito Santo, 251 boe/d in Alagoas and 170 boe/d in Sergipe.

https://tass.ru/ekonomika/13008745

NOV 24, 03:59

Ministry of Energy: almost all oil produced in Russia in 10 years will become hard-to-recover

Deputy Head of the Ministry of Energy Pavel Sorokin noted that hydrocarbons in the next 25-30 years will still remain the basis of the global energy balance, but their price may fall

Deputy Head of the Ministry of Energy of the Russian Federation Pavel Sorokin

MOSCOW, November 24. / TASS /. The quality of oil produced in Russia will deteriorate in 10 years to such an extent that almost all of it will pass into the category of hard-to-recover, that is, the cost of its production will be significantly higher than traditional reserves. Pavel Sorokin, Deputy Head of the RF Ministry of Energy, said this at the conference "Technological Development of the Oil and Gas Industry of the Russian Federation".

“On the horizon of ten years, almost 100% of production will be hard-to-recover,” he said. Sorokin recalled that the deterioration of reserves means the need to stimulate oil production in Russia, as well as geological exploration.

Speaking at another meeting - in the Federation Council - he noted that hydrocarbons in the next 25-30 years will still remain the basis of the world energy balance, but their price may fall.

"Hydrocarbons will still form the basis of the energy balance in the next 25-30 years, at least. This means that if the price falls in the long term due to overproduction, then we will not have to reduce production, our place in the market will remain ", - said the deputy minister.

Sorokin also added that fiscal revenues from the sale of hydrocarbons in the future may fall, as well as dividend payments from oil and gas companies in Russia, but the industry will retain the volume of investments and jobs. "This is more important," the deputy head of the Ministry of Energy stressed.

https://tass.ru/ekonomika/12290253

SEP 2, 17:44

Ministry of Energy: production of half of oil reserves in Russia is unprofitable at a price of $ 50 per barrel

Deputy head of the department Pavel Sorokin considers the range of $ 55-60 per barrel as a balanced oil price for 2022

MOSCOW, September 3. / TASS /. The production of about half of the oil reserves in the Russian Federation at a price of $ 50 per barrel is unprofitable. It is worth focusing on working with the current resource base, Deputy Energy Minister Pavel Sorokin said in an interview with the Izvestia newspaper published on Friday.

“Even in our current structure of reserves, a significant part of it is unprofitable at a price of $ 50 - about half there. There is a very large layer of opportunities for working with the current resource base: with small fields, with depleted, with tailing assets, with deeper and more difficult layers. what you need to concentrate on, "Sorokin said.

The Deputy Minister considers the range of $ 55-60 per barrel to be a balanced oil price for next year, but only after the completion of the recovery in the world of production under the OPEC + deal, which under the current terms of the agreement should take place in May 2022.

"In general, after everyone has restored their production to the pre-pandemic level, all other things being equal (and if there are no shocks), the equilibrium price, we think, is in the range of $ 55-60," he said.

Google Translate of TASS Russian story “В Минэнерго сообщили, что рентабельными в России являются только 36% запасов нефти” https://tass.ru/ekonomika/10559021

27 JAN, 04:40

The Ministry of Energy said that only 36% of oil reserves in Russia are profitable

Deputy head of the department Pavel Sorokin noted that the development of deep horizons of Western Siberia will require investments comparable to the cost of drilling in the Arctic

MOSCOW, January 27. / TASS /. Only 36% of 30 billion tons of oil reserves in Russia are profitable, which is associated with the deterioration of development conditions and a drop in the quality of reserves, writes the Deputy Minister of Energy of the Russian Federation Pavel Sorokin in an article for the Energy Policy magazine.

"According to the data of the inventory of the economics of field development, carried out on behalf of the Russian government, out of 30 billion tons of recoverable oil reserves in Russia, only 36% is profitable in the current macroeconomic conditions. This is due to the deterioration of development opportunities: an increase in water cut, the need to permeability and compartmentalization of reservoirs, withdrawal into marginal zones and strata with small thicknesses, and so on, "Sorokin explained.

"All this not only increases the cost of production, but also increases the risks of not confirming the planned development indicators due to the complexity of modeling processes and errors during drilling, for example, the exit from the productive formation during horizontal drilling. As a result, for some assets, the actual profitability of drilling may differ significantly from plans, and reserves are not confirmed, "the deputy minister stressed.

According to him, the quality of reproduction of the resource base is also deteriorating. The average size of new field discoveries in 2015-2019 amounted to 9-14 million tons (excluding several large ones on the shelf and the Payakhskoye field). The increase in reserves in recent years is provided by additional exploration in the operating regions of production, as well as by revaluation of reserves. Basically, in traditional regions, the growth is due to the search for missed deposits or drilling into deep horizons. At the same time, the technological complexity of geological exploration increases significantly.

"It is important to understand that the omission of promising formations when using traditional methods of data interpretation is associated with their small size and complexity. Therefore, it is necessary to apply completely new technologies for exploration and modeling of assets," Sorokin said.

Thus, the question of the future of the Russian oil industry is associated with advanced technological development and increased efficiency. "Only this will allow maintaining the position of one of the lowest producers in terms of cost on the world oil supply curve," the deputy minister sums up.

Investments in the further development of Western Siberia

The development of the deep horizons of Western Siberia will require investments comparable to the costs of drilling in the Arctic, which are traditionally very high, Sorokin also noted.

"The development of deep horizons requires increased investment. For example, for the pre-Jurassic complex of Western Siberia, capital expenditures for exploratory drilling are comparable to the Arctic - from 500 million rubles or more per well. In terms of major discoveries, the most promising region is the Arctic and the shelf. Here Several major discoveries have already been made in recent years - Neptune, Triton, Payakha with total reserves of more than 1.3 billion tons of oil However, these basins are poorly studied and, given the high cost of exploratory drilling, it is necessary to use completely new modeling technologies for effective localization hydrocarbon deposits, "Sorokin noted.

“Thus, the question of the future of the Russian oil industry is associated with advanced technological development and efficiency gains. Only this will allow us to maintain the position of one of the lowest producers in terms of cost on the world oil supply curve,” the deputy minister added.

According to him, the oil and gas industry is currently facing a number of problems that reduce its competitiveness in the world market.

A common problem is the gradual depletion of reserves in developed fields and a drop in oil production in traditional oil-producing regions. The highest rates are observed in the key oil-producing region of Russia - Western Siberia, where production has decreased by 10% over the past ten years - to 288 million tons, Sorokin concludes.

TASS English Posted Story https://tass.com/economy/1249505
27 JAN, 04:26
Only 36% of oil reserves profitable in Russia, energy minister says
This is related to worsening of development opportunities, according to the minister

MOSCOW, January 27. /TASS/. Just 36% of 30 bln tonnes of oil reserves are profitable, Deputy Energy Minister of Russia Pavel Sorokin wrote in his article for the Energy Policy magazine.

"According to data of fields' development economics inventory completed on the instruction of the Russian government, just 36% out of 30 bln tonnes of recoverable reserves of Russian oil are profitable in current macroeconomic environment. This is related to worsening of development opportunities: growing water cut, the need to build costly wells of complex design, low permeability and compartmentalization of reservoirs, the move to marginal areas and beds with low thickness, and so on," the official said.

"All that does not merely increase the lifting costs but also moves upward risks of failure to confirm target development figures because of the complexity of processes modeling and drilling errors, for example, leaving the pay bed in horizontal drilling. The result is the actual profitability of drilling may considerably differ from plans for certain assets and reserves will not be confirmed," Sorokin said.

https://www.opec.org/opec_web/en/press_room/6736.htm

23rd OPEC and non-OPEC Ministerial Meeting

No 36/2021
Vienna, Austria
02 Dec 2021

The 23rd OPEC and non-OPEC Ministerial Meeting (ONOMM), was held via videoconference, on Thursday December 2, 2021. The Meeting remains in session.

The meeting reaffirmed the continued commitment of the Participating Countries in the Declaration of Cooperation (DoC) to ensure a stable and balanced oil market. In view of current oil market fundamentals, the Meeting resolved to:

1. Reaffirm the decision of the 10th ONOMM on April 12, 2020 and further endorsed in subsequent meetings including the 19th ONOMM on July 18, 2021.
2. Reconfirm the production adjustment plan and the monthly production adjustment mechanism approved at the 19th ONOMM and the decision to adjust upward the monthly overall production by 0.4 mb/d for the month of January 2022, as per the attached schedule.
3. Agree that the meeting shall remain in session pending further developments of the pandemic and continue to monitor the market closely and make immediate adjustments if required.
4. Extend the compensation period until the end of June 2022 as requested by some underperforming countries and request that underperforming countries submit their plans by December 17, 2021. Compensation plans should be submitted in accordance with the statement of the 15th ONOMM.
5. Reiterate the critical importance of adhering to full conformity and to the compensation mechanism.
6. Hold the 24th OPEC and non-OPEC Ministerial Meeting on January 4, 2022.

	Jan 2022 Required Production
Algeria	972
Angola	1406
Congo	300
Eq.Guinea	117
Gabon	172
Iraq	4281
Kuwait	2585
Nigeria	1683
Saudi Arabia	10122
UAE	2916
Azerbaijan	661
Bahrain	189
Brunei	94
Kazakhstan	1572
Malaysia	548
Mexico	1753
Oman	812
Russia	10122
Sudan	69
South Sudan	119
OPEC 10	24554
Non-OPEC	15940
OPEC+	40494

Production table - December 2021

Download document

Saudi Aramco OSP Announced Dec 5, 2021

Crude Oil (FOB) Differentials (in US$) - JANUARY 2022

UNITED STATES (versus ASCI)

	DECEMBER	JANUARY	Change	VS. Light
Extra Light	+2.90	+3.50	+0.60	+1.35
Light	+1.75	+2.15	+0.40	0.00
Medium	+1.05	+1.45	+0.40	-0.70
Heavy	+0.60	+1.00	+0.40	-1.15

North West Europe (versus ICE Brent)

	DECEMBER	JANUARY	Change	VS. Light
Extra Light	+1.50	0.00	-1.50	+1.30
Light	-0.30	-1.30	-1.00	0.00
Medium	-1.10	-1.70	-0.60	-0.40
Heavy	-2.70	-2.90	-0.20	-1.60

FAR EAST (versus Oman/Dubai)

	DECEMBER	JANUARY	Change	VS. Light
Super Light	+5.85	+6.15	+0.30	+2.85
Extra Light	+4.00	+4.50	+0.50	+1.20
Light	+2.70	+3.30	+0.60	0.00
Medium	+2.35	+3.05	+0.70	-0.25
Heavy	+1.00	+1.80	+0.80	-1.50

Mediterranean (versus ICE Brent)

	DECEMBER	JANUARY	Change	VS. Light
Extra Light	+1.90	+0.50	-1.40	+1.70
Light	-0.30	-1.20	-0.90	0.00
Medium	-1.40	-2.00	-0.60	-0.80
Heavy	-2.70	-3.00	-0.30	-1.80

Source: Bloomberg

Quotes by the US Senior State Department Official at the briefing of the 7th round of JCPOA talks
https://www.state.gov/briefing-with-senior-state-department-official-on-the-seventh-round-of-the-jcpoa-talks/

"we don't know when the EU coordinator will reconvene talks"

“Vienna, what getting ready meant was to come with proposals that walked back anything – any of the compromises that Iran had floated during the sixth round of talks, pocket all of the compromises that others and the U.S. in particular had made, and then ask for more; in other words, not come back with a serious proposal about how we could resume mutual compliance with the JCPOA, but raising issues that go beyond the JCPOA, and on their side not being prepared to take the steps that, again”

“And I would say that the time that we have for – the time that the JCPOA has for still remaining a viable deal is inversely proportional to the speed with which Iran advances its nuclear program. If they choose to accelerate their nuclear program, as they seem to have done of late, then there’d be less time left for the JCPOA to be resurrected”

“Again, I’ve always said it’s less a chronological clock than it’s a technological clock, and Iran has chosen to accelerate that technological clock, which carries very troubling implications for whether the JCPOA can be revived. Our view is it still can be today; that’s President Biden’s view. “

“So suffice it to say that they have put on the table when it comes to sanctions relief demands that go well beyond the scope of the JCPOA. And it’s pretty clear what the JCPOA entailed in terms of sanctions relief. We’ve made clear that we’re prepared to lift all of the sanctions that are in consistence with the deal, but if Iran wants us to go beyond that, then, of course, we’re talking about a different deal, and Iran would have to go beyond what it did at the time of the JCPOA. So that’s after that question.”

“We’re obviously preparing for a world in which there is no return to the JCPOA. It is not our preference.”

“ What they have in mind is what I’d – what we’d call their own plan B, which is to use the talks as a cover, as a front for continued build-up of their nuclear program to serve as leverage for a better deal for them. And that’s what Secretary Blinken has said clearly we will not accept, and therefore if that’s – if Iran continues with this approach, we will adjust in ways that I think are pretty self-evident to all”

“Even as we are at the table in Vienna, President Biden has not lifted any of the sanctions because he has made clear he will lift all of the sanctions incompatible with the – inconsistent with the JCPOA if Iran is prepared to come back into compliance with the deal”

“The fact that we’re sitting in Vienna doesn’t mean that we can’t take steps to make clear to Iran that they have a price to pay if it continues to stonewall”

“I think they need to understand it and also understand that if they do come back into compliance then they will get the sanctions relief that we’ll offer and the stronger economic ties with the region and others that they say that they want.”

“So first, as you know, we’re well aware of the purchases that Chinese companies are making of Iranian oil in contravention of our sanctions, and we’ve used our sanctions authorities to respond to the sanctions evasion, including against entities doing business with China, and we’ll continue to do so if necessary. Again, as you know, as we’ve discussed, we think the best way to approach this is diplomatically with the Chinese – part of our overall dialogue, part of the dialogue that Presidents Biden and Xi had not long ago on Iran policy”

“On your other question, what we mean is at the end of the day we believe the best outcome to this problem is a diplomatic one. If the JCPOA cannot be revived because of Iran’s nuclear advances, which makes it impossible to come back to that deal, then there’ll have to be other diplomatic outcomes that we’d be prepared to pursue. Of course, as I said in response to the prior question, we will have to use other tools, tools that you could imagine, to try to increase the pressure on Iran to come back to a reasonable stance at the diplomatic table. But at that point, the diplomatic outcome they would be pursuing, it will have to be different from the JCPOA simply because, technically, we could not come back to it even if we wanted to because of the advances – irreversible advances that Iran will have made. So I don’t want to get into what format that might take. The point is at the end of the day we believe diplomacy is the best way to resolve this.”

Question to official “ And finally, just to be clear, when you say other tools and other options, does that include kinetic operations to ensure that Iran doesn’t develop a nuclear program? SENIOR STATE DEPARTMENT OFFICIAL: So quickly, answer to your third question – as you know, I’m not going to get into details here about what steps might be taken to prevent Iran from acquiring a nuclear weapon. I think the President and Secretary of State have spoken to that, and their word is more authoritative than mine"

". It has – it still has a little time to make it and to understand that they're not going to get a better deal than the JCPOA out of these talks. If they want a different deal, then that's what they should say. They should say we want a different deal, let's negotiate a different deal, and then we'll have to see what we do to make sure that they don't continue to grow their nuclear program during that time"

https://en.irna.ir/news/84566402/Iran-won-t-walk-back-demands-deputy-FM
Dec 5, 2021, 2:23 PM

Journalist ID: 1195

News Code: 84566402

Iran won't walk back demands: deputy FM

Tehran, IRNA – Iran's Deputy Foreign Minister Ali Bagheri Kani said on Sunday that the Islamic Republic of Iran won't walk back its demands on removing US sanctions against the Iranian nation.

In an interview with the Italian news agency ANSA, Bagheri Kani said that the US was the party that left the Joint Comprehensive Plan of Action (JCPOA) in 2018, so it was up to Washington to take the first step.

Bagheri Kani serves as Iran's top negotiator in the talks in Vienna between Iran and the remaining participants in the JCPOA for a possible return of the US and removing sanctions against Iran.

He told ANSA that the proposals offered by Iran in the talks this week were "logical and well-founded" and they could be a basis for further negotiations.

The Islamic Republic of Iran, said the top negotiator, believes in the negotiations and is "optimistic" about the possible results.

However, he added, the past non-constructive behavior by the other signatories of the deal and the repeated violation of their obligations require Iran not to be naive.

Iran delivered its proposals in two drafts regarding the US sanctions against Iran and Iran's nuclear program, he said, adding that the drafts were the basis of negotiation and the other parties should give documented response to Iran's demands.

Bagher Kani had previously said that the other participants to the deal couldn't reject Iran's proposals and if they accept them, Tehran would offer its third proposal.

9416**7129

https://en.mehrnews.com/news/181416/Iran-not-to-back-down-from-its-demands-in-negotiations

Dec 5, 2021, 3:20 PM

Bagheri Kani:

Iran not to back down from its demands in negotiations

TEHRAN, Dec. 5 (MNA) – Iran's chief negotiator at the Vienna talks Ali Bagheri Kani reiterated that Tehran will not back down from its demands in the Vienna talks to make sure the removal of the US oppressive sanctions against the Iranian nation.
Iran will not back down from its demands for removal of the sanctions in the process of the reoperation of the 2015 nuclear deal, Ali Bagheri Kani said in an interview with the Italian news agency ANSA recently.

Given that it was the United States that withdrew from the agreement in 2018, so it has to take the first step, the Iranian diplomat added.

The top Iranian negotiator described the proposed drafts by Iran to P4+1 during the negotiation process as 'documented and logical' so that they can be a basis for negotiations.

He also added that during the talks, Iran presented its plans in the form of two proposed drafts, one of which is on the removal of the oppressive and illegal sanctions and the other is on the nuclear issue. These proposals are the basis for negotiation and the other side must provide a documented response to the Iranian team's proposals.

He further noted that he remains optimistic in the talks but after seeing lots of violations of the deal by the other parties, it would be naive to be very optimistic.

Earlier, the top Iranian negotiator told Qatari Al-Jazeera that the European parties admitted to the need to create a mechanism to verify the removal of sanctions during the talks, adding that a third document is prepared to be handed over to the P4+1 soon.

In response to a question about the possibility of reviving the agreement, the diplomat said, "It all depends on the behavior of the other parties, and if the European parties fully live up to their obligations and the American side returns to the agreement, it will be revived. Both sides are determined to return to the 2015 agreement."

JB/IRN84566131

News Code 181416

Shell Won't Ride the Tightening Oil Market Wave, Says CEO
2021-11-30 16:13:01.797 GMT

By Laura Hurst
(Bloomberg) -- The oil and gas market may be tightening amid historically low investment levels, but that won't change Royal Dutch Shell Plc's strategy to shift from fossil fuels.
Shell is one of many European majors that have pledged to shrink its traditional hydrocarbon business, while increasing investments in clean energy. While some critics have raised concerns that high oil prices might tempt these firms to stick to fossil fuels, Shell's chief executive says its adhering to its energy transition strategy.
"You could be concerned that we have a very tight market coming up," Ben van Beurden told shareholders on Tuesday. "We have decided not to ride that wave up."
JPMorgan Sees $150 Oil in 2023 on Lack of OPEC+ Spare Capacity
That tightness is caused by investment in the oil and gas industry plunging to historically low levels, which aligns with an International Energy Agency report that says no new fields can be tapped if the worlds is to limit the impact of climate change.
"The problem, however, is that demand for oil and gas is not declining with that IEA outlook. As a matter of fact, it is going up," Van Beurden said.
Shell will "enjoy" the benefits of a rising market, so it can return more money to shareholders and fund its energy transition strategy, but that doesn't mean it will increase spending on fossil fuels.
"We are not minded to invest in a big way in a rising market because we believe that by the time we get there and start harvesting it we will then of course be beyond that peak again," Van Beurden said.

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To view this story in Bloomberg click here:
https://blinks.bloomberg.com/news/stories/R3E4MIDWLU6Q

Nov 30, 2021 12:47:49

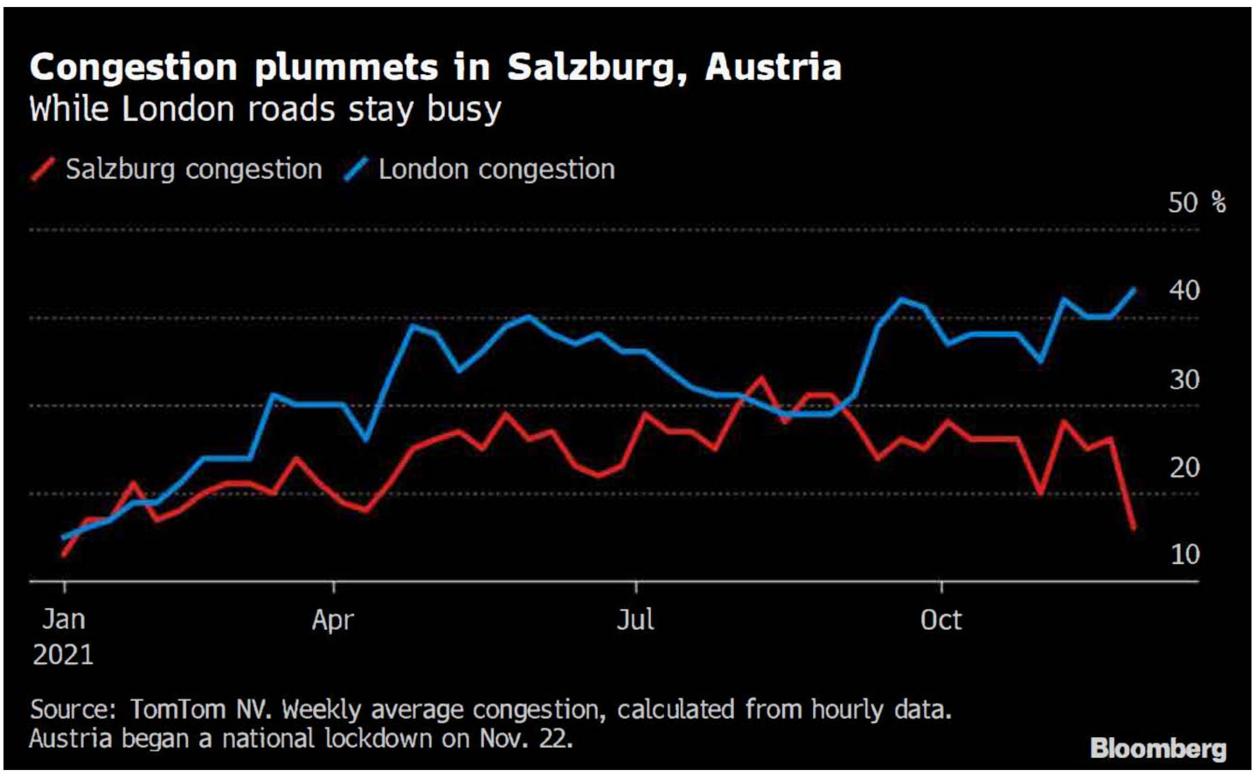
OIL DEMAND MONITOR: Austria Traffic Vanishes; Europe Watches (1)

- Salzburg road congestion hits lowest since first week of 2021
- Impact of U.S.-led releases, new virus variant being assessed

By Stephen Voss

(Bloomberg) -- Congestion plummeted in Austria last week as the country embarked on a new lockdown, yet the jury is still out on whether high Covid-19 infections are slowing oil-demand recovery across Europe, as governments implement measures to stem the spread of a threatening new variant.
Austria began a full national lockdown on Nov. 22 to stem the spread of coronavirus and, unsurprisingly, road congestion dropped sharply in its biggest cities, including Vienna, Graz, Linz and Salzburg, according to data collected from in-car navigation devices by TomTom NV.

Road traffic continues to march higher in other parts of the continent though, with congestion remaining heavier than typical 2019 levels in three of Europe's five biggest capital cities Monday morning. Flight data shows a recent rebound in Chinese air travel while Europe struggles to improve.



U.K. road fuel demand is stabilizing at about 9% below equivalent dates of 2019, after a brief surge in late September, according to weekly updates of sales at service stations.

Spanish and Portuguese demand for gasoline in October was ahead of the pre-pandemic level, and diesel a few percentage points below, though such data isn't yet available for November. Recent demand estimates for the U.S. are in a similar place, with gasoline 1.4% above and distillate fuels including diesel level pegging with two years ago.

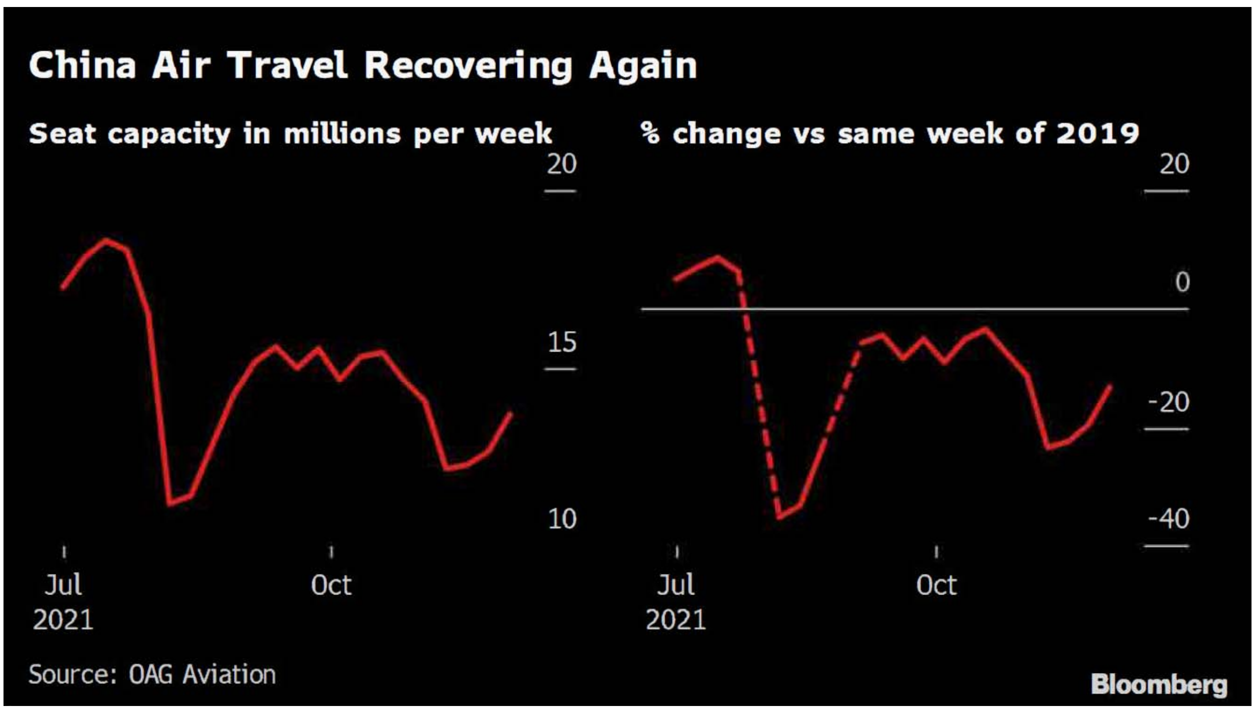
Two events rocked the oil market last week: the U.S. and other consuming nations announced the release of oil from strategic stockpiles and scientists discovered a new version of coronavirus, dubbed the omicron variant.

Oil prices plunged on Friday in a selloff that analysts at Goldman Sachs Group Inc. and Energy Aspects Ltd. deemed "excessive" and an "overreaction." Still, the stockpile release and omicron news both have the ability to affect the global supply-demand balance, and may influence OPEC+ nations when they meet on Thursday to decide whether to continue oil production increases at the same pace as previously planned.

What We Know About Omicron, the New Virus Variant: QuickTake

In air travel, the number of seats offered on planes in China rebounded by 8% in a week, to 13.7 million. That helped the global figure improve, trimming the deficit with 2019 to 26% from 27% the week before, according to data compiled by OAG Aviation. Europe's situation remains mixed: seat capacity in Spain and the U.K. improved from the week before while France and Germany weakened.

The omicron variant is impacting short-term demand but hasn't yet derailed a recovery in air travel, Johan Lundgren, the chief executive of U.K. discount carrier EasyJet Plc, said earlier Tuesday.
"We've seen in previous times, when there has been news such as this, you get an immediate dropoff," he said on Bloomberg Television. "It's not as significant this time. It's not to the same level of downside."



All of the world's biggest airline markets remain smaller than the same week of 2019. Mexico has the smallest deficit of 1.5%, followed by the U.S., India and China at 10.3%, 12.5% and 13.4%, respectively. The Bloomberg weekly oil-demand monitor uses a range of high-frequency data to help identify trends that may become clearer later in more comprehensive monthly figures.

