Energy Tidbits

August 1, 2021

Produced by: Dan Tsubouchi

Supplemental Documents

Dan Tsubouchi
Principal, Chief Market Strategist
dtsubouchi@safgroup.ca

Ryan Dunfield
Principal, CEO
rdunfield@safgroup.ca

Aaron Bunting
Principal, COO, CFO
abunting@safgroup.ca

Ryan Haughn
Principal, Energy
rhaughn@safgroup.ca

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	3,385	2,981	208	2,773	5	-74	730	-25	3,409
February	3,067	2,709	189	2,520	5	-97	586	-4	3,010
March	3,396	3,019	211	2,809	5	-121	257	-43	2,907
April	3,329	2,934	205	2,729	5	-132	-401	4	2,205
May	3,432	3,055	213	2,842	5	-161	-494	-67	2,126
June	3,317	2,969	207	2,761	5	-159	-452	-36	2,119
July	3,412	3,084	215	2,869	5	-163	-270	-31	2,410
August	3,467	3,159	220	2,939	5	-165	-303	-35	2,441
September	3,399	3,054	213	2,841	5	-186	-440	-2	2,217
October	3,571	3,200	223	2,977	5	-215	-364	-75	2,328
November	3,496	3,120	218	2,902	5	-218	159	-70	2,779
December	3,621	3,232	226	3,007	5	-225	433	-73	3,148
Total	**40,892**	**36,515**	**2,548**	**33,968**	**62**	**-1,915**	**-558**	**-458**	**31,099**
2020									
January	E3,590	E3,182	234	E2,948	6	-248	571	20	3,296
February	E3,342	E2,959	212	E2,747	6	-216	R536	-40	3,033
March	E3,561	E3,166	235	E2,931	6	-284	49	6	2,708
April	E3,372	E3,002	214	E2,788	6	-231	-306	-12	2,245
May	E3,298	E2,934	212	E2,722	5	-209	-448	1	2,071
June	E3,225	E2,876	226	E2,651	5	-151	-358	-11	2,135
July	E3,383	E3,023	241	E2,783	6	-139	-161	4	2,493
August	E3,388	E3,037	240	E2,797	4	-148	-227	-21	2,404
September	E3,273	E2,914	230	E2,684	4	-221	-323	30	2,174
October	E3,379	E2,996	238	E2,757	5	-282	-92	-64	2,323
November	E3,370	E2,990	231	E2,760	5	-316	-4	-4	2,440
December	E3,508	E3,094	225	E2,869	6	-287	587	-17	3,158
Total	**E40,690**	**E36,173**	**2,737**	**E33,436**	**64**	**-2,732**	**-178**	**-107**	**30,482**
2021									
January	E3,506	E3,100	232	E2,868	5	-279	707	-15	3,286
February	E2,924	E2,577	170	E2,407	6	R-152	781	R-8	3,034
March	RE3,482	RE3,081	229	RE2,852	5	R-357	59	R48	R2,607
April	RE3,390	RE3,008	R238	RE2,770	5	R-353	-174	R-5	2,244
May	E3,500	E3,109	245	E2,864	3	-370	-416	18	2,100
2021 5-Month YTD	**E16,801**	**E14,875**	**1,115**	**E13,760**	**25**	**-1,510**	**957**	**39**	**13,271**
2020 5-Month YTD	**E17,164**	**E15,242**	**1,106**	**E14,136**	**28**	**-1,188**	**401**	**-24**	**13,354**
2019 5-Month YTD	**16,609**	**14,698**	**1,025**	**13,672**	**25**	**-584**	**679**	**-135**	**13,658**

[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 2019 include underground storage and liquefied natural gas storage. Data for January 2020 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): 35 for 2019; -11 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 2018 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: 2016-2019: U.S. Energy Information Administration (EIA), *Natural Gas Annual 2019*. January 2020 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 5-Month YTD	2020 5-Month YTD	2019 5-Month YTD	2021 May	April	March	February
Exports							
Volume (million cubic feet)							
Pipeline							
Canada	399,554	402,638	413,526	70,561	R74,567	91,301	78,198
Mexico	862,315	762,283	728,773	189,018	179,505	183,051	137,381
Total Pipeline Exports	**1,261,869**	**1,164,921**	**1,142,299**	**259,579**	**R254,072**	**274,352**	**215,579**
LNG							
Exports							
By Vessel							
Argentina	22,949	8,372	13,107	16,226	4,485	2,238	0
Bahamas	187	90	64	45	46	39	29
Bangladesh	23,880	7,046	0	6,948	10,219	3,566	0
Barbados	98	122	83	19	30	14	19
Belgium	5,584	25,028	3,390	2,100	0	3,484	0
Brazil	87,568	25,762	12,623	19,726	11,615	21,977	13,118
Chile	65,519	45,200	28,555	17,598	10,293	21,320	6,524
China	155,400	53,374	6,851	37,731	46,837	28,476	3,415
Colombia	892	1,528	5,869	0	892	0	0
Croatia	14,397	0	0	3,364	3,666	7,367	0
Dominican Republic	26,349	7,264	2,942	5,283	2,905	5,577	5,689
Egypt	0	0	0	0	0	0	0
France	100,162	76,456	51,870	11,926	36,120	R33,678	R14,851
Greece	14,201	26,832	6,891	6,796	0	6,805	0
Haiti	47	46	2	12	3	10	11
India	93,534	47,763	42,149	28,259	13,752	17,381	13,776
Israel	6,051	3,197	0	0	3,225	2,826	0
Italy	20,558	42,406	27,200	2,923	6,896	10,739	0
Jamaica	13,826	9,554	5,211	2,925	2,370	2,458	2,365
Japan	164,090	107,602	56,338	25,058	28,756	27,673	18,271
Jordan	0	3,294	14,649	0	0	0	0
Kuwait	7,526	3,297	3,502	0	3,705	3,821	0
Lithuania	16,206	6,418	0	3,049	3,078	3,228	6,851
Malaysia	0	0	0	0	0	0	0
Malta	2,928	2,648	413	0	2,928	0	0
Mexico	13,354	16,968	58,678	0	0	0	13,354
Netherlands	93,600	51,683	37,585	26,611	17,060	24,204	22,777
Pakistan	10,426	10,224	6,647	0	3,323	3,421	0
Panama	6,136	7,384	6,461	2,341	0	3,279	0
Poland	21,569	23,324	16,877	3,581	7,382	3,507	7,099
Portugal	21,483	16,964	17,498	10,765	7,358	0	3,360
Singapore	17,378	10,610	17,597	3,089	7,297	3,303	0
South Korea	173,950	128,970	83,813	46,033	21,683	32,203	18,094
Spain	53,219	120,611	48,520	5,234	22,974	13,900	3,733
Taiwan	40,521	30,082	9,658	10,157	6,594	13,450	0
Thailand	10,841	25,664	3,401	3,453	7,388	0	0
Turkey	53,947	84,120	19,281	3,017	0	3,619	20,652
United Arab Emirates	0	3,474	6,787	0	0	0	0
United Kingdom	97,682	79,514	17,753	10,586	13,877	17,440	34,343
By Truck							
Canada	33	2	1	18	15	0	0
Mexico	261	373	386	48	48	19	63
Total LNG Exports	**1,456,352**	**1,113,264**	**632,652**	**314,922**	**306,818**	**R321,023**	**R208,394**
CNG							
Canada	0	179	110	0	0	0	0
Total CNG Exports	**0**	**179**	**110**	**0**	**0**	**0**	**0**
Total Exports	**2,718,221**	**2,278,364**	**1,775,061**	**574,501**	**R560,890**	**R595,375**	**R423,972**

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					
	January	Total	December	November	October	September	August
Exports							
Volume (million cubic feet)							
Pipeline							
Canada	84,927	902,449	84,307	81,358	72,833	62,211	60,810
Mexico	173,360	1,990,809	164,577	166,135	185,799	182,068	185,867
Total Pipeline Exports	**258,287**	**2,893,258**	**248,884**	**247,493**	**258,632**	**244,279**	**246,677**
LNG							
Exports							
By Vessel							
Argentina	0	17,232	0	0	0	0	4,413
Bahamas	28	257	36	31	25	20	21
Bangladesh	3,148	10,660	0	0	0	0	0
Barbados	17	241	25	15	17	14	14
Belgium	0	31,946	0	3,633	3,285	0	0
Brazil	21,132	111,908	29,927	30,191	22,508	0	3,520
Chile	9,784	80,615	9,793	3,252	6,836	3,277	7,428
China	38,940	214,401	45,525	45,083	35,115	11,245	13,699
Colombia	0	4,626	0	0	0	2,548	550
Croatia	0	3,275	3,275	0	0	0	0
Dominican Republic	6,895	26,050	5,000	5,106	5,909	0	2,772
Egypt	0	0	0	0	0	0	0
France	3,587	90,237	3,752	3,390	6,639	0	0
Greece	600	48,403	3,382	3,543	0	7,027	0
Haiti	12	118	17	11	9	8	11
India	20,367	124,402	10,241	10,299	17,762	10,514	10,319
Israel	0	15,834	0	0	0	3,041	3,001
Italy	0	68,453	0	3,083	0	0	6,734
Jamaica	3,708	17,052	2,374	0	2,514	2,610	0
Japan	64,331	288,058	54,004	32,967	31,636	6,855	22,541
Jordan	0	6,872	0	0	0	3,578	0
Kuwait	0	17,293	0	0	3,603	3,508	6,886
Lithuania	0	28,879	6,291	3,621	6,191	3,308	0
Malaysia	0	0	0	0	0	0	0
Malta	0	2,648	0	0	0	0	0
Mexico	0	34,408	0	3,056	7,398	3,285	3,701
Netherlands	2,949	85,573	3,316	6,684	3,603	6,671	0
Pakistan	3,682	36,934	0	3,436	10,009	9,853	3,412
Panama	516	12,764	271	1,448	433	3,228	0
Poland	0	36,900	7,033	0	3,157	0	0
Portugal	0	36,922	3,711	5,830	3,564	6,853	0
Singapore	3,688	28,341	0	7,658	3,416	0	2,967
South Korea	55,936	316,613	39,617	49,103	14,321	32,126	13,814
Spain	7,377	199,966	13,583	9,907	14,118	15,206	3,222
Taiwan	10,319	64,363	12,470	6,216	3,636	9,007	0
Thailand	0	32,622	0	3,705	0	0	0
Turkey	26,659	123,957	20,188	12,817	0	3,611	0
United Arab Emirates	0	10,110	0	0	0	0	3,359
United Kingdom	21,436	160,199	30,378	26,544	17,191	3,664	0
By Truck							
Canada	0	10	8	0	0	0	0
Mexico	83	822	46	52	68	73	78
Total LNG Exports	**305,196**	**2,389,963**	**304,263**	**280,682**	**222,963**	**151,128**	**112,462**
CNG							
Canada	0	386	29	35	26	17	20
Total CNG Exports	**0**	**386**	**29**	**35**	**26**	**17**	**20**
Total Exports	**563,483**	**5,283,607**	**553,176**	**528,210**	**481,621**	**395,424**	**359,159**

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						
	July	June	May	April	March	February	January
Exports							
Volume (million cubic feet)							
Pipeline							
Canada	71,778	66,516	67,752	71,722	86,579	77,354	99,231
Mexico	181,152	162,927	145,242	138,544	166,550	151,071	160,875
Total Pipeline Exports	**252,930**	**229,442**	**212,994**	**210,266**	**253,130**	**228,425**	**260,106**
LNG							
Exports							
By Vessel							
Argentina	2,218	2,229	8,372	0	0	0	0
Bahamas	15	18	20	23	20	13	15
Bangladesh	3,614	0	3,406	0	0	0	3,640
Barbados	15	20	20	15	28	26	33
Belgium	0	0	1,348	3,324	3,724	9,872	6,761
Brazil	0	0	0	0	6,891	10,433	8,438
Chile	1,515	3,313	11,068	14,098	3,216	10,731	6,087
China	10,358	0	14,535	21,140	17,699	0	0
Colombia	0	0	0	0	0	1,003	525
Croatia	0	0	0	0	0	0	0
Dominican Republic	0	0	2,554	1,838	2,872	0	0
Egypt	0	0	0	0	0	0	0
France	0	0	9,546	16,336	23,491	20,520	6,563
Greece	6,544	1,076	3,430	3,233	8,892	0	11,276
Haiti	8	7	10	8	9	11	7
India	7,404	10,100	10,534	16,674	17,245	0	3,309
Israel	3,317	3,277	0	0	3,197	0	0
Italy	3,232	12,998	6,452	3,135	9,895	16,616	6,308
Jamaica	0	0	0	5,770	1	2,914	869
Japan	10,618	21,836	13,729	18,387	21,845	21,360	32,280
Jordan	0	0	3,294	0	0	0	0
Kuwait	0	0	0	3,297	0	0	0
Lithuania	0	3,049	3,473	2,945	0	0	0
Malaysia	0	0	0	0	0	0	0
Malta	0	0	0	0	0	48	2,600
Mexico	0	0	0	0	7,037	3,167	6,764
Netherlands	6,746	6,870	6,826	10,305	13,772	14,099	6,681
Pakistan	0	0	0	3,334	0	3,567	3,323
Panama	0	0	3,070	0	906	3,408	0
Poland	0	3,385	6,258	3,523	3,583	6,677	3,282
Portugal	0	0	0	10,777	0	6,187	0
Singapore	3,690	0	0	0	10,610	0	0
South Korea	10,492	28,171	20,921	24,258	28,095	11,071	44,625
Spain	13,679	9,640	29,360	22,943	23,657	20,240	24,412
Taiwan	0	2,953	6,662	0	6,987	7,115	9,317
Thailand	3,254	0	7,397	11,049	3,783	3,435	0
Turkey	3,222	0	6,661	14,030	6,489	24,303	32,637
United Arab Emirates	3,277	0	3,474	0	0	0	0
United Kingdom	2,908	0	0	0	20,202	28,884	30,428
By Truck							
Canada	0	0	0	0	0	0	2
Mexico	72	61	18	23	123	87	122
Total LNG Exports	**96,200**	**109,002**	**182,438**	**210,466**	**244,269**	**225,786**	**250,305**
CNG							
Canada	37	43	39	35	38	34	33
Total CNG Exports	**37**	**43**	**39**	**35**	**38**	**34**	**33**
Total Exports	**349,167**	**338,486**	**395,472**	**420,767**	**497,437**	**454,245**	**510,444**

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

	2019						
	Total	December	November	October	September	August	July
Exports							
Volume (million cubic feet)							
Pipeline							
Canada	971,334	109,175	92,089	76,246	71,573	78,302	68,613
Mexico	1,865,329	151,308	158,633	171,535	162,649	168,089	167,902
Total Pipeline Exports	**2,836,662**	**260,483**	**250,722**	**247,781**	**234,222**	**246,391**	**236,515**
LNG							
Exports							
By Vessel							
Argentina	39,293	0	0	0	0	0	13,066
Bahamas	156	11	14	8	2	20	11
Bangladesh	3,419	3,419	0	0	0	0	0
Barbados	211	20	20	25	17	17	17
Belgium	23,897	10,407	3,293	3,402	3,404	0	0
Brazil	54,298	0	3,279	3,345	6,117	12,868	6,949
Chile	90,357	7,207	3,484	6,608	9,811	6,297	9,382
China	6,851	0	0	0	0	0	0
Colombia	6,518	0	0	0	0	649	0
Croatia	0	0	0	0	0	0	0
Dominican Republic	10,334	501	0	2,927	2,857	0	0
Egypt	0	0	0	0	0	0	0
France	117,791	14,758	26,946	14,228	6,740	3,249	0
Greece	14,643	7,752	0	0	0	0	0
Haiti	42	12	8	4	9	3	2
India	91,481	7,090	6,933	6,961	14,355	7,294	3,485
Israel	0	0	0	0	0	0	0
Italy	68,655	12,764	6,345	0	3,230	6,082	9,963
Jamaica	13,892	2,435	2,464	0	0	2,946	837
Japan	201,085	21,226	17,603	24,504	28,084	17,506	21,242
Jordan	32,332	0	0	0	3,616	3,277	3,449
Kuwait	10,308	0	0	0	0	3,401	3,405
Lithuania	3,455	3,455	0	0	0	0	0
Malaysia	3,698	0	3,698	0	0	0	0
Malta	413	0	0	0	0	0	0
Mexico	143,371	9,696	3,273	6,437	10,442	13,681	24,209
Netherlands	81,361	13,405	10,099	3,456	3,431	6,688	3,386
Pakistan	26,787	3,253	3,247	3,472	6,512	0	3,656
Panama	10,221	0	478	0	0	0	0
Poland	38,042	7,013	3,432	3,489	0	3,537	3,694
Portugal	53,342	6,345	0	6,621	2,924	6,051	6,994
Singapore	31,440	3,375	0	3,463	0	0	3,570
South Korea	270,025	38,139	24,962	42,233	10,818	16,995	32,663
Spain	166,684	13,874	19,985	13,704	37,938	15,861	3,297
Taiwan	27,397	3,658	3,736	3,138	0	7,207	0
Thailand	6,635	0	0	0	3,234	0	0
Turkey	30,611	536	7,266	3,528	0	0	0
United Arab Emirates	20,561	0	0	0	3,325	3,502	3,487
United Kingdom	118,662	30,054	39,957	26,260	3,303	1,335	0
By Truck							
Canada	25	0	1	14	9	0	0
Mexico	1,105	93	86	139	95	113	101
Total LNG Exports	**1,819,399**	**220,498**	**190,610**	**177,966**	**160,274**	**138,578**	**156,865**
CNG							
Canada	263	25	30	28	15	15	20
Total CNG Exports	**263**	**25**	**30**	**28**	**15**	**15**	**20**
Total Exports	**4,656,324**	**481,006**	**441,362**	**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						
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
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	14,231	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
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
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. 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	47,446	16,800	166,325	16,063	259,035	3,773	137,823	67,939	213,497
February	26,728	42,215	15,513	149,040	14,237	242,105	3,094	128,379	59,030	192,836
March	29,346	46,206	16,922	163,990	15,820	267,517	3,505	144,822	68,666	213,497
April	28,816	44,463	16,548	161,094	15,613	260,790	3,551	142,363	67,998	208,200
May	29,028	44,901	16,754	166,254	14,898	270,459	3,814	154,100	70,250	215,140
June	26,889	42,696	16,254	162,749	15,558	265,731	3,756	142,240	65,418	208,200
July	25,348	43,847	16,890	166,425	15,695	278,216	3,782	148,454	70,026	235,693
August	22,876	43,500	16,969	167,799	15,638	276,770	3,732	157,091	75,259	235,693
September	24,494	41,793	16,262	159,310	15,038	266,661	3,667	156,608	72,447	228,090
October	27,409	43,088	16,228	174,373	15,157	279,489	3,607	156,870	78,045	236,995
November	28,256	41,725	15,659	172,363	14,436	270,787	3,474	153,617	77,478	229,350
December	29,669	42,825	16,024	178,991	14,944	286,082	3,507	164,968	79,195	236,995
Total	**329,361**	**524,705**	**196,823**	**1,988,714**	**183,097**	**3,223,642**	**43,263**	**1,787,334**	**851,750**	**2,654,186**
2020										
January	30,018	E42,586	E15,661	E177,810	E13,349	E279,056	E3,580	E164,472	E74,489	E210,045
February	28,537	E39,455	E14,414	E165,333	E13,487	E251,755	E3,303	E158,434	E72,155	E179,594
March	29,219	E41,233	E15,135	E177,377	E14,598	E266,118	E3,587	E169,340	E78,018	E199,544
April	27,513	E40,141	E14,685	E171,025	E13,802	E262,712	E3,113	E159,064	E66,217	E193,938
May	27,076	E41,498	E14,944	E166,654	E13,796	E273,665	E2,616	E150,531	E48,821	E207,596
June	25,545	E39,113	E14,620	E161,714	E13,173	E263,819	E2,689	E152,401	E47,485	E198,554
July	26,779	E40,172	E14,826	E168,601	E13,465	E265,507	E3,144	E163,516	E57,433	E209,347
August	26,846	E41,148	E13,115	E168,528	E13,292	E257,893	E3,164	E168,443	E65,306	E207,182
September	26,978	E39,501	E12,635	E162,274	E12,745	E254,678	E3,035	E165,194	E67,978	E198,167
October	29,080	E41,014	E12,391	E165,226	E12,623	E263,309	E3,189	E179,908	E71,638	E200,302
November	29,575	E39,388	E12,034	E159,417	E10,865	E266,951	E3,059	E173,956	E69,830	E196,183
December	31,161	E40,183	E12,247	E161,889	E12,770	E276,772	E3,107	E172,786	E69,697	E207,905
Total	**338,329**	**E485,432**	**E166,709**	**E2,005,848**	**E157,963**	**E3,182,236**	**E37,587**	**E1,978,044**	**E789,065**	**E2,408,358**
2021										
January	31,632	E39,964	E12,033	E159,724	E12,578	E271,669	E3,168	E176,770	E69,019	E206,660
February	28,365	E30,061	E10,749	E143,329	E9,965	E220,985	E2,750	E149,598	E58,860	E170,668
March	31,481	RE39,947	RE12,028	RE156,440	RE12,340	RE281,322	E3,099	RE184,351	RE69,028	RE189,405
April	29,514	RE37,907	RE11,687	RE156,011	RE12,309	RE273,331	RE3,044	RE181,749	RE68,071	RE183,483
May	29,005	E38,718	E12,173	E162,351	E12,627	E283,940	E3,172	E192,681	E72,057	E184,875
2021 5-Month YTD	**149,997**	**E186,598**	**E58,669**	**E777,856**	**E59,819**	**E1,331,246**	**E15,233**	**E885,148**	**E337,035**	**E935,091**
2020 5-Month YTD	**142,364**	**E204,913**	**E74,839**	**E858,199**	**E69,031**	**E1,333,307**	**E16,200**	**E801,841**	**E339,700**	**E990,718**
2019 5-Month YTD	**144,421**	**225,231**	**82,537**	**806,703**	**76,631**	**1,299,906**	**17,738**	**707,487**	**333,883**	**1,043,170**

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	262,662	576,440	736,511	23,200	169,050	123,341	39,938	90,159	2,980,505
February	240,995	519,802	675,802	21,049	154,910	110,816	35,450	76,741	2,708,742
March	265,283	578,820	756,354	23,387	171,516	122,319	39,386	92,033	3,019,390
April	262,767	560,062	725,217	22,794	167,816	120,098	38,325	87,201	2,933,716
May	269,586	571,803	778,371	23,623	171,305	128,510	38,958	87,724	3,055,477
June	259,034	556,708	764,324	22,904	174,784	121,743	37,916	81,638	2,968,544
July	268,965	583,186	803,273	23,091	180,524	115,230	38,313	66,820	3,083,779
August	268,025	585,405	836,414	23,374	181,927	119,242	38,473	91,215	3,159,401
September	265,447	568,646	785,566	22,150	181,343	124,724	37,254	84,108	3,053,609
October	278,887	589,800	823,698	22,494	201,950	127,708	37,486	86,698	3,199,983
November	263,368	597,779	790,664	21,704	196,185	122,272	36,837	83,634	3,119,588
December	269,990	608,342	825,421	22,099	204,446	124,473	37,106	87,378	3,232,454
Total	**3,175,008**	**6,896,792**	**9,301,616**	**271,870**	**2,155,757**	**1,460,477**	**455,443**	**1,015,349**	**36,515,188**
2020									
January	E263,734	E607,697	E827,368	E21,856	E205,973	E122,406	E36,673	E84,739	E3,181,514
February	E243,139	E579,980	E771,344	E20,472	E197,173	E107,668	E34,050	E78,343	E2,958,634
March	E257,387	E616,101	E832,144	E21,805	E207,724	E116,328	E35,794	E84,669	E3,166,123
April	E235,642	E599,921	E772,841	E20,462	E202,046	E111,375	E29,768	E77,588	E3,001,855
May	E217,154	E598,263	E733,502	E19,555	E213,671	E106,760	E34,244	E63,304	E2,933,650
June	E222,324	E569,002	E733,102	E19,317	E215,274	E104,033	E33,369	E60,713	E2,876,248
July	E226,843	E614,943	E766,509	E20,241	E222,115	E108,027	E34,642	E67,343	E3,023,452
August	E226,344	E630,016	E788,459	E19,713	E224,409	E106,139	E33,367	E43,410	E3,036,773
September	E222,010	E582,197	E746,302	E19,027	E218,495	E103,457	E32,048	E47,449	E2,914,169
October	E219,403	E616,334	E760,569	E19,777	E225,807	E103,648	E34,202	E37,087	E2,995,509
November	E224,327	E619,815	E747,332	E18,991	E224,659	E103,334	E32,797	E57,936	E2,990,450
December	E228,057	E655,636	E763,930	E19,165	E237,246	E103,915	E33,648	E64,048	E3,094,164
Total	**E2,786,366**	**E7,289,906**	**E9,243,402**	**E240,382**	**E2,594,591**	**E1,297,092**	**E404,602**	**E766,630**	**E36,172,542**
2021									
January	E221,544	E657,704	E775,706	E19,235	E234,432	E105,897	E33,444	E68,505	E3,099,685
February	E163,094	E585,221	E588,953	E17,815	E208,571	E95,863	E29,898	E62,427	E2,577,173
March	RE220,130	RE647,681	RE772,550	RE20,356	E227,218	RE106,480	RE34,127	RE72,986	RE3,080,967
April	RE213,812	RE618,508	RE768,350	RE19,861	E225,103	RE103,167	RE32,839	RE68,900	RE3,007,646
May	E222,249	E640,548	E793,088	E20,258	E237,376	E104,642	E33,845	E65,628	E3,109,231
2021 5-Month YTD	**E1,040,830**	**E3,149,661**	**E3,698,647**	**E97,525**	**E1,132,700**	**E516,048**	**E164,154**	**E338,445**	**E14,874,702**
2020 5-Month YTD	**E1,217,056**	**E3,001,963**	**E3,937,200**	**E104,152**	**E1,026,586**	**E564,537**	**E170,529**	**E388,643**	**E15,241,776**
2019 5-Month YTD	**1,301,293**	**2,806,926**	**3,672,255**	**114,053**	**834,597**	**605,084**	**192,057**	**433,858**	**14,697,829**

E Estimated data.

RE Revised estimated data.

Notes: For 2020 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 2020, 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: 2016-2019: U.S. Energy Information Administration (EIA), *Natural Gas Annual 2019*, Bureau of Safety and Environmental Enforcement (BSEE), IHS Markit, Enverus DrillingInfo, and BENTEK Energy. January 2020 through current month: Form EIA-914, *Monthly Crude Oil and Lease Condensate, and Natural Gas Production Report*; and EIA computations.

Summary

Overview of Activity for May 2021

- **Top five countries of destination, representing 51.0% of total U.S. LNG exports in May 2021**
  - South Korea (46.6 Bcf), China (37.7 Bcf), India (28.3 Bcf), Netherlands (26.6 Bcf), and Japan (25.1 Bcf)
- **314.8 Bcf of exports in May 2021**
  - 2.6% increase from April 2021
  - 72.7% more than May 2020
- **103 cargos shipped in May 2021**
  - Sabine Pass (35), Freeport (21), Corpus Christi (19), Cameron (18), Cove Point (7), Elba Island (3)
  - 92 cargos in April 2021
  - 57 cargos in May 2020

1a. Table of Exports of Domestically-Produced LNG Delivered by Region (Cumulative from February 2016 through May 2021)

Region	Number of Countries Receiving Per Region	Volume Exported (Bcf)	Percentage Receipts of Total Volume Exported (%)	Number of Cargos*
East Asia and Pacific	7	2,879.4	37.7%	834
Europe and Central Asia	13	2,421.7	31.7%	747
Latin America and the Caribbean**	11	1,508.6	19.8%	518
Middle East and North Africa	5	289.8	3.8%	85
South Asia	3	533.3	7.0%	158
Sub-Saharan Africa	0	0.0	0.0%	0
Total LNG Exports	**39**	**7,632.7**	**100.0%**	**2,342**

*Split cargos counted as both individual cargos and countries

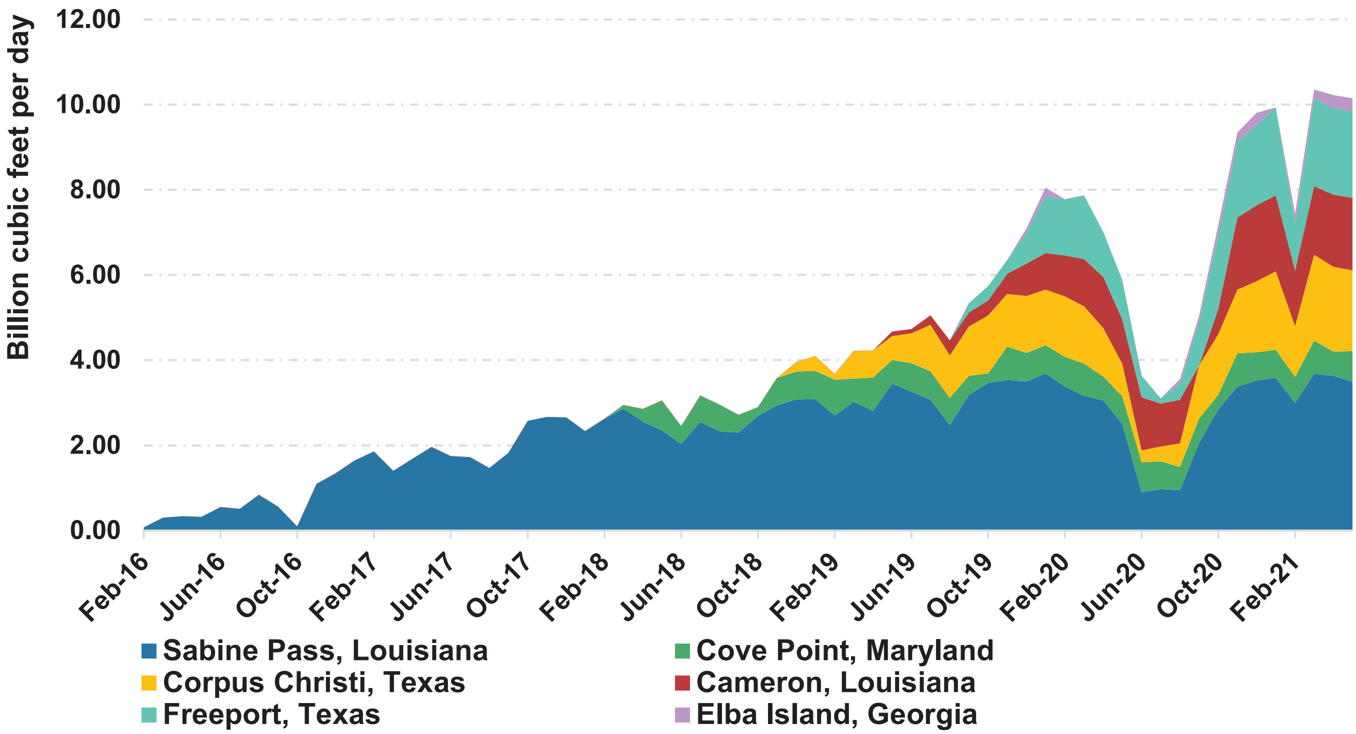
**Number of cargos does not include the shipments by ISO container

1b. Shipments of Domestically-Produced LNG Delivered – by Country
(Cumulative from February 2016 through May 2021)