Following are the latest indicators. The first two tables show fuel demand and mobility, the next shows air travel globally and the fourth is refinery activity:

Demand Measure	Location	% y/y	% vs 2019	% m/m	Freq	Latest Date	Latest Value	Source
Gasoline	U.S.	+15	+1.4	+0.1	w	Nov. 19	9.33m b/d	EIA
Distillates	U.S.	+5.2	unch	+13	w	Nov. 19	4.39m b/d	EIA
Jet fuel	U.S.	+29	-20	+4	w	Nov. 19	1.51m b/d	EIA
Total oil products	U.S.	+14	+3	+9.7	w	Nov. 19	21.8m b/d	EIA
All vehicles miles traveled	U.S.		+3.1		w	Nov. 21	16.3b miles	DoT
Passenger car VMT	U.S.		-0.4		w	Nov. 21	n/a	DoT
Truck VMT	U.S.		+17		w	Nov. 21	n/a	DoT
All motor vehicle use index	U.K.	+9	-3	+1	d	Nov. 22	97	DfT
Car use	U.K.	+8.2	-8	unch	d	Nov. 22	92	DfT
Heavy goods vehicle use	U.K.	+3.7	+11	+4.7	d	Nov. 22	111	DfT
Gasoline (petrol) avg sales per filling station	U.K.	+7	-8.3	+9	w	Nov. 15-21	6,681 liters/d	BEIS
Diesel avg sales per station	U.K.	+0.9	-10	+5.3	w	Nov. 15-21	9,410 liters/d	BEIS
Total road fuels sales per station	U.K.	+3.3	-9.3	+6.8	w	Nov. 15-21	16,091 liters/d	BEIS
Gasoline	India	+0.5	+1.2		2/m	Nov. 1-15	1.04m tons	Bberg
Diesel	India	-15	-19		2/m	Nov. 1-15	2.43m tons	Bberg
LPG	India	+4.2	+1.9		2/m	Nov. 1-15	1.12m tons	Bberg
Jet fuel	India	+22	-36		2/m	Nov. 1-15	212k tons	Bberg
Total Products	India	+0.8	+3.1	+12	m	October	17.9m tons	PPAC
Toll roads volume	Italy	+66	-0.7		w	Nov. 15-21	n/a	Atlantia
Toll roads volume	Spain	+61	+0.9		w	Nov. 15-21	n/a	Atlantia
Toll roads volume	France	+62	+2.8		w	Nov. 15-21	n/a	Atlantia
Toll roads volume	Brazil	+2.3	+5.6		w	Nov. 15-21	n/a	Atlantia
Toll roads volume	Chile	+17	+39		w	Nov. 15-21	n/a	Atlantia
Toll roads volume	Mexico	+13	+8		w	Nov. 15-21	n/a	Atlantia

All vehicles traffic	Italy	+9		-5.9	m	October	n/a	Anas
Heavy vehicle traffic	Italy	-2.5		-8.1	m	October	n/a	Anas
Gasoline	Portugal	+14	+6.8	+2.3	m	October	93k tons	ENSE
Diesel	Portugal	+3.9	-3.8	+2.4	m	October	421k tons	ENSE
Jet fuel	Portugal	+89	-29	+8.3	m	October	103k tons	ENSE
Gasoline	Spain	+25	+5.5		m	October	493k m3	Exolum
Diesel	Spain	+11	-1.7		m	October	2300k m3	Exolum
Jet fuel	Spain	+165	-34		m	October	440k m3	Exolum

Note: Click here for a PDF with more information on sources, methods. The frequency column shows d for data updated daily, w for weekly, 2/m for twice a month and m for monthly.
* In Dff U.K. data, the column showing versus 2019 is actually showing the change versus the first week of February 2020, to represent the pre-Covid era.
** In BEIS U.K. data, which is only released once per month, the column showing versus 2019 is actually showing the change versus the average of Jan. 27-March 22, 2020, to represent the pre-Covid era.

City congestion:

Measure	Location	% chg vs 2019	% chg m/m	Nov. 29	Nov. 22	Nov. 15	Nov. 8	Nov. 1	Oct. 25	Oct. 18	Oct. 11	Oct. 4
		(Nov. 29)		Congestion minutes added to 1 hr trip at 8am local time								
Congestion	Tokyo	-6	+5	35	30	38	34	33	34	35	12	34
Congestion	Mumbai	-84	+11	6	8	6	3	5	7	6	1	7
Congestion	New York	-12	-10	28	34	33	34	31	38	33	8	35
Congestion	Los Angeles	-19	+14	29	18	32	30	25	25	29	23	27
Congestion	London	+14	+11	43	43	46	43	39	19	34	44	43
Congestion	Rome	+9	n/a	53	49	56	44	0	41	40	64	44
Congestion	Madrid	-32	n/a	24	41	28	10	0	32	37	3	41
Congestion	Paris	+4	+1440	46	53	51	50	3	42	47	49	52
Congestion	Berlin	-9	-11	31	32	31	34	34	35	19	20	38
Congestion	Mexico City	-37	+126	31	32	1	34	14	29	28	28	29
Congestion	Sao Paulo	-33	+118	29	27	3	32	13	27	35	10	29

Source: TomTom. Click here for a PDF with more information on sources, methods.
NOTE: m/m comparisons are Nov. 29 vs Nov. 1, and in some instances show very large gains due to very low congestion on Nov. 1 when several countries had public holidays. TomTom has been unable to provide Chinese data since late April.

Air Travel:

Measure	Location	% chg y/y	% chg vs 2019	% chg m/m	Freq.	Latest as of Date	Latest Value	Source
Airline passenger throughput	U.S.	+108	+7.5	+33	d	Nov. 28	2.45m	TSA
Commercial flights	Worldwide	+35	-19	-5.2	d	Nov. 28	90,023	FlightRadar24
Air traffic (flights)	Europe		-24	-11	d	Nov. 28	20,003	Eurocontrol
Seat capacity	Worldwide	+43	-26		w	Nov. 29	78.8m	OAG
Seat cap.	U.S.	+61	-10		w	Nov. 29	19.3m	OAG
Seat cap.	China	-10	-13		w	Nov. 29	13.7m	OAG
Seat cap.	India	+46	-13		w	Nov. 29	3.79m	OAG
Seat cap.	Japan	+3.8	-40		w	Nov. 29	2.43m	OAG
Seat cap.	Brazil	+42	-19		w	Nov. 29	2.22m	OAG
Seat cap.	Spain	+196	-19		w	Nov. 29	2.01m	OAG
Seat cap.	Mexico	+44	-1.5		w	Nov. 29	1.87m	OAG
Seat cap.	U.K.	+290	-38		w	Nov. 29	1.80m	OAG
Seat cap.	Germany	+254	-42		w	Nov. 29	1.56m	OAG
Seat cap.	France	+249	-28		w	Nov. 29	1.37m	OAG
Seat cap.	Australia	+14	-59		w	Nov. 29	848k	OAG
Seat cap.	S. Africa	+17	-42		w	Nov. 29	367k	OAG
Seat cap.	Singapore	+128	-75		w	Nov. 29	215k	OAG

NOTE: Comparisons versus 2019 are a better measure of a return to normal.

Refineries:

Measure	Location/area	y/y chg	vs 2019 chg	m/m chg	Latest as of Date	Latest Value	Source
		Changes are in ppt unless noted					
Crude intake	U.S.	+9.7%	-4.2%	+3.9%	Nov. 19	15.6m b/d	EIA
Utilization	U.S.	+9.9	-0.7	+3.5	Nov. 19	88.6 %	EIA
Utilization	U.S. Gulf	+9.5	-1.8	+5.1	Nov. 19	89.3 %	EIA
Utilization	U.S. East	+20	+20	+12	Nov. 19	88.4 %	EIA
Utilization	U.S. Midwest	+8.2	+0.7	+3	Nov. 19	92 %	EIA
Apparent Oil Demand	China	+1.9%		+1.2%	October 2021	13.39m b/d	NBS
Indep. refs run rate	Shandong, China	-5.6	+0.7	-3	Nov. 26	69.6 %	SCI99
State refs run rate	East China	+1.1	+2.4	+0.4	Nov. 12	80.1 %	SCI99
State refs run rate	South China	-0.1	+7.2	+1.6	Nov. 12	84.4 %	SCI99
NOTE: All of the refinery data is weekly, except for SCI99 state refineries, which is twice per month, and the NBS apparent demand, which is usually monthly. Changes are shown in percentage points except for the rows on crude intake and apparent oil demand, which are shown as percent changes.							

NOTE: All of the refinery data is weekly, except for S CI99 state refineries, which is twice per month, and the NBS apparent demand, which is usually monthly. Changes are shown in percentage points except for the rows on crude intake and apparent oil demand, which are shown as percent changes.

Caixin China General Manufacturing PMI™

Output expands slightly in November, but demand conditions soften

Latest PMI data indicated that overall business conditions faced by Chinese manufacturers were broadly unchanged in November. Output rose for the first time in four months as disruption to production schedules from power supply issues eased, but total new business fell slightly. As a result, capacity pressures subsided, with backlogs rising only slightly, while softer demand conditions also contributed to a further drop in staff numbers. Prices data meanwhile showed notable slowdowns in the rates of both input cost and output charge inflation.

The headline seasonally adjusted *Purchasing Managers' Index™ (PMI™)* – a composite indicator designed to provide a single-figure snapshot of operating conditions in the manufacturing economy – dipped from 50.6 in October to just below the neutral 50.0 mark at 49.9 in November. This indicated that operating conditions were broadly unchanged on the month after a slight improvement in October.

Three of the five PMI components weighed on the headline index in November, namely new orders, employment and suppliers' delivery times (inverted for the calculation). Output and stocks of purchases indices meanwhile had positive directional influences on the PMI figure.

Chinese manufacturing output rose for the first time since July during November, though the rate of expansion was only fractional. Panel members indicated that firmer market conditions and a relative improvement in energy supply had supported higher production. That said, subdued customer demand, rising costs and limited power supply at some firms dampened overall growth.

Total new work fell marginally in November, following two months of expansion. Some firms linked relatively muted demand conditions to the pandemic and high output prices. New work from abroad also fell, albeit at the softest rate for four months, amid reports of reduced foreign demand due to the ongoing pandemic and challenges in shipping items to clients.

Softer demand conditions and improved production led to a slower rise in backlogs of work midway through the fourth quarter. Unfinished business rose at the slowest rate for nine months and only slightly. At the same time, manufacturers cut their staff numbers for the fourth time in as many months. That said, the rate of job shedding remained marginal.

Reduced sales also contributed to a further drop in buying activity, which declined modestly overall. Inventories of both pre- and post-production items meanwhile rose only slightly.

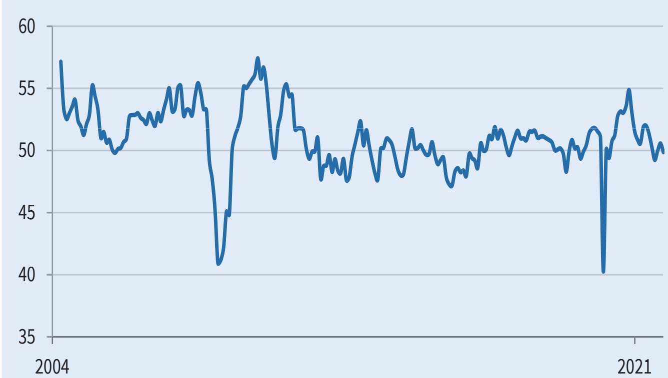
Although supplier performance deteriorated again in November amid reports of low stock levels at vendors and logistical delays, the degree to which times lengthened was only mild. Notably, the incidence of delays was the lowest since March.

After rising rapidly in October, manufacturing input costs rose only modestly in November. Moreover, the rate of inflation was the slowest seen since October 2020. While many firms commented on higher raw material and transportation costs, others indicated that some materials had fallen in price. Subsequently, the rate of output charge inflation also slowed considerably on the month.

Looking ahead, goods producers were generally confident that output will rise over the next year, with the degree of positive sentiment picking up from October.

China General Manufacturing PMI

sa, >50 = improvement since previous month



Sources: Caixin, IHS Markit

Key findings:

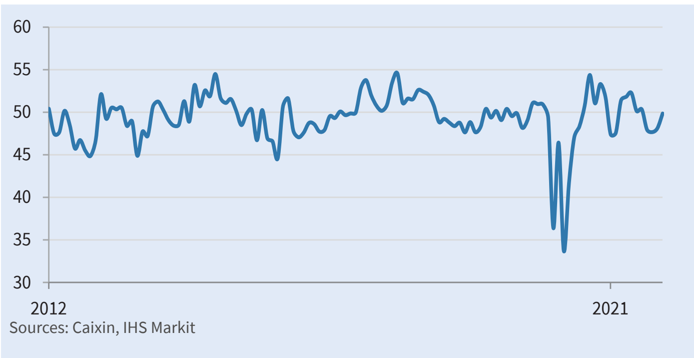
Output rises for first time in four months as power supply issues unwind...

...but total new orders fall slightly

Inflationary pressures ease markedly

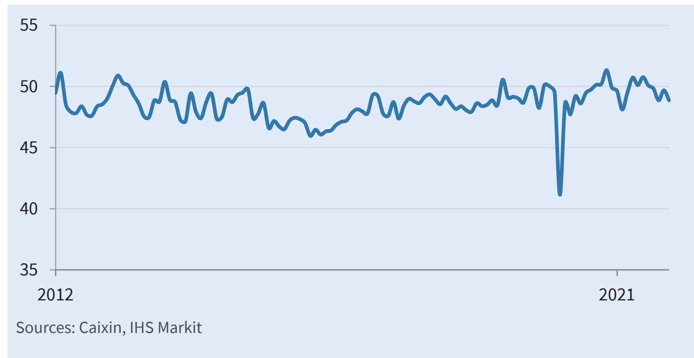
New Export Orders Index

sa, >50 = growth since previous month



Employment Index

sa, >50 = growth since previous month



Commenting on the China General Manufacturing PMI™ data, Dr. Wang Zhe, Senior Economist at Caixin Insight Group said:

"The Caixin China General Manufacturing PMI came in at 49.9 in November, down from 50.6 the previous month. The index plunged into contractionary territory for the second time since April 2020.

"Supply in the manufacturing sector recovered, while demand weakened. Relaxing constraints on the supply side, especially the easing of the power crunch, quickened the pace of production recovery. In November, the measure for output returned to positive territory after remaining in negative territory for three consecutive months. But demand was relatively weak, supressed by the Covid-19 epidemic and rising product prices. The pandemic hurt external demand, with the gauge for new export orders staying in negative territory for the fourth straight month in November.

"The job market continued to contract. Weak market demand and cost pressures restricted manufacturing enterprises' recruitment. The measure for employment remained in negative territory for the fourth month in a row in November, with the pace of contraction even steeper than the previous month. Consumer goods manufacturers showed a particularly obvious reduction in hiring.

"Inflationary pressure was partly eased. Under the impact of regulations to contain surging commodity prices, manufacturing enterprises' input costs in November increased at a slower pace than the previous month. Surveyed enterprises said the prices of steel fell at a steep pace. But the prices of chemicals and electronics remained high, as did freight rates. Thanks to the drop in the measure for input costs, the gauge of output prices fell in November, though both remained in positive territory. Still, the gauges of input costs and output prices have remained in expansionary territory for 18 months and 19 months, respectively, indicating that inflationary pressure should not be underestimated.

"Manufacturing enterprises' inventories expanded. Production by manufacturing enterprises recovered, but due to the gap between supply and demand, the inventories grew. Both the gauges of stocks of purchases and stocks of finished goods returned to positive territory in November. Logistics improved in November compared to the previous month, but suppliers' delivery times were still extended.

"Entrepreneurs remained optimistic about the outlook for market demand. The improvement of the epidemic situation, the increase in demand and the recovery of supply chains are all positive factors.

"To sum up, the manufacturing sector remained stable overall in November. Increased downward pressure and easing inflationary pressure were prominent features of the economic situation. From late October to mid-November, there were sporadic new Covid outbreaks in several Chinese regions, which had a negative impact on the economy and particularly supressed the demand side. After the shortage of power was alleviated, the supply side began to recover. But due to weak demand, the supply recovery was limited, and the foundation of the recovery was not solid. The government's measures to stabilize commodity supplies and prices began to bear fruit, which significantly eased cost pressures on manufacturing enterprises. But the gauges of input costs and output prices remained in expansionary territory, showing inflationary pressure still remained.

"Policymakers should still focus on supporting small and midsize enterprises. They should also pay attention to problems including deteriorating employment, limited growth of household income and weak purchasing power for consumer goods. In addition, the prices of some raw materials remained high. Enterprises are still facing high cost pressures. Policymakers should treat inflation seriously."

Covid-19 indicators: Global road traffic

Snapshot (TomTom): December 2

Methodology change: Effective since September 23, congestion data will be compiled from Thursday to Wednesday every week (i.e. the week to Wednesday).

BloombergNEF is tracking road congestion data for the following cities to gauge the impact of the Covid-19 outbreak on road fuel demand:

		Cities covered	TomTom data week: November 25 – December 1
Asia	China	Beijing, Shanghai, Guangzhou, Shenzhen, Tianjin, Changsha, Hangzhou, Chongqing, Chengdu, Nanjing, Zhengzhou, Wuhan, H.K., Taipei	Congestion in Mainland China rose slightly but remained below 2020 levels. Congestion in Hong Kong remained steady above 2019 (normal) levels, while Taipei remained steady below 2019 levels
Asia	Japan	Tokyo, Osaka	Tokyo rebounded to close to normal (2019) levels after last week's holiday; Osaka fell slightly but remained close to normal
Asia	Southeast Asia	Singapore, Jakarta, Bangkok, Kuala Lumpur, Manila	Manila fell to normal due to Bonifacio Day; Kuala Lumpur steady at normal; others steady below normal
Asia	India	New Delhi, Mumbai	Congestion remained significantly below normal
Europe	Italy	Rome, Milan, Turin, Naples	Congestion in Rome and Naples rose further above normal; other cities remained stable above normal
Europe	Iberia	Madrid, Lisbon	Lisbon fell below normal due to a national holiday; Madrid steady at normal
Europe	Germany	Berlin, Munich, Hamburg	Congestion steady at normal levels
Europe	France	Paris, Lyon, Marseille	Congestion remained steady above normal levels
Europe	U.K.	London, Manchester, Birmingham	Congestion steady above normal levels
Europe	Scandinavia	Copenhagen, Stockholm	Copenhagen rose further above normal; Stockholm steady above normal
Europe	Rest of Europe	Zurich, Athens, Istanbul	Congestion steady at normal levels
Americas	North America	Seattle, San Francisco, L.A., Dallas, Houston, Chicago, Washington D.C., N.Y.C., Phoenix, Atlanta, Toronto, Montreal, Vancouver, Mexico City	Congestion in North America sank significantly below normal due to the Thanksgiving holiday in the U.S. Congestion in Canadian cities remained close to normal
Americas	South America	Rio de Janeiro, Sao Paulo, Buenos Aires, Bogota, Lima, Santiago	Congestion in Buenos Aires rose but remained below normal; other cities steady below normal

*Source: BloombergNEF. Note: **Green** signals increasing congestion, **red** indicates traffic is decreasing, and **orange** indicates a stable trend with congestion.*

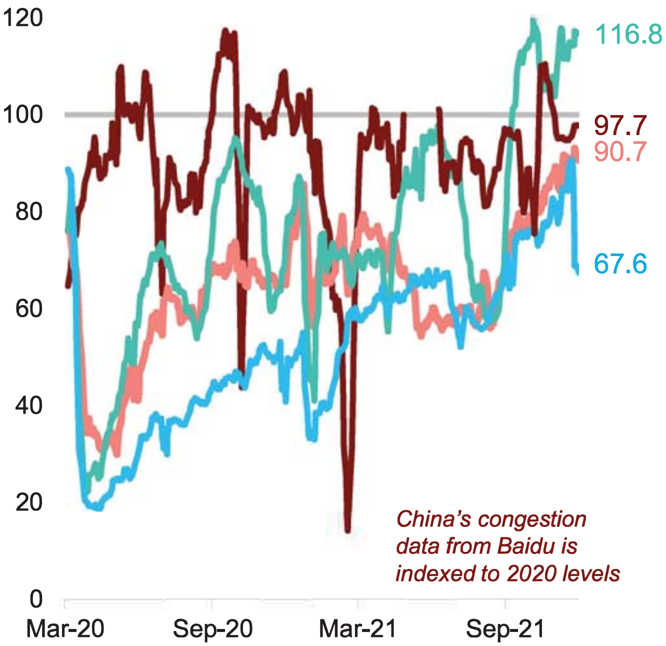
- Aggregated traffic congestion levels for Asian cities excluding China were flat at 90.7% of pre-virus levels week-on-week. They are up 1.6 percentage points over the past four weeks. In China, road traffic rose by 1.1 percentage points to 97.7% of 2020 levels (calculated based on Baidu's data).
- Road traffic in European cities increased by 2.5 percentage points to 116.8% of pre-virus levels.
- In North America, congestion levels dipped 20.2 percentage points to 67.6% of pre-virus levels, due to the Thanksgiving holiday in the U.S. Congestion levels in Latin American cities remained steady below normal levels.

Comparing the three mobility indicators

Congestion in North America dips on holidays; Europe faces headwinds

TomTom (Baidu for China) congestion index

Indexed to peak congestion of the average week in 2019 (five-day weekday MA)

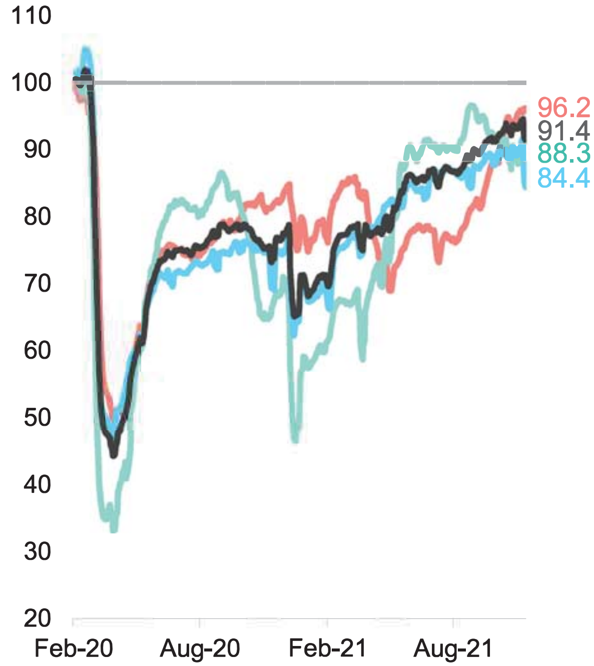


	Week Δ	Four-week Δ
Europe	2.5 (+2.2%)	9.5 (+8.8%)
China	1.1 (+1.1%)	1.7 (+1.8%)
Rest of Asia	0.0 (-0.0%)	1.6 (+1.8%)
North America	-20.2 (-23.0%)	-13.8 (-16.9%)

Source: BloombergNEF, TomTom Traffic Index. Note: 'Peak congestion index' is calculated by BloombergNEF. Index is arithmetic daily average of hourly weekday peak congestion data, compared to the 2019 average values. We use congestion index data from Baidu as an alternative source for Chinese cities from June 10. ***Data updated to December 1.***

Google mobility index

Indexed to Jan – Feb 2020 (seven-day MA)

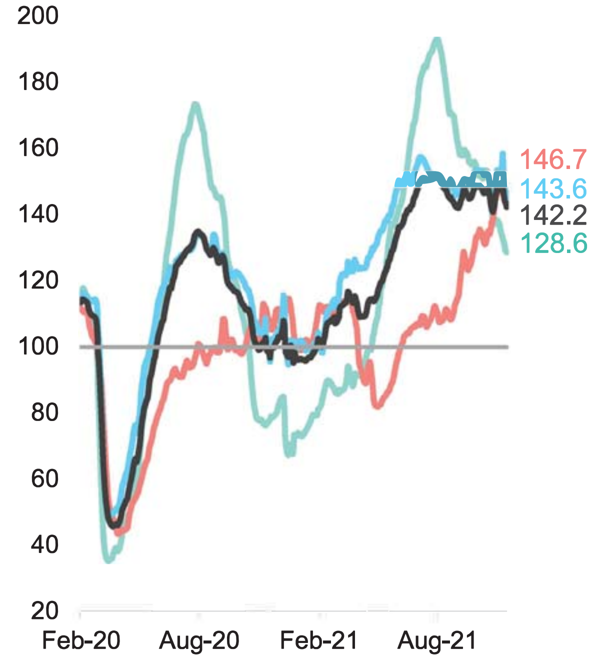


	Week Δ	Four-week Δ
Asia Pacific	0.3 (+0.3%)	2.0 (+2.1%)
World	-2.5 (-2.7%)	-2.5 (-2.6%)
Europe	-0.9 (-1.0%)	-3.3 (-3.6%)
Americas	-5.9 (-6.6%)	-5.5 (-6.1%)

Source: Google Community Mobility Report, BloombergNEF. Note: ***Data excludes China and Russia.*** *Calculation includes retail & recreation, workplaces, transport hubs.* ***Data updated to November 28.*** *The world index rating is weighted by the 2019 road fuels demand of each country.*

Apple mobility (driving) index

Indexed to Jan 13, 2020 (seven-day MA)

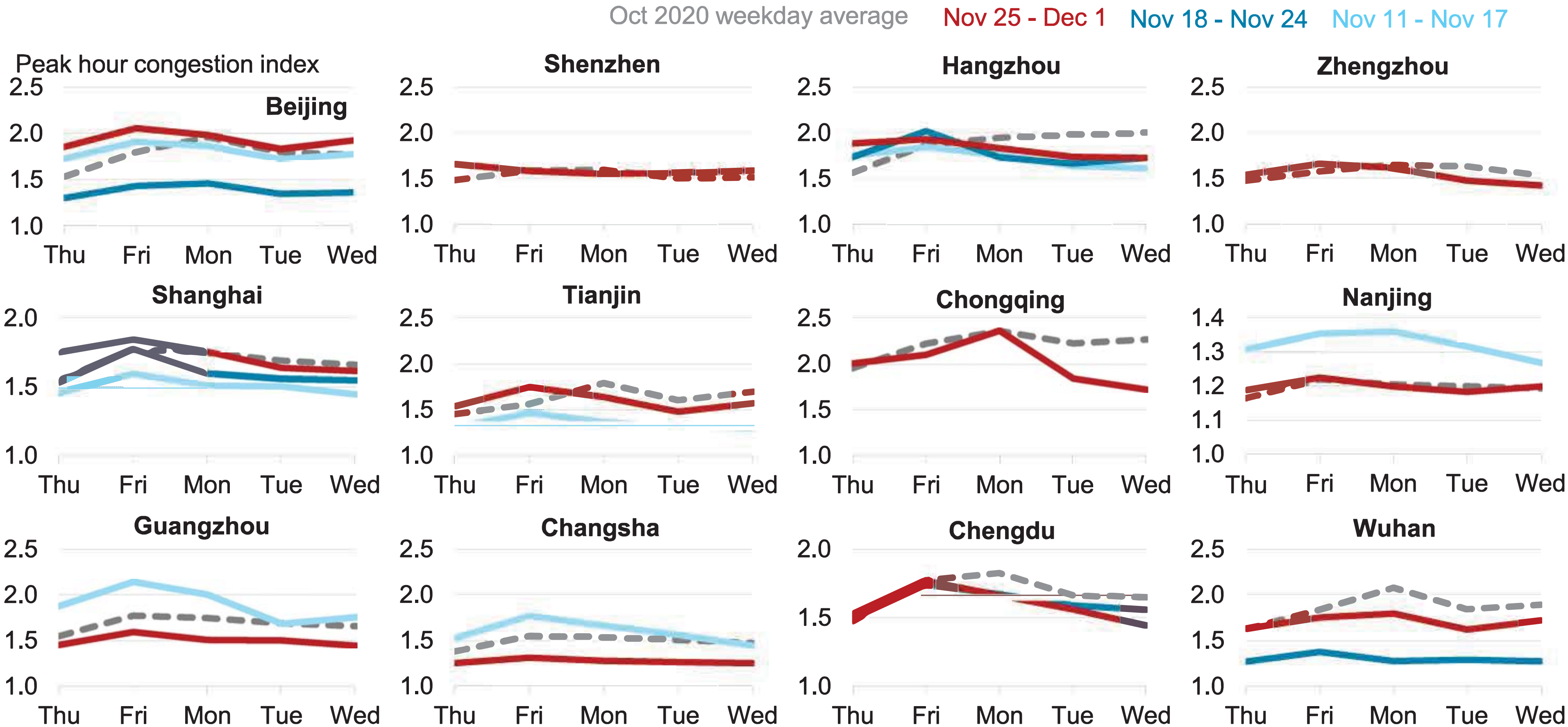


	Week Δ	Four-week Δ
Asia Pacific	-2.8 (-1.9%)	11.6 (+8.6%)
Americas	-11.7 (-7.5%)	-8.2 (-5.4%)
World	-6.1 (-4.1%)	-5.5 (-3.7%)
Europe	-4.9 (-3.7%)	-23.5 (-15.4%)

Source: Apple Mobility Report, BloombergNEF. Note: ***Asia Pacific excludes China. Data updated to November 30.*** *The world index rating is weighted by the 2019 road fuels demand of each country.*

China (Baidu)

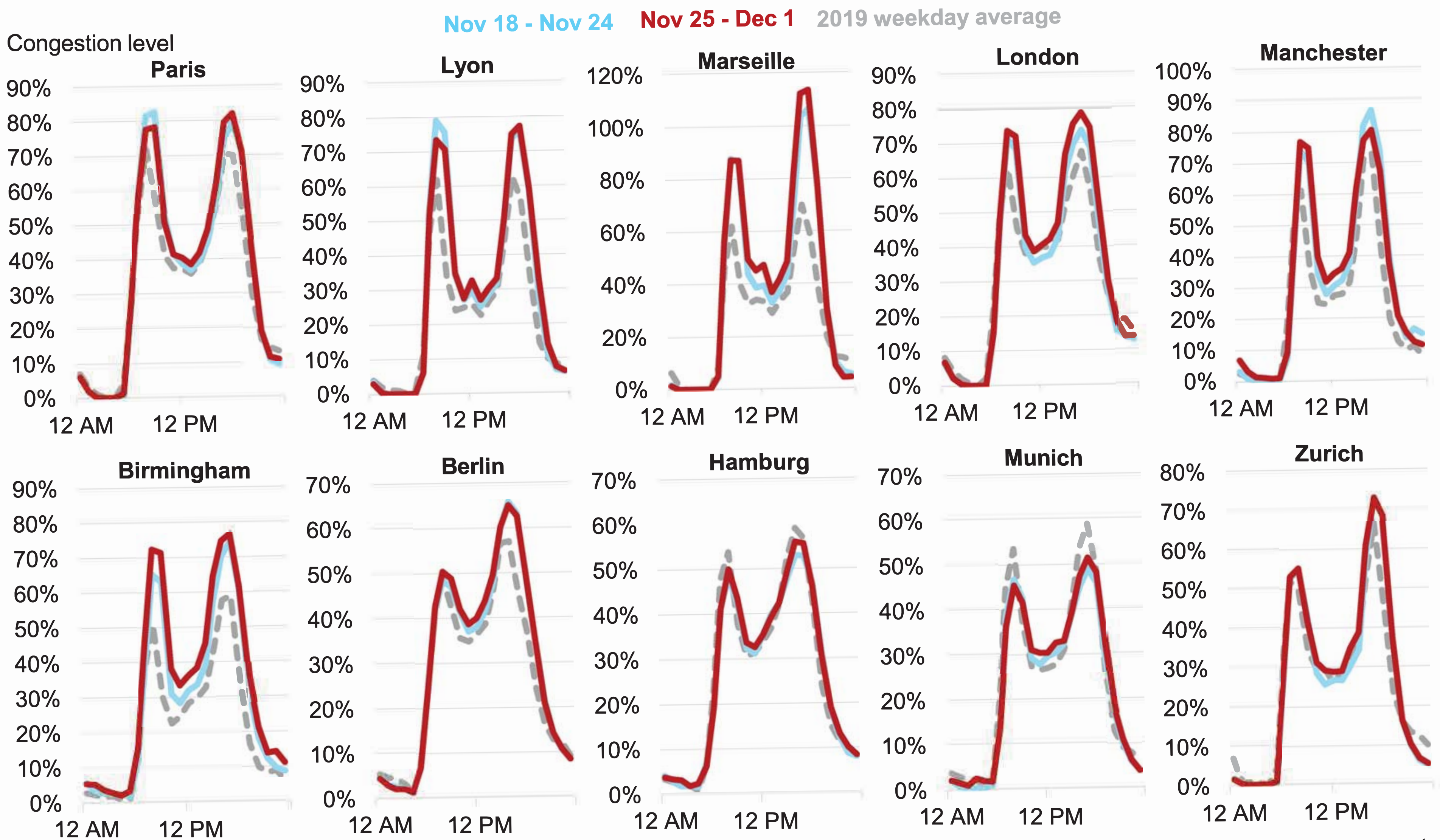
Road congestion rose to 98% of 2020 levels



Source: BloombergNEF, Baidu. Note: Congestion index is calculated by Baidu, which estimates the increase in time that a journey within a city will take compared to uncongested conditions during peak hours. Peak hours are 7:00-9:00 and 17:00-19:00. Charts show and compare average peak hour congestion levels over Thu-Wed for each week. Dotted line shows the weekday average congestion index of the city for the same month in 2020.