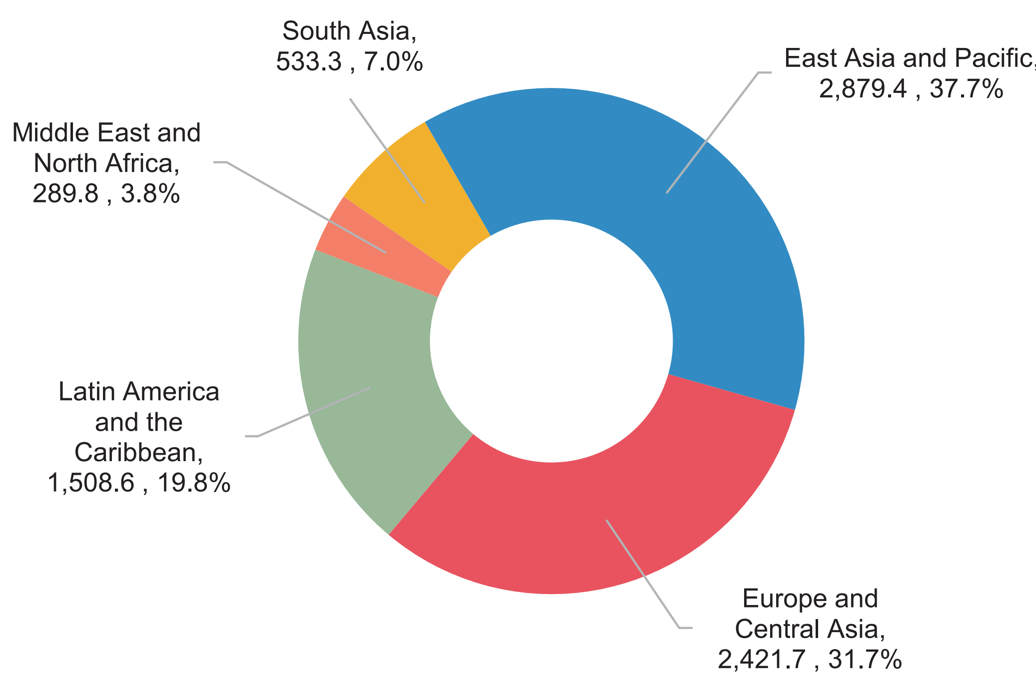
	Country of Destination	Region	Number of Cargos	Volume (Bcf of Natural Gas)	Percentage of Total U.S LNG Exports (%)
1.	South Korea*	East Asia and Pacific	332	1,153.4	15.1%
2.	Japan*	East Asia and Pacific	242	842.5	11.0%
3.	China	East Asia and Pacific	170	587.8	7.7%
4.	Mexico*	Latin America and the Caribbean	160	541.2	7.1%
5.	Spain*	Europe and Central Asia	145	462.4	6.1%
6.	United Kingdom	Europe and Central Asia	129	430.9	5.6%
7.	India*	South Asia	119	404.9	5.3%
8.	Chile*	Latin America and the Caribbean	104	332.2	4.4%
9.	France*	Europe and Central Asia	97	326.5	4.3%
10.	Brazil*	Latin America and the Caribbean	112	316.2	4.1%
11.	Netherlands*	Europe and Central Asia	84	275.8	3.6%
12.	Turkey*	Europe and Central Asia	82	265.3	3.5%
13.	Italy	Europe and Central Asia	57	184.9	2.4%
14.	Taiwan*	East Asia and Pacific	49	158.0	2.1%
15.	Portugal*	Europe and Central Asia	45	147.5	1.9%
16.	Argentina*	Latin America and the Caribbean	56	137.7	1.8%
17.	Jordan*	Middle East and North Africa	36	124.2	1.6%
18.	Poland	Europe and Central Asia	32	103.2	1.4%
19.	Pakistan	South Asia	28	90.4	1.2%
20.	Greece*	Europe and Central Asia	28	81.0	1.1%
21.	Singapore*	East Asia and Pacific	25	80.8	1.1%
22.	Dominican Republic*	Latin America and the Caribbean	36	80.2	1.1%
23.	Kuwait	Middle East and North Africa	21	72.4	0.9%
24.	Belgium	Europe and Central Asia	19	61.4	0.8%
25.	Lithuania	Europe and Central Asia	17	55.4	0.7%
26.	Thailand	East Asia and Pacific	15	53.2	0.7%
27.	United Arab Emirates	Middle East and North Africa	15	51.1	0.7%
28.	Jamaica*	Latin America and the Caribbean	20	46.1	0.6%
29.	Bangladesh	South Asia	11	38.0	0.5%
30.	Panama*	Latin America and the Caribbean	18	35.9	0.5%
31.	Israel	Middle East and North Africa	8	25.2	0.3%
32.	Croatia	Europe and Central Asia	5	17.7	0.2%
33.	Colombia*	Latin America and the Caribbean	12	17.1	0.2%
34.	Egypt	Middle East and North Africa	5	16.9	0.2%
35.	Malta*	Europe and Central Asia	7	9.8	0.1%
36.	Malaysia	East Asia and Pacific	1	3.7	0.0%
	Total Exports by Vessel		**2,342**	**7,630.8**	
37.	Barbados	Latin America and the Caribbean	258	1.0	0.0%
38.	Bahamas	Latin America and the Caribbean	362	0.7	0.0%
39.	Haiti	Latin America and the Caribbean	74	0.2	0.0%
	Jamaica	Latin America and the Caribbean	1	0.0	0.0%
	Total Exports by ISO		**695**	**2.0**	
	Total Exports by Vessel		**3,037**	**7,632.7**	

Note:
Volume and Number of Cargos are the cumulative totals of each individual Country of Destination by Region starting from February 2016.
Jamaica has received U.S. LNG exports by both vessel and ISO container. The volumes are totaled separately
* Split cargos counted as both individual cargos and countries.
Vessel = LNG Exports by Vessel and ISO container = LNG Exports by Vessel in ISO Containers.
Does not include re-exports of previously-imported LNG. See table 2c for re-exports data.
Totals may not equal sum of components because of independent rounding.

1c. Domestically-Produced LNG Exported by Terminal
(February 2016 through May 2021)

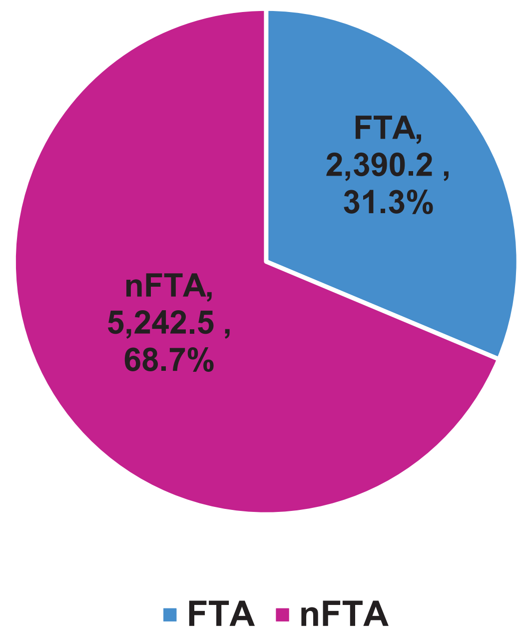


1d. Domestically-Produced LNG Exported by Region
(Cumulative from February 2016 through May 2021)
(Bcf, %)



1e. Volumes and Percentages of FTA and nFTA Shipments of Domestically-Produced LNG Delivered
(Cumulative from February 2016 through May 2021)

	Volume (Bcf)	Percentage of Total Volume	Number of Countries
FTA	2,390.2	31.3%	9
nFTA	5,242.5	68.7%	30
Total LNG Exports	**7,632.7**	**100.0%**	**39**



Spot cargos total 466.8 Bcf - or 6.1 percent - of the 7,632.7 Bcf total volume of shipments.

These totals are cumulative starting from February 2016 through May 2021 - a cumulative listing of cargos and regions in Table 1b and a cumulative list of FTAs and nFTAs in Table 1h.

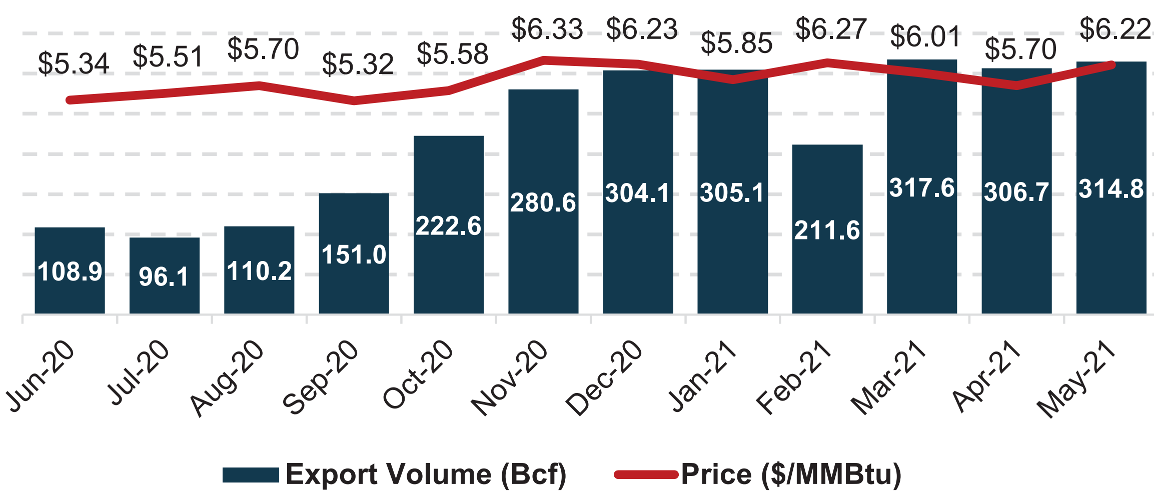
FTA Countries that Require National Treatment for Trade in Natural Gas -As of October 31, 2012, the United States has FTAs that require national treatment for trade in natural gas with Australia, Bahrain, Canada, Chile, Colombia, Dominican Republic, El Salvador, Guatemala, Honduras, Jordan, Mexico, Morocco, Nicaragua, Oman, Panama, Peru, Republic of Korea and Singapore. Panama is the most recent country with which the United States has entered into a FTA that requires national treatment for trade in natural gas, effective October 31, 2012. Not all countries that have a FTA with the United States require national treatment for trade in natural gas (i.e. Costa Rica and Israel). A list of all countries with which the United States has a FTA can be found at: http://www.ustr.gov/trade-agreements/free-trade-agreements.

More information can be found on DOE’s website - https://energy.gov/fe/services/natural-gas-regulation/how-obtain-authorization-import-andor-export-natural-gas-and-lng

Totals may not equal sum of components because of independent rounding.

1f. Domestically-Produced LNG Delivered – Volume (Bcf) and Weighted Average price ($/MMBtu) by Export Terminal per month

	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Total
Sabine Pass, LA	26.9	30.2	29.3	61.7	88.3	101.4	109.4	111.1	83.8	114.1	108.9	108.2	**973.3**
	$4.93	$4.63	$4.89	$5.32	$5.05	$5.96	$5.79	$5.42	$5.66	$5.77	$5.32	$6.01	**$5.54**
Cove Point, MD	21.0	20.2	17.0	17.1	10.6	23.4	20.4	20.4	17.2	24.0	17.1	22.4	**230.9**
	$6.29	$6.09	$6.17	$6.66	$6.25	$6.65	$7.11	$6.82	6.81	$7.09	$6.88	$6.89	**$6.67**
Corpus Christi, TX	8.5	10.6	17.1	37.5	44.1	45.0	51.8	57.2	33.3	62.6	59.9	58.8	**486.3**
	$3.90	$5.33	$3.73	4.43	$5.08	$6.38	$6.18	$6.27	$5.81	$5.60	$5.58	$6.03	**$5.64**
Cameron, LA	37.6	31.3	31.8	-	18.3	50.6	55.1	55.3	36.5	49.9	50.9	52.8	**470.0**
	$5.52	$6.15	$6.88	-	$9.40	$6.87	$6.60	$5.93	$7.86	$6.25	$5.86	$6.60	**$6.54**
Freeport, TX	14.9	3.7	11.3	31.0	53.8	53.7	58.5	61.1	30.5	63.6	60.6	63.2	**506.1**
	$5.07	$4.68	$5.86	$5.58	$5.45	$6.38	$6.44	$5.84	$6.08	$6.28	$6.00	$6.26	**$6.02**
Elba Island, GA	-	-	3.7	3.7	7.4	6.5	8.9	-	10.3	3.3	9.4	9.4	**62.6**
	-	-	$8.40	$6.08	$5.36	$5.98	$6.27	-	$6.78	$5.90	$5.84	$5.74	**$6.17**
Total	**108.9**	**96.1**	**110.2**	**151.0**	**222.6**	**280.6**	**304.1**	**305.1**	**211.6**	**317.6**	**306.7**	**314.8**	**2,729.2**
	$5.34	**$5.51**	**$5.70**	**$5.32**	**$5.58**	**$6.33**	**$6.23**	**$5.85**	**$6.27**	**$6.01**	**$5.70**	**$6.22**	**$5.93**



Notes:

*Beginning with July 2019 data, with the exception of some commissioning cargos as indicated in Table 2(a), all average export cargo prices include liquefaction fees.
From January to June 2019, some cargos at Sabine Pass and Corpus Christi do not include liquefaction fees. For further details, please see Tables 2a(i) and 2a(iii).

Does not include re-exports of previously-imported LNG. See table 2c for re-exports data.

Totals may not equal sum of components because of independent rounding.

https://rbnenergy.com/dark-horse-sweetening-sour-natural-gas-and-sequestering-co2-in-the-permian

Dark Horse - 'Sweetening' Sour Natural Gas And Sequestering CO2 In The Permian

Wednesday, 07/28/2021
Published by: Housley Carr

The gas that emerges from wells in U.S. shale plays differs widely in its characteristics and quality. In the aptly named "dry" Marcellus in northeastern Pennsylvania, the gas is almost all methane, with only minute volumes of NGLs and contaminants, and requires minimal treatment before it's fed into transmission pipelines. At the other end of the spectrum, the associated gas from a subset of crude-oil-focused wells in the Permian has high levels of hydrogen sulfide (a potentially deadly chemical) and carbon dioxide (a potent greenhouse gas), as well as a lot of NGLs. If the H_2S level in the gas is relatively low, it can be removed from the gas stream onsite with a chemical "scavenger," but higher levels of H_2S quickly make that method prohibitively expensive. Another alternative, an onsite amine treatment facility, is more economical for removing higher levels of H_2S — and it removes CO_2 as well — but air permits typically limit how much can be flared off, requiring the costly and time-consuming development of acid-gas injection wells. Yet another, more centralized approach to dealing with H_2S and CO_2 — one that permanently stores large volumes of both deep underground — is being implemented over the next few weeks in southeastern New Mexico, as we discuss in today's blog.

According to our weekly NATGAS Permian report, residue natural gas production (that is, the gas left over after processing) in the extraordinarily fecund Permian Basin has been in record territory lately, regularly topping 13 Bcf/d. Given that producing crude oil is the primary aim of Permian E&Ps, the associated gas that emerges from wells in the Delaware, Central, and Midland sub-basins is of secondary concern — something to be dealt with and, if all goes well, something to goose profits, but not what gets producers up in the morning. In other words, it's crude oil that makes the real money in the Permian, and the less complicated and less costly the associated gas side of production is to deal with, the better. That's been especially true when local gas prices are low, as we've blogged about many times (see Hold on Loosely for our latest). To some degree, all this has led many Permian producers to steer clear of areas within the 70,000-square-mile play where the associated gas is what you might call "nasty," with high concentrations of hydrogen sulfide and carbon dioxide that need to be removed before the associated gas can be piped to gas processing plants.

We should note upfront that "sour gas" is gas that has significant concentrations of H_2S, and "acid gas" is any gas that has too much H_2S and/or CO_2, both of which can form acidic solutions when mixed with water or water vapor and cause corrosion in pipes and equipment. In the Permian, the H_2S concentration in the gas emerging from wells varies widely, from only a few parts per million (ppm) to more than 100,000 ppm. (Yes, that's 10% by volume!) Our understanding is that over 85% of the gas streams in the Permian are H_2S-rich (more than 100 ppm) and over 40% are extremely rich in H_2S (more than 10,000 ppm). Generally speaking, the H_2S content in gas is higher in shallower geological formations, like the Guadalupian, and lower in deeper ones. The concentration is also higher in the Permian's Central Basin than in the Midland or Delaware basins, though there are localized exceptions.