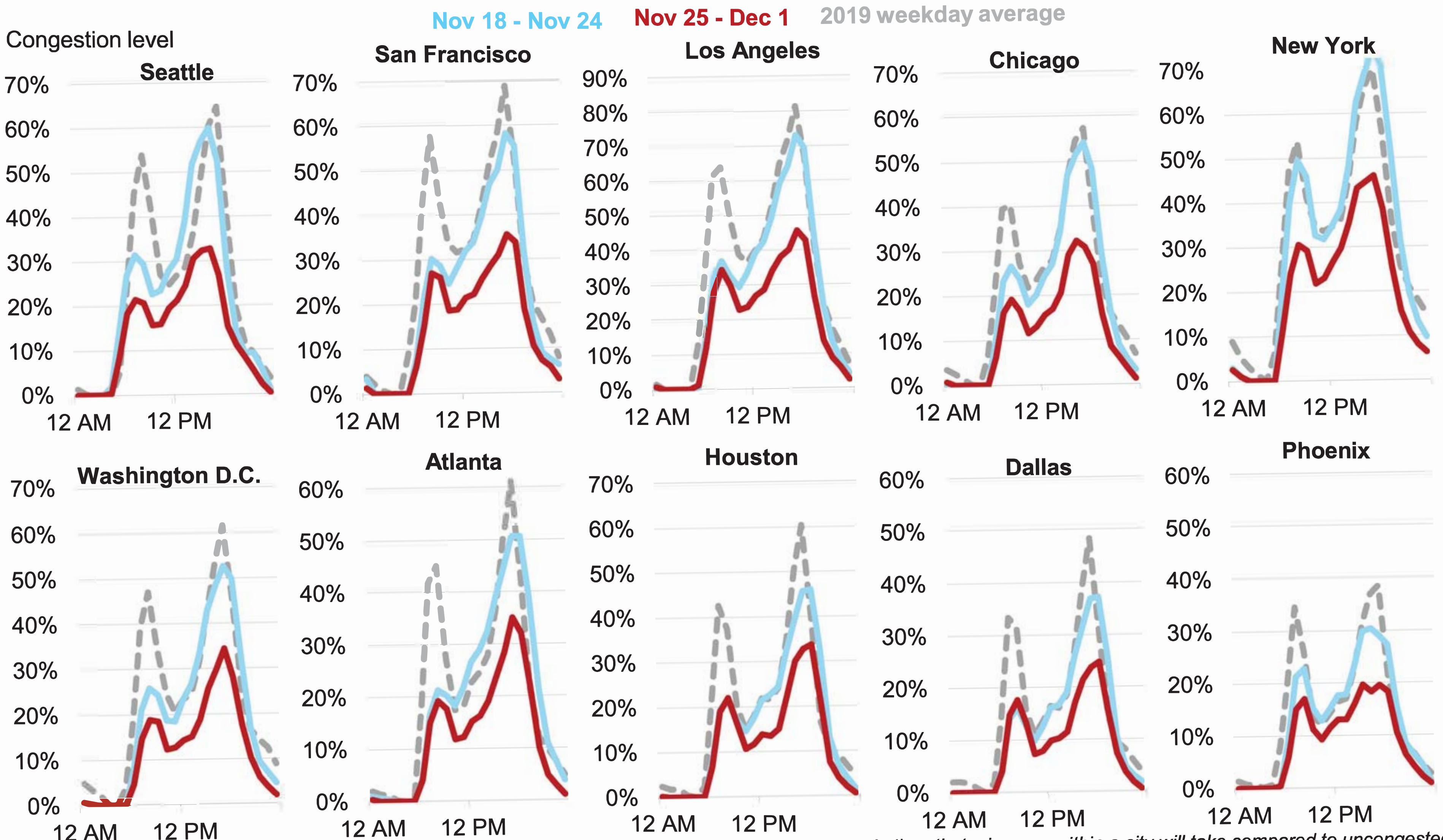
- In China, road traffic rose by 1.1 percentage points to 97.7% of 2020 levels (calculated based on Baidu's data).

Major European cities (1/2) (TomTom)



Source: BloombergNEF, TomTom Traffic Index. Note: 'Congestion level' is an estimate of the increase in time that a journey within a city will take compared to uncongested conditions – so, 40% congestion implies that a journey will take 40% longer than on empty roads. Charts show Thu-Wed average hourly congestion levels.

Major Americas cities (1/2) (TomTom)



Source: BloombergNEF, TomTom Traffic Index. Note: 'Congestion level' is an estimate of the increase in time that a journey within a city will take compared to uncongested conditions – so, 40% congestion implies that a journey will take 40% longer than on empty roads. Charts show Thu-Wed average hourly congestion levels.

BloombergNEF

https://www.rystadenergy.com/newsevents/news/press-releases/us-shale-spending-set-to-shake-off-uncertainty-and-jump-19-in-2022-topping-83-billion/

US shale spending set to shake off uncertainty and jump 19% in 2022, topping $83 billion

December 1, 2021

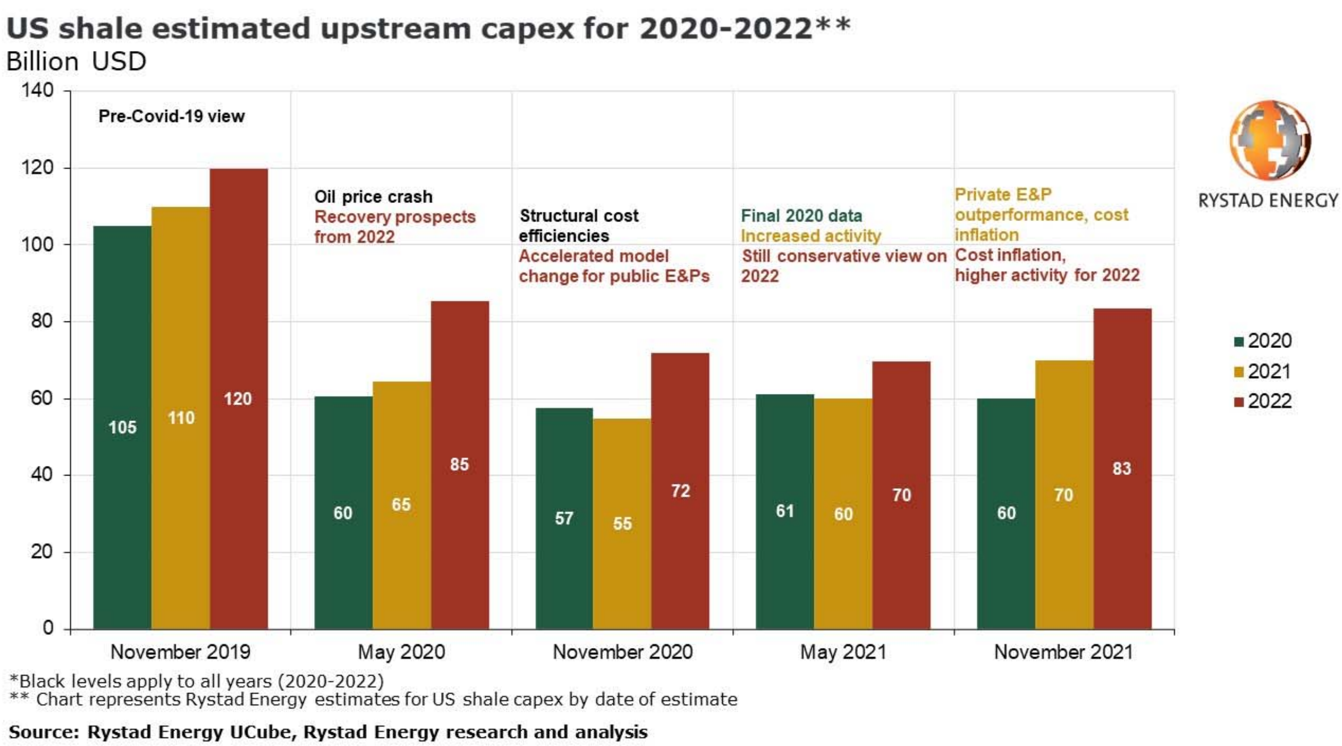
US shale expenditure is projected to surge 19.4% next year, leaping from an expected $69.8 billion in 2021 to $83.4 billion, the highest level since the onset of the Covid-19 pandemic and signaling the industry's emergence from a prolonged period of uncertainty and volatility, according to a Rystad Energy report.

As the impact of the pandemic on demand and activity levels out, US Land players are poised to loosen their purse strings. As the Omicron variant of the novel coronavirus tightens travel restrictions and raises concerns over a potential industry slowdown, some hesitancy in spending could yet materialize.

Of the expected year-on-year increase, service price inflation alone is set to add $9.2 billion, with increased activity chipping in $8.6 billion. These increases will be partially offset by $4.2 billion in savings from efficiency gains. Efficiency gains are expected to be driven predominantly by further adoption of simul-fracs. Despite the sizeable annual spending growth, the 2022 total will still end up well below the level forecast for 2022 before the pandemic took hold.

“Oil and gas activity and upstream spending in US Land has been exposed to significant volatility in the last two years. Aggressive strategies from private operators in the US shale patch have driven spending this year, but we anticipate significant growth in 2022 from public and private operators alike,” says Artem Abramov, head of shale research at Rystad Energy.

In November 2019, before the market downturn caused by Covid-19, Rystad Energy forecast total US shale spending for 2020 would be $104.9 billion, with $109.7 billion and $119.8 billion per annum estimated for 2021 and 2022, respectively. The estimate for 2020 was taken down sharply in that year's second quarter to $60.4 billion following the unprecedented oil price crash and a domestic storage crisis. While modest adjustments to this estimate were observed in the second half of 2020 and the first half of this year, the final numbers for all public producers and final estimates for private exploration and production (E&P) players had only a marginal net impact on that original estimate. Currently, the number for 2020 still stands at $60 billion.



Learn more in Rystad Energy's Shale Analytics.

Public independents largely maintained their 2021 US shale budgets compared with 2020 on a full-year basis, with a modest increase in the weighted-average well activity index (two-thirds of completion count and one-third of drilled well count). Somewhat higher activity was offset by structural efficiency gains and lower service costs behind actual drilling and completion (D&C) operations. While the latter might sound counterintuitive from the perspective of significant spot rate inflation in most service segments throughout 2021, it should be noted that there was an opposite trend throughout 2020, which allowed large independents to lock in cheaper service rates in early 2021 compared to what was behind their D&C spending in 2020.

Meanwhile, private operators, which moved aggressively throughout 2021, warmed up spot service rates and have already felt the impact of cost inflation this year. As a result of this private E&P activity uptick, total US shale capital expenditure increased by around 16% in 2021 compared with 2020.

How the regions stack up

At the regional level, spending in the Permian and Haynesville plays stayed resilient during 2020's downturn, seeing a faster structural increase in activity this year. As a result, full-year upstream spending in these regions has increased by between 23% and 24% so far this year, outperforming the national average growth rate. The Niobrara saw an even steeper increase in spending in 2021 on a percentage basis, albeit starting from a particularly low base after the massive collapse last year.

Appalachia and the Eagle Ford, on the other hand, have experienced only minor growth in 2021, with spending rising between 3% and 6% compared with last year. While the Eagle Ford has seen a healthy recovery in rig count during 2021, its full-year spending growth numbers were dragged down by low drilled but uncompleted (DUC) wells to completion activity, especially when compared to the Permian, and inflated 2020 spending amid robust activity in the first quarter of 2020. Spending in the Bakken and Anadarko regions in 2021 has declined by between 7% and 14% from last year.

Looking ahead to 2022, the Eagle Ford, Niobrara and Anadarko regions are anticipated to beat nationwide average spending growth due to the rig activity expansion observed in recent months, which provides some momentum to the increase in the running rate of frac activity in 2022. The Bakken is forecast to have 19% spending growth next year, matching the national average growth rate, while the Permian is set to grow by 17%, slightly less than the national average as other basins are catching up. On the gas side, we anticipate a 15% increase in spending from Appalachia and an around 10% increase in the Haynesville. While the full-year growth rate is seen higher in Appalachia, this does not really suggest a stronger increase in the running rate of frac activity in the northeast region, where supply remains constrained by the takeaway capacity situation.

For more analysis, insights and reports, clients and non-clients can apply for access to Rystad Energy's Free Solutions and get a taste of our data and analytics universe.

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CAPP CANADA'S OIL & NATURAL GAS PRODUCERS

FREQUENTLY USED STATISTICS — NOVEMBER 2021

ECONOMICS

Capital Investment ($ billions)	2016	2017	2018	2019	2020	2021E
Conventional (included East Coast offshore)	23	29	27	26	14	16
Oil Sands	15	14	12	9	7	9
Canada	39	43	39	35	21	25
East Coast	5.6	3.2	2.7	2.8	1.5	1.5

Upstream sector second largest private sector investor in Canada based on 2019 data (most recent).

Source: Statistics Canada/CAPP

Annual Revenue ($ billions)*	2018-2020
Upstream oil and natural gas	209

* average over 3 years ending 2020

Source: Statistics Canada

Payments to Governments ($ billions) *	2018-2020
Canada	9

* average of 3 years includes royalties, income tax, land sales, carbon, muncipal and corporate taxes.

2016 lower with decrease in royalty revenue and land sales.

Source: CAPP

Real GDP Impact	2016	2017	2018	2019	2020
Canada's Total GDP ($ billions)	1 839	1 896	1 945	1 980	1 876
Conventional GDP ($ billions)	46	49	54	55	52
Conventional GPD Share (%)	2.5	2.6	2.8	2.8	2.7
Oil Sands GDP ($ billions)	48	53	57	57	53
Oil Sands GPD Share (%)	2.6	2.8	2.9	2.9	2.8
Upstream GDP ($ billions)	94	102	110	112	105
Upstream GDP Share (%)	5.1	5.4	5.7	5.7	5.6

Source: Statistics Canada

Oil Sands Provincial Supply Chain Outside of Alberta	2017		2018		2019	
# suppliers and $ spent	#	$MM	#	$MM	#	$MM
British Columbia	572	430.1	541	468.5	513	534.7
Saskatchewan	214	86.4	189	118.0	167	130.7
Manitoba	58	43.7	50	58.0	55	68.6
Ontario	1665	1 936.0	1 339	2 087.4	1 302	2 427.9
Québec	680	465.4	592	577.7	585	760.0
Prince Edward Island	5	0.9	2	0.3	2	0.4
Nova Scotia	40	51.3	38	46.7	38	49.0
Newfoundland and Labrador	34	52.5	22	32.6	23	38.8
New Brunswick	29	11.1	25	22.4	19	18.8
Northwest Territories	1	2.3	1	0.9	4	0.4
Yukon Territories	3	2.9	3	0.8	3	0.1
Suppliers Outside of Alberta*	**2 872**	**3 082.6**	**2 420**	**3 413.3**	**2 711**	**4 029.4**

*** Suppliers do not add due to suppliers in multiple provinces**

Source: CAPP 2021

Indigenous Supply Chain in Alberta	2017	2018	2019
Spend on Suppliers ($MM)	1 545	2 025	2 358
Number of Suppliers	263	260	275

Source: CAPP 2021

Employment (thousands)	2014	2015	2016	2017	2018	2019	2020
Direct & indirect jobs o&g conv & offshore	383	357	267	323	330	308	234
Direct & indirect oil sands jobs	361	287	228	205	217	214	166
Total upstream	744	644	495	528	546	522	399

Source: CAPP based on data and analysis from Prism Economics and Statistics Canada

Oil and Gas Value on TSX (at year end)	2017	2018	2019	2020	Nov-21
Canadian producer companies trading on the TSX	10.0%	7.3%	6.5%	4.2%	6.7%

Source: Stifel First Energy/CAPP

ACTIVITY

Drilling	2016	2017	2018	2019	2020	2021E
# of Wells Drilled in W Canada	3 751	6 414	6 125	4 318	3 000	4 200

Source: CAPP

Production	2016	2017	2018	2019	2020	2021 YTD	2035 Forecast
Crude Oil (Mb/d):							
Alberta conv. & C5+	666	716	808	824	754	764	989
Saskatchewan conv.	461	487	491	490	438	449	464
WCSB Conv. & C5+	1 241	1 317	1 449	1 477	1 348	1 364	1 510
East Coast	210	221	230	262	284	274	91
Oil sands	2 415	2 675	2 914	2 950	2 836	3 038	4 253
Canada	3 867	4 213	4 594	4 688	4 467	4 677	5 855
Natural Gas (Bcf/d):							
Alberta	10.2	10.4	10.5	10.1	9.6	9.9	
British Columbia	4.6	4.7	5.4	5.5	5.7	5.6	
East Coast	0.2	0.1	0.1	0.0	0.0	-	
Canada	15.2	15.7	16.2	15.7	15.4	15.7	

Oil is ranked 5th and natural gas 5th in world production. Canada is ranked 3rd in crude oil reserves

Y= with Market Opportunity Source: CAPP; N=without Market Opportunity Source: CAPP

Source: Provinces

MARKETS

Exports to U.S.	2015	2016	2017	2018	2019	2020	Jan-Sep 2021
Crude Oil (MMb/d)	3 046	3 101	3 320	3 431	3662	3608	3652
Natural gas (Bcf/d)	7.6	7.9	8.2	7.8	7.2	6.7	7.2

Source: Statistics Canada

Foreign Imports	2015	2016	2017	2018	2019	2020	Jan-Sep 2021
Crude Oil (Mb/d):							
Atlantic Canada	321	308	333	326	351	287	270
Ontario	26	90	95	48	21	32	59
Québec	296	214	158	153	203	170	136
Share of refinery capacity of Québec and Atlantic	79%	67%	63%	59%	67%	58%	52%
Natural Gas (Bcf/d):							
Canada	1.9	2.1	2.4	2.2	2.5	2.2	3.0

Source: Statistics Canada

Global Energy Supply (EJ)*	2020	2030	2040	2020-30 Growth	2020-40 Growth	2020 Share	2040 Share
Coal	156	150	134	-3%	-14%	26%	19%
Oil	171	199	200	16%	16%	29%	28%
Natural Gas	139	157	169	13%	22%	24%	24%
Nuclear	29	34	38	16%	31%	5%	5%
Hydro	16	18	21	17%	35%	3%	3%
Biomass	24	21	19	-13%	-21%	4%	3%
Other Renewables	53	91	132	71%	149%	9%	18%
Total Energy Supply	588	670	713	14%	21%	100%	100%

* International Energy Agency World Energy Outlook 2021

Source: International Energy Agency 2021 World Energy Outlook, Stated Policies Scenario

ENVIRONMENT

GHG Emissions (Mt CO_2 e) *	2015	2016	2017	2018	2019	% Cdn	% Global
Oil Sands	72	69	76	81	83	11%	0.15%
Conventional Oil & Gas	86	79	77	80	78	11%	0.16%
Total Upstream	169	160	163	172	172	24%	0.31%
Total Canada	723	707	716	728	730		<1.5%

*National Inventory Report megatonnes of CO_2 equivalent

Source: Environment & Climate Change Canada, 2019/WRI

Water Use	2014	2015	2016	2017	2018
Non-saline water use (million m3)					
Oil sands mining	172	181	182	206	246
Oil sands in situ	14	16	15	18	18
Enhanced oil recovery (EOR)	16	16	14	13	11
Hydraulic fracturing	10	10	11	23	28
Non-saline water use intensity (barrels of non-saline make-up water used to produce one BOE)					
Oil sands mining	2.57	2.41	2.45	2.50	2.59
Oil sands in situ	0.22	0.23	0.20	0.20	0.2
EOR	0.78	0.77	0.74	0.69	0.61
Hydraulic fracturing	0.27	0.35	0.46	0.56	0.52
Recycled water use (% of total water used)					
Oil sands mining	76%	77%	78%	75%	75%
Oil sands in situ	84%	84%	85%	87%	86%
EOR	93%	93%	93%	93%	94%
Hydraulic fracturing	5%	6%	4%	4%	2%

Source: AER

Land	
Share of boreal forest disturbed by oil sands mining	0.04%
Size of boreal forest (km^2)	2 700 000
Land covering oil sands (km^2)	142 000
Active mining footprint (km^2)	1 030

Source: AER/AB Environment

Prices	2016	2017	2018	2019	2020	2021 Jan-Oct
North Sea Brent (US$/b)	43.55	54.23	71.00	64.33	41.74	69.21
WTI Nymex (US$/b)	43.32	50.95	64.73	57.03	39.35	66.39
Cdn Heavy - WCS (US$/b)	29.65	39.08	38.58	43.61	27.42	53.72
Henry Hub Gas US$/mcf	2.55	3.02	3.07	2.53	2.13	3.56
AECO NIT (C$/mcf)	2.22	2.38	1.55	1.64	2.23	3.47

Note: Numbers may not add due to rounding

Source: CAPP Statistical Handbook

Legend

Abbreviation	Description
b/d	barrels per day
bbl	barrel
m3	cubic metre
Mm3	thousand cubic metres
MMm3	million cubic metres
Mb/d	thousand barrels per day
MMb	million barrels
MMb/d	million barrels per day
Bcf	billion cubic feet
Bcf/d	billion cubic feet per day
GJ	gigajoule
Mcf	thousand cubic feet
MMBtu	million British thermal units
MMcf	million cubic feet
BOE	barrels of oil equivalent
BOE/d	barrels of oil equivalent per day
CO2e	carbon dioxide equivalent
Mtoe	million tonnes of oil equivalent
E	estimate
F	forecast
GDP	gross domestic product

Independent Statistics & Analysis
U.S. Energy Information Administration

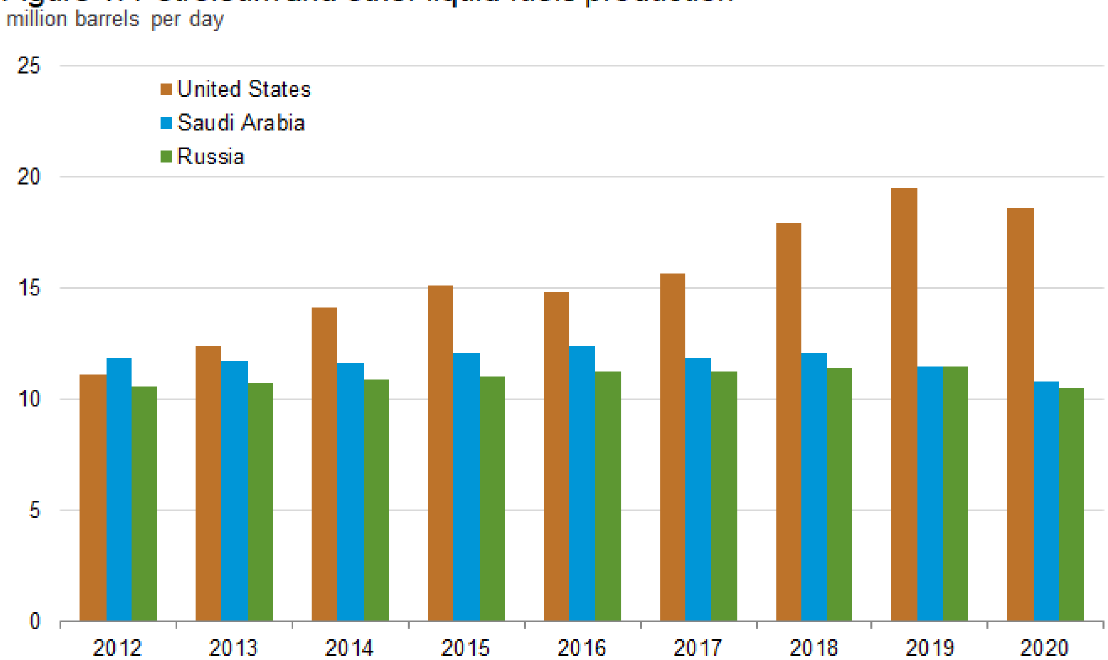
Country Analysis Executive Summary: Saudi Arabia

Last Updated: December 2, 2021

Overview

- Saudi Arabia holds 15% of the world's proved oil reserves.[1] It is the largest exporter of crude oil in the world[2] and maintains the world's largest crude oil production capacity at nearly 12 million barrels per day, including capacity from the Neutral Zone that is shared with Kuwait.[3] Saudi Arabia is the largest crude oil producer in OPEC and the second-largest total petroleum liquids producer in the world after the United States (Figure 1).[4]
- Saudi Arabia, one of the key members of the OPEC+ agreement, reduced production in order to rebalance the global oil market, reduce record-high oil inventory levels, and stabilize volatile crude oil prices in 2020 as a result of the economic downturn and restriction measures taken as a result of the global COVID-19 pandemic. Saudi Arabia initially reduced its production by 3.1 million barrels per day (b/d) as part of the OPEC+ agreement that began in April 2020.[5] Saudi Arabia has increased production each month since February 2021, and, by October 2021, their production returned to an estimated 9.8 million b/d, similar to the level at the beginning of 2020.
- Petroleum exports account for a large share of Saudi Arabia's economy. They accounted for nearly 70% of the country's total exports in terms of value in 2020, and about 53% of the Saudi government's revenues were oil-based.[6] Real GDP fell by 4.1% in 2020 as a result of the decrease in global oil demand driven by the COVID-19 pandemic and voluntary cuts to oil production to comply with the OPEC+ agreement.[7] Saudi Arabia's oil revenues fell between 2018 and 2020 because average crude oil prices and oil export volumes declined during this time period. EIA estimates that Saudi Arabia's net oil export revenues totaled $202 billion in 2019, compared with $238 billion (in 2019 dollars) in 2018. We expect that the oil price declines and production cuts in 2020 further reduced Saudi Arabia's net oil export revenues.[8]
- Saudi Arabia consumed an estimated 10 quadrillion British thermal units of total primary energy in 2020, making it the second-largest energy consumer in the Middle East, behind Iran, and the 11th-largest energy consumer in the world. Oil accounted for 62% of the country's energy consumption in 2020, and natural gas accounted for 38%. Natural gas supplies and processing capacity has risen since 2015, but oil production has declined during this period, which has allowed natural gas to replace a significant portion of crude oil burned for power generation. Solar energy and coal contributed only slight amounts to Saudi Arabia's energy consumption.[9]

Figure 1. Petroleum and other liquid fuels production



Source: Created by the U.S. Energy Information Administration, based on data from EIA' *Short-Term Energy Outlook*, August 2021, and from International Energy Statistics

Note: The total petroleum and other liquid fuels category includes crude oil and lease condensate, natural gas plant liquids, other liquids, and refinery processing gain.

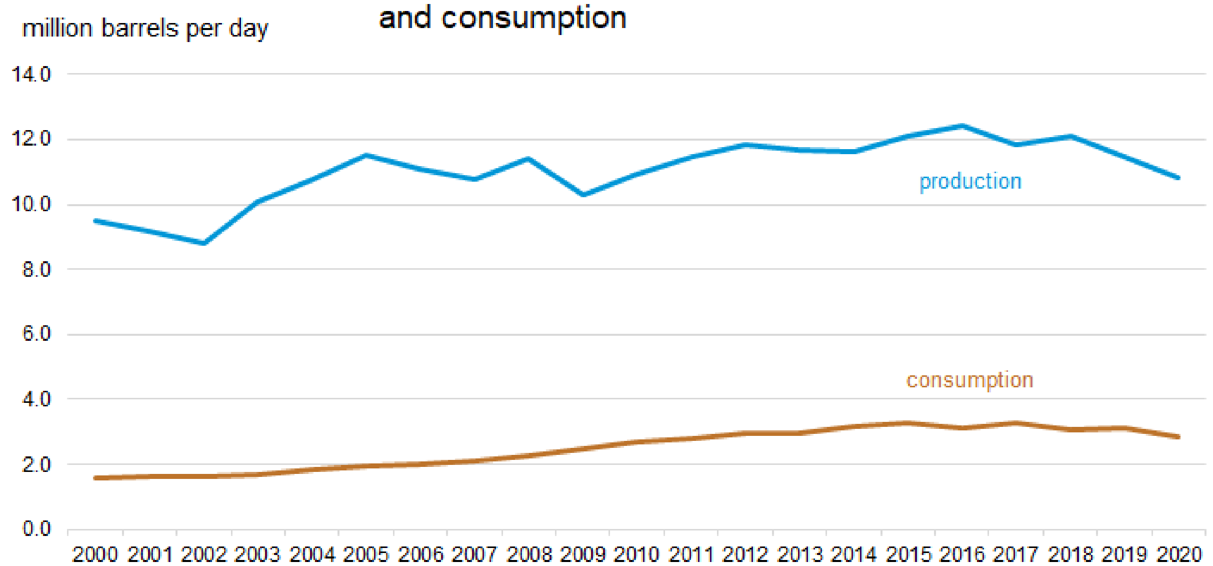
Petroleum and other liquids

- At the end of 2020, Saudi Arabia held the world's second-largest proved oil reserves, at 259 billion barrels, representing 31% of proved reserves in the Middle East and 15% of global reserves, according to *Oil and Gas Journal*.[10] Saudi Arabia's major fields are located both onshore and offshore in the eastern part of the country.
- Total oil production, which includes crude oil, condensates, and natural gas liquids, in Saudi Arabia has declined since 2018, when output reached 12.1 million b/d (Figure 2). Saudi Arabia produced, on average, 10.8 million b/d of total petroleum liquids in 2020, of which 9.2 million b/d was crude oil and about 1.6 million b/d was non-crude liquids. Saudi Arabia, which holds the world's largest spare crude oil capacity, affects global oil markets by quickly increasing or decreasing its oil production.
- Saudi Arabia's crude oil production in 2020 was 9.2 million b/d, a 10-year low, as a result of its commitment to the April 2020 OPEC+ agreement to curtail oil production. Before the OPEC+ agreement was signed, Saudi Arabia's crude oil production was a record-high 11.6 million b/d in April 2020. Saudi Arabia's defined agreement cuts and an additional voluntary 1.0 million b/d reduction for one month led to crude oil output falling to 7.7 million b/d in June 2020.
- In January 2021, OPEC+ participants raised production by 150,000 b/d,[11] but Saudi Arabia volunteered another additional cut of 1.0 million b/d from February through April 2021 because of low global oil demand growth and high global supply inventories that resulted from renewed COVID-19 containment measures. During the first half of 2021, Saudi Arabia's crude oil production fell to an average of 8.5 million b/d. Based on the outcome of the July 2021 OPEC+

meeting, we forecast that Saudi Arabia will gradually increase its production through the second half of 2021.[12]

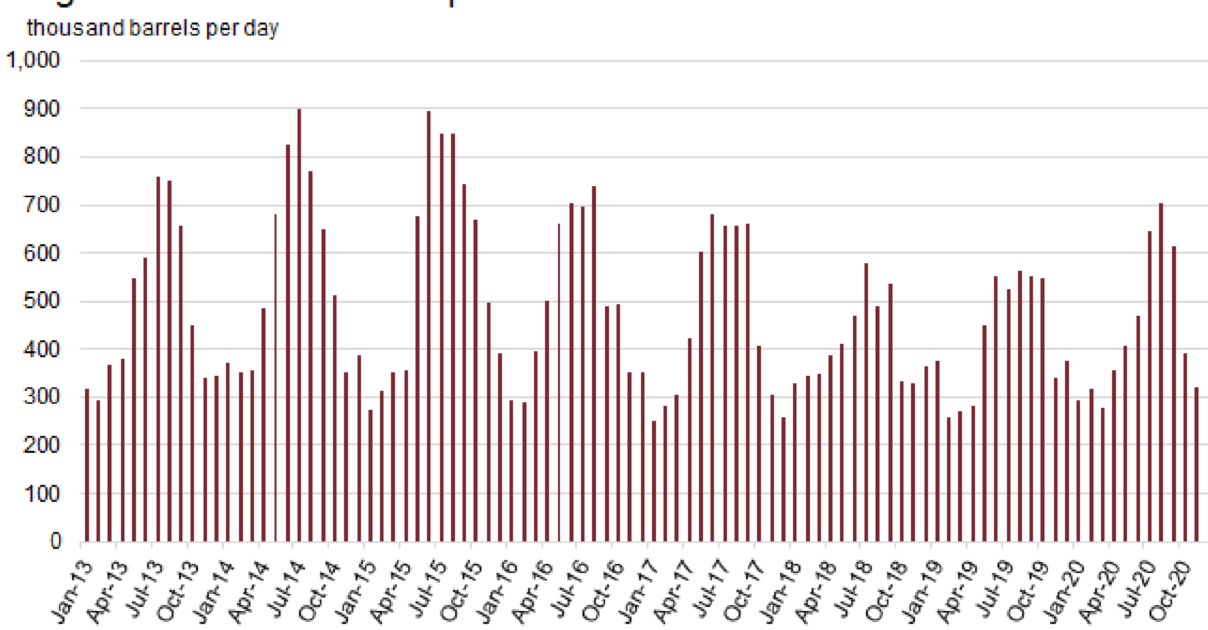
- Saudi Arabia and Kuwait agreed at the end of 2019 to restart production in the Partial Neutral Zone (PNZ) after a five-year shutdown, and as a result, production began in early 2020 at the Wafra and Al-Khafji fields. By April 2021, PNZ oil production rose to an estimated 270,000 b/d.[13]
- Saudi Arabia, the largest oil-consumer in the Middle East, consumed 2.9 million barrels per day (b/d) of petroleum products and crude oil in 2020, down from 3.1 million b/d in 2019, primarily as a result of the global COVID-19 pandemic and accompanying economic and industrial downturns.[14] Consumption of gasoline and jet fuel, the key transportation fuels in Saudi Arabia, decreased considerably. However, the higher consumption of fuel oil for the power sector partially offset the gasoline and jet fuel declines.[15]
- The OPEC+ agreement reduced natural gas supply from fields associated with oil production, leading Saudi Arabia's power plants to rely on more fuel oil and crude oil as generation sources, especially during the peak demand season in summer.[16] Overall, fuel oil demand reached a record high in 2020 of 600,000 b/d, according to data from the Joint Oil Development Initiative (JODI).[17]
- Crude oil consumption for power generation rose slightly from a 10-year low of 410,000 b/d in 2018 to more than 420,000 b/d in both 2019 and 2020, according to JODI data.[18] In 2020, decreasing global oil demand and significant crude oil production cuts constrained Saudi Arabia's crude oil exports, lowered associated gas production, and increased crude oil and fuel oil consumption for power generation (mainly during the summer). Direct crude oil burn from July through September 2020 averaged 654,000 b/d, up from 545,000 b/d during the same time in 2019.[19] The Saudi government maintains its long-term policy to displace more crude oil and fuel oil with less-polluting sources such as natural gas and renewable energy in its power sector. As the OPEC+ countries gradually reverse their significant production cuts in 2021 from the April 2020 OPEC+ agreement and Saudi Arabia continues to expand its natural gas infrastructure, we expect Saudi Arabia's power sector to reduce its consumption of crude oil for power generation.[20]

Figure 2. Saudi Arabia's petroleum and other liquid fuels production and consumption



Source: Created by the U.S. Energy Information Administration (EIA), based on data from EIA's *Short-Term Energy Outlook*, August 2021, and International Energy Statistics

Figure 3. Crude oil used at power stations in Saudi Arabia



Source: Graph by the U.S. Energy Information Administration, based on data from Joint Oil Data Initiative

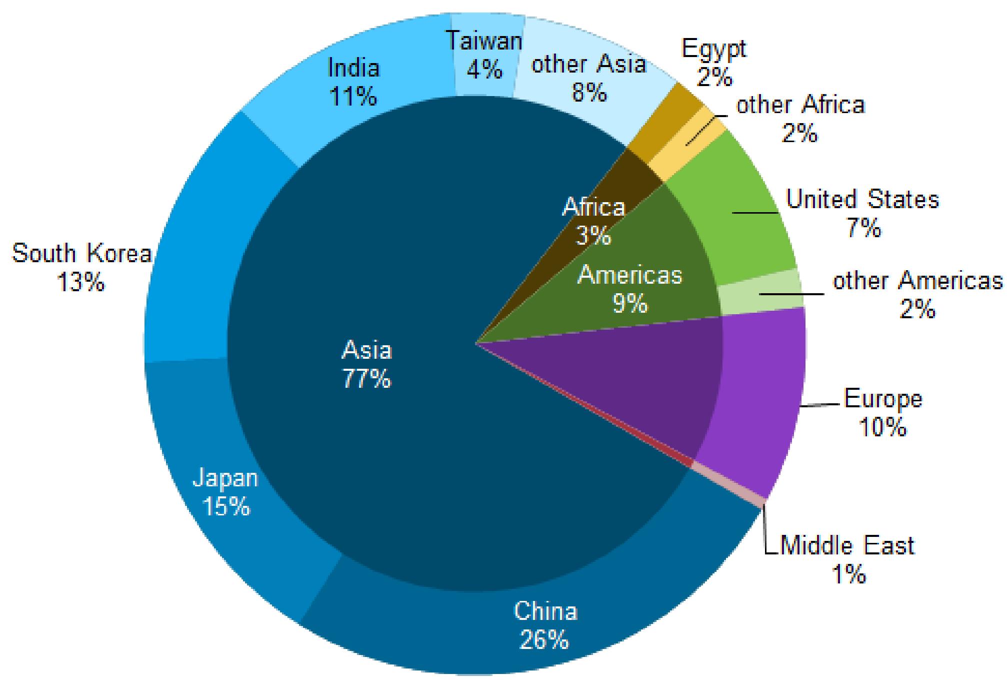
Exports

- Saudi Arabia exported an estimated 6.6 million b/d of crude oil in 2020, down nearly 300,000 b/d from 2019, according to Global Trade Tracker (GTT). A 570,000 b/d decline in petroleum production combined with a decline in global demand caused exports to drop in 2020.[21]
- Asia received an estimated 77% of Saudi Arabia's crude oil exports (Figure 4) in 2020 and more than one-third of its refined petroleum products (Figure 5). Asia's oil demand and refining

capacity grew significantly in the past decade, and it increased its share of Saudi Arabia's crude oil exports during that time. Other regions that import Saudi Arabia's crude oil include Europe (10%), the Americas (9%), Africa (3%), and other Middle Eastern countries (1%).[22]

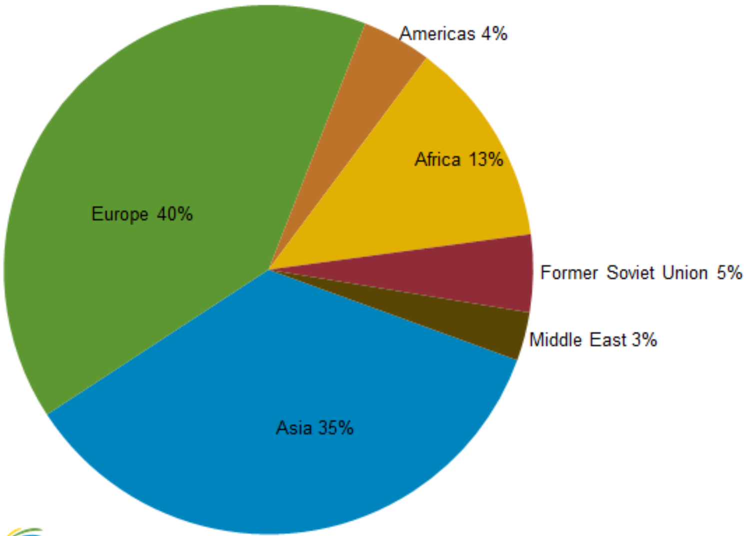
- The United States imported an average of 0.5 million b/d of total petroleum liquids from Saudi Arabia in 2020, most of which was crude oil. U.S. crude oil imports from Saudi Arabia have been generally declining since 2012 as U.S. produces more of its own crude oil and imports more crude oil from Canada.[23]
- In 2020, Saudi Arabia exported nearly 900,000 b/d of petroleum products, and most of these exports went to Europe and Asia, according to GTT (Figure 5).

Figure 4. Saudi Arabia's crude oil exports by destination, 2020



Source: Graph by the U.S. Energy Information Administration, based on data from Global Trade Tracker

Figure 5. Saudi Arabia's refined products exports by destination, 2020



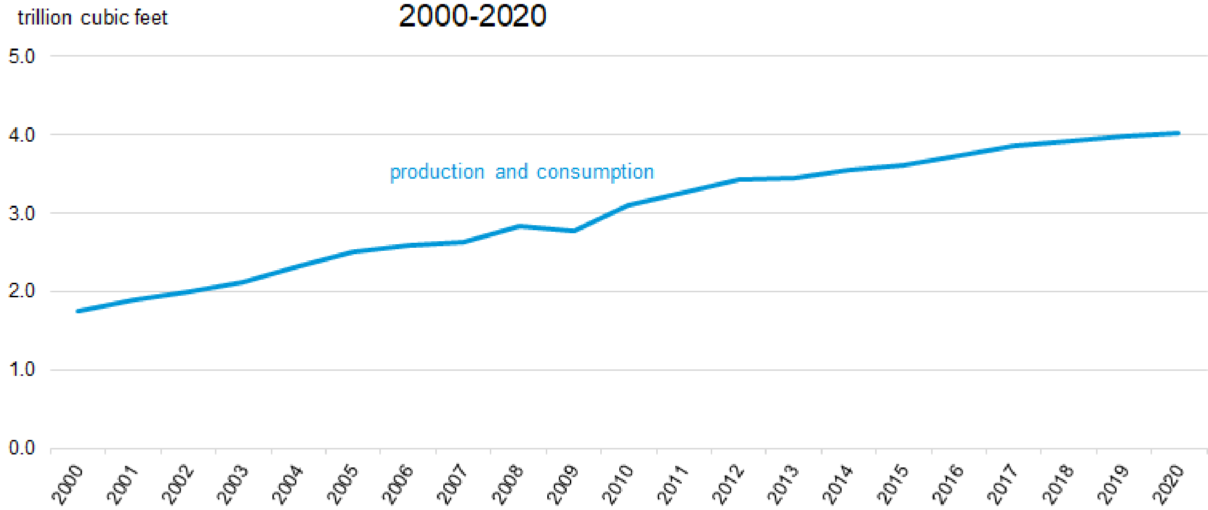
Source: Graph by the U.S. Energy Information Administration, based on data from Global Trade Tracker

Natural gas

- Saudi Arabia (including the Neutral Zone) had proved natural gas reserves of 333 trillion cubic feet (Tcf) as of January 2021, the sixth largest in the world behind Russia, Iran, Qatar, the United States, and Turkmenistan.[24]
- Saudi Arabia's dry natural gas production exceeded 4 Tcf for the first time in 2020, marking a 30% increase since 2010 (Figure 6).[25] The mix of natural gas from fields associated with crude oil production (associated gas) and natural gas from fields not associated with oil production (nonassociated gas) shifted during this period. The rapid development of nonassociated gas fields, especially since 2015, bolstered growth in total domestic natural gas production. However, growth in total natural gas production began to slow in 2017 because of declining associated gas production.[26] Associated gas, which accounted for more than 80% of Saudi Arabia's natural gas production in 2016, provided about half of the country's natural gas production in 2020 (Figure 7).[27]
- Saudi Aramco commissioned the Fadhili natural gas processing plant in 2019, which began processing natural gas from nonassociated fields in the eastern region.[28] Growth in Saudi Arabia's natural gas supply in the next few years will hinge on the return of some associated gas production that was shut in during Saudi Arabia's crude oil production cuts and the continued growth of nonassociated gas production.
- Saudi Arabia vented or flared approximately 80 billion cubic feet (Bcf) of natural gas, about 2% of its dry natural gas production, in 2020.[29] Aramco's widespread natural gas infrastructure can capture, process, and transport most of the country's associated gas production, reducing the need for flaring. Saudi Arabia intends to eliminate flaring by 2030 as a part of the World Bank's zero flaring initiative.[30]

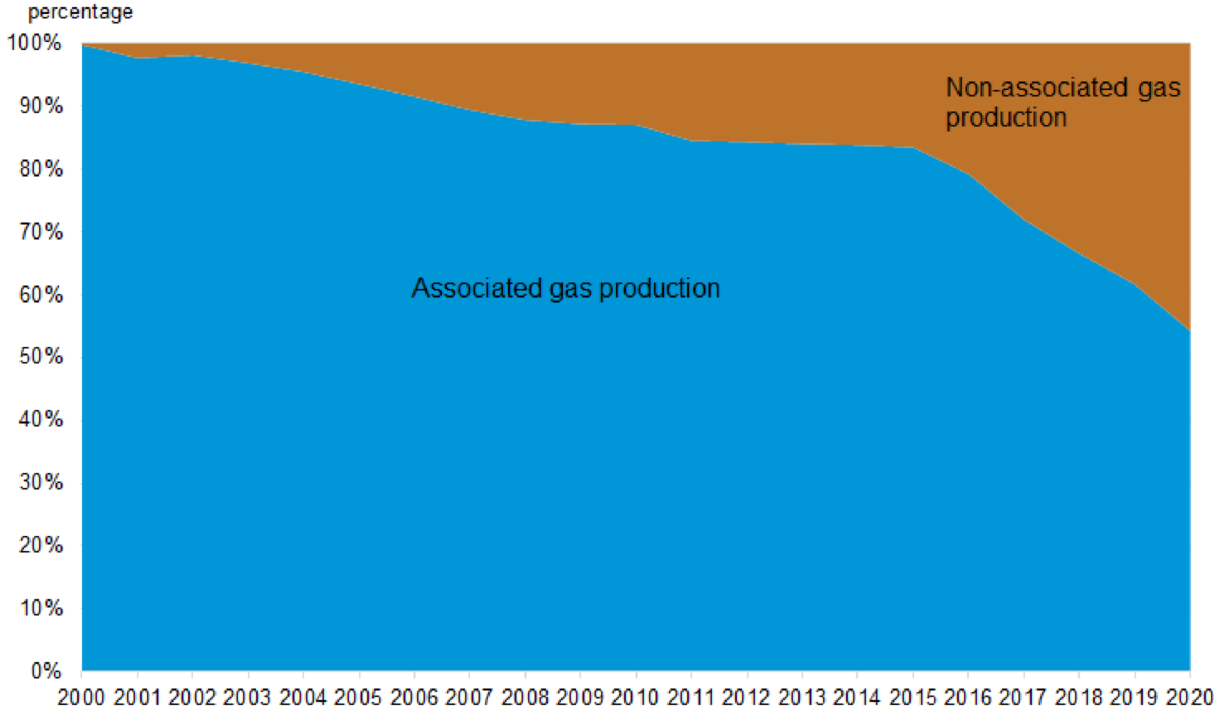
- Saudi Arabia does not import or export natural gas, and all natural gas consumption is met by domestic production. The power sector and industrial sector, primarily petrochemicals, consume most of the natural gas produced in Saudi Arabia.[31] The Saudi government plans to replace crude oil, fuel oil, and diesel with natural gas and renewable energy for power generation by 2030, which would likely increase natural gas demand and investment for natural gas supply in the next several years. However, this target will be difficult to reach given the country's limited progress in phasing out crude oil, fuel oil, and diesel fuel to date.
- Natural gas consumption in Saudi Arabia varies by region. The eastern and central regions consumed natural gas for 97% and 72% of their power generation, respectively, in 2019. However, the western and southern regions consumed petroleum liquids for almost all of their power generation because they lack sufficient natural gas pipeline capacity from the eastern fields, where most of the country's production is located.[32] Expanding the natural gas pipeline and processing capacities to the western and southern regions could help meet more natural gas demand in those regions and reduce oil burning in the power sector.[33]

Figure 6. Saudi Arabia's dry natural gas production and consumption, 2000-2020



Source: Created by the U.S. Energy Information Administration, based on data from International Energy Statistics
Note: All natural gas consumption is met with domestic production.

Figure 7. Saudi Arabia's natural gas production, 2000–2020



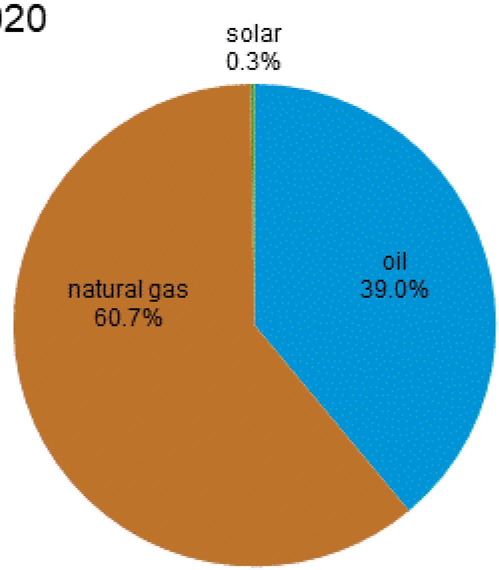
Source: Graph by the U.S. Energy Information Administration, based on data from Rystad Energy UCube

Electricity

- Saudi Arabia generated more electric power in the Middle East than any other country, with an estimated 362 terawatthours in 2019, which was about the same as in 2018.[34] After increasing at an average annual rate of 6% between 2000 and 2015, growth in power generation declined significantly because population growth slowed, GDP growth slowed, energy efficiency and demand-side management measures were implemented, and electricity prices increased between 2016 and 2018.[35] Power generation declined by 1% in 2020, according to data from *BP Statistical Review of World Energy 2021,* as a result of the economic slowdown from the COVID-19 pandemic.[36] Residential power use rose because of the COVID-19-related lockdowns and restrictions, but electricity sales to the commercial and government sectors fell.[37]
- Saudi Arabia fueled nearly all of its electricity generation with natural gas (61%) and crude oil (39%) in 2020, although the Saudi government plans to diversify fuels consumed for electricity output to increase available crude oil for export and to reduce its carbon emissions (Figure 8). The share of natural gas rose substantially over the past decade from 42% of total power generation in 2010 because of expanded natural gas-fired generation capacity that is supported by higher production.[38] In 2019 and 2020, growth in natural gas production slowed substantially, which encouraged crude oil use in the power sector, particularly during the peak summer season. The Saudi government intends to replace most of the crude oil burn and diesel-fired power generators with natural gas and heavy fuel oil in the next few years.[39]

- Although solar generation accounted for an insignificant share of total power generation, several utility-scale solar projects are under development.[40] The Saudi government aims to develop electricity plants powered by solar and wind energy during the next decade, but building these plants will depend on their cost competitiveness against fossil fuels, energy pricing policies set by the Saudi government, and sufficient investment in project development. Some regions of the country are remote and not connected to the natural gas system, and the Saudi government plans to replace some of the oil used for power generation with renewables (mostly solar).[41]
- Saudi Arabia recently began developing large-scale renewable energy projects through its National Renewable Energy Program of Saudi Arabia (NREP) to meet its ambitious renewable energy goals. ACWA Power, a developer of power generation and water desalination plants, connected the 300-megawatt (MW) Sakaka solar power plant (the country's first utility-scale renewable energy project) to the electric grid in November 2019.[42] The 400-MW Dumat Al Jandal wind farm, Saudi Arabia's first commercial wind project, came online in August 2021.[43] In April 2021, Saudi Arabia signed power purchase agreements for seven solar projects with a combined capacity of 3 gigawatts. These projects are slated to come online during the next few years.[44]

Figure 8. Saudi Arabia's electric power generation by fuel, 2020



Source: Graph by the U.S. Energy Information Administration, based on data from *BP Statistical Review of World Energy 2021*

Notes

- Data presented in the text are the most recent available as of December 2, 2021.
- Data are EIA estimates unless otherwise noted.

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Independent Statistics & Analysis
U.S. Energy Information Administration

Background Reference: Saudi Arabia

Last Updated: December 2, 2021

Overview

Compared with other countries, Saudi Arabia is a top holder of proved oil reserves, producer of petroleum liquids, and exporter of total petroleum liquids (crude oil and petroleum products) in the world. Most of Saudi Arabia's exports ship to markets in Asia and Europe.

Saudi Arabia continuously invests in maintaining crude oil production capacity and developing considerable resources in natural gas, refining, petrochemicals, and electric power industries. The country's natural gas and electric power industries, in particular, are designed to meet increasing domestic demand. Investments in refining and petrochemical industries aim to improve Saudi Arabia's ability to compete internationally in these sectors.

In 2016, Saudi Arabia announced a national transformation plan called *Vision 2030*, which encompasses cultural, governance, and economic aspects of Saudi society. On the economic front, *Vision 2030* plans to decrease the large role that revenue from oil production currently plays in the economy by broadening the economic base. The plan outlines far-reaching reforms of the energy sector and includes the partial privatization of state-owned Saudi Aramco. Income from Saudi Aramco's initial public offering (IPO) may help finance the economic transition. Saudi Aramco raised $29.4 billion from the sale of 1.7% shares through an IPO on the Tadawul (Saudi) stock exchange in December 2019.[1] The company is seeking other means to raise money following the economic downturn and oil price crash in 2020. Other options include two bond offerings and the $12.4 billion, 25-year crude oil pipeline lease agreement signed with a consortium led by EIG Global Energy Partners in early 2021.[2]

Saudi Arabia is located near two of the world's busiest chokepoints, and most of its crude oil and petroleum liquid exports travel through them. The Strait of Hormuz, which connects the Persian Gulf with the Gulf of Oman and the Arabian Sea, is the world's most important chokepoint. The flow of 20.7 million barrels per day (b/d) of crude oil in 2018 through this strait accounted for about one-third of all seaborne-traded crude oil and other liquids during that year. This strait is an important route for the Persian Gulf countries for oil and liquefied natural gas exports.[3]

Another regional chokepoint, Bab el Mandeb, links the Gulf of Aden and the Red Sea. This waterway is a strategic link between the Mediterranean Sea and the Indian Ocean. An estimated 6.2 million b/d of crude oil and refined petroleum products flowed through this waterway in 2018 toward Europe, the United States, and Asia.[4]

Figure 1. Map of Saudi Arabia

Source: Central Intelligence Agency World Factbook

Total primary energy consumption

Total energy use in Saudi Arabia peaked in 2016 at 10.4 quadrillion British thermal units (Btu) and then fell to 10 quadrillion Btu in 2020 when the effects of the COVID-19 pandemic reduced domestic energy demand. Total use of energy in Saudi Arabia grew steadily between 2006 and 2016, increasing by about 66% over that period.[5] Domestic energy consumption growth during that period was driven by the economic expansion that was supported by historically high oil-related revenues that persisted until mid-2014. Further, large fuel subsidies, which reportedly cost the Saudi government an estimated $61 billion in 2015, led to energy demand growth of more than 5% per year between 2006 and 2016.[6] The level of energy use in Saudi Arabia has been marked by ups and downs since 2015 for several reasons. The Saudi government introduced subsidy cuts in 2016 and the beginning of 2018, which significantly increased prices on transportation fuels. The government also increased its electricity tariffs in 2015 and natural gas prices in 2016 to encourage more efficient energy use in all customer sectors.[7] In addition to reducing energy use through higher prices, the government encouraged energy efficiency measures.

Petroleum and Other Liquids

Sector organization

Saudi Aramco, the national oil company that manages Saudi Arabia's oil and natural gas operations, was the world's largest integrated oil and natural gas company in terms of oil production in 2019, according to Saudi Aramco.[8] The Saudi Aramco Supreme Council, chaired by the country's Deputy Crown Prince, oversees Saudi Aramco.[9] The Ministry of Energy oversees policies related to the country's oil and natural gas sectors. The government regulates the prices of oil products such as gasoline, diesel, fuel oil, liquefied petroleum gas (LPG), asphalt, and kerosene, which tend to be lower than market prices. The

Council of Ministers regulates all natural gas prices, and the Ministry of Energy regulates natural gas sales within Saudi Arabia.[10]

Reserves

At the end of 2020, Saudi Arabia held the world's second-largest proved oil reserves, at 259 billion barrels, according to *Oil and Gas Journal*. To be more transparent regarding reserves, Saudi Arabia hired consulting firm DeGolyer and MacNaughton in 2017 to conduct the first independent audit of the kingdom's reserves in 40 years, which confirmed the long-standing claims of Saudi Aramco (the national oil and natural gas company) that its petroleum liquids reserves were around 260 billion barrels.[11] Although Saudi Arabia has about 130 major oil and natural gas fields, most of the oil reserves lie in five fields in the eastern part of the country, according to Saudi Aramco. Saudi Arabia's Ghawar field is the world's largest conventional oil field, and Safaniyah is the largest conventional offshore field. Other fields with large reserves include Zuluf, Khurais, and Shaybah.[12]

Saudi Arabia has half of the estimated 5.4 billion barrels of total proved oil reserves located in the Saudi-Kuwait Partitioned Neutral Zone (PNZ).[13] The PNZ consists of the area between the Saudi-Kuwaiti border, which was established in 1922 to settle a territorial dispute between the two countries. Neutral Zone reserves were divided equally between the countries.

Figure 2. Map of the Saudi-Kuwaiti Partitioned Neutral Zone

Source: Central Intelligence Agency World Factbook

Production

Ghawar—Saudi Arabia's largest oil field, located onshore in the eastern region—accounted for an average of 40% of Saudi Arabia's crude oil and condensate production from 2014 through 2020, according to Rystad Energy data. Safaniya, the country's second-largest field, accounted for an average 9% of production over the same period.[14]

Saudi Arabia maintains the world's largest crude oil production capacity, estimated at nearly 12 million b/d including the PNZ shared with Kuwait.[15] Moreover, the country is invested in increasing its maximum sustainable capacity. In 2020, the Saudi government announced it intends to raise capacity to 13 million b/d by 2027.[16] Aramco is able to maintain its high production capacity and to have a level of flexibility in its production levels by not maximizing output from mature fields, regularly bringing new reservoirs online, and developing large expansion projects. Low field depletion rates (just 1%–2% in 2019) and low upstream oil production costs ($2.80/b at the end of 2019) give Saudi Arabia a competitive edge over other countries in terms of cost savings and long-term production. Saudi Arabia's long-term goal for oil production is to maintain current output by offsetting declines in mature fields with capacity from new fields and expansion projects.[17]

Recent field additions include the 250,000 b/d capacity expansion at the onshore Shaybah field in 2016, the 300,000 b/d expansion at the Khurais field in 2018, and a combined 175,000 b/d expansion from the Ain Dar and Farzan incremental oil projects in early 2021.[18]

Furthermore, Saudi Aramco plans to expand several offshore fields by 2026 and raise output capacity by at least 1.2 million b/d of crude oil. These fields will add heavier grades of oil, replacing lighter grades from the older fields. Development of the Berri and Marjan expansions are underway, and Saudi Aramco intends to award contracts for development of the Zuluf and Safaniyah expansions in late 2021. A smaller play, the Dammam oil field, is under development and is expected to add 75,000 b/d by 2026. The Berri field expansion project is slated to add 250,000 b/d, and the Marjan project will likely provide another 300,000 b/d. Saudi Aramco expects to raise capacity at the Zuluf field by 600,000 b/d of Arab Heavy crude oil. Historically, Zuluf has produced Arab Medium crude oil.[19]

Al-Khafji, located offshore, and Wafra, located onshore, are the primary producing fields in the PNZ, which overlaps the borders between Kuwait and Saudi Arabia. Al-Khafji Joint Operations Company, a joint venture between Kuwait Gulf Oil Company (KGOC) and Aramco, operates the Khafji field, and Saudi Arabia Chevron jointly operates the Wafra field with KGOC. Onshore production in the PNZ centers on the Wafra oil field, which began producing oil in 1954. Wafra is the largest of the PNZ's onshore fields and yields a heavy sour crude oil grade. Oil production capacity in the PNZ averaged 450,000 b/d before output was shut down in May 2015 following a dispute between Saudi Arabia and Kuwait.[20] Output from the PNZ resumed in January 2020.