There's a little fuzziness around what constitutes sour gas. The Texas Railroad Commission's Statewide Rule 36 imposes certain additional requirements on producers dealing with gas with an H_2S content of 100 ppm or more, while the Texas Council on Environmental Quality (TCEQ), which regulates air emissions, designates operations as sour when the gas being dealt with has H_2S concentrations of only 24 ppm. (An aside on how small a concentration 1 ppm represents: There are about one million words in the seven-book Harry Potter series or in three years' worth of RBN blogs. One single word in the entire series or all the RBN blogs posted since July 2018 is the rough equivalent of 1 ppm.) In any case, a significant portion of the associated gas emerging from Permian wells in both West Texas and southeastern New Mexico needs to be treated (often referred to as "gas sweetening") to bring down the concentrations of both H_2S and CO_2 to acceptable levels. What's acceptable? Again, there's some fuzziness and variety, but many midstreamers require that gas flowing through their pipelines has an H_2S content of no more than 4 ppm (or 0.0004%) and CO_2 content of no more than 2 or 3%. (Most Permian gas comes out of the ground with a CO_2 content of only a few percent, though it's not unheard of for some to be 10% or more CO_2.)

Typically, the required reductions in sour/acid-gas content are made onsite. As we said in our introduction, if the H_2S content in the associated gas is relatively low by Permian standards — say, less than 1,000 ppm — a typical treatment would be to inject a scavenger, or specialty chemical, into the gas stream. The scavenger converts the H_2S into a harmless product. Using a scavenger only mitigates H_2S; any CO_2 content above acceptable levels is removed at the gas processing plant, and the typical current process is vent it into the atmosphere — though if you've been reading our blog series called The Air I Breathe, you'd know that there are plans in the works to rethink that practice. The advantage of using a scavenger is low up-front capital costs, but the volume of specialty chemical needed to remove the H_2S rises with the associated gas's H_2S content and can become cost-prohibitive.

Another option is an onsite amine treatment facility in which the H_2S-and-CO_2-rich associated gas stream is run through an amine solution that absorbs the H_2S and CO_2 to produce a "sweetened" gas stream with only minimal volumes of the sour/acid gases remaining. The resulting "rich" amine is then routed through a regenerator to strip out the now-concentrated H_2S and CO_2 and thereby enable the amine to be reused. If the H_2S concentration is low, it can be flared off along with the CO_2 and other contaminants, but if — as is often the case — the H_2S content is high, flaring may well violate the air permit (and could even be dangerous, given the substance's toxicity) and the H_2S is instead compressed and/or heated into a liquid and disposed of in deep injection wells. Once the associated gas has undergone amine treatment, it is piped to a gas processing plant, where NGLs are separated from the natural gas.

That's as deep as we'll go into onsite amine treatment here. Suffice it to say that in areas (and geological formations) where associated gas has high levels of H_2S, removing it can be a complicated and costly process — as much as $2 or even $3/Mcf using an H_2S scavenger, for instance (and you'd still need to pay a processing plant to remove the CO_2). As a result, producers generally tend to avoid areas where these H_2S and CO_2 issues would be the most serious.

Which brings us to Piñon Midstream's new Dark Horse project in the southeastern corner of New Mexico, which has been under construction for the past several months and is set to begin operating in early August. The heart of the project is a large, centralized amine treatment and carbon capture facility (blue pentagon in Figure 1), whose primary aims are to provide producers in the northern Delaware and Central basins with (1) a centralized alternative to onsite gas-sweetening services and (2) an ability to capture and sequester the H_2S and CO_2 that are removed from the associated gas produced from the wells. There's a lot more to it all, though.

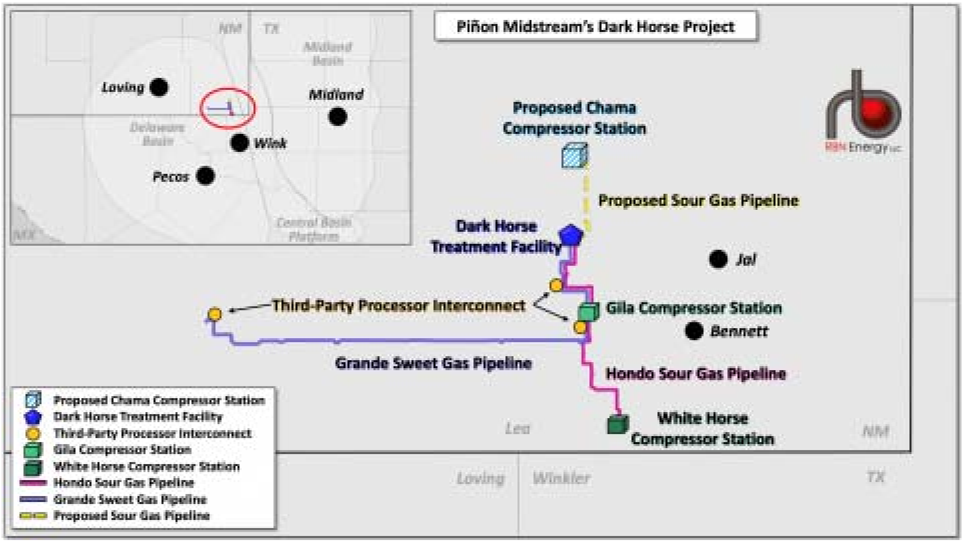


Figure 1. Piñon Midstream's Dark Horse Project. Sources: Piñon Midstream, RBN

In fact, there are a few key elements to the project, beginning with the Hondo Pipeline (hot pink line), an existing 16-inch-diameter, high-pressure gas-gathering pipe that delivers untreated associated gas to the centralized amine treatment facility from crude-oil-focused wells in southern Lea County, NM. The pipeline was designed and fabricated to meet the toughest sour gas specifications (special metallurgy and welding, etc.) so it can handle the most acidic gas. A second, 16-inch, high-pressure line (dashed yellow line) and the Chama compressor station (blue-and-white-striped box) are planned to enable the transport of untreated gas from areas north of the treatment plant. Both the second line and the compressor station are scheduled to enter service in the first quarter of 2022.

Then there's the treatment facility itself, which initially will consist of a single amine "train" capable of removing H_2S and CO_2 from up to 85 MMcf/d of associated gas. Ameredev II LLC, an independent E&P active in the northern Delaware Basin, has made a long-term commitment to send its gas through the Dark Horse facility and serves as the project's anchor producer. A second 85-MMcf/d amine train is expected to begin operating in the fourth quarter of 2021, and Piñon Midstream has said its initial plan calls for a total of four trains of gas-sweetening capacity there. (There is room for further expansion if warranted.) The company has also indicated that while there are limits to the H_2S concentrations that small, onsite amine treatment facilities can handle, there are no such limits at Piñon's centralized facility because it, like the associated gas lines feeding the plant, was designed and built to handle very acidic gas.

The H_2S and CO_2 removed by the Dark Horse amine trains will be compressed into a supercritical/dense-phase state (with some characteristics of a liquid and others of a gas — see our blog on that topic) and injected into an 18,000-feet-deep, Class 2 acid-gas injection/sequestration well that has been drilled near the amine treatment facility. The well, which reaches into the Devonian formation, has the capacity to permanently store up to 175,000 tons of CO_2 and 75,000 tons of H_2S annually. A second well of the same depth will be drilled in 2022, doubling the facility's sequestration capacity and providing redundancy. As we discussed in our blog series on ESG, an increasing number of producers have been working to reduce their emissions of greenhouse gases (including CO_2). Permanently storing CO_2 that is captured via amine treatment rather than releasing it into the atmosphere via flaring would help producers achieve that goal.

Dark Horse Amine Treatment and Carbon Capture Facility. Source: Piñon Midstream

A final element of the Dark Horse project is the 20-inch-diameter Grande Pipeline (purple line in Figure 1) to transport sweet associated gas west across southern Lea County from the centralized amine trains to connections with a number of existing gas processing plants (orange dots). Our understanding is that Piñon Midstream determined that while the northern Delaware and Central basins have ample gas processing capacity — see our … Ready for It? blog series for more on that — producers with extensive acreage there have been wary of developing areas where the massive volumes of associated gas have unusually high levels of H_2S and CO_2 that must be dealt with well by well. The midstreamer's thinking is that by providing a large, centralized amine treatment facility; deep wells for sequestering CO2; and pipeline connections to the gas processing plant of the producer's choice, Dark Horse will help to encourage more drilling and completion activity in and near Lea County.

We'll know before too long whether Piñon Midstream's novel approach will work on a larger scale. From what we've heard, Ameredev II produces enough associated gas to use all of the Dark Horse amine train's capacity and part of the capacity of the second train that will come online later this year. The test for Piñon will be whether it can line up long-term commitments from other producers interested in making the switch from onsite to centralized gas sweetening.

"Dark Horse" was written by Katy Perry, Jordan Houston, Lukasz Gottwald, Sarah Hudson, Max Martin, and Henry Walker. It appears as the sixth cut on Katy Perry's fourth studio album, *Prism*. Released as the third official single from the album in December 2013, "Dark Horse" (featuring Juicy J) went to #1 on the Billboard Hot 100 and Dance Club Songs Singles charts. It was recorded in

2013 at Playback Recording Studios in Santa Barbara, CA; MXM Studios in Stockholm, Sweden; Luke's in the Boo in Malibu, CA; and Secret Garden Studios in Montecito, CA. It was produced by Dr. Luke, Max Martin, and Cirkut. The video for the song, directed by Mathew Cullen, won Best Female Video at the 2014 MTV Video Music Awards. The song has been certified 11x Platinum by the Recording Industry Association of America (RIAA) and was the second bestselling song worldwide in 2014. Personnel on the record were: Katy Perry (lead, backing vocals), Juicy J (featured rapper, backing vocals), Dr. Luke (programming), Max Martin (programming), and Cirkut (programming).

Prism was a prominently dance-oriented record for Katy Perry. Produced by Katy Perry, Klas Ahlund, Benny Blanco, Bloodshy, Cirkut, Dr. Luke, Greg Kurstin, Max Martin, Stargate, and Greg Wells, the album was released in October 2013. It debuted at #1 on the Billboard Top 200 Albums chart, and it has been certified 2x Platinum by the RIAA. The album was nominated for a Grammy for Best Pop Vocal Album at the 57th annual Grammy Awards. Five singles were released from the LP.

Katy Perry (Kathryn Elizabeth Hudson) is an American singer, songwriter, record producer, and television talent judge. She has released six studio albums, one live album, one compilation album, six EPs, and 34 singles. She has won five American Music Awards, 11 ASCAP Awards, two Billboard Music Awards, 10 BMI Awards, one Brit Award, and four MTV Video Music Awards. She continues to record and perform, starting a residency at The Theater at the Resorts World Casino in Las Vegas in December 2021.

https://ir.tellurianinc.com/press-releases/detail/244/tellurian-and-shell-sign-agreements-for-3-mtpa

Tellurian and Shell Sign Agreements for 3 mtpa

JULY 29, 2021

LNG sales from Driftwood's first two plants complete

HOUSTON--(BUSINESS WIRE)-- Tellurian Inc. (Tellurian) (NASDAQ: TELL) announced today it has finalized liquefied natural gas (LNG) sale and purchase agreements (SPAs) with Shell NA LNG. The SPAs are on a free on board (FOB) basis at Driftwood LNG for a combination of three million tonnes per annum (mtpa) for a ten-year period, indexed to a combination of two indices: the Japan Korea Marker (JKM) and the Dutch Title Transfer Facility (TTF), each netted back for transportation charges.

The agreements mark the third deal that Tellurian has finalized in ten weeks, totaling nine mtpa and nearly all of the capacity of Driftwood LNG's first two plants.

President and CEO Octávio Simões said, "Tellurian welcomes Shell to the Driftwood project. Shell manages one of the largest and most diverse portfolios of LNG in the world, and is leading the industry in delivering CO_2e neutral LNG cargoes. Owing to Driftwood's integrated project, our ability to accurately measure well to loading arm emissions and reduce emissions where operationally possible, further enables Shell's CO_2e neutral LNG offering."

Steve Hill, EVP Shell Energy stated, "LNG demand is expected to nearly double by 2040. This deal secures additional competitive volumes for our portfolio by the mid-2020s, enabling us to continue providing diverse and flexible LNG supply to our customers. We look forward to working with Tellurian."

Simões added, "With these SPAs, we have now completed the sales to support the launching of the first two plants. Tellurian will now focus on financing Driftwood, in order to give Bechtel notice to proceed with construction in early 2022."

About Tellurian Inc.

Tellurian intends to create value for shareholders by building a low-cost, global natural gas business, profitably delivering natural gas to customers worldwide. Tellurian is developing a portfolio of natural gas production, LNG marketing and trading, and infrastructure that includes an ~ 27.6 mtpa LNG export facility and an associated pipeline. Tellurian is based in Houston, Texas, and its common stock is listed on the Nasdaq Capital Market under the symbol "TELL". For more information, please visit www.tellurianinc.com. Follow us on Twitter at twitter.com/TellurianLNG

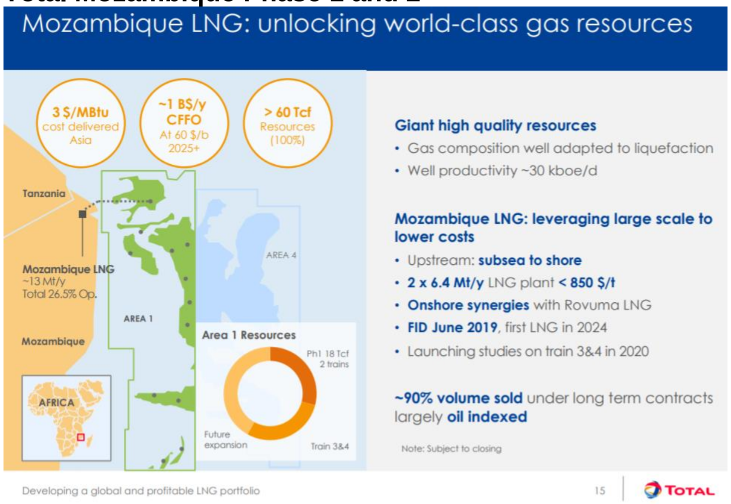
Multiple Brownfield LNG FIDs Now Needed To Fill New LNG Supply Gap From Mozambique Chaos? How About LNG Canada Phase 2?

Posted Wednesday April 28, 2021. 9:00 MT

The next six months will determine the size and length of the new LNG supply gap that is hitting harder and faster than anyone expected six months ago. Optimists will say the Mozambique government will bring sustainable security and safety to the northern Cabo Delgado province and provide the confidence to Total to quickly get back to LNG development such that its LNG in-service delay is a matter of months and not years. We hope so for Mozambique's domestic situation, but will it be that easy for Total's board to quickly look thru what just happened? Total suspended LNG development for 3 months, restarted development on March 25, but then 3 days of violence led it to suspend development again on March 28, and announce force majeure on Monday April 26. Even if the optimists are right, Mozambique LNG is counted on for LNG supply and the major LNG supply project that are in LNG supply forecasts are now all delayed – Total Phase 1 of 1.7 bcf/d and its follow on Phase 2 of 1.3 bcf/d, and Exxon's Rozuma Phase 1 of 2.0 bcf/d. It is important to remember this 5.0 bcf/d of major LNG supply is being counted in LNG supply forecasts and starting in 2024. At a minimum, we think the more likely scenario is a delay of at least 2 years in this 5.0 bcf/d from the pre-Covid timelines. And this creates a much bigger and sooner LNG supply gap starting ~2025 and stronger outlook for LNG prices. Thermal coal in Asia will play a role in keeping a lid on LNG prices. But there will be the opportunity for LNG suppliers to at least review the potential for brownfield LNG projects to fill the growing supply gap. The thought of increasing capex was a non-starter six months ago, but there is a much stronger outlook for global oil and gas prices. Oil and gas companies are pivoting from cutting capex to small increases in 2021 capex and expecting for higher capex in 2022. We believe this sets the stage for looking at potential FID of brownfield LNG projects before the end of 2021 to be included in 2022 capex budgets. Mozambique is causing an LNG supply gap that someone will try to fill. And if brownfield LNG is needed, what about Shell looking at 1.8 bcf/d brownfield LNG Canada Phase 2? Cdn natural gas producers hope so as this would mean more Cdn natural gas will be tied to Asian LNG markets and not competing in the US against Henry Hub.