Although Saudi Arabia's crude oil production is subject to OPEC production targets, non-crude liquids are not subject to OPEC quotas or targets, and production in the country has averaged around 1.6 million b/d since 2017. Upcoming crude oil field expansions will also yield increased natural gas liquids (NGL) production, and Saudi Arabia expects to produce up to 500,000 b/d of condensates and NGLs from the Jafurah natural gas project.[21]

Historically, Saudi Aramco has not required the use of enhanced oil recovery (EOR) techniques, although fields in the PNZ could require steam flooding. In 2009, Chevron developed a full-field steam flood injection EOR project at the Wafra field to offset field declines and to boost production of the heavy oil play. However, because of the dispute between Saudi Arabia and Kuwait and Chevron's difficulty in securing work and equipment permits, Chevron stopped activities in the PNZ from May 2015 until the end of 2019 when the governments reached an agreement and allowed production to restart.[22]

In 2015, Saudi Aramco developed a carbon capture project at the Uthmaniyah field which is part of the Ghawar field. Since then, the pilot project has captured carbon dioxide that is injected into the mature Uthmaniyah field to support oil production.[23]

Figure 3. Major oil fields in Saudi Arabia

Source: Saudi Aramco

Table 1. Major oil fields in Saudi Arabia

Field	Location	Production capacity as of 2020 (million b/d)	Crude oil grade
Ghawar	Onshore	3.8	Arab Light
Safaniya	Offshore	1.3	Arab Heavy
Khurais	Onshore	1.5	Arab Light
Manifa	Offshore	0.9	Arab Heavy
Shaybah	Onshore	1.0	Arab Extra Light
Qatif	Onshore	0.5	Arab Light
Khursaniyah	Onshore	0.5	Arab Light
Zuluf	Offshore	0.8	Arab Medium

Sources: Saudi Aramco, Energy Intelligence
Note: b/d = barrels per day

Saudi crude oil streams

Saudi Arabia produces a wide range of crude oils, from heavy to super light. About 65% of Saudi Arabia's total crude oil production capacity in 2020 were light gravity grades, and the remaining crude oil were medium or heavy gravity grades.[24] Lighter grades generally are produced from onshore fields, while medium and heavy grades come mainly from offshore fields. Most of Saudi Arabia's crude oil production, except for the Arab Extra Light and Arab Super Light crude oil types, is considered sour (meaning it contains relatively high levels of sulfur).[25]

Consumption

Saudi Arabia's economy uses the most crude oil and petroleum products of any economy in the Middle East, particularly for transportation and direct crude oil burn for power generation. Most of the petroleum products used are LPG, diesel, gasoline, and fuel oil.[26] Oil consumption grew by 5% per year on average between 2005 and 2015, mainly as a result of strong economic growth and government-subsidized energy prices.[27] Petroleum use peaked, but it then began declining in 2017. Key drivers behind the weaker demand in recent years were slower economic growth, new vehicle efficiency measures, price reforms that led to raising gasoline prices closer to international averages, and a policy shift to substitute more oil with natural gas in the electric power sector.[28]

Another contributing factor to the petroleum consumption growth before 2015 was the direct burn of crude oil for power generation, which peaked at about 900,000 b/d in July 2014 and June 2015. Direct crude oil burn in the summer months (June–September) from 2014 through 2016 averaged more than 750,000 b/d, according to the Joint Oil Data Initiative (JODI).[29] Crude oil burn for electric power generation during summer months fell each year between 2016 and 2018 compared with year-ago levels. This decrease freed up crude oil for exports and refining. This shift away from directly burning crude oil occurred around the same time that the Wasit natural gas processing plant, with a capacity of 900 billion cubic feet per year, began operations in 2016. More natural gas became available for power generation.[30] Crude oil and petroleum liquids reserves in the country remain plentiful, but Saudi Arabia wants to diversify its mix of fuels for electric power generation, focusing on natural gas, nuclear, and renewable energy generation.

The country's large petrochemical industry consumes most of the LPG and naphtha supply that accounted for almost 30% of petroleum demand in 2020, according to FGE Global Energy.[31] Saudi Aramco intends to integrate its upstream supply with the domestic petrochemical industry through its acquisition of a 70% share in SABIC, the national petrochemical company, in 2020.[32] Two major petrochemical plants are slated to come online in 2024 and will likely increase naphtha and LPG consumption.[33]

The use of hydrocarbon gas liquids (HGLs) in the country's growing petrochemical sector has also driven the growth in oil consumption since 2005.

Oil processing

Saudi Aramco operates the world's largest oil processing facility and crude oil stabilization plant in the world at Abqaiq in eastern Saudi Arabia. The plant has a crude oil processing capacity of more than 7 million b/d. The plant processes the majority of Arab Extra Light and Arab Light crude oils, as well as NGLs. The facility's infrastructure includes pumping stations, gas-oil separation plants (GOSPs), hydro-desulphurization units, and an extensive network of pipelines that connects the plant to the ports of

Jubail, Ras Tanura, and Yanbu (for NGLs).[34] The Abqaiq processing plant is a vital part of Saudi Arabia's oil infrastructure. Abqaiq processed approximately half of the crude oil produced in the country in 2018.[35]

Houthi rebels from Yemen attacked Saudi Arabia's Abqaiq and Kurais oil processing facilities on September 14, 2019, causing a major global oil disruption. Saudi Arabia immediately removed 5.7 million b/d of crude oil, slightly more than half of their crude oil production at the time, and 2 billion cubic feet per day of associate natural gas (which also shut in some NGL production).[36] Although crude oil production for September 2019 fell by about almost 1.4 million b/d from August 2019, Saudi Aramco was quickly able to restore oil production at the facilities by October 2019.[37]

Refining

Saudi Arabia has eight domestic refineries, which have a combined crude oil throughput capacity of nearly 2.9 million b/d.[38] Saudi Aramco operates five refineries exclusively (including the Jazan refinery), and the remaining four are joint ventures. Saudi Arabia has continued to integrate its refinery projects with large petrochemicals complexes in industrial cities, which are centered on the country's petrochemicals and heavy industries.

Table 2. Refineries in Saudi Arabia

Name	Company	Nameplate crude oil distillation capacity (thousand barrels per day) 2021
Ras Tanura	Saudi Aramco	550
SATORP Jubail	Saudi Aramco, Total S.A.	450
Rabigh	Saudi Aramco, Sumitomo	400
SAMREF Yanbu	Saudi Aramco, Mobil	400
YASREF Yanbu	Saudi Aramco, Sinopec	400
SASREF Jubail	Saudi Aramco	305
Yanbu	Saudi Aramco	245
Riyadh	Saudi Aramco	126
Total		**2,876**

Source: Saudi Aramco, SATORP, SAMREF, *Oil & Gas Journal,* FACTS Global Energy

Saudi Arabia has expanded its domestic refinery capacity extensively since 2014. In 2014 and 2015, the company added more than 800,000 b/d of capacity from the SATORP and YASREF refineries.[39] The higher refinery output from these projects lifted Saudi Arabia's oil products exports, particularly for diesel.[40]

Saudi Aramco developed the 400,000 b/d Jazan refinery project, which is located in southwestern Saudi Arabia near the Yemen border and which processes Arab Heavy and Arab Medium crude oils. Refinery construction was completed in late 2019, but Aramco has delayed the full commissioning until the adjacent natural gas power plant and air separation units, which have encountered operational and logistical issues, are complete. These facilities are slated to provide electricity to the Jazan refinery. By mid-2021, the Jazan refinery had produced around 200,000 b/d of mostly fuel oil and off-specification products in trial runs. Commissioning could occur as soon as the end of 2021.[41] Apart from Jazan, Saudi Arabia does not expect to add any further refining capacity during the next few years.

Oil terminals

Saudi Arabia's total crude oil export and loading capacity is about 14.5 million b/d and its primary port is Ras Tanura on the Persian Gulf.

The port of Ras Tanura is the world's largest offshore oil exporting port and has a combined handling capacity of about 6.4 million b/d. All of Saudi Arabia's crude oil grades load at this port, along with condensates and products. The port consists of three terminals: Ras Tanura terminal, Ju'aymah crude terminal, and Ju'aymah LPG export terminal.[42]

Most of Saudi Arabia's export capacity comes from its four primary oil export terminals:

- The Ras Tanura terminal, the largest terminal at the port of Ras Tanura, has an average handling capacity of 3.28 million b/d[43] and 33 million barrels of storage capacity. The terminal can accommodate tankers up to 500,000 deadweight tons (dwt). All of Saudi Arabia's crude oil grades except Arab Super Light are loaded at the Ras Tanura terminal.[44]

- The Ras al-Ju'aymah terminal at the port of Ras Tanura has an average handling crude oil capacity of about 3.12 million b/d,[45] and because of the availability of six single-point mooring buoys, the terminal can accommodate some of the largest tankers (700,000 dwt) for crude oil loadings.[46] Most of Saudi Arabia's crude oil grades are loaded at this terminal, along with bunker fuel (at a maximum loading capacity of 120,000 b/d).[47]

- The Yanbu terminal on the Red Sea has a loading capacity of 4.5 million b/d.[48] The terminal includes four loading berths and can accommodate tankers up to 500,000 dwt. Total crude oil storage capacity at this terminal is 12.5 million barrels. Only Arab Light crude oil grade is loaded at the Yanbu North terminal.[49]

- The Yanbu South terminal on the Red Sea is about 12 miles south of the Yanbu terminal. Saudi Aramco began exports from the overhauled Yanbu South (formerly known as Muajjiz) oil terminal in October 2018. This terminal provides Saudi Arabia with another major Red Sea outlet for its oil exports in case of a disruption at the Strait of Hormuz. Yanbu South, which includes three loading berths, has an export loading capacity of 3 million b/d, which raised Saudi Arabia's total loading and export capacity to nearly 15 million b/d. Before the Iraqi Pipeline in Saudi Arabia (IPSA) was converted to a natural gas line, Muajjiz was used as an export terminal for crude oil from Iraq that flowed through the IPSA. Total crude oil storage capacity at the terminal is 10 million barrels. Yanbu South exports both Arab Light and Arab Super Light.[50]

In addition to these primary export terminals, Saudi Arabia has other smaller ports, including Ras al-Khafji, Jubail, Jazan, and Jeddah.

Shipping

The National Shipping Company of Saudi Arabia (also known as Bahri) is the world's largest operator and owner of Very Large Crude Carriers (VLCCs) that transport crude oil between the Middle East, Europe, and the U.S. Gulf Coast. It operates a fleet of 89 vessels, including 41 VLCCs, 10 product tankers, 23 chemical tankers, and 15 other cargo carriers.

Bahri and Vela International Marine Limited, Saudi Aramco's shipping subsidiary, merged in 2014, giving Saudi Aramco a stake in Bahri. The Public Investment Fund (PIF) of the Saudi government holds 22.5% of the company's shares, Saudi Aramco Development Company holds 20%, and the remaining shares are traded publicly on the Saudi stock exchange.[51] Bahri is the sole transporter of Saudi Aramco's crude oil using VLCCs.[52]

In addition to tankers, Saudi Aramco owns or leases oil storage facilities around the world, including Rotterdam, Sidi Kerir (the Sumed pipeline terminal on Egypt's Mediterranean coast), Japan, and India.[53]

Major domestic petroleum pipelines

Saudi Aramco operates more than 90 pipelines and 12,000 miles of crude oil and petroleum product pipelines throughout the country, all of which link production areas to processing facilities, export terminals, and consumption centers.

The 750-mile Petroline, also known as the East-West Pipeline, is significant because of its large capacity and because it connects crude oil production and processing facilities in the east of the country to export facilities in the west, allowing the crude oil to bypass the Strait of Hormuz.[54] The Petroline system, which runs across Saudi Arabia from the Abqaiq complex to the Red Sea, consists of two parallel pipelines with a total nameplate (installed) capacity of 5 million b/d. Although the pipeline has operated well below capacity (transporting 2.1 million b/d of crude oil on average in 2019), Saudi Aramco plans to expand the capacity of the East-West pipeline to 7 million b/d to diversify its outlets for oil exports. Initially, the expansion was slated to be completed by 2023, but Aramco reported it achieved this new capacity temporarily through a conversion of NGL pipelines in 2019.[55]

Running parallel to the Petroline is the East-West NGL pipeline,[56] which serves petrochemical plants in Yanbu. The East-West NGL pipeline is Saudi Arabia's largest NGL pipeline.

International petroleum pipelines

With the exception of a small pipeline to Bahrain, Saudi Aramco does not operate any major functioning international pipelines. The Trans-Arabian Pipeline (TAPLINE), built in 1947 to transport crude oil from Qaisumah through Jordan to Sidon, Lebanon, has been partially closed since 1984. The portion of the pipeline that runs to Jordan was closed in 1990.

The 1.65 million b/d, 48-inch Iraqi Pipeline in Saudi Arabia (IPSA) runs parallel to the Petroline from pump station #3 (11 pumping stations run along the Petroline) to the port of Muajjiz, just south of Yanbu, Saudi Arabia. The pipeline was built in 1989 to carry Iraq's crude oil to the Red Sea. The pipeline closed indefinitely following the August 1990 Iraqi invasion of Kuwait. In June 2001, Saudi Arabia seized ownership of IPSA as compensation for debts Iraq owed and converted it to transport natural gas to power plants. The portion of the pipeline that goes north into Iraq remains a closed, inactive oil pipeline.[57] Saudi Aramco pumped test volumes of crude oil through the pipeline in response to Iran's threats to close the Strait of Hormuz in 2012.[58]

Saudi Arabia's only functioning international crude oil pipeline system carries Arab Light crude oil from Saudi Arabia's Abu Safah field to Bahrain. A 73-year old complex of four small underwater pipelines was decommissioned after the construction of the current pipeline, which has a capacity of 350,000 b/d and runs between Abqaiq and Bahrain's refinery at Sitra. The current pipeline was commissioned in October 2018.[59]

Natural Gas

Saudi Arabia has been gradually developing its sizeable natural gas reserves over the past two decades to supply its expanding petrochemical sector and natural gas-fired electric power generation.

Reserves

Saudi Arabia (including the Neutral Zone) has one of the largest proved natural gas reserves in the world. Most of the natural gas produced in Saudi Arabia is associated with petroleum deposits and is found in the same wells as crude oil. However, Saudi Aramco has developed more natural gas from reserves containing nonassociated gas fields since 2014.

Production and consumption

Nearly half of Saudi Arabia's dry natural gas production in 2020 came from four oil fields: Ghawar, Safaniya, Berri, and Zuluf. Associated natural gas produced at the Ghawar oil field alone accounted for 36% of total production, according to Rystad Energy field-level production data.[60] In the past decade, the share of natural gas produced from natural gas fields increased from 15% to 46% as Saudi Aramco began to focus on developing nonassociated gas. Production of associated gas with crude oil fields has been restrained by the OPEC+ production cuts.

Saudi Arabia does not import or export natural gas, so, aside from changes in inventories, its production is equal to its domestic consumption. Rapid reserve development is part of Saudi Arabia's plans to increase its petrochemical sector and provide fuel for power generation and for water desalination while it frees up crude oil for exports. All current and future natural gas supplies (except NGLs) reportedly remain earmarked for domestic use, in part to minimize the use of crude oil for power generation.

Natural gas developments

Saudi Aramco's strategy outlines a push for greater nonassociated natural gas development and further expansion of natural gas reserves through new reservoirs near existing fields and new discoveries to help meet growing domestic demand. The company plans to continue increasing its natural gas production, processing, and transmission infrastructure, including unconventional natural gas developments to limit the use of oil in power generation and to provide feedstock to the country's growing petrochemical industry.[61]

In the upstream production stages, Saudi Aramco has focused on major offshore natural gas developments in the Persian Gulf, the southern portion of the Ghawar oil field, and the Jafura unconventional field.[62]

Saudi Arabia's notable offshore nonassociated natural gas fields:

- The Karan natural gas field, discovered in 2006, is Saudi Arabia's first offshore nonassociated natural gas development. The Karan field came online in 2012 and has a production capacity of 1.8 billion cubic feet per day (Bcf/d) of sour natural gas, which is delivered via a 68-mile subsea pipeline to the Khursaniyah natural gas plant.[63]

- The Hasbah offshore field began production in March 2016 for processing at the Wasit natural gas plant. Total natural gas output capacity at the field was originally 1.3 Bcf/d. An expansion of the Hasbah field provided 2 Bcf/d of natural gas to the Fadhili processing plant.[64]
- The Arabiyah offshore natural gas field (known as the Farzad B field on Iran's side of the border) began production in 2016 and has a production capacity of 1.2 Bcf/d.[65]

Saudi Arabia nearly doubled its natural gas processing capacity since 2003 from 9.3 Bcf/d to 18.3 Bcf/d in 2020 after Saudi Aramco added several natural gas processing facilities over the past few years. This capacity does not include the 2.4-Bcf/d Shaybah natural gas processing and NGL plant in the Rub al-Khali (also known as the Empty Quarter) because this facility is solely used to extract NGLs for the petrochemical industry and does not market its dry gas production.[66] Recently-commissioned natural gas plants include the following:

- The Wasit natural gas plant reached full operating capacity in 2016 at 2.5 Bcf/d of dry gas production and 240,000 b/d of NGL output. The offshore Arabiyah and Hasbah natural gas fields supply the plant. Commissioning the Wasit gas processing plant made it possible for Saudi Arabia to reduce the direct burn of crude oil for electric power generation and expand natural gas-fired generation.[67]
- The Midyan natural gas plant, a very small facility at 75 million cubic feet per day (MMcf/d), was commissioned in 2017 in the Tabuk region in northwestern Saudi Arabia to supply a local power plant.[68]
- The Fadhili natural gas plant, located near the Jubail industrial city, began operations in 2019 and reached full capacity in early 2020. The plant, which serves the electric power sector, can process up to 2.5 Bcf/d of raw natural gas from the offshore Hasbah field and the onshore Khursaniyah field, both nonassociated gas fields.[69] The Fadhili plant will reduce the electric power sector's need to burn crude oil by supplying more processed natural gas for natural gas-fired power generation.

Saudi Arabia plans to meet growing natural gas demand by increasing natural gas production capacity and to replace more liquid fuels with natural gas in power generation and the seawater desalination process. Saudi Aramco plans on commissioning two more natural gas projects. The Hawiyah natural gas processing plant, which began operations in 2001, is set for an expansion of its natural gas processing capacity by 1.3 Bcf/d in 2022. This facility processes nonassociated gas from the Ghawar field.[70] In 2020, Saudi Aramco began constructing the 2.5 Bcf/d Tanajib natural gas plant, which will process associated gas from the Marjan, Safaniyah, and Zuluf fields and is scheduled to begin operations in 2025.[71]

Saudi Aramco has an unconventional resource program to assess areas that could yield shale gas and tight gas and associated liquids for development. Saudi Aramco developed its first unconventional natural gas project in northern Saudi Arabia, delivering 55 MMcf/d of natural gas to electrical power facilities in the Wa'ad al Shamal industrial city starting in 2018.[72] Saudi Aramco intends to launch its largest unconventional field, located to the east of the Ghawar field near the Persian Gulf, in 2024. Saudi Aramco pledged to spend $110 billion on the Jafurah project—a project that the company expects will gradually bring online 2.2 Bcf/d of dry natural gas, 425 MMcf/d of ethane, and 550,000 b/d of condensate by 2036.[73] Saudi Aramco plans to use desalinated water to develop Jafurah and other shale gas projects.

Figure 4. Major natural gas fields in Saudi Arabia

Source: Saudi Aramco

Domestic natural gas pipelines

Domestic demand for natural gas, particularly the delivery of feedstock to petrochemical plants, has driven the expansion of the Master Gas System (MGS), the domestic natural gas distribution network in Saudi Arabia. The MGS, first built in 1975, is an integrated natural gas gathering, processing, and transmission system originally put in place to recover the associated natural gas produced at the Ghawar oil field. Before the MGS came online, all of Saudi Arabia's natural gas output was flared. The MGS transports natural gas from associated and nonassociated fields to natural gas processing plants, which separate out the NGLs. The NGLs are then transported to straddle recovery and fractionation plants in Ju'aymah, Yanbu, Hawiya, Ras Tanura, Wasit, Uthmaniyah, and Shaybah.[74]

Further development of natural gas production will likely require MGS expansion, especially to the western region of the country where natural gas pipeline infrastructure is lacking. In 2018, Saudi Aramco raised the capacity of the MGS by 1.0 Bcf/d to 9.6 Bcf/d, its current capacity.[75] Saudi Aramco's plans include another expansion to 12.5 Bcf/d, but the company has not announced a completion date.[76] If fully implemented, these expansions, combined, will add at least 1,000 miles of natural gas pipeline to the system and will transport natural gas to plants at Yanbu in the west and to natural gas lines in central Saudi Arabia.

Electricity

Between 2009 and 2017, demand for electric power in Saudi Arabia rose by an average of 7% per year, but it declined after 2017. Rising demand was driven by:

- Population growth
- A rapidly expanding industrial sector that was led by the development of petrochemical complexes as well as high demand for air-conditioning during the summer months
- Heavily subsidized electricity rates

Saudi Arabia added generation capacity to meet the growing electricity demand. Growth in electricity consumption slowed after a number of government actions (including raising electricity tariffs in 2016 and 2018) improved energy efficiency in buildings and implemented demand management systems to reduce inefficient electricity consumption.

Nearly all of the existing generating capacity is powered by oil or natural gas, but Saudi Arabia plans to diversify fuels used for generation, in part, to free up oil for export. Although the Saudi Electricity Company (SEC) plans to continue reducing direct crude oil burn for electricity generation by switching to natural gas, plans are also in place to develop renewable sources for electric power generation. The National Renewable Energy Program (NREP) has plans to raise Saudi Arabia's renewable energy capacity to 27.3 gigawatts (GW) by 2024 and 58.7 GW by 2030 and to generate 50% of its electricity from renewable sources by 2030.[77] NREP has several solar projects under development and invited tenders for another round of bids in 2021 for solar power projects, which have a combined capacity of 1.2 GW.[78] Although Saudi Arabia has vast potential for renewable energy capacity, these goals are ambitious, particularly given the slow pace of progress on currently planned renewable projects.

The Saudi government issued a scaled-down plan to develop nuclear power capacity in January 2015 and revised its target of building 17 GW of nuclear capacity from 2032 to 2040. In July 2017, the Council of Ministers approved proposals to establish the National Project for Atomic Energy, which includes two large-scale (1.2 GW to 1.6 GW) and two small-scale (10 MW to 300 MW) reactors that would be built in areas that are outside the national grid to provide electricity to desalination plants and industries. Saudi Arabia's King Abdullah City for Atomic and Renewable Energy (KACARE) plans to request proposals from five international firms about the nuclear technology for the large reactors by the end of December 2021 and is assessing technologies for the smaller reactors.[79] Argentine firm INVAP started construction of a 30-kilowatt low-power research reactor in Riyadh in November 2018.[80]

Sector organization

The Water and Electricity Regulatory Authority (WERA), formerly known as the Electricity and Cogeneration Regulatory Authority, is the regulatory body for the electricity, water desalination, and district cooling industries in Saudi Arabia. WERA is responsible for assuring adequate and reliable supply of electricity and water, reviewing consumer tariffs, and promoting fair competition and investment in these industries.[81]

The National Renewable Energy Program (NREP) is an initiative under the purview of the Ministry of Energy to promote Saudi Arabia's clean energy development and reduce its heavy use of oil-fired power generation.[82]

Saudi Electricity Company (SEC) is the largest provider of electricity in Saudi Arabia. It had a total available generation capacity of 53 GW in 2020, which was around 67% of the country's total installed capacity. The SEC is responsible for generation, and the National Grid S.A. Company, SEC's subsidiary, is responsible for the transmission and distribution of electrical power.[83]

The state-owned Saline Water Conversion Corporation (SWCC), which provides most of Saudi Arabia's desalinated water, had 7.2 megawatts (MW) of installed electricity capacity in 2020 to produce electricity used in its desalination process.[84] Saudi Arabia plans to rapidly increase its desalination capacity by about 60% by the end of 2023,[85] with an equivalent increase in generation capacity, through the Saudi Water Partnership Company (SWPC), a utility fully owned by the Ministry of Finance. SWPC oversees project development for the privately owned independent water and power producers.[86]

Saudi Aramco continues to build cogeneration plants to generate power for its own needs at various oil and natural gas facilities. By the end of 2019, Saudi Aramco had 6.5 GW of power generation capacity, including 2.5 GW from joint ventures and third-party power producers.[87] The 3.8-GW Jazan Integrated Gasification, Combined Cycle Power Plant is expected to start operations by 2022 to partially serve Saudi Aramco's adjacent refinery.[88]

In 2007, Saudi Arabia began allowing private participation in the electric power sector, approving the first Independent Power Producer (IPP). The first two projects, the Rabigh 1 project in Mecca and the Riyadh 11 project in Dharma, began operating in 2013. These projects were followed the Qurayyah project in the Eastern Province, which started operations in 2016, and a second Rabigh power plant that came online in 2018. According to WERA data, these four plants have a combined capacity of more than 9 GW.[89] A few other major IPP projects, such as the natural gas-fired Taibah and North Qassim power plants, each with a capacity of 3.6 GW, are under development and expected online by 2025.[90]

Physical improvements are needed to allow more companies to sell power to the grid. SEC has ongoing and planned projects that will link power plants in the eastern, western, and southern portions of the country. To meet peak demand requirements, Saudi Arabia participates in the Gulf Cooperation Council's (GCC) efforts to link the power grids of member countries. The GCC is an alliance between six Persian Gulf states: Bahrain, Kuwait, Oman, Qatar, Saudi Arabia, and the United Arab Emirates. The alliance seeks to build closer ties with the member countries, including the construction of electric power interconnections. The GCC Interconnection Authority is owned by the six member countries. The GCC member states' grid interconnection was completed in 2011. In 2020, the member states traded 1.06 gigawatthours of electric power during both winter and peak summer months.[91] Separately, Saudi Arabia signed a power connection agreement with Egypt to connect their electricity grids with 3 GW of capacity by 2025.[92]

Note

- Data presented in the text are the most recent available as of December 2, 2021.
- Data are EIA estimates unless otherwise noted.

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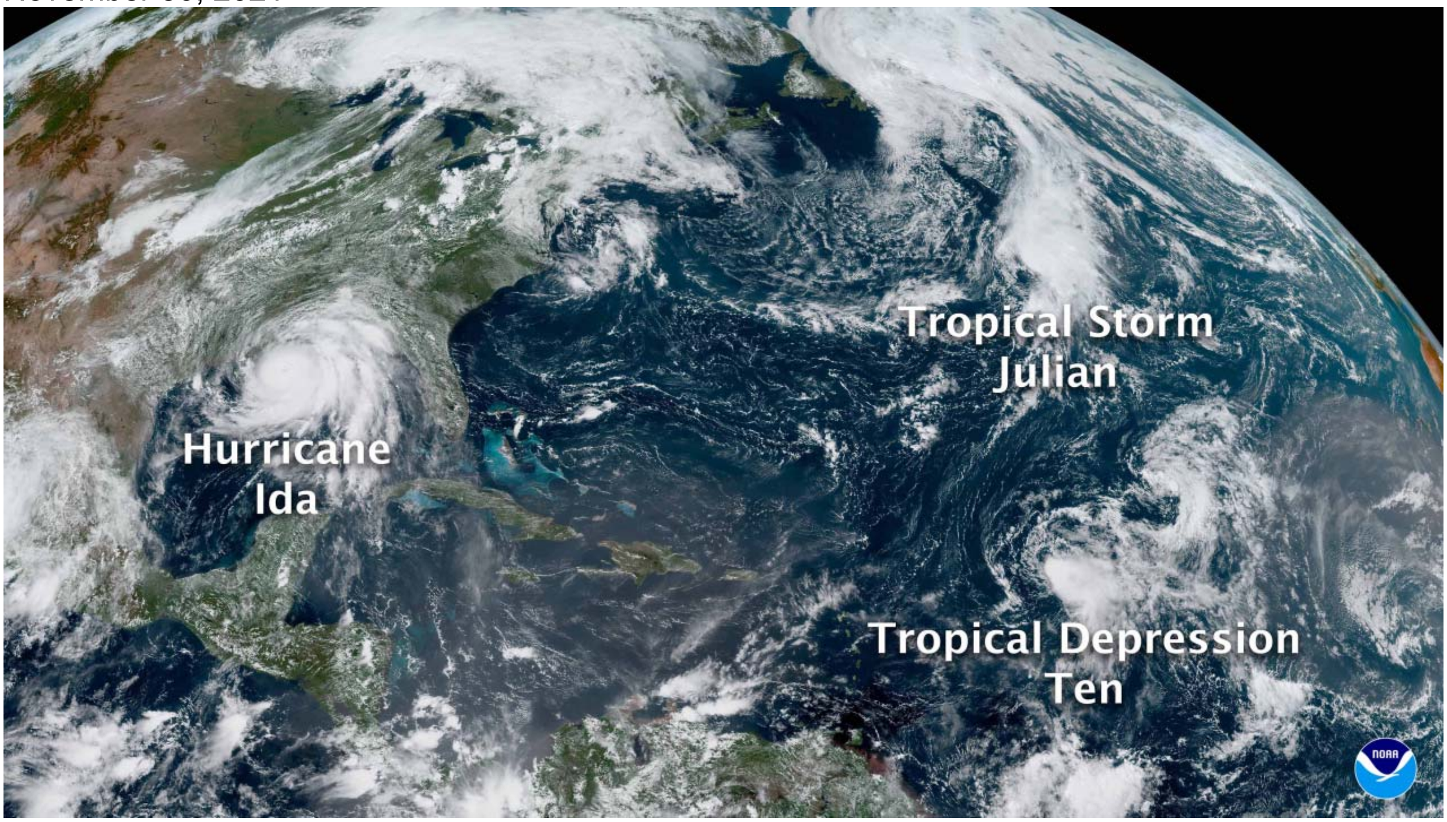
https://www.noaa.gov/news-release/active-2021-atlantic-hurricane-season-officially-ends

Active 2021 Atlantic hurricane season officially ends

Reliable early NOAA forecasts helped safeguard communities

November 30, 2021



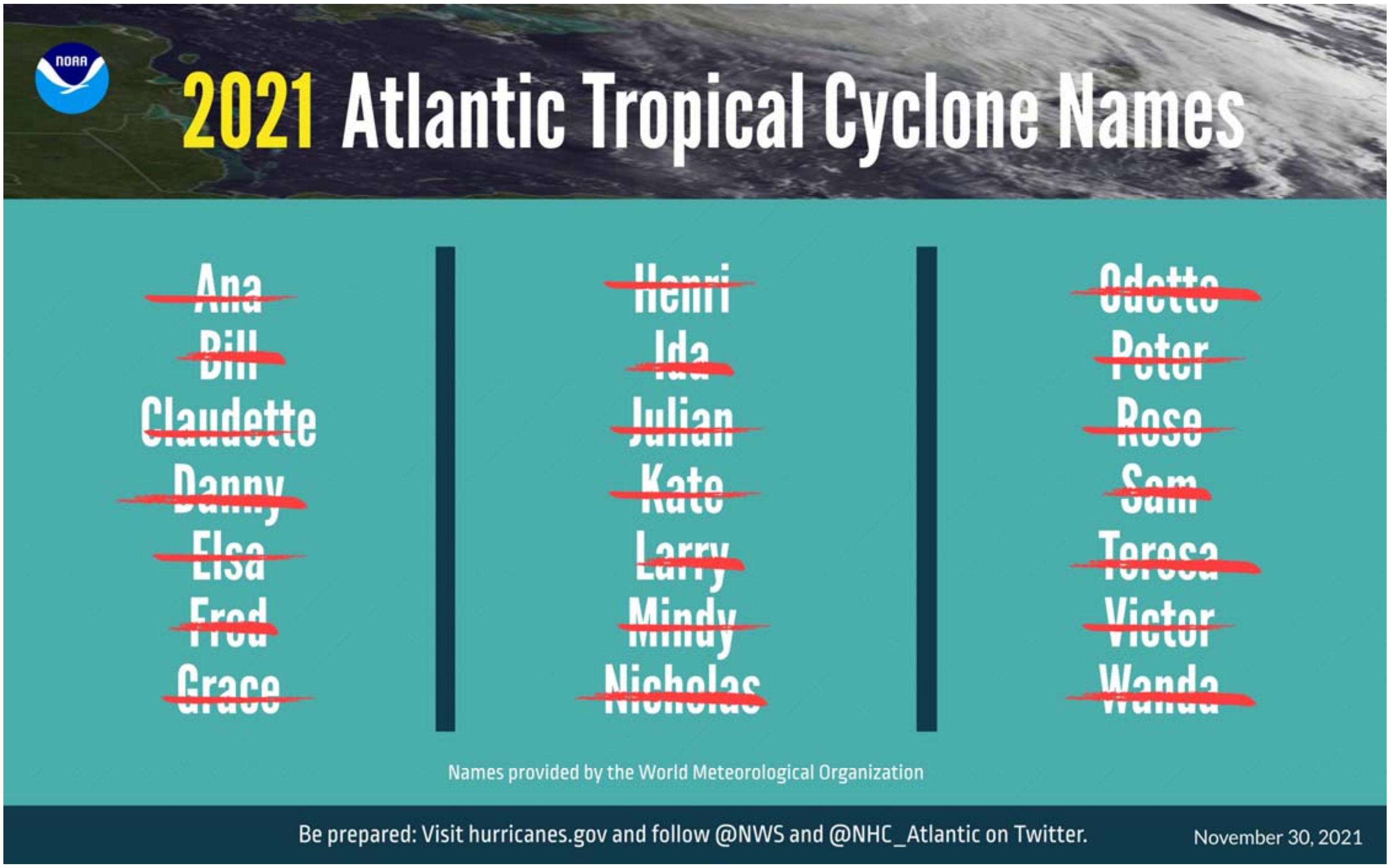
GeoColor image of Hurricane Ida, Tropical Storm Julian, and Tropical Depression Ten (which intensified into Tropical Storm Kate on August 30) from NOAA's GOES-16 satellite on August 29, 2021. (NOAA)

RESOURCES

Hurricane Hunter video: Flying into the eye of Cat 4 Hurricane Ida August 29, 2021. (NOAA)

The active 2021 Atlantic hurricane season officially concludes today having produced 21 named storms (winds of 39 mph or greater), including seven hurricanes (winds of 74 mph or greater) of which four were major hurricanes (winds of 111 mph or greater). This above-average hurricane season was accurately predicted by NOAA’s Climate Prediction Center, a division of the National Weather Service, in their May and August outlooks.

“NOAA provided the science and services necessary to protect life and property before, during and after storms all season long,” said NOAA Administrator, Rick Spinrad, Ph.D. “From essential observations to advanced warnings to critical response actions, NOAA supports communities so they are ready, responsive and resilient to the impact of tropical cyclones each and every hurricane season.”



The list of 21 named storms that have occurred during the 2021 Atlantic Hurricane Season. The season officially ends November 30. (NOAA)
Download image

This year was the third most active year on record in terms of named storms, it marks the sixth consecutive above-normal Atlantic hurricane season, and this was the first time on record that two consecutive hurricane seasons exhausted the list of 21 storm names.

Scientists attribute the heightened hurricane activity in recent years to the warm phase of the Atlantic Multidecadal Oscillation that began in 1995 and favors more, stronger and longer-lasting storms. The Atlantic Multidecadal Oscillation is thought to be driven by a combination of internal climate variability and changes over time in small airborne particles, often referred to as aerosols, over the North Atlantic. However, the relative contributions of internal variability and aerosols to the observed Atlantic Multidecadal Oscillation remain uncertain. Additionally, the Intergovernmental Panel on Climate Change's Sixth Assessment Reportoffsite link, released in August 2021, projects with high confidence that the global proportion of tropical cyclones that reach very intense (category 4-5) levels, along with their peak winds and rainfall rates, are expected to increase with climate warming at the global scale.

This infographic highlights key facts and statistics from the 2021 Atlantic Hurricane Season. The Atlantic hurricane season officially ends November 30, but storm activity in the tropics can sometimes continue beyond that date. (NOAA)
Download image

“The hard-working forecasters at NOAA’s National Weather Service weather and water forecast offices and national centers, along with the National Hurricane Center, provided reliable forecasts and advanced warnings around the clock to safeguard communities in the pathway of destructive storms throughout this active hurricane season,” said National Weather Service Director Louis W. Uccellini, Ph.D. “Their dedication and service are a recognized asset to the nation's resilience to these extreme events.”

This season’s storm activity started early and quickly ramped up, as it was the seventh consecutive year with a named storm forming before the official start to the season on June 1, and held the earliest fifth named storm on record. As to why, Matthew Rosencrans, lead seasonal hurricane forecaster at NOAA’s Climate Prediction Center says, “Climate factors, which include La Niña, above-normal sea surface temperatures earlier in the season, and above-average West African Monsoon rainfall were the primary contributors for this above-average hurricane season.”

Video summary of all the named storms that formed during the 2021 Atlantic hurricane season. (NOAA)

NOAA’s hurricane research and observations

Scientists at NOAA’s Atlantic Oceanographic and Meteorological Laboratory successfully deployed five new extreme weather Saildrones to collect data at the ocean and atmosphere interface in the Caribbean and western tropical Atlantic. One uncrewed Saildrone captured the first ever video and measurements at the surface of the ocean during a major hurricane, withstanding 125-mph winds and 50-foot waves during Hurricane Sam. This data combined with data from other Saildrones, ocean gliders and aircraft-released sensors is helping NOAA to better represent the conditions that drive hurricanes within forecast models.

NOAA aircraft flew more than 462 mission hours to support hurricane forecasting and research. Data collected by these high-flying meteorological laboratories help forecasters make accurate storm predictions and allow hurricane researchers to achieve a better understanding of storm processes, which ultimately improves their forecast models. Thanks to data from these aircraft, NOAA satellites, and other sources, the National Hurricane Center accurately forecasted Hurricane Ida — which is tied for the fifth strongest hurricane to ever make landfall in the United States — hitting Louisiana as a major hurricane.

Since the launch of the storm surge warning and new inundation mapping in 2017, there have been 16 U.S hurricane landfalls, of which seven were major hurricanes. During this period, there are only seven known direct fatalities attributed to storm surge in the United States. In 2021, only one life was lost due to the storm surge accompanying the eight landfalling storms. Additionally, the delivery of Impact-Based Decision Support Services to NOAA's core partners throughout the season helped communities better prepare for and respond to landfalling hurricanes.

In the aftermath of Hurricane Ida, NOAA Aircraft flew 32 mission hours collecting aerial damage assessment images to support emergency response efforts at NOAA's National Ocean Service. NOAA's aerial imagery aids safe navigation and is a critical tool in determining the extent of damage inflicted by flooding and assessing damage to major ports and waterways, coastlines, critical infrastructure and coastal communities.

Looking ahead

The 2022 hurricane season will officially begin on June 1. NOAA's Climate Prediction Center will issue its initial seasonal outlook in May, but now is the time to make sure your family is Weather-Ready by preparing for the season ahead.

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Japan Quietly Endorses Fossil Fuel Investments Weeks After COP
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By Stephen Stapczynski and Tsuyoshi Inajima
(Bloomberg) -- It's been less than a month since world leaders pledged to combat climate change at the COP26 summit in Glasgow, yet Japan is already showing signs of putting the brakes on divestment from fossil fuels.
Government officials have been quietly urging trading houses, refiners and utilities to slow down their move away from fossil fuels, and even encouraging new investments in oil-and-gas projects, according to people within the Japanese government and industry, who requested anonymity as the talks are private.
The officials are concerned about the long-term supply of traditional fuels as the world doubles down on renewable energy, the people said. The import-dependent nation wants to avoid a potential shortage of fuel this winter, as well as during future cold spells, after a deficit last year sparked fears of nationwide blackouts.
Japan joined almost 200 countries last month in a pledge to step up the fight against climate change, including phasing down coal power and tackling emissions. However, the moves by the officials show the struggle to turn those pledges into reality, especially for countries like Japan which relies on imports for nearly 90% of its energy needs, with prices spiking partly because of the world's shift away from fossil fuel investments.
The nation has been slow to make any concrete commitments to phase out coal in the near term, and has often been criticized for its funding of overseas power plants that use the dirtiest burning fossil fuel. The government has also avoided joining efforts by developed nations to reduce consumption of natural gas.
Japan's Ministry of Economy, Trade and Industry declined to comment directly on whether it is encouraging industries to boost investment in upstream energy supply, and instead pointed to a strategic energy plan approved by Prime Minister Fumio Kishida's cabinet on October 22. That plan says "no compromise is acceptable to ensure energy security, and it is the obligation of a nation to continue securing necessary resources."
That latest strategy calls for the share of oil and natural gas produced either domestically or under the control of Japanese enterprises overseas to increase from 34.7% in fiscal year 2019 to more than 60% in 2040. Japanese officials plan to convey to other nations the importance attached to continued investments in upstream supply, the people added.
While Japan will likely avoid rolling blackouts or gasoline rationing this winter when demand for energy peaks in the region, the global energy crisis is leaving many within the government thinking about how to prepare for the future.
Japan is still expected to be highly dependent on fossil fuels for the next decade as there is limited available space to significantly expand solar power, and the nation's wind sector is developing slowly. It's also struggling to restart nuclear reactors in the wake of the Fukushima disaster.
To achieve net-zero emissions by 2050, the world needs to stop developing new gas, oil and coal fields, the International Energy Agency said in May. Japanese officials are echoing concerns highlighted by Australia last month, which said Europe's gas supply squeeze is proof that nations need to continue to add more production.
Japan's trading houses, including Sumitomo Corp. and Marubeni Corp., are aggressively divesting from fossil fuels amid an uncertain future for the energy sources and pressure from shareholders. These companies, formally known as "Sogo Shosha," have traditionally been among the biggest investors in oil and natural gas assets in order to bring the fuel to resource-poor Japan.
Oil prices had surged to the highest level since 2014 in October, which many Japanese government officials believe was exacerbated by a lack of investment in new supply, the people said. Meanwhile, liquefied natural gas prices have jumped to a record on the back of a global shortage, helping to push Japan's wholesale power rate to the highest level for this time of year.

--With assistance from Isabel Reynolds, Shoko Oda and Javier Blas.

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Video conference between Ms. Ono, Director General of Economic Affairs Bureau, Ministry of Foreign Affairs of Japan, and Dr. Birol, Executive Director of the International Energy Agency (IEA)

e-mail

November 9, 2021

Japanese

On November 9, Ms. ONO Hikariko, Director General of Economic Affairs Bureau, held a videoconference with Dr. Fatih Birol, Executive Director of the IEA.

1. At the outset, Ms. Ono expressed concern over the rapid surge in crude oil prices, which could hamper the global economic recovery from COVID-19. She stated that Japan is engaged in dialogues with oil-producing countries and would like to work closely with the IEA, which plays a central role in stabilizing the energy market.
2. In his response, Dr. Birol mentioned that he is closely watching the energy market including oil, and expressed the IEA's willingness to cooperate with member countries and oil-producing countries to work for stabilization of market. He also shared with Ms. Ono the IEA's analysis of the future energy market following the results of the OPEC Plus Ministerial Meeting held on November 4, 2021. He pointed out that the gap between supply and demand will continue to be tight in the short term, however, the supply and demand balance will improve around the turn of the year and the market will gradually regain stability.
   Furthermore, he underscored the need for additional investment to meet future demand, explaining that the demand for oil and natural gas will not drastically decrease even through our path towards transition to renewable energy. The two sides agreed to further strengthen cooperation to enhance energy security, including that of oil. Dr. Birol expressed his wish to visit Japan to exchange views with Japanese counterparts.
3. The two sides also exchanged views on acceleration of decarbonization efforts following COP26, and shared the importance on measures with pragmatic time frame based on individual circumstances that each countries face including its renewable energy potentials, while it is important to expand investment on renewable energy to achieve carbon neutral. In addition, the two sides frankly exchanged their views on Japan's funded initiative with the IEA for clean energy transition in resource producing countries, as well as on the Ministerial meeting scheduled to be held in February 2022.

https://www.ft.com/content/8385f5d8-b045-46a7-a822-47a9ba09e219

Macron warns of threat to global economy from energy crisis

French president urges world leaders to act on climate change with more financial pledges ahead of COP26 summit

Leila Abboud in Paris and Leslie Hook in London YESTERDAY

President Emmanuel Macron has warned that an energy crisis threatens the world's post-pandemic recovery, calling for leaders at a G20 summit in Rome this weekend to work together to stabilise supplies.

In an interview, the French president also urged bigger financial commitments towards the fight against global warming on the eve of the COP26 climate summit in Scotland, and for particular attention to be paid to a deal to phase out coal power.

The G20 needed to co-ordinate between energy producers and consuming countries to prevent a supply breakdown this winter, which risked "extreme tensions both economically and socially", Macron said.

"In the coming weeks and months, we need to get better visibility and stability on prices so tension on the energy prices doesn't generate uncertainties, and undermine the global economic recovery, " he told the Financial Times in the Elysée Palace. "What we expect is to have co-ordination to avoid soaring prices."

Global energy costs have surged this year, disrupting industry and hitting consumers with higher prices. Eurozone inflation surged in October to a 13-year-high of 4.1 per cent, according to a flash estimate published by the EU's statistics arm on Friday.

"I don't think we're going to be able to lower prices given tensions on the demand side," Macron said. "But what we need to avoid is to have a break in supply [and further] increases in prices, particularly as we're moving into the winter period for the northern hemisphere."

Emmanuel Macron: 'I don't think we're going to be able to lower [gas] prices given tensions on the demand side' © Magali Delporte/FT

Rapid economic recovery from the pandemic has pushed up energy prices "almost too rapidly" which risked "weighing on economic growth and putting a burden on households", Macron said.

France and a number of other EU governments have sought to protect consumers and businesses with billions in aid and price freezes.

Concerns have mounted that Russia's state-backed gas producer Gazprom has kept storage levels unusually low in western Europe, exacerbating fears over supplies and driving up prices.

Asked whether he blamed high European energy prices on Russia, Macron said: "I have no evidence that there's been manipulation of prices and I'm not accusing anybody. These are trading relations. They shouldn't be used for geopolitical reasons."

Asked about Gazprom's power over Europe, Macron said: "It's not a matter of whether we're too dependent on a company or not, it's how do we create alternatives. And the only alternatives are to have European renewables and of course, European nuclear."

France is the EU's biggest user of nuclear power, contrasting with a move away from atomic power by Germany and some other countries.

Macron called for Europe to develop a more diverse gas supply but also to speed up a transition away from fossil fuels, which will be necessary to slow rising temperatures and tame the climate disruptions caused by global warming.

“What is happening now is ironic, because we are building a system where in the medium and long term fossil energy will cost more and more, that’s what we want [to fight climate change],” he said. “The problem is that industries and households will need to be accompanied in this transition . . . or it won’t be sustainable.”

The French president, who is facing national elections in April, has been a vocal advocate of multilateralism. He has pushed for more co-operation globally and at EU level to reach deals on issues including international taxation and global warming.

“The first subject for the G20 is to accelerate the exit from coal power” Emmanuel Macron

Against a backdrop of global tensions, a supply chain crisis and the Covid-19 pandemic, Macron said the G20 had a responsibility to work together, especially to help low-income countries. He urged leaders at the Rome summit to agree a plan for faster vaccine delivery to developing countries.

“France has always stressed the importance of maintaining multilateralism, but we have to get concrete results from it,” he said.

The leaders of China, Russia and Japan will not attend the summit in Rome in person this weekend because of Covid-19 concerns and an election in Japan.

Macron said the G20 meeting, which is being hosted by Italian leader Mario Draghi on the eve of COP26, would also give countries a chance to hammer out more ambitious plans to fight climate change.

“When we’ll be meeting in Rome, the major challenge is to ensure that members of G20 can usefully contribute in Glasgow, to making this COP26 a success,” he said. “Nothing can be taken for granted before a COP,” he added.

“The first subject for the G20 is to accelerate the exit from coal power,” he said. G20 leaders expect a heated debate this weekend over including a pledge to end international coal financing.

“We need the G20 to go right through to the eradication of all international financing of coal-fired power plants,” Macron said.

Macron also called for rich countries, particularly the US, to commit more financially to help developing countries meet their climate goals. And he called on China to bring forward the date at which it will peak emissions, from 2030, to 2025.

“So as not to lose more time, we have to do as much as is absolutely possible in terms of financing, and encourage the US administration so that they can convince Congress to front-load its financing.”

Another issue will be to hold countries to their emissions targets for 2030 and 2050. “Our objective is to get maximum results from all countries,” he said. “This pathway is possible, even if it’s a challenge, especially for emerging countries which at the same time are trying to recover from the Covid crisis.”

Macron also urged the G20 leaders to do more to help vaccinate the world against Covid-19. The group should end vaccine export bans, increase its donations of vaccine doses, and support vaccine production in Africa, he said.

“Every French person has given one vaccine to somebody else in the world,” he said, referring to the roughly 60m doses that were on the way to Covax, the World Health Organisation’s procurement scheme for low-income countries. “If everybody in the G20 could do that we would get to the 20 per cent of the population vaccinated. This is vital,” he said.

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SAF Group created transcript of excerpts from ADNOC's H.E Dr. Sultan Al Jaber 11 minute speech to open ADIPEC on Nov 15, 2021 https://energynow.ca/2021/11/worth-a-watch-opening-speech-at-adipec-2021-november-15-18-2021/

Items in *"italics"* are SAF Group created transcript

At 0.55 min mark. Al Jaber "*we meet at a historic moment. The global community has just concluded COP26. And, on balance, it was indeed a success. Yet, current energy dynamics have revealed a basic dilemma. "While the world has agreed to accelerate the energy transition, it is still heavily reliant on oil and gas. As economies bounce back from the Covid-19 pandemic at the fastest rate in 50 years, demand has outpaced supply and, after almost a decade of underinvestment in our industry, the world has sleepwalked into a supply crunch. It is time to wake up. The oil and gas industry will have to invest over 600 billion US dollars every year until 2030 just to keep up with the expected demand. And Yes. renewable energy is the fastest growing segment of the energy mix. But oil and gas is still the biggest and will be for decades to come. In short, the future is coming. But it is not here yet. We must make progress, with pragmatism. And if we are to successfully transition to the energy system of tomorrow, we cannot simply unplug from the energy system of today. We cannot just flip a switch".*

At 7:50 min mark. Al Jaber "*if the world is to resolve the dilemma of the energy transition, the solutions will be found where the energy expertise exist. That means, that means that we, in our industry, have a phenomenal, huge opportunity in front of us. Rewiring the energy system is a multi-trillion dollar business opportunity that it good for the climate, good for humanity, and good for sustainable economic growth. These are fundamental reasons why we, in the United Arab Emirates, are excited about hosting COP28 in 2023. We will make this forum a catalyst for practical, commercial, sustainable energy solutions. Solutions that are both pro climate and pro growth. Solutions that come from our industry and, of course, beyond our industry*."

At 9:55 min mark. Al Jaber "*and lets us remember, the energy transition is exactly that. A transition. And transitions take time. We must invest in the energy the world needs today while we create the energy system of tomorrow. Because what the really needs is to hold back emissions. Not to hold back progress and development. Let us together drive that progress and ensure that sustainable development. And let us always keep in mind, our industry must play a pivotable role in the energy transition. We have the knowledge. We have the skills. And the people to make the difference in our world*".

Prepared by SAF Group https://safgroup.ca/news-insights/

SAF Group created transcript of IMF Managing Director Kristalina Georgieva speaking with Reuters Andrea Shalal at ReutersNext Summit on Dec 3, 2021. https://twitter.com/IMFNews/status/1466857567754375170

Items in "*italics*" are SAF Group created transcript

At 29:45 min mark. Re the role of World Bank and IMF for climate finance. Reuters: "*How well prepared are they [World Bank and IMF] to take on what will be trillions and trillions of dollars of funding that is required?*"

Georgieva *"let me first praise the World Bank and the Multi Lateral Development Banks for stepping up. they all have significantly increased their financing for mitigation, adaptation and transition. this being said, we need not billions, we need trillions. Our assessment is between 6 and 10 trillions for mitigation action in this decade. About 6 trillion, this is [UN's?] assessment for adaptation in this decade*."

Prepared by SAF Group https://safgroup.ca/news-insights/

https://www.imf.org/en/Topics/climate-change

The IMF and Climate Change

Climate change presents a major threat to long-term growth and prosperity, and it has a direct impact on the economic wellbeing of all countries.

The IMF has a role to play in helping its members address those challenges of climate change for which fiscal and macroeconomic policies are an important component of the appropriate policy response.

The Fund publishes research on economic implications of climate change and provides policy advice to our membership to help them capture the opportunities of low-carbon, resilient growth.

Our Policy Guidance Relates to:

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1. Mitigation: including advice on measures to contain and reduce emissions through policies—such as increasing carbon taxes, reducing fuel subsidies and improving regulation—and providing tools to help countries achieve their Nationally Determined Contributions.

2. Adaptation: including guidance on building financial and institutional resilience to natural disasters and extreme weather events, and infrastructure investments to cope with rising sea levels and other warming-related phenomena.

3. Transition to a low-carbon economy: including updates to financial sector regulation to cover climate risks and exposure to "brown" assets, as well as measures to help countries diversify economies away from carbon intensive industries while mitigating the social impact on affected communities.

https://www.rwe.com/en/investor-relations/news-and-ad-hoc-announcements/news/news-2021-12-01

Success in offshore auction: RWE secures concession for 1,000-megawatt wind farm off the Danish coast

Essen, 01 December 2021

- Full commissioning of Thor offshore wind farm expected in 2027
- RWE will contribute to Denmark's green energy transition

Sven Utermöhlen, CEO Wind Offshore, RWE Renewables: "Denmark is one of the key offshore markets in Europe with high growth ambitions. As one of the global leading players in offshore wind, we are delighted to be awarded the Thor project – Denmark's largest offshore wind farm to date. This success creates further momentum to boost our activities in the country by realising our second offshore wind farm off the Danish coast. With Thor we will contribute significantly to Denmark's green energy transition."

RWE forges ahead with its growth in offshore wind: As announced by the Danish Energy Agency (Energistyrelsen) today, the German-based energy company was awarded the concession for the offshore wind project Thor. With a planned capacity of around 1,000 megawatts (MW) Thor will be Denmark's largest offshore wind farm to date. The wind farm will be built off the Danish west coast and is scheduled to reach full operation in 2027. Once fully operational, Thor would be capable of producing enough green electricity to supply the equivalent of around 1.4 million Danish households.

Sven Utermöhlen, CEO Wind Offshore of RWE Renewables, explains: "We look forward to working with the Danish government and all other stakeholders to take our new offshore wind development project forward. In the coming months, we will prepare for the permit application and focus on the soil investigations."

RWE is a leading global player in renewables and number 2 worldwide in offshore wind. The company currently operates 17 offshore wind farms in five countries, and is developing and constructing some of the world's most advanced offshore wind farms. In Denmark RWE is operating the Rødsand 2 offshore project, which is located south of the Danish island of Lolland, approximately 10 kilometres southeast of Rødbyhavn. The wind farm has an installed capacity of 207 MW (RWE share: 20%) and has been in operation since 2010. By 2030, as part of its ambitious investment and growth plan 'Growing Green', RWE intends to triple its global offshore wind capacity from 2.4 to 8 gigawatts.

The press release of the Danish Energy Agency can be downloaded here: LINK

Excerpts RWE Capital Markets Day Nov 15, 2021

Strict investment criteria ensure attractive returns

IRR requirements for future investments

Offshore wind

Global | 5.0% – 9.0%

Onshore wind, solar and batteries

Europe and US | 4.0% – 7.0%

Flexible generation and hydrogen

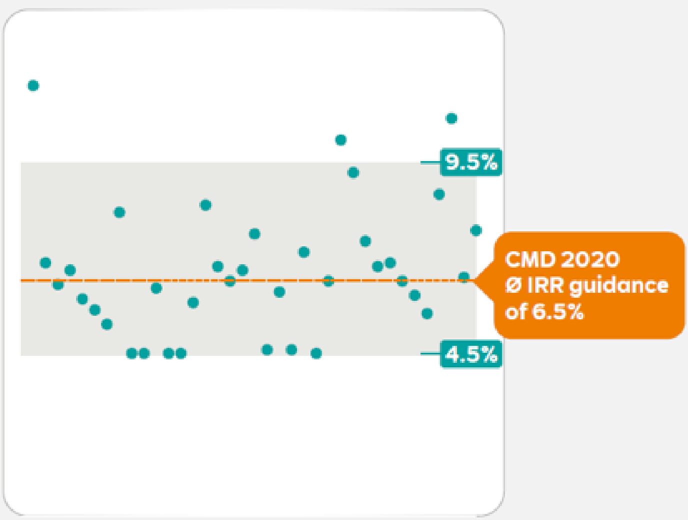
Europe | 6.0% – 11.0%

Note: IRRs post tax, unlevered, nominal.

- Investment decisions based on **strict hurdle rate approach** with project IRR typically exceeding base WACC by 100 to 300 bps
- Hurdle rates include **risk premia** depending on project risk profile
- **Regular post completion reviews** to monitor investment performance and derive learnings for future decisions

We delivered on our promises: Value creation from investment decisions

IRR of investment decisions since CMD 2020 incl. development costs



- IRR targets met ✓
- On track to deliver capacity target ✓
- Earnings guidance exceeded/ confirmed ✓

Joe Biden Is Avoiding Jimmy Carter's Biggest Blunder
2021-11-29 13:10:20.593 GMT

By Meg Jacobs

(Washington Post) -- With gasoline prices up about 60 percent over last year, many are worrying that we're returning to the 1970s, when Americans faced their first full-blown energy crisis. There was a "panic at the pump" and elsewhere as food and transport prices soared.

So what is President Biden going to do? The answer is, whatever it takes. That means releasing reserves — as he did last week — along with browbeating oil companies and pressuring petroleum producers abroad. The United States is not going to "stand by idly and wait for prices to drop on their own. Instead, we're taking action," the president proclaimed. Such moves reflect his political effort to balance the urgent need for bold environmental legislation with being responsive to the needs of working-class families — and making sure Americans know that he cares.

In taking this approach, Biden seems to be learning from the mistakes that hurt President Jimmy Carter. Biden had a front-row seat as the 39th president treated politics as the enemy of a good energy policy. While Carter had lots of good ideas about how to "solve" the gas crisis of the 1970s, he didn't match that with understanding the basic pocketbook needs of working Americans — and it cost him a second term.

By the time Carter took office in 1977, inflation was running high. So was unemployment. Contemporaries coined a new term, "stagflation," to capture this simultaneous occurrence of rising prices and stagnating employment.

To conservatives, and even to some moderate Democrats like Carter, fighting inflation took precedence over priming the pump. "We cannot afford to do everything," a somber Carter said in his inaugural address.

Inflation only worsened, reaching a high of nearly 15 percent, driven in part by a dramatic increase in oil prices led by the Organization of the Petroleum Exporting Countries (OPEC). For the first time, consumers feared paying more than a dollar a gallon to fill up, signaling not only the tripling of gas prices in less than a decade but also more generally the decline of the United States as a global independent superpower.

In response, Carter urged Americans to sacrifice, and led by example. He turned down White House thermostats and addressed the American public wearing a cardigan sweater to keep warm. When an oil shock hit in 1979 in response to the Iranian Revolution, he famously asked Americans to stop driving so much as the solution to high prices at the pump.