Total declares force majeure on Mozambique LNG, Yesterday, Total announced [LINK] "*Considering the evolution of the security situation in the north of the Cabo Delgado province in Mozambique, Total confirms the withdrawal of all Mozambique LNG project personnel from the Afungi site. This situation leads Total, as operator of Mozambique LNG project, to declare force majeure. Total expresses its solidarity with the government and people of Mozambique and wishes that the actions carried out by the government of Mozambique and its regional and international partners will enable the restoration of security and stability in Cabo Delgado province in a sustained manner".* Total is working Phase 1 is ~1.7 bcf/d (Train 1 + 2, 6.45 mtpa/train) and was originally expected to being LNG deliveries in 2024. There was no specific timeline for Phase 2 of 1.3 bcf/d (Train 3 + 4, 5.0 mtpa/train), but was expected to follow Phase 1 in short order to keep capital costs under control with a continuous construction process with a potential onstream shortly after 2026.

Total Mozambique Phase 1 and 2



Source: Total Investor Day September 24, 2019

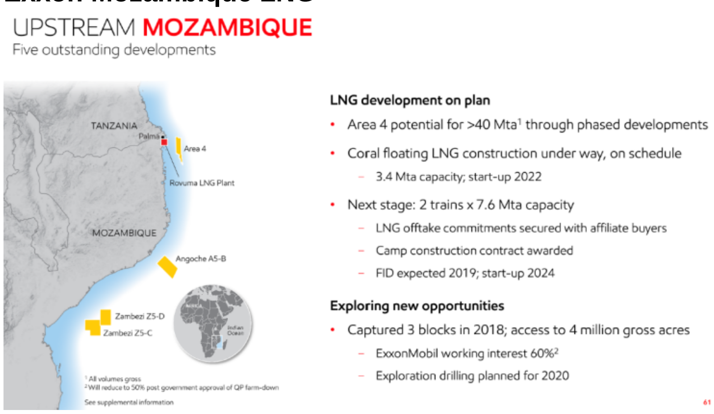
<u>Total's Mozambique force majeure is no surprise, especially the need to the restoration of security and stability "in a sustained manner"</u>. Yesterday, Total announced [LINK] "*Considering the evolution of the security".* No one should be surprised by the force majeure or the sustained manner caveat. SAF Group posts a weekly Energy Tidbits research memo [LINK], wherein we have, in multiple weekly memos, that Total had shut down development in December for 3 months due to the violent 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. Local violence/attacks shut development down in Dec, the situation gets settled enough for Total to restart in March, only to be shut down 3 days thereafter. No one should be surprised especially with Total's need to see security and stability "in a sustained manner".

<u>Does anyone really think Total will risk another quick 2-3 month restart or even in 2021?</u> The Mozambique government will be working hard to convince Total to restart soon. We just find it hard to believe Total board will risk a replay of March 24-27 in 2021. Unfortunately, Mozambique has had internal conflict for years. It reached a milestone to the positive in August 2019. Our SAF Group August 11, 2019 Energy Tidbits memo [LINK] highlighted the signing of a peace pact between Mozambique President Nyusi and leader of the Renamo opposition Momade. This was the official end to a 2013 thru 2016 conflict following a failure to hold up the prior peace pact. At that time, FT reported [LINK] "Mr Nyusi has said that "*the government and Renamo will come together and hunt" rebels who fail to disarm. The government has struggled to stem the separate insurgency in the north, which has killed or displaced hundreds near the gas-rich areas during the past two years. While the roots of the conflict remain murky, it is linked to a local Islamist group and appears to be drawing on disaffection over sharing gas investment benefits, say analysts*." This is just a reminder this is not a new issue. LNG is a game changer to Mozambique's economic future. It is, but also has been, a government priority to have the security and safety for Total and Exxon to move on their LNG developments. Its hard to believe the Mozambique government will be able to quickly convince Total and Exxon boards that they can be comfortable there is a sustained security/safety situation and they can send their people back in to develop the LNG. Total's board would allow any resumption of development before year end 2021. The last thing Total wants is a replay of March 24-27. The first question is how long will it take before the Total board is convinced its safe to restart. Could you imagine them doing a replay of what just happened? Wait three months, restart development and have to stop again right away? We have to believe that could lead the Total board to believe it is unfixable for years. We just don't think they are to prepared to risk that decision in 3 months. Its why we have to think there isn't a restart approval until at least in 2022 at the earliest ie. why we think the likely scenario is a delay of 2-3 years, and not a matter of months.

<u>Mozambique's security issues pushes back 5.0 bcf/d of new LNG supply at least a couple years.</u> The global LNG issue is that 5 bcf/d of new Mozambique LNG supply (apart from the Eni Coral FLNG of 0.45 bcf/d) won't start up in 2024 and

continuing thru the 2020s. And we believe all LNG forecasts included this 5.0 bcf/d to be in service in the 2020s as Mozambique had been considered the best positioned LNG supply to access Asia after Australia and Papua New Guinea. (i) Eni Coral Sul (Rovuma Basin) FLNG of 0.45 bcf/d planned in service in 2022. [LINK] This is an offshore floating LNG vessel that is still expected to be in service in 2022. (ii) Total Phase 1 to add 1.7 bcf/d with an in service originally planned for 2024. We expect the in service data to be pushed back to at least 2026 assuming Total gives a development restart approval in Dec 2021. In theory, this would only be a 1 year loss of time. However, Total has let services go, the project will be idle for 9 months, it isn't clear if the need to get people out quickly let them do a complete put the project on hold, and how many people will be on site maintaining the status of the development during the force majeure. Also what new procedures and safety will be put in place for a restart. These all mean there will be added time needed to get the project back to where it was when force majeure was declared ie. why we think a 12 month time delay will be more like an 18 month project delay. (iii) Exxon's Rozuma Phase 1 LNG will add 2.0 bcf/d and, pre-Covid, was expected to be in service in 2025. We believe the delays related to security and safety at Total are also going to impact Exxon. We find it highly unlikely the Exxon board would take a different security and safety decision than Total. 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 in 2024. 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 the expectation was that FID would now be in 2022 (3 years later than original timeline0 and that would push first LNG likely to 2027. (iv) 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 2 years, so will Phase 2 so more likely 2028/2029.. (v) Total Phase 1 + 2 and Exxon Rozuma Phase 1 total 5.0 bcf/d and would have been (and still are) in all LNG supply forecasts for the 2020s. (vi) We aren't certain if the LNG supply forecasts include Exxon Rozuma Phase 2 ,which would be an additional 2.0 bcf/d on top of the 5.0 bcf/d noted above. Exxon Rozuma has always been expected to be at least 2 Phases. This has been the plan since the Anadarko days given the 85 tcf size of the resource on Exxon's Area 4. There was no firm in service data for Phase 2, but it was expected they would also closely follow Phase 1 to maintain services. We expect that original timeline would have been 2026/2027 and that would not be pushed back to 2029/2030. (vii) It doesn't matter if its only 5 bcf/ of Mozambique that is delayed 2 to 3 years, it will cause a bigger LNG supply gap and sooner. The issue for LNG markets is this is taking projects that are in development effectively out of the queue for some period.

Exxon Mozambique LNG



Source: Exxon Investor Day March 6, 2019

Won't LNG and natural gas get hit by Biden's push for carbon free electricity? Yes, in the US. For the last 9 months, we have warned on Biden's climate change plan that were his election platform and now form his administration's energy transition map. We posted our July 28, 2020 blog "*Biden To Put US On "Irreversible Path to Achieve Net-Zero Emissions, Economy-Wide" Is a Major Negative To US Natural Gas in 2020s* "[LINK] on Biden's platform "*The Biden Plan to Build a Modern, Sustainable Infrastructure and an Equitable Clean Energy Future*" [LINK]. Biden's new American Jobs Plan

[LINK] lines up with his campaign platform including to put the US "*on the path to achieving 100 percent carbon-free electricity by 2035*.". Our July 28, 2020 blog noted that it would require replacing ~60% of US electricity generation with more renewable and it could eliminate ~40% (33.5 bcf/d) of 2019 US natural gas consumption. If Biden is 25% successful by 2030, it would replace ~6.3 bcf/d of natural gas demand. It would be a negative to US natural gas and force more US natural gas to export markets. The wildcard when does US natural gas start to decline if producers are faced with the reality of natural gas being phased out for electricity. The other hope is that when Biden says "carbon-free", its not what ends up in the details of any formal policy statement ie. carbon electricity will be allowed with Biden's push for CCS.

Will Cdn natural gas be similarly hit by if Trudeau move to "emissions free" and not "net zero emissions" electricity? Yes and No. Our SAF Group April 25, 2021 Energy Tidbits memo [LINK] was titled ""*Bad News For Natural Gas, Trudeau's Electricity Goal is Now 100% "Emissions Free" And Not "Net Zero Emissions*". On Thursday, PM Trudeau spoke at Biden's global climate summit [LINK] and looks like he slipped in a new view on electricity than was in last Monday's budget and his Dec climate plan. Trudeau said "*In Canada, we've worked hard to get to over 80% emissions-free electricity, and we're not going to stop until we get to 100%."* Speeches, especially ones made on a global stage are checked carefully so this had to be deliberate. Trudeau said "*emissions free*" and not net zero emissions electricity. It seems like this language is carefully written to exclude any fossil fuels as they are not emissions free even if they are linked to CCS. Recall in Liberals big Dec 2020 climate announcement [LINK], Liberals said ""*Work with provinces, utilities and other partners to ensure that Canada's electricity generation achieves net-zero emissions before 2050*." There is no way Trudeau changed the language unless he meant to do so. And this is a major change as it would seem to indicate his plan to eliminate all fossil fuels used for electricity. If so this would be a negative to Cdn natural gas that would be stuck within Western Canada and/or continuing to push into the US when Biden is trying to switch to carbon free electricity. We recognize that there is still some ambiguity in what will be the details of policy and the Liberals aren't changing to no carbon sourced electricity at all. Let's hope so. But let's also be careful that politicians don't change language without a reason or at least with a view to setting up for some future hit. Plus Trudeau had a big warning in that same speech saying "*we will make it law to respect our new 2030 target and achieve net-zero emissions by 2050*". They plan to make it the law that Canada has to be on track for the Liberals 2030 emissions targets. This means that the future messaging will be that the Liberals have no choice but to take harder future emissions actions as it is the law. They will be just obeying the law as they will be obligated to obey the law. Everyone knows the messaging will be we have to do more get to Net Zero, that in itself will inevitably mean it will be the law if he actually does move to eliminate any carbon based electricity. So yes it's a negative, that is unless more Cdn natural gas can be exported via LNG to Asia. We believe this would be a plus to be priced against global LNG instead of Henry Hub.

Biden's global climate summit reminded there is too much risk to skip over natural gas as the transition fuel. Apart from the US and Canada, we haven't seen a sea shift to eliminating natural gas for power generation, especially from energy import dependent countries. There is a strong belief that hydrogen and battery storage will one day be able to scale up at a competitive cost to lead to the acceleration away from fossil fuels. But that time isn't yet here, at least not for energy import dependent countries. One of the key themes from last week's leader's speeches at the Biden global climate summit – to get to Net Zero, the world is assuming there wilt be technological advances/discoveries that aren't here today and that have the potential to immediately ramp up in scale. IEA Executive Director Faith Birol was blunt in his message [LINK] saying "*Right now, the data does not match the rhetoric – and the gap is getting wider*." And "*IEA analysis shows that about half the reductions to get to net zero emissions in 2050 will need to come from technologies that are not yet ready for market. This calls for massive leaps in innovation. Innovation across batteries, hydrogen, synthetic fuels, carbon capture and many other technologies.* US Special Envoy for Climate John Kerry said a similar point that half of the emissions reductions will have to come from technologies that we don't yet have at scale. UK PM Johnson [LINK] didn't say it specifically, but points to this same issue saying "*To do these things we've got to be constantly original and optimistic about new technology and new solutions whether that's crops that are super-resistant to drought or more accurate weather forecasts like those we hope to see from the UK's new Met Office 1.2bn supercomputer that we're investing in*." It may well be that the US and other self sufficient energy countries are comfortable going on the basis of assuming technology developments will occur on a timely basis. But, its clear that countries like China, India, South Korea and others are not prepared to do so. And not prepared to have the confidence to rid themselves of coal power generation. This is why there hasn't been any material change in the LNG demand outlook

We expect the IEA's blunt message that the gap is getting wider will be reinforced on May 18. We have had a consistent view on the energy transition for the past few years. We believe it is going to happen, but it will take longer, be a bumpy road and cost more than expected. This is why we believe the demise of oil and natural gas won't be as easy and fast as hoped for by the climate change side. The IEA's blunt warning on the gap widening should not be a surprise as they warned on this in June 2020. Birol's climate speech also highlighted that the IEA will release on May 18 its roadmap for how the global energy sector can reach net zero by 2050. Our SAF Group June 11, 2020 blog "*Will The Demise Of Oil Take Longer, Just Like Coal? IEA and Shell Highlight Delays/Gaps To A Smooth Clean Energy Transition*" [LINK] feature the IEA's June 2020 warning that the critical energy technologies needed to reduce emissions are nowhere near where they need to be. In that blog, we said "there was an excellent illustration of the many significant areas, or major pieces of the puzzle, involved in an energy transition by the IEA last week. The IEA also noted the progress of each of the major pieces and the overall conclusion is that the vast majority of the pieces are behind or well behind where they should be to meet a smooth timely energy transition. It is important to note that these are just what the IEA calls the "*critical energy technologies*" and does not get into the wide range of other considerations needed to support the energy transition. The IEA divides these "critical energy technologies "into major groupings and then ranked the progress of each of these pieces in its report "*Tracking Clean Energy Progress*" [LINK] by on track, more efforts needed, or not on track". Our blog included the below IEA June 2020 chart.

IEA's Progress Ranking For "Critical Energy Technologies" For Clean Energy Transition

Power	Renewable Power	Geothermal
	Solar PV	Ocean Power
	Onshore Wind	Nuclear Power
	Offshore Wind	Natural Gas-Fired Power
	Hydropower	Coal-Fired Power
	Bioenergy Power Generation	CCUS in Power
	Concentrating Solar Power	
Fuel Supply	Methane Emissions from O&G	Flaring Emissions
Industry	Chemicals	Pulp and Paper
	Iron and Steel	Aluminum
	Cement	CCUS in Industry and Transformation
Transport	Electric Vehicles	Transport Biofuels
	Rail	Aviation
	Fuel Consumption of Cars and Vans	International Shipping
	Trucks and Busses	
Buildings	Building Envelopes	Lighting
	Heating	Appliances and Equipment
	Heat Pumps	Data Centres and Data Transmission Networks
	Cooling	
Energy Integration	Energy Storage	Demand Response
	Hydrogen	Direct Air Capture
	Smart Grids	

Source: IEA

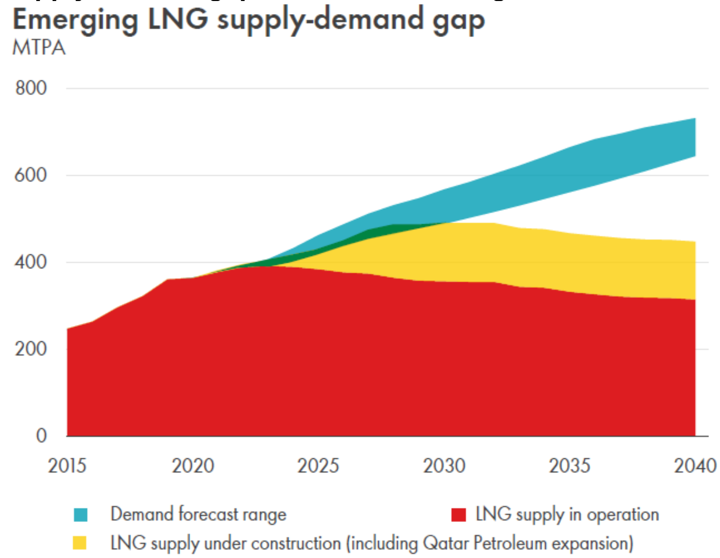
On Track | More Efforts Needed | Not on Track

Source: IEA Tracking Clean Energy Progress, June 2020

We are referencing Shell's long term outlook for LNG. We recognize there are many different forecasts for LNG, but are referencing Shell' LNG Outlook 2021 from Feb 25, 2021 for a few reasons. (i) Shell's view on LNG is the key view for when and what decision will be made for LNG Canada Phase 2. (ii) Shell is one of the global leaders in LNG supply and trading. (iii) Shell provides on the record LNG outlooks every year so there is the ability to compare and make sure the outlook fits the story. It does. (iv) Shell, like other supermajors, has had to make big capex cuts post pandemic and that certainly wouldn't put any bias to the need for more capex.