Carter also believed in market solutions — even if they caused pain to American consumers. When a Democratic Congress hesitated to eliminate price controls on gas that Republican Richard M. Nixon had opportunistically adopted during the decade's first oil shock in 1973, Carter used executive authority to get rid of them. Only higher prices would teach Americans to use less. "I'd rather do that and accept the political blame than spend another two years arguing with you about what ought to be done — when you know what ought to be done," he told congressional leaders, as Newsweek reported in 1979.

He also appointed Paul Volcker to the Federal Reserve in the hope that he would tamp down inflation at any cost, which meant a drastic increase in interest rates at the expense of employment.

These policies reflected the reality that Carter was fundamentally a moderate-to-conservative Southern Democrat. Voters had elected him to restore morality to the White House, and he resolutely told them the unvarnished truth, showing little interest in worrying about political ramifications or making promises that he found fiscally irresponsible. "I'll give it to you straight," Carter said. "Each one of us will have to use less oil and pay more for it."

This strategy didn't work. Carter couldn't solve the energy crisis, and he handed a new conservative coalition the keys to the White House. The energy crisis was Exhibit A for Ronald Reagan during the 1980 campaign when he wanted to claim Carter's government was incompetent. "Carter Kiss My Gas" was a popular bumper sticker. In the end, Carter lost to Reagan in a landslide.

Biden witnessed all of this as a young senator. He joined the Senate in 1973 during the throes of the first oil shock when the Arab OPEC producers imposed an embargo on the United States because of its support for Israel during the Yom Kippur war. While moderate on cultural issues, economically, the young Biden was a New Deal liberal through and through. He instinctively sympathized with the pain that rising prices caused. In an open letter to Nixon, Biden asked "why the oil industry should be permitted to make record profits at a time when the average citizen is being told to turn down his heat, slow down his car and throw away his Christmas lights." He also took a 15-hour ride with a truck driver to see firsthand the pain that higher fuel prices caused. "I didn't realize the seriousness of the situation," he said after talking to more than 300 truckers. "These guys are scared. They are confused and worried."

In the 1974 midterm elections, Democrats swept Republicans out of office. Voters were upset about the Watergate scandal, but polls revealed that they cared just as much about the pain in their pocketbooks inflicted by inflation. And they were hopeful that Democrats, from the young Biden to the old-school liberal House Speaker Tip O'Neill, would help them out. But Carter showed little interest, instead turning into a national scold preaching tough love.

A half-century later, Biden appears to be learning from this mistake, willing to do whatever it takes to avoid a panic at the pump. That's a lesson Carter fundamentally didn't understand.

Sure, Carter had excellent policies. He placed the solar panels on the White House roof, supported other renewables, got excited about energy efficiency and preached the necessity of seemingly esoteric policies like cogeneration of heat and electricity in his fireside chats.

But Carter was also too far removed from the legacy of Franklin D. Roosevelt and Lyndon B. Johnson to remember that a president couldn't tackle conservation issues without also making American working families feel economically secure and offering immediate relief to alleviate their struggling. A Southern peanut farmer, Carter was as much a part of the shift away from New Deal government — premised on the idea that government could help make life better for Americans — as the Republicans he was running against.

Biden, by contrast, came into the White House, amid the global pandemic, channeling his inner Roosevelt. He vowed the government was here to help, providing a "shot in arms and money in pockets." And he promised massive infrastructure and social spending.

Last week's release of oil from the nation's Strategic Petroleum Reserve is Biden's short-term political choice to make his long-term policy decisions possible. It also symbolizes that he won't forget about ordinary Americans as he pushes for climate solutions within his larger infrastructure and social spending bills, including $555 billion in climate-related spending.

Biden seems to understand that he can't repeat the mistakes of Carter. Instead of responding to the dual crises of a pandemic and climate change just with restrictions and calls for Americans to conserve, he's pushing for infrastructure and human spending. Instead of asking people to change their wasteful ways to beat back inflation, Biden believes it's government's job to solve big problems and relieve pain. It's an effective political strategy that may also smooth the transition away from fossil fuels and help Americans plan for a better future.

Click Here to see the story as it appeared an the Washington Post website.

-0- Nov/29/2021 13:10 GMT

S&P Dow Jones Indices

A Division of S&P Global

PRESS RELEASE

S&P Dow Jones Indices Announces Changes to the S&P/TSX Composite Index

Toronto, Ontario, December 3, 2021 – As a result of the quarterly review, S&P Dow Jones Indices will make the following changes to the S&P/TSX Composite Index prior to the open of trading on Monday, December 20, 2021:

S&P/TSX COMPOSITE INDEX – December 20, 2021			
	COMPANY	GICS SECTOR	GICS SUB-INDUSTRY
ADDED	Advantage Energy Ltd. (TSX:AAV)	Energy	Oil & Gas Exploration & Production
ADDED	Baytex Energy Corp. (TSX:BTE)	Energy	Oil & Gas Exploration & Production
ADDED	Energy Fuels Inc. (TSX:EFR)	Energy	Coal & Consumable Fuels
ADDED	Freehold Royalties Ltd. (TSX:FRU)	Energy	Oil & Gas Exploration & Production
ADDED	Hut 8 Mining Corp. (TSX:HUT)	Information Technology	Application Software
ADDED	Lion Electric Company (TSX:LEV)	Industrial	Construction Machinery & Heavy Trucks
ADDED	Peyto Exploration & Development Corp. (TSX:PEY)	Energy	Oil & Gas Exploration & Production
ADDED	Park Lawn Corporation (TSX:PLC)	Consumer Discretionary	Specialized Consumer Services
ADDED	Paramount Resources Ltd (TSX:POU)	Energy	Oil & Gas Exploration & Production
ADDED	Secure Energy Services Inc (TSX:SES)	Energy	Oil & Gas Exploration & Production
ADDED	Topaz Energy Corp. (TSX:TPZ)	Energy	Integrated Oil & Gas
ADDED	Tamarack Valley Energy Ltd. (TSX:TVE)	Energy	Oil & Gas Exploration & Production
DELETED	OrganiGram Holdings Inc. (TSX:OGI)	Health Care	Pharmaceuticals
DELETED	Real Matters Inc. (TSX:REAL)	Real Estate	Real Estate Services
DELETED	SunOpta Inc (TSX:SOY)	Consumer Staples	Biotechnology
DELETED	Westport Fuel Systems Inc. (TSX:WPRT)	Industrials	Construction Machinery & Heavy Trucks

For more information about S&P Dow Jones Indices, please visit **www.spdji.com**

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S&P Dow Jones Indices is a division of S&P Global (NYSE: SPGI), which provides essential intelligence for individuals, companies, and governments to make decisions with confidence. For more information, visit www.spdji.com.

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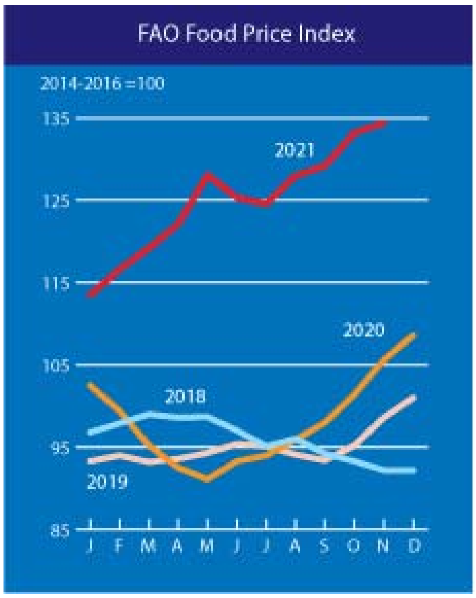
https://www.fao.org/worldfoodsituation/foodpricesindex/en/

FAO Food Price Index

The FAO Food Price Index (FFPI) is a measure of the monthly change in international prices of a basket of food commodities. It consists of the average of five commodity group price indices weighted by the average export shares of each of the groups over 2014-2016. A feature article published in the June 2020 edition of the Food Outlook presents the revision of the base period for the calculation of the FFPI and the expansion of its price coverage, to be introduced from July 2020. A November 2013 article contains technical background on the previous construction of the FFPI.

November marked a further increase in the value of the FAO Food Price Index

Release date: 02/12/2021



» The **FAO Food Price Index (FFPI)** averaged 134.4 points in November 2021, up 1.6 points (1.2 percent) from October and 28.8 points (27.3 percent) from November 2020. The latest increase marked the fourth consecutive monthly rise in the value of the FFPI, putting the index at its highest level since June 2011. Among the sub-indices, in November those for cereals and dairy rose most significantly, followed by sugar, while those for meat and vegetable oils were down, albeit slightly, from the previous month.

» The **FAO Cereal Price Index** averaged 141.5 points in November, up 4.3 points (3.1 percent) from October and 26.6 points (23.2 percent) above its level one year ago. Strong demand amid tight supplies, especially of higher quality wheat among major exporters, continued to lift wheat prices for a fifth consecutive month, to their highest level since May 2011. Potentially reduced quality of the ongoing harvest in Australia, following untimely rains, and uncertainty regarding potential changes to export measures in the Russian Federation also provided support. Among coarse grains, international barley prices continued to rise on tight supplies and spillovers from wheat markets. Maize export prices rose slightly in November, receiving support from strong pace in sales from Argentina, Brazil and Ukraine, while seasonal supply pressure capped export prices from the United States of America. By contrast, international rice prices remained broadly steady in November, reined in by harvest progress in various Asian suppliers and scattered import demand.

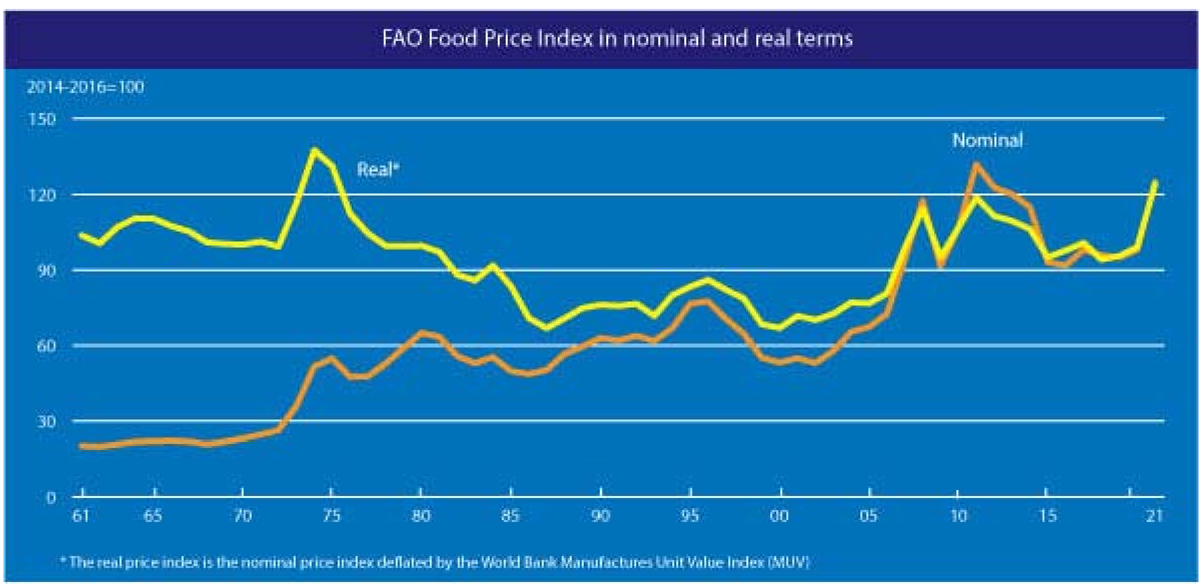
» The **FAO Vegetable Oil Price Index** averaged 184.6 points in November, down marginally (by 0.3 points or 0.2 percent) from the record high registered in the previous month. The slight decrease reflected somewhat lower values for soy and rapeseed oils, while quotations for palm oil remained virtually unchanged. International palm oil prices maintained their firmness in November, with the downward pressure linked to rising concerns over the impact of a resurgence in COVID-19 cases largely offset by the support stemming from the anticipation of production slowdowns in major producing countries. As for soy and rapeseed oils, world prices retreated moderately, broadly softened by demand rationing. Meanwhile, lower crude oil values also weighed on vegetable oil prices.

» The **FAO Dairy Price Index** averaged 125.5 points in November, up 4.1 points (3.4 percent) from October and 20.2 points (19.1 percent) above its level in the same month last year. In November, international price quotations for butter and milk powders rose sharply for the third consecutive month, driven by tight global export availabilities and depleted stocks, as deliveries declined in several large milk-producing countries in Western Europe, coinciding with lower-than-anticipated output in Oceania. Strong global import demand persisted amidst buyers' efforts to secure spot supplies in anticipation of tightening markets, adding further upward pressure on prices, notwithstanding market uncertainty over near-term demand caused by increasing COVID-19-related social restrictions. Cheese quotations rose slightly, reflecting increased demand and shipping delays that hindered sales from global suppliers.

» The **FAO Meat Price Index*** averaged 109.8 points in November, down 1.0 point (0.9 percent) from October, falling for the fourth consecutive month, though still 16.5 points (17.6 percent) above its value in the corresponding month a year ago. In November, international quotations for pig meat fell for the fifth consecutive month, underpinned by reduced purchases by China, especially from the European Union. Ovine price quotations also fell steeply on increased exportable supplies, mainly from Australia. Meanwhile, international bovine meat prices remained stable, as decreased quotations for Brazil's meat were offset by higher Australian export values, reflecting low cattle sales for slaughter amid high herd-rebuilding demand. Poultry meat prices were also largely stable, as global supplies seemed adequate to meet demand, despite supply-side constraints, especially shipping container shortages and avian flu in Europe and Asia.

» The **FAO Sugar Price Index** averaged 120.7 points in November, up by 1.6 points (1.4 percent) from October, reversing most of the previous month's decline and reaching levels nearly 40 percent above those registered in the same month last year. The November rebound in international sugar price quotations was mainly prompted by higher ethanol prices, which encouraged a greater use of sugarcane for ethanol production in Brazil, the world's largest sugar exporter. Further support to world sugar prices was provided by stronger global import demand, prompted by lower freight costs. Overall, however, the upward pressure on world sugar prices was limited by large shipments from India and the positive outlook for sugar exports by Thailand.

** Unlike for other commodity groups, most prices utilized in the calculation of the FAO Meat Price Index are not available when the FAO Food Price Index is computed and published; therefore, the value of the Meat Price Index for the most recent months is derived from a mixture of projected and observed prices. This can, at times, require significant revisions in the final value of the FAO Meat Price Index which could in turn influence the value of the FAO Food Price Index.*



FAO food price index

		Food Price Index [1]	Meat [2]	Dairy [3]	Cereals [4]	Vegetables Oils [5]	Sugar [6]
2003		**57.8**	**58.3**	**54.5**	**59.4**	**62.6**	43.9
2004		**65.6**	**67.6**	**69.8**	**64.0**	**69.6**	44.3
2005		**67.4**	**71.8**	**77.2**	**60.8**	**64.4**	61.2
2006		**72.6**	**70.5**	**73.1**	**71.2**	**70.5**	91.4
2007		**94.3**	**76.9**	**122.4**	**100.9**	**107.3**	62.4
2008		**117.5**	**90.2**	**132.3**	**137.6**	**141.1**	79.2
2009		**91.7**	**81.2**	**91.4**	**97.2**	**94.4**	112.2
2010		**106.7**	**91.0**	**111.9**	**107.5**	**122.0**	131.7
2011		**131.9**	**105.3**	**129.9**	**142.2**	**156.5**	160.9
2012		**122.8**	**105.0**	**111.7**	**137.4**	**138.3**	133.3
2013		**120.1**	**106.2**	**140.9**	**129.1**	**119.5**	109.5
2014		**115.0**	**112.2**	**130.2**	**115.8**	**110.6**	105.2
2015		**93.0**	**96.7**	**87.1**	**95.9**	**89.9**	83.2
2016		**91.9**	**91.0**	**82.6**	**88.3**	**99.4**	111.6
2017		**98.0**	**97.7**	**108.0**	**91.0**	**101.9**	99.1
2018		**95.9**	**94.9**	**107.3**	**100.8**	**87.8**	77.4
2019		**95.1**	**100.0**	**102.8**	**96.6**	**83.2**	78.6
2020		**98.1**	**95.5**	**101.8**	**103.1**	**99.4**	79.5
2020	November	**105.6**	93.3	105.4	114.8	121.9	87.5
	December	**108.6**	94.8	109.2	116.4	131.2	87.1
2021	January	**113.5**	96.0	111.2	125.0	138.9	94.2
	February	**116.6**	97.8	113.1	126.1	147.5	100.2
	March	**119.2**	100.8	117.5	123.9	159.3	96.2
	April	**122.1**	104.3	119.1	126.2	162.2	100.0
	May	**128.1**	107.4	121.1	133.7	174.9	106.8
	June	**125.3**	110.7	119.9	130.3	157.7	107.7
	July	**124.6**	114.1	116.7	126.3	155.5	109.6
	August	**128.0**	113.5	116.2	130.4	165.9	120.5
	September	**129.2**	112.7	118.1	132.8	168.6	121.2
	October	**132.8**	110.8	121.5	137.1	184.8	119.1
	November	**134.4**	109.8	125.5	141.5	184.6	120.7

1 Food Price Index: Consists of the average of 5 commodity group price indices mentioned above, weighted with the average export shares of each of the groups for 2014-2016: in total 95 price quotations considered by FAO commodity specialists as representing the international prices of the food commodities are included in the overall index. Each sub-index is a weighted average of the price relatives of the commodities included in the group, with the base period price consisting of the averages for the years 2014-2016.

2 Meat Price Index: Based on 35 average export unit values/market prices of four meat types (bovine, pig, poultry and ovine) from 10 representative markets. Within each meat type, export unit values/prices are weighted by the trade shares of their respective markets, while the meat types are weighted by their average global export trade shares for 2014-2016. Quotations for the two most recent months may consist of estimates and be subject to revision.

3 Dairy Price Index: Computed using 8 price quotations of four dairy products (butter, cheese, SMP and WMP) from two representative markets. Within each dairy product, prices are weighted by the trade shares of their respective markets, while the dairy products are weighted by their average export shares for 2014-2016.

4 Cereals Price Index: Compiled using the International Grains Council (IGC) wheat price index (an average of 10 different wheat price quotations), the IGC maize price index (an average of 4 different maize price quotations), the IGC barley price index (an average of 5 different barley price quotations), 1 sorghum export quotation and the FAO All Rice Price Index. The FAO All Rice Price Index is based on 21 rice export quotations, combined into four groups consisting of Indica, Aromatic, Japonica and Glutinous rice varieties. Within each varietal group, a simple average of the relative prices of appropriate quotations is calculated; then the average relative prices of each of the four rice varieties are combined by weighting them with their (fixed) trade shares for 2014-2016. The Cereal Price Index combines the relative prices of sorghum, the IGC wheat, maize and barley price indices (re-based to 2014-2016) and the FAO All Rice Price Index by weighing each commodity with its average export trade share for 2014-2016.

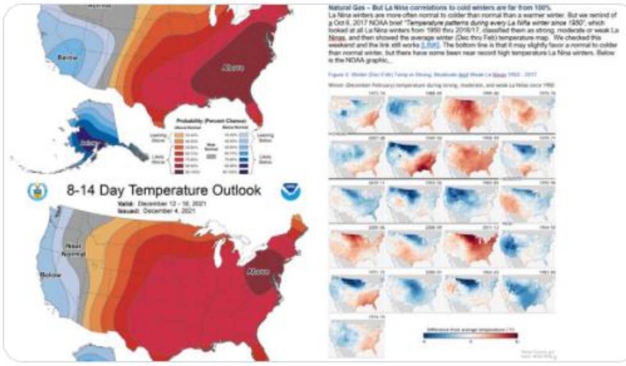
5 Vegetable Oil Price Index: Consists of an average of 10 different oils weighted with average export trade shares of each oil product for 2014-2016.

6 Sugar Price Index: Index form of the International Sugar Agreement prices with 2014-2016 as base.

SAF

Dan Tsubouchi @Energy_Tidbits · 47m

Continued negative near term outlook to US #NatGas prices from warm weather forecast for Dec. Also reminds that not all #LaNina winters are cold. Thx @NOAA #OOTT



2 2

SAF

Dan Tsubouchi @Energy_Tidbits · 4h

Iran's response just now to US #JCPOA briefing. @Bagheri_Kani reiterates its position US was the party that left JCPOA so it was up to US to take the first step. will someone blink? or are they going back to pre JCPOA? #OOTT

https://en.irna.ir/news/84566402/Iran-won-t-walk-back-demands-deputy-FM

Dec 5, 2021, 2:22 PM Journalist ID: 1195 News Code: 84566402

Iran won't walk back demands: deputy FM

Tehran, IRNA – Iran's Deputy Foreign Minister Ali Bagheri Kani said on Sunday that the [illegible]

[illegible]

Bagheri Kani serves as Iran's top negotiator in the talks in Vienna between Iran and the remaining participants in the JCPOA for a possible return of the US and removing sanctions against Iran.

He told ANSA that the proposals offered by Iran in the talks this week were "logical and well-founded" and they could be a basis for further negotiations.

The Islamic Republic of Iran, said the top negotiator, believes in the negotiations and is "optimistic" about the possible results.

However, he added, the past non-constructive behavior by the other signatories of the deal and the repeated violation of their obligations require Iran not to be naive.

Iran delivered its proposals in two drafts regarding the US sanctions against Iran and Iran's nuclear program, he said, adding that the drafts were the basis of negotiation and the other parties should give documented response to Iran's demands.

Bagher Kani had previously said that the other participants to the deal couldn't reject Iran's proposals and if they accept them, Tehran would offer its third proposal.

https://en.mehrnews.com/news/181416/Iran-not-to-back-down-from-its-demands-in-negotiations

Dec 5, 2021, 3:20 PM

Bagheri Kani:

Iran not to back down from its demands in negotiations

[illegible]

> **Dan Tsubouchi** @Energy_Tidbits · 4h
>
> #JCPOA. key quotes from US State Dept briefing. no idea when next 7th round negotiations, "time that the JCPOA has for still remaining a viable deal is inversely proportional to the speed with which Iran advances its nuclear program. #OOTT ...

1

SAF

Dan Tsubouchi @Energy_Tidbits · 4h

#JCPOA. key quotes from US State Dept briefing. no idea when next 7th round negotiations, "time that the JCPOA has for still remaining a viable deal is inversely proportional to the speed with which Iran advances its nuclear program. #OOTT

state.gov/briefing-with-...

[illegible]

1 1

Dan Tsubouchi @Energy_Tidbits · 5h

An unplanned #LNG supply interruption just as peak winter #NatGas demand season is starting. #Shell Prelude FLNG is 0.47 bcf/d capacity. Thx @PeteMilne4n @SStapczynski #OOTT

> **Stephen Stapczynski** @SStapczynski · 5h
>
> Shell evacuated staff from its Prelude LNG export plant as it struggled to restore power knocked offline earlier this week 🇦🇺 🚢
>
> The evacuation indicates that the plant could be shut longer than originally anticipated, exacerbating a global gas shortage…
>
> Show this thread

4 · 1

Dan Tsubouchi @Energy_Tidbits · 18h

#Vortexa crude #Oil floating storage for 12/03 est 73.08 mmb, -14.59 WoW vs revised up 11/26 87.67 mmb (was 77.28). 12/03 is lower than when #OPEC+ started production increases in June. Down 150.66 mmb vs June 26/2020 peak of 223.74 mmb. Thx @Vortexa @TheTerminal #OOTT

Source: Bloomberg, Vortexa

1 · 1 · 5

Dan Tsubouchi @Energy_Tidbits · 19h

#TransMountain "plans to safely restart tomorrow". No indication of at what throughput levels or how/when volumes will ramp up. But its restarting so good news for Cdn oil. #OOTT

//www.transmountain.com/news/2021/ensuring-safety-during-bc-and-wa-storm-impacts

ans Mountain Pipeline Plans to Safely Restart Tomorrow

e › News

4, 2021

ber 4, 2021, 12:00 pm PDT

wing the precautionary shutdown of the Trans Mountain Pipeline as a result of heavy rains and flooding, Trans Mountain plans to restart the pipeline rrow.

ghout the shutdown period, the pipeline remained safely in a static condition and there was no indication of any product release or serious damage Trans Mountain completed detailed investigations of the pipe's integrity and geotechnical assessments of the surrounding landscape to confirm rea tart the line. Restarting the pipeline has required a significant, sustained effort to re-instate access lost due to damaged roads, changes in river flow se weather. Crews worked around the clock to clear highways, build bridges and manage watercourses to allow for access and repairs to the pipelin

xpect that all assessments, repairs and protective earthworks necessary for a safe restart will be completed by tomorrow and plans have been devel hared with the Canada Energy Regulator.

ct to CER concurrence and final repair work, the restart will take place during daylight hours tomorrow and the pipe will be closely monitored by our s in the field and technology systems operated by our Control Centre. Emergency management teams and equipment remain staged in key areas wit s proactively deployed in the unlikely event of a release.

the coming weeks Trans Mountain will continue with additional emergency work. Some of this work includes conducting additional inline inspection uring of riverbanks and adding ground cover or relocating sections of the pipeline.

1 · 7 · 35

Dan Tsubouchi @Energy_Tidbits · Dec 4

If more leaders have a "Macron Moment" in 2022, maybe COPE28 UAE in 2023 can be catalyst for getting down to work on practical, commeical, sustainable energy solutions: pro climate/pro growth? See SAF Group transcript of @SultanAhmedalj8 #ADIPEC keynote. #EnergyTransition #OOTT

SAF Group created transcript of excerpts from ADNOC's H.E Dr. Sultan Al Jaber 11 minute speech to open ADIPEC on Nov 15, 2021 https://energynow.ca/2021/11/worth-a-watch-opening-speech-at-adipec-2021-november-15-18-2021/

Items in *"italics"* are SAF Group created transcript

At 0.55 min mark. Al Jaber *"we meet at a historic moment. The global community has just concluded COP26. And, on balance, it was indeed a success,…Yet, current energy dynamics have revealed a basic dilemma. "While the world has agreed to accelerate the energy transition, it is still heavily reliant on oil and gas. As economies bounce back from the Covid-19 pandemic at the fastest rate in 50 years, demand has outpaced supply and, after almost a decade of underinvestment in our industry, the world has sleepwalked into a supply crunch. It is time to wake up. The oil and gas industry will have to invest over 600 billion US dollars every year until 2030 just to keep up with the expected demand. And Yes, renewable energy is the fastest growing segment of the energy mix. But oil and gas is still the biggest and will be for decades to come. In short, the future is coming. But it is not here yet. We must make progress, with pragmatism. And if we are to successfully transition to the energy system of tomorrow, we cannot simply unplug from the energy system of today. We cannot just flip a switch"*.

At 7:50 min mark. Al Jaber *"if the world is to resolve the dilemma of the energy transition, the solutions will be found where the energy expertise exist. That means, that means that we, in our industry, have a phenomenal, huge opportunity in front of us. Rewiring the energy system is a multi-trillion dollar business opportunity that it good for the climate, good for humanity, and good for sustainable economic growth. These are fundamental reasons why we, in the United Arab Emirates, are excited about hosting COP28 in 2023. We will make this forum a catalyst for practical, commercial, sustainable energy solutions. Solutions that are both pro climate and pro growth. Solutions that come from our industry and, of course, beyond our industry."*

At 9:55 min mark. Al Jaber *"and lets us remember, the energy transition is exactly that. A transition. And transitions take time. We must invest in the energy the world needs today while we create the energy system of tomorrow. Because what the really needs is to hold back emissions. Not to hold back progress and development,…Let us together drive that progress and ensure that sustainable development. And let us always keep in mind, our industry must play a pivotable role in the energy transition. We have the knowledge. We have the skills. And the people to make the difference in our world"*.

Prepared by SAF Group https://safgroup.ca/news-insights/

Dan Tsubouchi @Energy_Tidbits · Dec 2

Is Japan having a "Macron Moment"? Govt "officials have been quietly urging trading houses, refiners & utilities to slow down their move away from #FossilFuels". Supports #Oil #NatGas #LNG to be stronger thru 2030. Thx @SStapczynski @Inajima17 ...

1 2 2

Dan Tsubouchi @Energy_Tidbits · Dec 4

#EnergyTransition will cost big $$. Note #IMF definitions below. @KGeorgieva $6-10T for mitigation of emissions plus $6T for adaptation this decade. That's before she incl the big number, the $ trillions needed for transition to a low-carbon economy. Thx @andrea_shalal. #OOTT

SAF Group created transcript of IMF Managing Director Kristalina Georgieva speaking with Reuters Andrea Shalal at ReutersNext Summit on Dec 3, 2021. https://twitter.com/IMFNews/status/1466857567754375170

Items in *"italics"* are SAF Group created transcript

At 29:45 min mark. Re the role of World Bank and IMF for climate finance. Reuters: *"How well prepared are they [World Bank and IMF] to take on what will be trillons and trillons of dollars of funding that is required?"*

Georgieva *"let me first praise the World Bank and the Multi Lateral Development Banks for stepping up,… they all have significantly increased their financing for mitigation, adaptation and transition. this being said, we need not billions, we need trillions. Our assessment is between 6 and 10 trillons for mitigation action in this decade. About 6 trillion, this is [UN's?] assessment for adaptation in this decade."*

Prepared by SAF Group https://safgroup.ca/news-insights/

https://www.imf.org/en/Topics/climate-change

The IMF and Climate Change

Climate change presents a major threat to long-term growth and prosperity, and it has a direct impact on the economic wellbeing of all countries.

The IMF has a role to play in helping its members address those challenges of climate change for which fiscal and macroeconomic policies are an important component of the appropriate policy response.

The Fund publishes research on economic implications of climate change and provides policy advice to our membership to help them capture the opportunities of low-carbon, resilient growth.

Our Policy Guidance Relates to:

1. Mitigation: including advice on measures to contain and reduce emissions through policies—such as increasing carbon taxes, reducing fuel subsidies and improving regulation—and providing tools to help countries achieve their Nationally Determined Contributions.

2. Adaptation: including guidance on building financial and institutional resilience to natural disasters and extreme weather events, and infrastructure investments to cope with rising sea levels and other warming-related phenomena.