Shell's March 2021 long term outlook for LNG demand was basically unchanged vs 2020 and leads to a LNG supply gap in mid 2020s. Shell does not provide the detailed numbers in their Feb 25, 2021 LNG forecast. We would assume they would have reflected some delay, perhaps 1 year, at Mozambique but would be surprised if they put a 2-3 year delay in for the 5 bcf/d from Total Phase 1 +2 and Exxon Rozuma Phase 1. Compared to their LNG Outlook 2020, it looks like there was no change for their estimate of global natural gas demand growth to 2040, which looked relatively unchanged at approx. 5,000 bcm/yr or 484 bcf/d. Similarly, long term LNG demand looked unchanged to 2040 of ~700 mm tonnes (92 bcf/d) vs 360 mm tonnes (47 bcf/d) in 2020. In the 2021 outlook, Shell highlighted that the pandemic delayed project construction timelines and that the "*lasting impact expected on LNG supply not demand"*. And that Shell sees a LNG "*supply-demand gap estimated to emerge in the middle of the current decade as demand rebounds*". Comparing to 2020, it looks like the supply-demand gap is sooner.

Supply-demand gap estimated to emerge in the middle of the current decade



Source: Shell LNG Outlook 2021, Feb 25, 2021

Mozambique delays are redefining the LNG markets for the 2020s: Delaying 5 bcf/d of Mozambique new LNG supply 2-3 years means a much bigger supply gap starting in 2025.. Even if the optimists are right, there are now delays to all major Mozambique LNG supply from LNG supply forecasts. We don't have the detail, but we believe all LNG forecasts, including Shell's LNG Outlook 2021, would have included Total's Phase 1 and Phase 2 and Exxon Rozuma Phase 1. As noted earlier, we believe that the likely impact of the Mozambique security concerns is that these forecasts would likely have to push back 1.7 bcf/d from Total Phase 1 to at least 2026, 2.0 bcf/d Exxon Rozuma Phase 1 to at least 2027, and 1.3 bcf/d Total Phase 2 to at least 2028/2029 with the real risk these get pushed back even further. 5.0 bcf/d is equal to 38 mtpa. These delays would mean there is an increasing LNG supply gap in 2025 and increasingly significantly thereafter. And even if a new greenfield LNG project is FID's right away, it wouldn't be able to step in to replace Total Phase 1 prior startup timing for 2024 or likely the market at all until at least 2027. Its why the decision on filling the gap will fall on brownfield LNG projects.

And does this bigger, nearer supply gap force LNG players to look at what brownfield LNG projects they could advance? A greenfield LNG project would likely take at least until 2027 to be in operations. Its why we believe the Mozambique delays will effectively force major LNG players to look to see if there are brownfield LNG projects they should look to advance. Prior to the just passed winter, no one would think Shell or other major LNG players would be considering any new LNG FIDs in 2021. All the big companies are in capital reduction mode and debt reduction mode. But Brent oil is now solidly over $60 and LNG prices hit record levels in Jan 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. We would not expect any major LNG players to move to FID right away. But we see them watching to see if 2021 plays out to still support this increasing LNG supply gap. 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 5 months. The question facing Shell and others, 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 than expected a few months ago. We expect these decisions to be looked at before the end of 2021. LNG prices will be stronger, but we expect the limiting cap in Asia will be that thermal coal will be used to mitigate some LNG price pressure.

<u>Back to Shell, does increasing LNG supply gap provide the opportunity to at least consider a LNG Canada Phase 2 FID over the next 9 months?</u> 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 6 months ago. No one has been or is talking about this Mozambique impact and how it will at least force major LNG players to look at if they should FID new brownfield LNG projects to take advantage of this increasing supply gap. 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. No one is talking about the need for these new brownfield LNG projects, but, unless Total gets back developing Mozambique and keeps the delay to a matter of months, 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

<u>A LNG Canada Phase 2 would be a big plus to Cdn natural gas.</u> A LNG Canada Phase 2 FID would be a big plus for Cdn natural gas. It would allow another ~1.8 bcf/d of Cdn natural gas to be priced against Asian LNG prices and not against 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 may be in Africa, but, unless sustained peace and security is attained, it is 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 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 to 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.

https://pgnig.pl/aktualnosci/-/news-list/id/pgnig-planuje-kupic-wiecej-gazu-od-venture-global-l-1/newsGroupId/10184

27/07/2021 PGNiG plans to buy more gas from Venture Global LNG

Polskie Górnictwo Naftowe i Gazownictwo has concluded agreements with Venture Global Plaquemines and Venture Global Calcasieu Pass regarding the terms of purchasing additional 2 million tons of liquefied natural gas annually for 20 years. As a result, the total volume of LNG that PGNiG will receive from Venture Global LNG may increase to 5.5 million tonnes annually.

- *Liquefied gas plays a key role in the implementation of PGNiG's strategic aspirations. It is an essential element in the diversification of our import portfolio and serves to strengthen the energy security of our customers. At the same time, we want to use LNG to intensively develop our commercial activities on the global natural gas market. Extending our cooperation with Venture Global LNG is in line with the achievement of both of these goals* - **said Paweł Majewski, President of the Management Board of PGNiG SA** .

The agreements signed by PGNiG and American companies concern the annexes to the agreements signed by the parties in 2018 and the increase of the liquefied natural gas sales volumes provided for therein. In the case of the contract with Venture Global Calcasieu Pass, the annex provides for an increase in the volume of gas purchased by PGNiG by 0.5 million tons to 1.5 million tons per year. On the other hand, the annexation of the contract with Venture Global Plaquemines will enable the volume to be increased by 1.5 million tonnes to 4.0 million tonnes of LNG per year. The signing of both annexes will mean that the total volume of liquefied natural gas that PGNiG will receive from Venture Global companies will increase to a total of 5.5 million tonnes annually, i.e. to approx. 7.4 billion cubic meters. natural gas after regasification for 20 years.

The annexed contracts are contracts in the free-on-board (FOB) formula, which means that the buyer, i.e. PGNiG, is responsible for collecting the purchased gas. The contracts are to be performed in two liquefying terminals - Calcasieu Pass and Plaquemines on the Gulf of Mexico. The first is to start operating in 2023.

https://en.pgnig.pl/news/-/news-list/id/pgnig-terminates-port-arthur-lng-agreement/newsGroupId/1910852?changeYear=2021&currentPage=1

27.07.2021 PGNiG terminates Port Arthur LNG agreement

Polish Oil and Gas Company (PGNiG) decided to terminate the SPA with Port Arthur LNG. The companies continue cooperation in order to shift the contracted volumes to other liquefaction projects from Sempra LNG's portfolio.

PGNiG terminated the sale and purchase agreement (SPA) that provided for 2 Mtpa of LNG supply to be delivered from the Port Arthur LNG project. The decision was made due to delays in the project's development. Simultaneously PGNiG and Sempra signed a Memorandum of Understanding (MoU) for a potential replacement of approximately 2 million tonnes per annum (Mtpa) of liquefied natural gas (LNG) supplied from other Sempra LNG's portfolio of projects in North America.

"We highly value our relationship with Sempra LNG and we are keen to continue it. The MoU allows for shifting the volumes originally contracted at Port Arthur LNG to other facilities from Sempra LNG's projects portfolio," **said Paweł Majewski, Chief Executive Officer of PGNiG SA**.

Sempra LNG is a majority stakeholder in Cameron LNG, a 12-Mtpa export facility operating in Hackberry, Louisiana (Phase 1) and is working with Cameron LNG to expand the facility through one additional liquefaction train with an offtake capacity of over 6 Mtpa. Moreover, Sempra LNG is one of the stakeholders building the 3-Mtpa ECA LNG project in Baja California, Mexico. Phase 1 of the project has started construction and first production of LNG is expected by the end of 2024. A potential expansion project is in early stages of development.

"*We look forward to continuing to work with PGNiG to help meet their energy objectives from our strategically positioned LNG facilities and projects on the Gulf and Pacific Coasts of North America,"* **said Justin Bird, chief executive officer of Sempra LNG.**

As part of the MOU, Sempra LNG and PGNiG will also work toward a framework for the reporting, mitigation and reduction of greenhouse gas (GHG) emissions throughout the LNG value chain.

"We are also determined to curb the carbon footprint of fuels offered by PGNiG and we are convinced that cooperation with LNG producers like Sempra LNG will contribute to reaching this goal in the most effective way," **commented Mr. Majewski.**

PGNiG and Port Arthur LNG SPA was signed in 2018. Under the agreement, LNG was to be delivered on a FOB (*free on board*) basis with PGNiG being responsible for lifting the cargoes from the 11 Mtpa liquefaction facilities located at Port Arthur LNG in Texas and shipping them to final destinations. The FID to build Port Arthur LNG has not been taken.

https://www.sempra.com/sempra-lng-and-pgnig-sign-mou-lng-capacity-north-american-lng-portfolio

July 27, 2021

Sempra LNG And PGNiG Sign MOU For LNG Capacity From North American LNG Portfolio

- Companies to collaborate to transition prior 2 Mtpa LNG SPA with Port Arthur LNG to Sempra LNG's portfolio of projects

- Sempra LNG and PGNiG to work toward development of GHG reporting and mitigation agreements for LNG cargoes

SAN DIEGO, July 27, 2021 /PRNewswire/ -- Sempra LNG today announced that it has entered into a memorandum of understanding (MOU) with the Polish Oil & Gas Company (PGNiG) for the potential purchase of approximately 2 million tonnes per annum (Mtpa) of liquefied natural gas (LNG) from Sempra LNG's portfolio of projects in North America. As part of the MOU, Sempra LNG and PGNiG are also working toward a framework for the reporting, mitigation and reduction of greenhouse gas (GHG) emissions throughout the LNG value chain.

"We look forward to continuing to work with PGNiG to help meet their energy objectives from our strategically positioned LNG facilities and development projects on the Gulf and Pacific Coasts of North America," said Justin Bird, chief executive officer of Sempra LNG. "As we look to extend our LNG business to include net-zero solutions, working with companies like PGNiG to advance best practices in GHG mitigation can build on the global environmental benefits of substituting higher-emission fuels with lower-carbon LNG while also continuing to drive down emissions in the U.S. natural gas value chain."

"We highly value our relationship with Sempra LNG and we are keen to continue it. The MOU allows for shifting the volumes originally contracted at Port Arthur LNG to other facilities from Sempra's projects portfolio," said Paweł Majewski, chief executive officer of PGNiG SA. "We are also determined to curb the carbon footprint of fuels offered by PGNiG and are convinced that our cooperation with LNG producers like Sempra LNG will contribute to reach this goal most effectively."

The MOU is non-binding and was completed in connection with the termination of the parties' sale and purchase agreement (SPA) signed in 2018 that provided for 2 Mtpa of LNG supply to be delivered from the Port Arthur LNG project.

Sempra LNG owns a 50.2% interest in Cameron LNG, a 12-Mtpa export facility operating in Hackberry, Louisiana (Phase 1), and is working with Cameron LNG on a proposed expansion of the facility through one additional liquefaction train with an offtake capacity of over 6 Mtpa.

Sempra LNG, IEnova and TotalEnergies are building the 3-Mtpa ECA LNG project in Baja California, Mexico. Phase 1 of the project is under construction and first production of LNG is expected by the end of 2024. A potential expansion project is in the early stages of development.

Sempra LNG is also developing additional LNG facilities and carbon sequestration infrastructure along the LNG value chain on the Gulf and Pacific Coasts of North America.

About Sempra LNG
Sempra LNG's mission is being North America's premier LNG infrastructure company by providing sustainable, safe and reliable access to U.S. natural gas for global markets. Sempra LNG owns interests in Cameron LNG, a 12 Mtpa export facility operating in Hackberry, Louisiana and Energía Costa Azul (ECA) LNG, a 3 Mtpa export facility under construction in Baja California, Mexico. Sempra LNG is developing additional LNG export facilities on the Gulf and Pacific Coasts of North America including Port Arthur LNG in Texas, Vista Pacífico LNG in Mexico, expansions of Cameron LNG and ECA LNG, as well as supporting pipelines, storage and carbon sequestration projects. Through disciplined and innovative processes, Sempra LNG is facilitating the global energy transition by leading the responsible development of lower-carbon energy infrastructure investments along the LNG value chain. For more information about Sempra LNG, please visit www.SempraLNG.com.

About PGNiG
Polish Oil and Gas Company (PGNiG) is the leader of the Polish natural gas market. Listed on the Warsaw Stock Exchange the company's core business includes exploration and production of natural gas and crude oil. Its key branches and subsidiaries import, store, sell and distribute gaseous and liquid fuels. They also generate heat and electricity. PGNiG holds stake in about 30 companies including entities that provide professional geophysical, drilling and maintenance services. PGNiG holds exploration and production licenses on the Norwegian Continental Shelf, in Pakistan and United Arab Emirates. The exploration and production activity in Norway is carried out by PGNiG Upstream Norway. While Munich-based PGNiG Supply & Trading is engaged in gas trading in Western Europe, also operating the LNG trading office in London. In 2020, PGNiG launched a research program aimed at developing alternative fuels and ultimately including them in the sales offer. The PGNiG Group wants to become involved in the use of biomethane as well as the production, storage and

distribution of hydrogen. PGNiG wants to expand its competences in the area of generating electricity from renewable energy sources based on photovoltaic and wind farms.

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".*

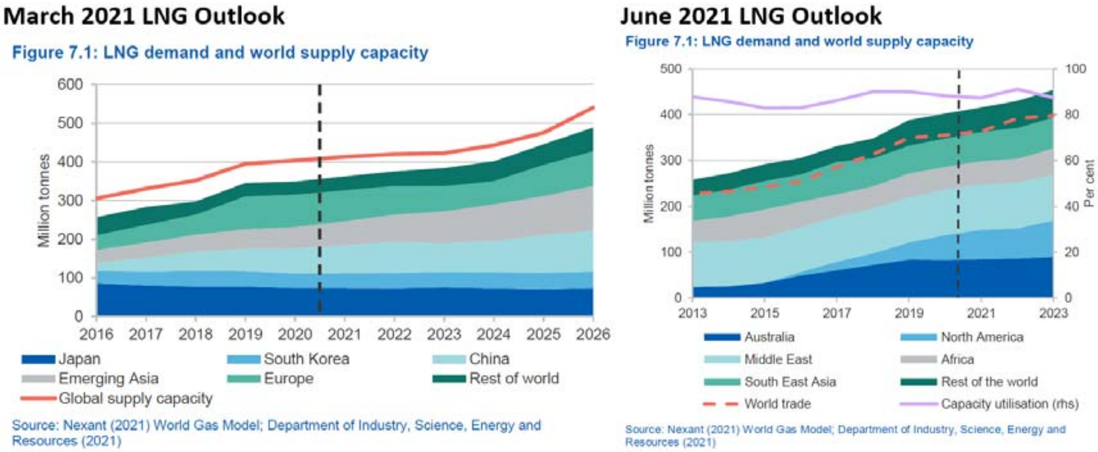
<u>There are other LNG supply delays/interruptions beyond Mozambique.</u> There have been a number of other smaller LNG delay or existing supply interruptions that add to Asian LNG buyers feeling less secure about the reliability of mid to long term LNG supply. Here are just a few examples. (i) Total 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."*

Cheniere stopped the game playing the game on June 30. 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

But we still see major LNG suppliers like Australia hinting but not outright saying that LNG supply gap is coming sooner. 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

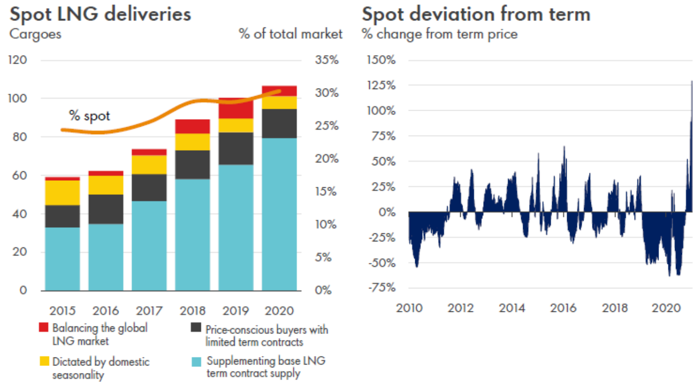


Source: Australia Resources and Energy Quarterly

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.

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.

share in fact the same views. We decided and we have the opportunity offered by PDVSA to exit and rather than dragging our feet and not willing to participate in the new CapEx, it's better to leave PDVSA the capacity to do what they want. But this as clearly an influence.

I know that you not a big fan of opposition in Venezuela, so you know it took time to us to execute your comment, but sometimes you know it came -- one by one. If you have another question, do we have a varieties like that, my answer is not. We don't have so many assets on which we like that and -- of course, again, the example of (inaudible) Brazil large portfolio of large project like Mero is fitting with the criteria and by the way again, the jump we have taken a strong commitment in our resolution, which is, that every year, you will see a report coming from Total Energy's demonstrating that for each of these project hydrocarbon projects. If we, yes or no. We respect to this criteria and if we do not respect, of course, we will have to explain why we consider that it was still acceptable to make a sanction. But this is a clear guideline for all our teams.

Mozambique. You know the situation. You can read the newspaper like me, we have been quite clear. There is a war in Mozambique. It's a severe war in this area in the north of Mozambique. We have been forced to declare force measure. We have decided to stop and even to I don't know, do we see that to dismantle to stop the project and dismantled the teams because we don't see a variety of timeline. I said publicly it would take or at least one year.

In fact, today it's no more in our hand. You know there is a, it's a question is a government of Mozambique is taking actions to reinstate a stability in this Cabo Delgado region is not just by the way, only via was a project is not only is of paramount for the Afungi areas. It's the Cabo Delgado as a whole because with insurgence everywhere I would say, you've seen that we have taken decision at the AC/DC level to the government -- Mozambique government has asked AC/DC to mobilize some air military out, we have seen our of, you're right. Probably as well but Rwanda is involved now.

But frankly, to be clear, Total Energy is not involved at al in this military actions. We are aware to -- of course we are following, but my view is, that it will take time. We, of course, we -- what I can just tell you is that I had a chance to discuss with the President Nyusi in May in Paris. He told me his willingness to solve the issue and what they can absolutely is that months after weeks after weak is respecting and taking the actions, that he described to me.

So then, let's see if we can get out, but again this issue is beyond, it's not a measure of gas development it's beyond this. It's the question of peace and stability and when we pay, back you know there was quite a lot of casualty, so the populations there is suffering. And of course, this is a priority for them and us Total Energy we, if we can support, we continue to support the population as much as we can including by keeping some means to evacuate some people, when there are difficulties. So this is a situation and Mozambique I have observed that area for us just with last week recently joined or declares force majeure declaration, but again I guess is where -- the project is there so let's be patient. And the timeline I said at least one year will we hope, that again the military actions taken by the government will be able to restore peace in that part of the of the planet.

Q - Jon Rigby {BIO 1760839 <GO>}

Okay, thank you. So comprehensive. Thanks a lot.

Operator

Thank you. Your next question comes from the line of Irene Himona of Societe Generale. Please go ahead.

Q - Irene Himona {BIO 1758849 <GO>}

Thank you, guys. Good afternoon. Thank you, Patrick for clarifying the investor distribution policy and the amount. My question is really regarding the dividend, obviously as you said it is flat euro amount, an increase in dollar terms, how does the Board think around dividend progression. If it is a progressive policy what would drive an increase in that quarterly euro amount going forward?

And I had a second question specific to the second quarter result in marketing and services where your sales volumes remain around 21% below pre-crisis levels. And yet, but no participate in much the same. So clearly unit margins are exceptionally strong. I wonder if you can talk a little bit about the sustainability of this in the second half of the year. Is it likely to be sustainable as demand recovers post COVID. Thank you.

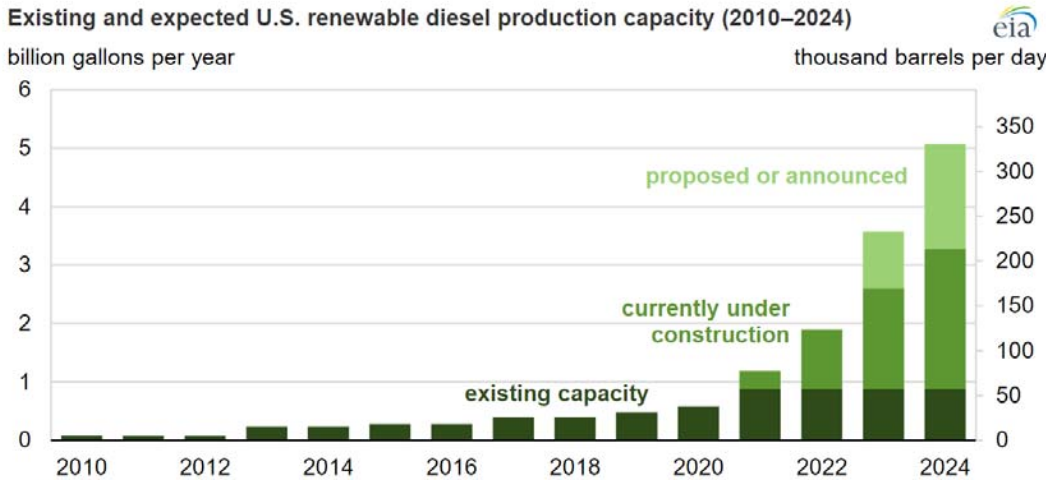
A - Patrick Pouyanne {BIO 7506265 <GO>}

Yeah. Irene. So your first question, I mean I'm always amazed by the capacity -- your capacity when we announce something on one side to go the other side, but I mean I think we are quite clear. No, we. I said, that we will support the dividend through the cycle. We've done it when it was down. So today, obviously we have not, the capacity to severable field were decided the dividend by free to announce big increase because it will be not reasonable. So we have decided in the policy, which is to continuous we never decrease the dividend for 30 years so we progress when we have the feeling that we have, we are able, but fundamentally that dividend will grow when it will be linked to a structural increase of free cash flow.

So it means by, as you know, within the next three, four, five years, we will have some increase of productions we've large projects and then it will be able to deliver an increase of free cash flows, we told you last year between 20 and 25 or 26, we have an increase of cash flows of $5 billion per year. So that will be obviously the source of dividend increase. Dividend increase for me is linked to a structural increase of cash flow of operations. That's fundamental. So today it's not the case this year we are benefiting from higher oil price, which is good. We are, and so the tool that we want to use when we are in such a situation as we announced it in February. Again, it was quite clear we have a this share buyback boxes, which is when we have higher. We benefit from higher oil price. We want to return part of it to shareholders. And today, we give you the crew, which is above $60 https://www.eia.gov/todayinenergy/detail.php?id=48916

JULY 29, 2021

U.S. renewable diesel capacity could increase due to announced and developing projects



Source: Graph by the U.S. Energy Information Administration (EIA), based on data from company announcements in trade press

U.S. production capacity for renewable diesel could increase significantly through 2024, based on several announcements for projects that either are currently under construction or could be in development soon. This growth is driven by higher state and federal targets for renewable fuel, favorable tax credits, and the conversion of existing petroleum refineries into renewable diesel refineries.

As of the end of 2020, U.S. renewable diesel production capacity totaled nearly 0.6 billion gallons per year (gal/y), or 38,000 barrels per day (b/d). Several projects currently under construction could increase this capacity by 2.4 billion gal/y; proposed and announced projects would add another 1.8 billion gal/y by 2024. If all projects come online as intended, U.S. renewable diesel production would total 5.1 billion gal/y (330,000 b/d) by the end of 2024.

Despite growth in renewable diesel production, renewable diesel will make up about 5% of current U.S. diesel production capacity by 2024 if all estimates of proposed renewable diesel capacity expansions occur as planned and petroleum diesel refinery capacity remains largely unchanged.

Renewable diesel is a renewable fuel that is chemically the same as petroleum diesel and nearly identical in its performance characteristics. Renewable diesel can be blended into petroleum diesel at any level, making it different from biodiesel, which can only be blended at rates between 2% and 20% of diesel fuel by volume.

Renewable diesel receives some of the most favorable greenhouse gas (GHG) reduction scores among existing programs, such as the federal Renewable Fuel Standard (RFS) and the California Low-Carbon Fuel Standard (LCFS). As a result, participants in those programs are increasingly using renewable diesel to meet rising renewable fuel targets.

Although most new capacity for renewable diesel will be on the West Coast, some announced projects are on the Gulf Coast. California and other western states such as Oregon and Washington will likely consume the majority of renewable diesel produced on the Gulf Coast to meet future LCFS program targets in those states.

Several former petroleum refineries plan to begin producing renewable biodiesel. Marathon Petroleum's refinery in Martinez, California, plans to start producing renewable diesel in 2022 and could reach its full production capacity of 730 million gal/y (48,000 b/d) in 2023. Phillips 66's Rodeo Renewed project in San Francisco, California, plans to produce 800 million gal/y (52,000 b/d) of renewable fuels when completely converted in 2024. If realized, this project would be the world's largest facility of its kind.

One of the primary risks to the expansion in renewable diesel production capacity is the availability of fat, oil, and grease feedstocks. Prices for most renewable diesel feedstocks have increased as renewable diesel production has increased. Biodiesel and renewable diesel producers have been relying on incentives such as the biomass-based diesel tax credit and tradeable credit prices for renewable diesel in the RFS and LCFS to make a profit. Feedstock availability and government incentives will likely continue to play a role in the financial viability of new renewable diesel production capacity in the near term.

Principal contributors: Sean Hill, Estella Shi, Peter Colletti https://www.lapatilla.com/2021/07/26/argentina-fracking-de-lutitas-alcanza-un-nuevo-record-de-produccion-con-150-mil-b-d/

Argentina: Shale fracking reaches a new production record with 150 thousand b / d

July 26 2021, 11:19 am
Posted in: News , Economy
Share it:

Referential. A YPF worker observes a drilling rig in the Vaca Muerta shale basin in Argentina / AFP photo

In June, the Vaca Muerta unconventional oil field reached a new production record: it exceeded 150 thousand barrels per day.

lapatilla.com

As a result, the Neuquén province, which is home to Vaca Muerta, obtained large income from oil royalties, which doubled in the first half.

In that period, the accumulated royalties Neuquén increased 92% and provincial taxes 63%. In this way, they were the province's two main sources of income, relegating resources from federal co-participation to third place. According to data from Neuquén, production has been growing at a rate of 3% per month, according to review *Profile*

In January, the Patagonian province had received some $ 3.5 billion from oil and gas activity, while in July it was close to $ 7 billion.

It should be noted that the data reflects June production, but since they are settled the following month, royalties are counted as entered in July.

Then, in May, the megafield had already reached 147,000 barrels per day of production, from a record level of hydraulic fractures, the system through which oil is extracted in unconventional reservoirs.

However, a barrel of Brent from the North Sea (a reference for our country and much of the planet) closed the week in London with a rise of 0.42%, to US $ 74.10 for delivery in September. In New York, a barrel of WTI for September delivery gained 0.22% to $ 72.07.

Subsequently, in June, the Patagonian province was consolidated as the main oil province in Argentina. In second place, Chubut was located, where the Cerro Dragón field operates, one of the most productive in the country.

In the case of Vaca Muerta, so far most of the production is destined for local demand. For their part, local refiners recognize a barrel at around US $ 53, when the export price exceeds US $ 65, 20 dollars above 2020.

In relation to the gas activity, there were also improvements in production, since, thanks to official incentives, through the Gas Plan, Neuquén managed to triple its royalty level. Thus, production went from 55 million cubic meters per day to 69 million.

The difference pocketed by the Government is for better prices. In the winter, gas is paid more expensive than in the summer.

https://www.reuters.com/world/middle-east/iran-denies-involvement-attack-israeli-managed-tanker-off-oman-2021-08-01/

August 1, 20213:16 AM MDTLast Updated an hour ago

Middle East

Iran denies involvement in attack on Israeli-managed tanker off Oman

Reuters

DUBAI, Aug 1 (Reuters) - Iran said on Sunday it was not involved in an attack on an Israeli-managed petroleum product tanker off the coast of Oman, referring to an incident last week that killed two and which Israel blamed on the Islamic Republic.

Israeli Prime Minister Naftali Bennett accused Tehran of "trying to shirk responsibility" for Thursday's incident, and called its denial "cowardly".

Iranian Foreign Ministry spokesman Saeed Khatibzadeh told a weekly news conference that the "Zionist regime (Israel) has created insecurity, terror and violence...These accusations about Iran's involvement are condemned by Tehran."

"Such accusations are meant by Israel to divert attention from facts and are baseless," Khatibzadeh said.

A Briton and a Romanian were killed when the Mercer Street, a Liberian-flagged, Japanese-owned ship managed by Israeli-owned Zodiac Maritime was attacked-apparently by a drone, a U.S. defense official said, thoughconclusive evidence was still needed.

Speaking during a weekly meeting of his cabinet on Sunday, Bennett said: "I declare unequivocally: Iran is the one that carried out the attack on the ship," adding that intelligence supports his claim.

"We, in any case, have our own way to relay the message to Iran," Bennett said. Israel's foreign minister said earlier the incident deserved a harsh response. read more

There were varying explanations for what happened to the tanker. Zodiac Maritime described the incident as "suspected piracy" and a source at the Oman

Maritime Security Center as an accident that occurred outside Omani territorial waters.

U.S. and European sources familiar with intelligence reporting said Iran was their leading suspect for the incident.

Iran and Israel have traded accusations of carrying out attacks on each other's vessels in recent months.

Tensions have risen in the Gulf region since the United States reimposed sanctions on Iran in 2018 after then-President Donald Trump withdrew Washington from Tehran's 2015 nuclear deal with major powers.

Additional reporting by Jeffrey Heller in Jerusalem Writing by Parisa Hafezi Editing by Mark Heinrich

https://www.centcom.mil/MEDIA/PRESS-RELEASES/Press-Release-View/Article/2715108/drone-strike-in-north-arabian-sea-kills-two-us-navy-rendering-assistance/

PRESS RELEASE | July 30, 2021

Drone strike in North Arabian Sea kills two: US Navy rendering assistance

U.S. FIFTH Fleet

Arabian Sea –

For Immediate Release

ARABIAN SEA (July 30, 2021) – U. S. naval forces responded to an emergency distress call following an attack on a merchant vessel in the international waters of the Arabian Sea, Jul. 30.

Upon arrival, U.S. forces determined through clear visual evidence that an attack had occurred.

The Liberian-flagged merchant vessel, Mercer Street, is now underway on its own power and there is no ongoing threat to the vessel's personnel. The vessel is currently being escorted by the aircraft carrier USS Ronald Reagan, with embarked Carrier Strike Group 5, and the Guided Missile Destroyer USS Mitscher.

U.S. Navy personnel are on the Mercer Street, assisting the vessel's crew. The U.S. Navy's 5th Fleet headquarters is coordinating with vessel ownership regarding the type of assistance requested.

U.S. Navy explosives experts are aboard to ensure there is no additional danger to the crew, and are prepared to support an investigation into the attack. Initial indications clearly point to a UAV-style attack. There were no U.S. citizens onboard the vessel at the time of the attack. Regretfully, two members of the ship's crew were killed in the attack, and governments of the nations of those two crewmembers are aware of the tragedy.

The U.S. 5th Fleet regularly works with coalition forces, regional partners and the shipping industry to maintain the regional awareness necessary to facilitate aid to mariners in distress.

https://saudigazette.com.sa/article/609309/SAUDI-ARABIA/Arab-Coalition-foils-Houthis-bid-to-target-Saudi-commercial-ship

Arab Coalition foils Houthis' bid to target Saudi commercial ship

July 30, 2021

Saudi Gazette report

RIYADH — The Arab Coalition forces have thwarted an attempt by the Houthi militia to target a Saudi commercial vessel with an armed drone.
In a statement on Friday, the Coalition to Restore Legitimacy in Yemen said that the Iran-backed militia continues to threaten global maritime shipping routes.