3. Transition to a low-carbon economy: including updates to financial sector regulation to cover climate risks and exposure to "brown" assets, as well as measures to help countries diversify economies away from carbon intensive industries while mitigating the social impact on affected communities.

3 3

Dan Tsubouchi @Energy_Tidbits · Dec 3

Forgot $TPZ OOTT

Dan Tsubouchi @Energy_Tidbits · Dec 3

S&P TSX Composite Index quarterly index changes announced, to be added effective Mon Dec 20. Several #Oil #NatGas added $AAV $BTE $EFR $FRU $POU $PEY $SES $TVE #OOTT

S&P Global Public

S&P Dow Jones Indices
A Division of S&P Global

PRESS RELEASE

S&P Dow Jones Indices Announces Changes to the S&P/TSX Composite Index

Toronto, Ontario, December 3, 2021 – As a result of the quarterly review, S&P Dow Jones Indices will make the following changes to the S&P/TSX Composite Index prior to the open of trading on Monday, December 20, 2021:

S&P/TSX COMPOSITE INDEX – December 20, 2021			
	COMPANY	GICS SECTOR	GICS SUB-INDUSTRY
ADDED	Advantage Energy Ltd. (TSX:AAV)	Energy	Oil & Gas Exploration & Production
ADDED	Baytex Energy Corp. (TSX:BTE)	Energy	Oil & Gas Exploration & Production
ADDED	Energy Fuels Inc. (TSX:EFR)	Energy	Coal & Consumable Fuels
ADDED	Freehold Royalties Ltd. (TSX:FRU)	Energy	Oil & Gas Exploration & Production
ADDED	Hut 8 Mining Corp. (TSX:HUT)	Information Technology	Application Software
ADDED	Lion Electric Company (TSX:LEV)	Industrial	Construction Machinery & Heavy Trucks
ADDED	Peyto Exploration & Development Corp. (TSX:PEY)	Energy	Oil & Gas Exploration & Production
ADDED	Park Lawn Corporation (TSX:PLC)	Consumer Discretionary	Specialized Consumer Services
ADDED	Paramount Resources Ltd (TSX:POU)	Energy	Oil & Gas Exploration & Production
ADDED	Secure Energy Services Inc (TSX:SES)	Energy	Oil & Gas Exploration & Production
ADDED	Topaz Energy Corp. (TSX:TPZ)	Energy	Integrated Oil & Gas
ADDED	Tamarack Valley Energy Ltd. (TSX:TVE)	Energy	Oil & Gas Exploration & Production
DELETED	OrganiGram Holdings Inc. (TSX:OGI)	Health Care	Pharmaceuticals
DELETED	Real Matters Inc. (TSX:REAL)	Real Estate	Real Estate Services
DELETED	SunOpta Inc (TSX:SOY)	Consumer Staples	Biotechnology
DELETED	Westport Fuel Systems Inc. (TSX:WPRT)	Industrials	Construction Machinery & Heavy Trucks

2 3

Dan Tsubouchi @Energy_Tidbits · Dec 3

S&P TSX Composite Index quarterly index changes announced, to be added effective Mon Dec 20. Several #Oil #NatGas added $AAV $BTE $EFR $FRU $POU $PEY $SES $TVE #OOTT

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1 4 2

Dan Tsubouchi @Energy_Tidbits · Dec 3

Good recap of global road traffic indicators, but some uncertainty/headwinds ahead until better understanding of #Omicron impact. Thx @BloombergNEF @WayneTanMing. #OOTT #Oil

Dan Tsubouchi @Energy_Tidbits · Dec 2

Today's Japan "go slow" getting rid of #Oil #NatGas fits Japan's Nov 9 on acceleration of decarbonization that must have "the importance of measures with pragmatic time frame". Japan is having a "Macron Moment". See Nov 9 tweet twitter.com/Energy_Tidbits... #OOTT

https://www.mofa.go.jp/press/release/press1e_000227.html

Video conference between Ms. Ono, Director General of Economic Affairs Bureau, Ministry of Foreign Affairs of Japan, and Dr. Birol, Executive Director of the International Energy Agency (IEA)

e-mail

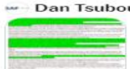
November 9, 2021

Japanese

On November 9, Ms. ONO Hikariko, Director General of Economic Affairs Bureau, held a videoconference with Dr. Fatih Birol, Executive Director of the IEA.

1. At the outset, Ms. Ono expressed concern over the rapid surge in crude oil prices, which could hamper the global economic recovery from COVID-19. She stated that Japan is engaged in dialogues with oil-producing countries and would like to work closely with the IEA, which plays a central role in stabilizing the energy market.
2. In his response, Dr. Birol mentioned that he is closely watching the energy market including oil, and expressed the IEA's willingness to cooperate with member countries and oil-producing countries to work for stabilization of market. He also shared with Ms. Ono the IEA's analysis of the future energy market following the results of the OPEC Plus Ministerial Meeting held on November 4, 2021. He pointed out that the gap between supply and demand will continue to be tight in the short term, however, the supply and demand balance will improve around the turn of the year and the market will gradually regain stability.
   Furthermore, he underscored the need for additional investment to meet future demand, explaining that the demand for oil and natural gas will not drastically decrease even through our path towards transition to renewable energy. The two sides agreed to further strengthen cooperation to enhance energy security, including that of oil. Dr. Birol expressed his wish to visit Japan to exchange views with Japanese counterparts.
3. The two sides also exchanged views on acceleration of decarbonization efforts following COP26, and shared the importance on measures with pragmatic time frame based on individual circumstances that each countries face including its renewable energy potentials, while it is important to expand investment on renewable energy to achieve carbon neutral. In addition, the two sides frankly exchanged their views on Japan's funded initiative with the IEA for clean energy transition in resource producing countries, as well as on the Ministerial meeting scheduled to be held in February 2022.

Dan Tsubouchi @Energy_Tidbits · Dec 2



Is Japan having a "Macron Moment"? Govt "officials have been quietly urging trading houses, refiners & utilities to slow down their move away from #FossilFuels". Supports #Oil #NatGas #LNG to be stronger thru 2030. Thx @SStapczynski @Inajima17 ...

1 3

Dan Tsubouchi @Energy_Tidbits · Dec 2

Is Japan having a "Macron Moment"? Govt "officials have been quietly urging trading houses, refiners & utilities to slow down their move away from #FossilFuels". Supports #Oil #NatGas #LNG to be stronger thru 2030. Thx @SStapczynski @Inajima17 #OOTT #EnergyTransition

Japan Quietly Endorses Fossil Fuel Investments Weeks After COP
2021-12-01 23:30:14.75 GMT

By Stephen Stapczynski and Tsuyoshi Inajima
(Bloomberg) -- It's been less than a month since world leaders pledged to combat climate change at the COP26 summit in Glasgow, yet Japan is already showing signs of putting the brakes on divestment from fossil fuels.
Government officials have been quietly urging trading houses, refiners and utilities to slow down their move away from fossil fuels, and even encouraging new investments in oil-and-gas projects, according to people within the Japanese government and industry, who requested anonymity as the talks are private.
The officials are concerned about the long-term supply of traditional fuels as the world doubles down on renewable energy, the people said. The import-dependent nation wants to avoid a potential shortage of fuel this winter, as well as during future cold spells, after a deficit last year sparked fears of nationwide blackouts.
Japan joined almost 200 countries last month in a pledge to step up the fight against climate change, including phasing down coal power and tackling emissions. However, the moves by the officials show the struggle to turn those pledges into reality, especially for countries like Japan which relies on imports for nearly 90% of its energy needs, with prices spiking partly because of the world's shift away from fossil fuel investments.
The nation has been slow to make any concrete commitments to phase out coal in the near term, and has often been criticized for its funding of overseas power plants that use the dirtiest burning fossil fuel. The government has also avoided joining efforts by developed nations to reduce consumption of natural gas.
Japan's Ministry of Economy, Trade and Industry declined to comment directly on whether it is encouraging industries to boost investment in upstream energy supply, and instead pointed to a strategic energy plan approved by Prime Minister Fumio Kishida's cabinet on October 22. That plan says "no compromise is acceptable to ensure energy security, and it is the obligation of a nation to continue securing necessary resources."
That latest strategy calls for the share of oil and natural gas produced either domestically or under the control of Japanese enterprises overseas to increase from 34.7% in fiscal year 2019 to more than 60% in 2040. Japanese officials plan to convey to other nations the importance attached to continued investments in upstream supply, the people added.
While Japan will likely avoid rolling blackouts or gasoline rationing this winter when demand for energy peaks in the region, the global energy crisis is leaving many within the government thinking about how to prepare for the future. Japan is still expected to be highly dependent on fossil fuels for the next decade as there is limited available space to significantly expand solar power, and the nation's wind sector is developing slowly. It's also struggling to restart nuclear reactors in the wake of the Fukushima disaster.
To achieve net-zero emissions by 2050, the world needs to stop developing new gas, oil and coal fields, the International Energy Agency said in May. Japanese officials are echoing concerns highlighted by Australia last month, which said Europe's gas supply squeeze is proof that nations need to continue to add more production.
Japan's trading houses, including Sumitomo Corp. and Marubeni Corp., are aggressively divesting from fossil fuels amid an uncertain future for the energy sources and pressure from shareholders. These companies, formally known as "Sogo Shosha," have traditionally been among the biggest investors in oil and natural gas assets in order to bring the fuel to resource-poor Japan.
Oil prices had surged to the highest level since 2014 in October, which many Japanese government officials believe was exacerbated by a lack of investment in new supply, the people said. Meanwhile, liquefied natural gas prices have jumped to a record on the back of a global shortage, helping to push Japan's wholesale power rate to the highest level for this time of year.

--With assistance from Isabel Reynolds, Shoko Oda and Javier Blas.

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To view this story in Bloomberg click here: https://blinks.bloomberg.com/news/stories/R3ETT1DWRGG7

Dan Tsubouchi @Energy_Tidbits · Oct 30

Oops, #Macron on #EnergyTransition "ironic, because we are building a system where in the medium & long term fossil energy will cost more & more, that's what we want to [to fight climate change]". 2020s will be very good for #Oil #NatGas prices. Great report ...

11 17

Dan Tsubouchi @Energy_Tidbits · Dec 2

Great thought from @CroftHelima "And yet we believe that non-market factors likely played a role in today's decision and perhaps there will be a geopolitical pay off coming for staying the oil course." ie. what did US offer to get KSA & others to keep +400 kpd in Jan? #OOTT

1 5

Dan Tsubouchi @Energy_Tidbits · Dec 2

#OPEC to keep +400,000 b/d for Jan, but "Agree that the meeting shall remain in session pending further developments of the pandemic and continue to monitor the market closely and make immediate adjustments if required". #OOTT opec.org/opec_web/en/pr...

23rd OPEC and non-OPEC Ministerial Meeting

No 36/2021
Vienna, Austria
02 Dec 2021

The 23rd OPEC and non-OPEC Ministerial Meeting (ONOMM), was held via videoconference, on Thursday December 2, 2021. The Meeting remains in session.

The meeting reaffirmed the continued commitment of the Participating Countries in the Declaration of Cooperation (DoC) to ensure a stable and balanced oil market. In view of current oil market fundamentals, the Meeting resolved to:

1. Reaffirm the decision of the 10th ONOMM on April 12, 2020 and further endorsed in subsequent meetings including the 19th ONOMM on July 18, 2021.
2. Reconfirm the production adjustment plan and the monthly production adjustment mechanism approved at the 19th ONOMM and the decision to adjust upward the monthly overall production by 0.4 mb/d for the month of January 2022, as per the attached schedule.
3. Agree that the meeting shall remain in session pending further developments of the pandemic and continue to monitor the market closely and make immediate adjustments if required.
4. Extend the compensation period until the end of June 2022 as requested by some underperforming countries and request that underperforming countries submit their plans by December 17, 2021. Compensation plans should be submitted in accordance with the statement of the 15th ONOMM.
5. Reiterate the critical importance of adhering to full conformity and to the compensation mechanism.
6. Hold the 24th OPEC and non-OPEC Ministerial Meeting on January 4, 2022.

Production table - December 2021
Download document

2 5

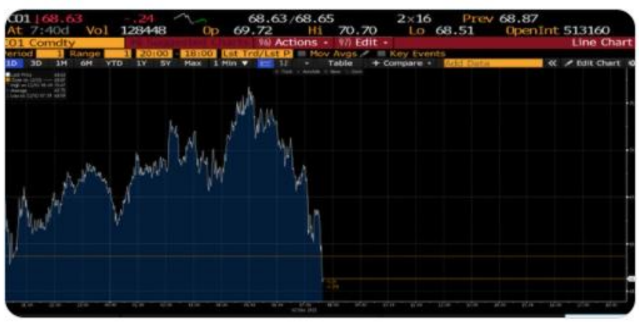
Dan Tsubouchi @Energy_Tidbits · Dec 2

russia moves with formal proposal for #OPEC+ to lift oil output by 400,000 bd for Jan. reports @JavierBlas #OOTT

Dan Tsubouchi @Energy_Tidbits · Dec 2

Brent now down ~$2 from earlier as speculation increases #OPEC+ to stay the course for now with planned +400,000 b/d increase for Jan. Thx @TheTerminal

#OOTT



4

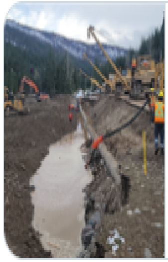
Dan Tsubouchi @Energy_Tidbits · Dec 2

Biden "will announce additional steps to strengthen the safety of international travel as we face this new threat – just as we have faced those that have come before it." seems a return to tougher travel restrictions as more #Omicron cases pop up. #OOTT

whitehouse.gov
Fact Sheet: President Biden Announces New Actions to Protect Ameri...
New Actions Aim to Get Americans Boosted for Even Greater Protection Against the Delta and Omicron Variants, Keep Schools and...

Dan Tsubouchi @Energy_Tidbits · Dec 1

""we are only a few days away from restarting the pipeline at a reduced capacity" says #TransMountain #Oil pipeline. no indication of how many b/d is reduced capacity or ETA for return to full b/d." #OOTT



transmountain.com

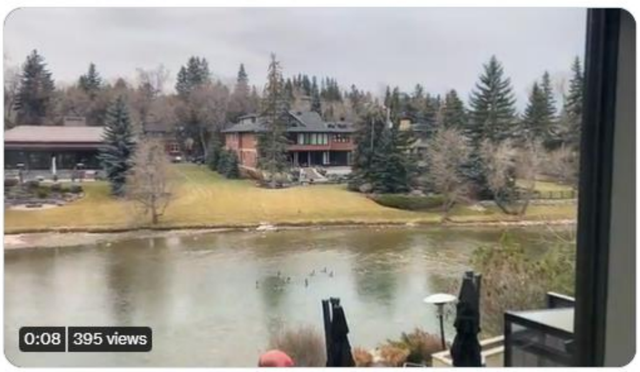
Trans Mountain Continues With Reinforcement of ...

The Trans Mountain Pipeline remains shut down following a precautionary shut down on Sunday, ...

1 3 5

Dan Tsubouchi @Energy_Tidbits · Dec 1

not your normal dec 1 in #Calgary along the Elbow River. looks more like late oct. although supposed to get some snow tonight. skies are turning a little grey.



2 6

Dan Tsubouchi @Energy_Tidbits · Dec 1

for those not near their laptop, just out, @EIAgov weekly #Oil #Gasoline #Distillates inventory as of Nov 26. Prior to release, WTI was $68.38 #OOTT

ir.eia.gov/wpsr/overview....

Inventory Nov 26: EIA, Bloomberg Survey Expectation

s)	EIA	Expectations
	-0.90	-1.45
	4.00	-0.33
	2.20	-0.80
	5.30	-2.58

uded in the above, there was 1.9 mmb draw from SPR for N
d in the data, Cushing had an injection of 1.1 mmb for Nov 2
Bloomberg
SAF Group

2

Dan Tsubouchi @Energy_Tidbits · Dec 1

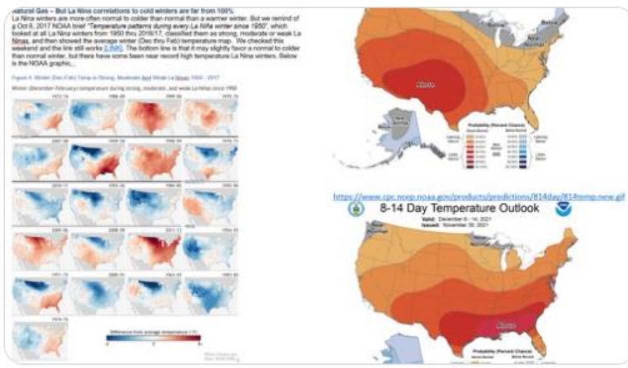
wonder what iran wants in a "good and accurate agreement" as opposed to a return to the #JCPOA? not pointing to a quick deal of some sort unless usa gives in to something. #OOTT.

> **IRNA News Agency** @IrnaEnglish · Dec 1
>
> Iran state-affiliated media
>
> An official close to the Iranian negotiating team told IRNA: The Islamic Republic of #Iran considers reaching a good and accurate agreement more important than reaching an agreement quickly. #JCPOA #IranTalks

1 1

Dan Tsubouchi @Energy_Tidbits · Dec 1

No one can miss the #NatGas HH price crash this week with @NOAA forecasts for a warm Dec. Also reminds that not all #LaNina winters are cold. #OOTT



3 5

Dan Tsubouchi @Energy_Tidbits · Nov 30

#Caixin China PMI just out. Nov 49.9 vs est 50.5 vs Oct 50.6, Sept 50.0 & Aug 49.2. "index plunged into contractionary territory for the 2nd time since April 2020" says Caixin sr Economist. Thx @IHSMarkitPMI #OOTT markiteconomics.com/Public/Home/Pr...

3 2

Dan Tsubouchi @Energy_Tidbits · Nov 30

Looks like Michigan feels the sports analogy "home court advantage" is the place to fight the fight to shut down $ENB #Line5. #OOTT

> Michigan Attorney General Dana Nessel @MIAttyGen · Nov 30
>
> .@MIAttyGen @dananessel released the following statement in response to voluntarily dismissing the governor's lawsuit against Enbridge in federal court:
>
> michigan.gov/ag/0,4534,7-35...
>
> "I fully support the Governor in her decision to dismiss the federal court case and instead focus on our ongoing litigation in state court. The state court case is the quickest and most viable path to permanently decommission Line 5. The Governor and I continue to be aligned in our commitment to protect the Great Lakes and this dismissal today will help us advance that goal."
>
> Attorney General Dana Nessel

2 2 1

Dan Tsubouchi @Energy_Tidbits · Nov 30

"we have a very tight market coming up" "demand for oil & gas is not declining with that @IEA outlook. As a matter of fact, it is going up" says @VanBeurdenShell. #Omicron may be hitting #Oil today, but supply/demand fundamental will rule the day for 2020s. thx @lc_hurst. #OOTT

> (Bloomberg) -- The oil and gas market may be tightening amid historically low investment levels, but that won't change Royal Dutch Shell Plc's strategy to shift from fossil fuels.
> Shell is one of many European majors that have pledged to shrink its traditional hydrocarbon business, while increasing investments in clean energy. While some critics have raised concerns that high oil prices might tempt these firms to stick to fossil fuels, Shell's chief executive says its adhering to its energy transition strategy.
> "You could be concerned that we have a very tight market coming up," Ben van Beurden told shareholders on Tuesday. "We have decided not to ride that wave up."
> JPMorgan Sees $150 Oil in 2023 on Lack of OPEC+ Spare Capacity
> That tightness is caused by investment in the oil and gas industry plunging to historically low levels, which aligns with an International Energy Agency report that says no new fields can be tapped if the worlds is to limit the impact of climate change.
> "The problem, however, is that demand for oil and gas is not declining with that IEA outlook. As a matter of fact, it is going up," Van Beurden said.
> Shell will "enjoy" the benefits of a rising market, so it can return more money to shareholders and fund its energy transition strategy, but that doesn't mean it will increase spending on fossil fuels.
> "We are not minded to invest in a big way in a rising market because we believe that by the time we get there and start harvesting it we will then of course be beyond that peak again," Van Beurden said.
>
> To contact the reporter on this story:
> Laura Hurst in London at lhurst3@bloomberg.net
> To contact the editors responsible for this story:
> James Herron at jherron9@bloomberg.net

1 7 20

Dan Tsubouchi @Energy_Tidbits · Nov 30

Challenge for economies to rely upon wind - there are days when wind generation is huge like today but also days where the minimum generation isn't 30% or 50% but basically zero %. need to have storage that can send out for muliple days and not mulitple hours. #NatGas #OOTT

> Javier Blas @JavierBlas · Nov 30
>
> EUROPEAN ENERGY CRISIS: Record wind generation in Germany today (which explain the 'lower' power prices), with the country producing a staggering ~47GW from wind turbines. One factoid: the lowest wind day in Germany YTD was June 25, with less 0.6 GW. The delta is simply massive

1 5

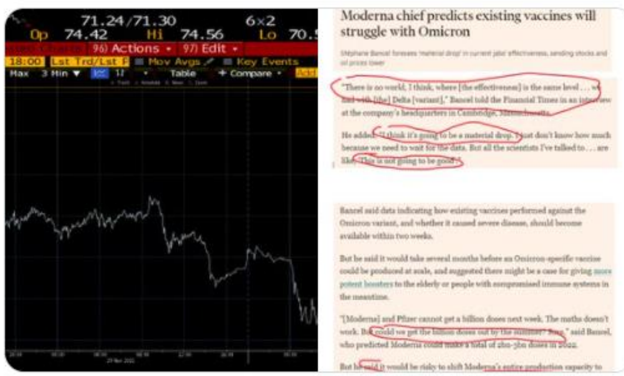
Dan Tsubouchi @Energy_Tidbits · Nov 30

#Omicron oops . guess it was too late to pull this commercial or change the opening line that ran just before @BNNBloomberg The Street started

4

Dan Tsubouchi @Energy_Tidbits · Nov 30

ICYMI, #Moderna @sbancel key quotes from interview with @JamieSmythF that drove #Oil down overnight, erasing Monday's modest price rebound and more. #OOTT



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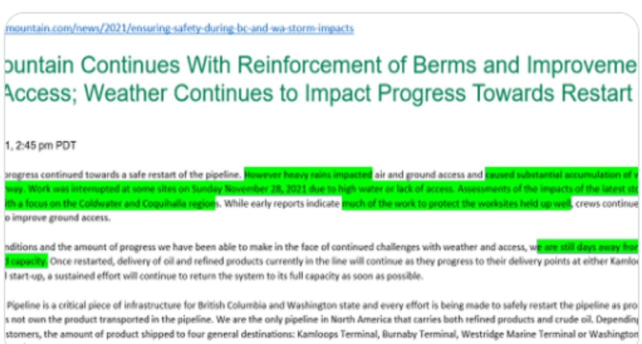
Dan Tsubouchi @Energy_Tidbits · Nov 29

#TransMountain #Oil pipeline update "we are still days away from restarting at a reduced capacity". no surprise, rains pushing back restart from early to mid this week to "still days away". #OOTT



2 3 7

Dan Tsubouchi @Energy_Tidbits · Nov 29

Reminds geopolitical risk to Libya #Oil supply comes after Dec 24 election. if someone from west wins, surely no one expects Haftar to just say okay, it's over, time to hold hands & move in peace together? #OOTT

> **The Libya Observer** @Lyobserver · Nov 29
>
> Militia groups of warlord Khalifa Haftar cordon off Sabha Court and close roads in its vicinity to prevent judges from entering the court for a scheduled hearing on Saif Gaddafi's appeal against his presidential election ban

3 4

Dan Tsubouchi @Energy_Tidbits · Nov 29

#OOTT

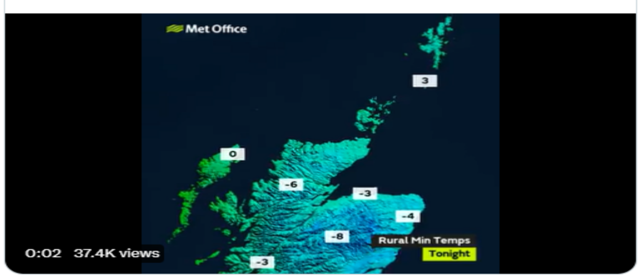
> **Dan Tsubouchi** @Energy_Tidbits · Nov 28
>
> #Oil overreaction on Fri? "i frankly think that a lot of human being traders on leave Thurs/Fri & the algorithmic systems & stop orders did the rest" @michaelwmuller. "the algos took over and monday, the humans will return" @Jorgecomments. Thx @gulf_intel @sean_evers #OOTT

1 2

Dan Tsubouchi @Energy_Tidbits · Nov 29

"autumn". reminds the colder winter temps are still to come. #NatGas #LNG #OOTT

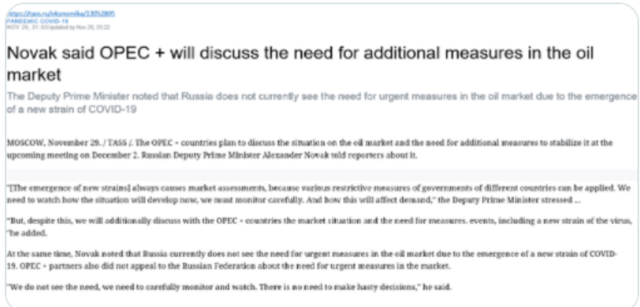
> **Met Office** @metoffice · Nov 28
>
> Tonight is likely to be the coldest night of the autumn so far 📉 🥶
>
> Temperatures widely falling well below freezing, with a severe #frost in places and #ice an additional hazard, especially where there is a covering of #uksnow ❄️
>
> Stay #WeatherAware ⚠️



2 1 4

Dan Tsubouchi @Energy_Tidbits · Nov 29

#Omicron emergence "always causes market assessments, because various restrictive measures of governments of different countries can be applied. We need to watch how the situation will develop now, we must monitor carefully. And how this will affect demand" says RUS Novak. #OOTT



https://tass.ru/ekonomika/13052805
PANDEMIC COVID-19

Novak said OPEC + will discuss the need for additional measures in the oil market

The Deputy Prime Minister noted that Russia does not currently see the need for urgent measures in the oil market due to the emergence of a new strain of COVID-19

MOSCOW, November 29. / TASS /. The OPEC + countries plan to discuss the situation on the oil market and the need for additional measures to stabilize it at the upcoming meeting on December 2. Russian Deputy Prime Minister Alexander Novak told reporters about it.

"[The emergence of new strains] always causes market assessments, because various restrictive measures of governments of different countries can be applied. We need to watch how the situation will develop now, we must monitor carefully. And how this will affect demand," the Deputy Prime Minister stressed ...

"But, despite this, we will additionally discuss with the OPEC + countries the market situation and the need for measures. events, including a new strain of the virus, "he added.

At the same time, Novak noted that Russia currently does not see the need for urgent measures in the oil market due to the emergence of a new strain of COVID-19. OPEC + partners also did not appeal to the Russian Federation about the need for urgent measures in the market.

"We do not see the need, we need to carefully monitor and watch. There is no need to make hasty decisions," he said.

1 1

Dan Tsubouchi @Energy_Tidbits · Nov 28

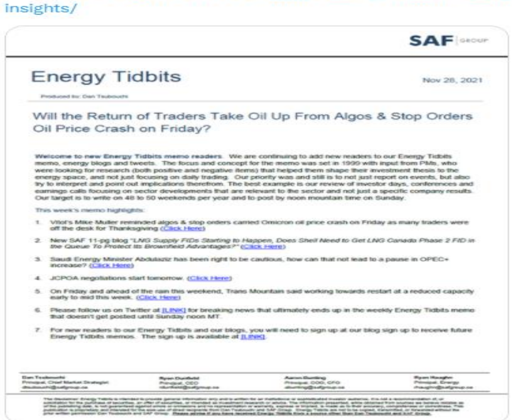
#NatGas HH gas price theme for Monday. #OOTT

> **Breaking Weather by AccuWeather** @breakingweather · Nov 28
>
> Residents from southern Alberta to parts of Oklahoma, Texas and Missouri will see a stretch of well above-average temperatures, and could even see some daily high-temperature records challenged, early this week: bit.ly/3p75rPp

4

Dan Tsubouchi @Energy_Tidbits · Nov 28

Our weekly SAF Nov 28, 2021 Energy Tidbits memo is posted on our SAF Group website. This 43-pg energy research memo expands upon & covers more items than tweeted this week. See news/insights section of SAF website #Oil #OOTT #LNG #NatGas #EnergyTransition safgroup.ca/news-insights/



SAF GROUP

Energy Tidbits

Nov 28, 2021

Produced by: Dan Tsubouchi

Will the Return of Traders Take Oil Up From Algos & Stop Orders Oil Price Crash on Friday?

Welcome to new Energy Tidbits memo readers. We are continuing to add new readers to our Energy Tidbits memo, energy blogs and tweets. The focus and concept for the memo was set in 1999 with input from PMs, who were looking for research (both positive and negative items) that helped them shape their investment thesis to the energy space, and not just focusing on daily trading. Our priority was and still is to not just report on events, but also try to interpret and point out implications therefrom. The best example is our review of investor days, conferences and earnings calls focusing on sector developments that are relevant to the sector and not just a specific company results. Our target is to write on 48 to 50 weekends per year and to post by noon mountain time on Sunday.

This week's memo highlights:

1. Vitol's Mike Muller reminded algos & stop orders carried Omicron oil price crash on Friday as many traders were off the desk for Thanksgiving (Click Here)
2. New SAF 11-pg blog *"LNG Supply FIDs Starting to Happen, Does Shell Need to Get LNG Canada Phase 2 FID in the Queue To Protect its Brownfield Advantages?"* (Click Here)
3. Saudi Energy Minister Abdulaziz has been right to be cautious, how can that not lead to a pause in OPEC+ increase? (Click Here)
4. JCPOA negotiations start tomorrow. (Click Here)
5. On Friday and ahead of the rain this weekend, Trans Mountain said working towards restart at a reduced capacity early to mid this week. (Click Here)
6. Please follow us on Twitter at [LINK] for breaking news that ultimately ends up in the weekly Energy Tidbits memo that doesn't get posted until Sunday noon MT.
7. For new readers to our Energy Tidbits and our blogs, you will need to sign up at our blog sign up to receive future Energy Tidbits memos. The sign up is available at [LINK].

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