The coalition added in the statement that its efforts have contributed to securing the freedom of navigation and the safety of ships transiting through the Bab Al-Mandeb Strait.

The sabotage attempt on Friday by the Houthi militia comes just a couple of days after the coalition forces intercepted and destroyed a Houthi explosive-laden drone targeting the Kingdom's southern region.

Just hours before the drone attack, the coalition forces destroyed two booby-trapped drones and three ballistic missiles launched by the militia toward the southern city of Jazan.

https://www.spa.gov.sa/viewfullstory.php?lang=en&newsid=2267174#2267174

Arab Interior Ministers Council Condemns Houthi Terrorist Militia's Targeting of Saudi Commercial Ship

Saturday 1442/12/21 - 2021/07/31

Tunis, July 31, 2021, SPA -- The General Secretariat of the Council of Arab Interior Ministers expressed its strong condemnation and denunciation of the terrorist act carried out by Houthi militia, through which it attempted to attack a Saudi commercial ship by using a booby-trapped drone in the southern Red Sea.
It said in a statement issued from its headquarters in Tunis yesterday, that while it condemns these sabotage and criminal terrorist acts carried out by this Iranian-backed terrorist militia, which does not target the security of the Kingdom of Saudi Arabia only and its vital facilities, but also the international shipping movement and its security and freedom of global trade in the Red Sea, and supplies energy for the world as well as the global economy and international peace and security, in blatant defiance of the international community and disregard for all international laws and norms calling for peace, security and stability.
It renews its full support for the Kingdom against these terrorist attacks and its absolute support for all measures it takes to defend its security, stability vital facilities, and to protect the security of International shipping lines.
--SPA
03:05 LOCAL TIME 00:05 GMT

https://www.eia.gov/todayinenergy/detail.php?id=41073
AUGUST 27, 2019

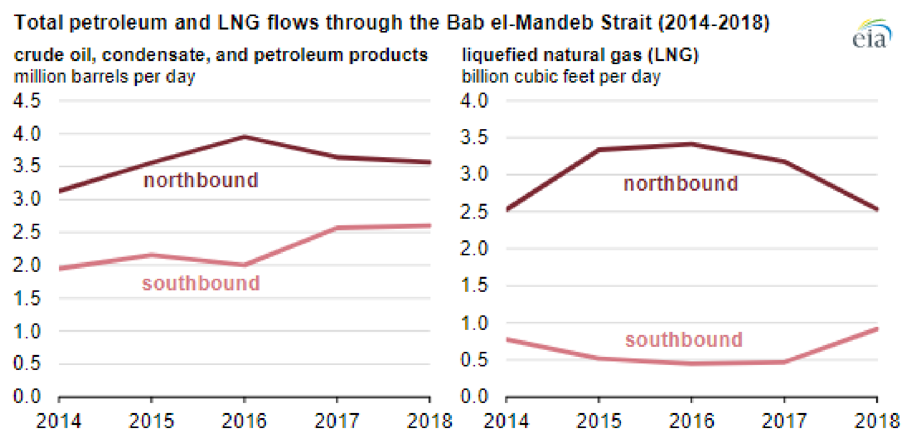
The Bab el-Mandeb Strait is a strategic route for oil and natural gas shipments

Source: U.S. Energy Information Administration

The Bab el-Mandeb Strait is a sea route chokepoint between the Horn of Africa and the Middle East, connecting the Red Sea to the Gulf of Aden and Arabian Sea. Most exports of petroleum and natural gas from the Persian Gulf that transit the Suez Canal or the SUMED Pipeline pass through both the Bab el-Mandeb and the Strait of Hormuz.

Chokepoints are narrow channels along widely used global sea routes that are critical to global energy security. The Bab el-Mandeb Strait is 18 miles wide at its narrowest point, limiting tanker traffic to two 2-mile-wide channels for inbound and outbound shipments. Closure of the Bab el-Mandeb Strait could keep tankers originating in the Persian Gulf from transiting the Suez Canal or reaching the SUMED Pipeline, forcing them to divert around the southern tip of Africa, which would increase transit time and shipping costs.

In 2018, an estimated 6.2 million barrels per day (b/d) of crude oil, condensate, and refined petroleum products flowed through the Bab el-Mandeb Strait toward Europe, the United States, and Asia, an increase from 5.1 million b/d in 2014. Total petroleum flows through the Bab el-Mandeb Strait accounted for about 9% of total seaborne-traded petroleum (crude oil and refined petroleum products) in 2017. About 3.6 million b/d moved north toward Europe; another 2.6 million b/d flowed in the opposite direction mainly to Asian markets such as Singapore, China, and India.



Source: U.S. Energy Information Administration, based on ClipperData, Inc; Suez Canal Authority; and International Group of LNG Importers (GIIGNL) using EIA conversion factors.
Note: CSV data

Before 2015, volumes of liquefied natural gas (LNG) passing through the Bab el-Mandeb Strait matched those passing through the Suez Canal because the Red Sea did not have any LNG infrastructure. In 2015, both Jordan and Egypt began importing small volumes of LNG into Red Sea ports, and these countries' imports of LNG peaked in 2016 at 1.4 billion cubic feet per day, 80% of which was delivered through the Bab el-Mandeb Strait.

More recently, as new natural gas fields in Egypt have come online, the need for Egypt to import LNG has decreased. Like flows to Egypt, total northbound flows of LNG via the Bab el-Mandeb have also decreased since 2016 as northbound flows to other destinations have remained fairly constant.

Independent Statistics & Analysis
U.S. Energy Information Administration

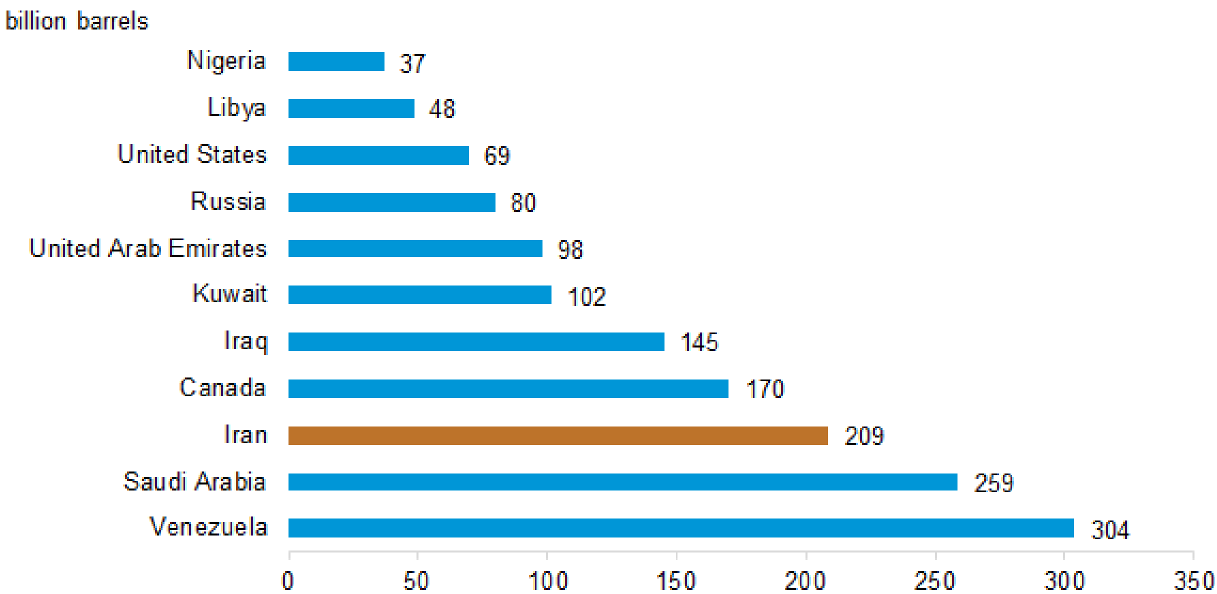
Country Analysis Executive Summary: Iran

Last Updated: July 16, 2021

Overview

- Iran was the fifth-largest crude oil producer in OPEC in 2020 and the third-largest natural gas producer in the world in 2019.[1] It holds some of the world's largest deposits of proved oil and natural gas reserves, ranking as the world's third-largest and second-largest reserve holder of oil and natural gas, respectively, in 2020. At the end of 2020, Iran accounted for 25% of oil reserves in the Middle East and 12% in the world (Figure 1).[2] Despite its abundant reserves, Iran's crude oil production has fallen since 2017 because the oil sector has been subject to underinvestment and international sanctions for several years.
- Although Iran is a member of OPEC, it is exempt from the production cuts under the OPEC+ agreement because its crude oil production remains limited by U.S.-imposed nuclear-related sanctions. Iran's crude oil production reached a 30-year low in 2020 as a result of these sanctions and the impacts of the global COVID-19 pandemic. EIA assesses that Iran's production could return to full capacity, at 3.8 million barrels per day (b/d), if the United States lifts oil sector sanctions.

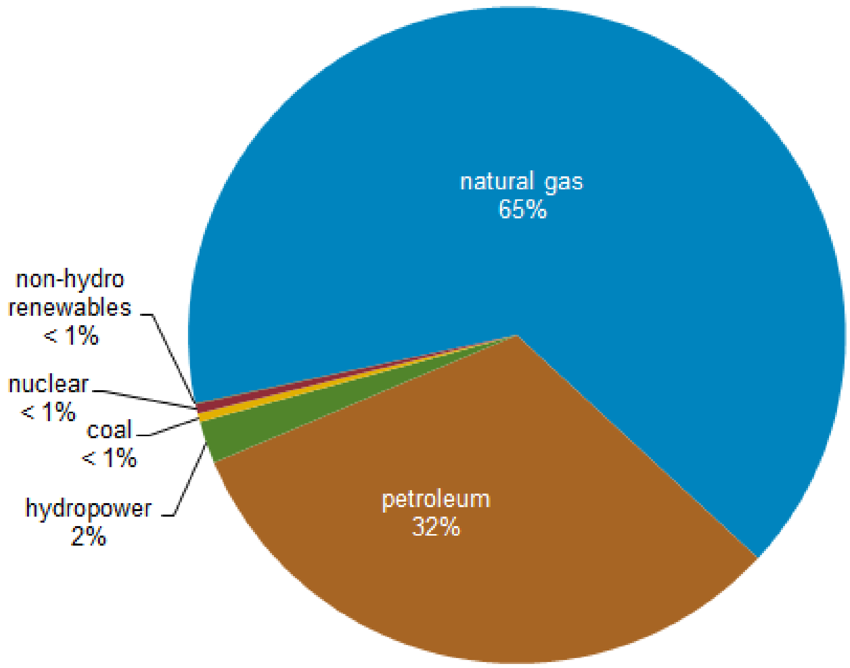
Figure 1. Largest proved reserve holders of oil, 2020



Source: Graph by U.S. EIA based on data from *Oil & Gas Journal*, December 2020
Note: Oil reserves include crude oil, condensates, natural gas liquids, and oil sands.

- Iran's economy is relatively diversified compared to many other Middle Eastern countries, but it still relies heavily on petroleum and other liquids revenues. In FY 2016 (April 2016–March 2017), the latest year of available data, crude oil export revenue accounted for nearly 40% of Iraq's total government revenues, according to the International Monetary Fund (IMF).[3] In 2019, Iran earned $30 billion in net oil export revenues, down from $66 billion in 2018. Export revenues fell in 2019 after U.S. sanctions were imposed on Iran's oil exports, which resulted in a decrease in both crude oil production and exports in Iran.[4] We estimate the oil price declines in 2020 further reduced Iran's revenues.
- Iran's economy consumed an estimated 11.7 quadrillion British thermal units of primary energy in 2019, making it the largest energy consumer in the Middle East. Natural gas and oil accounted for almost all of Iran's total primary energy consumption, with marginal contributions from hydropower, coal, nuclear, and non-hydro power renewables (Figure 2).[5]

Figure 2. Iran's total primary energy consumption, share by fuel, 2019



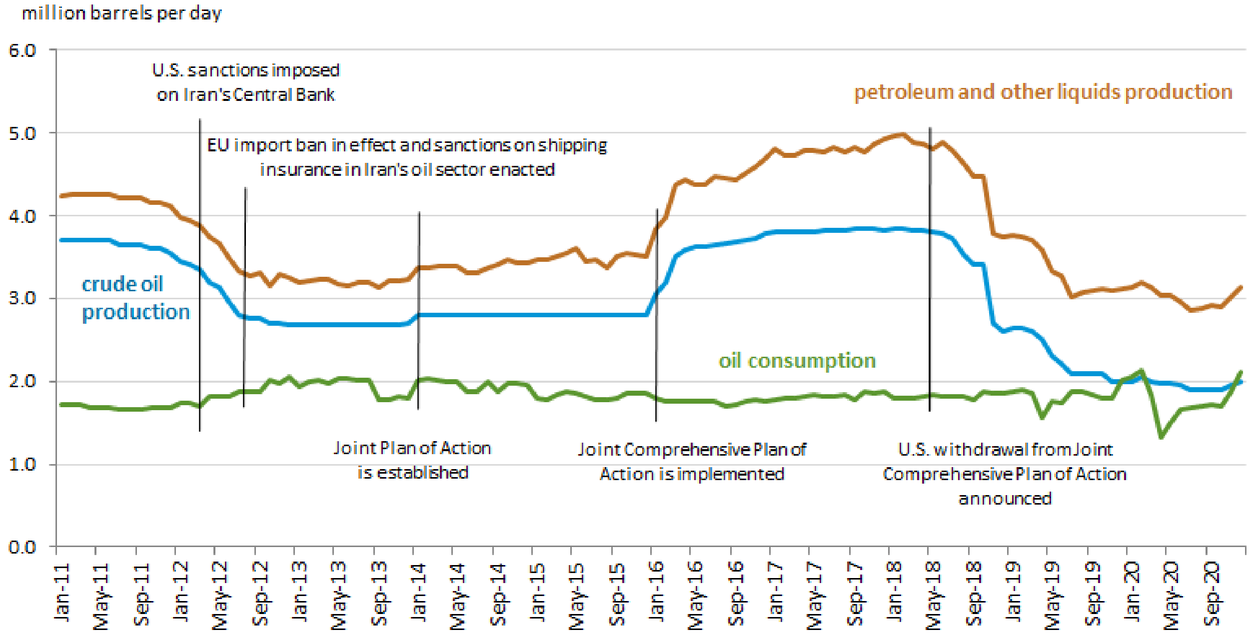
Source: Graph by U.S. EIA based on data from *BP Statistical Review of World Energy 2020*
Note: Chart does not include traditional biomass and waste, such as burning firewood and waste.

Petroleum and other liquids

- Total oil production in Iran has declined since 2017, when output reached a high of 4.8 million b/d. Iran's production averaged 3.0 million b/d of petroleum and other liquids in 2020, and almost 2.0 million b/d was crude oil and the remainder was condensate and hydrocarbon gas liquids. Iran's crude oil exports and production have declined since the United States announced in May 2018 that it would withdraw from the Joint Comprehensive Plan of Action (JCPOA) and reinstate sanctions targeting Iran's oil exports (Figure 3). Crude oil production reached 2.6 million b/d during the first few months of 2019 when the United States government granted sanctions waivers for some of Iran's key oil-importing countries. However, after these waivers expired in May 2019, output fell further to about 2.1 million b/d. Economic fallout from the COVID-19 pandemic, including lockdowns and mobility restrictions, resulted in Iran's crude oil production dipping below 2.0 million b/d in 2020. We assess that Iran's crude oil production could increase to 3.8 million b/d if global demand continues to rise and sanctions on Iran's oil exports are lifted.
- Consumption of petroleum products in Iran remained steady in 2019 at 1.8 million b/d compared to 2018 levels, despite the economic downturn that occurred after U.S. sanctions were re-imposed. Sanctions limit Iran's ability to export crude oil, condensate, and petroleum products, and these liquid fuels replaced some of the natural gas used in the power sector, mainly diesel and fuel oil. In the wake of the COVID-19 pandemic, Iran's economy consumed less than 1.8 million b/d in 2020. Use of gasoline, the key transportation fuel in Iran, decreased considerably. Use of petroleum and petroleum products will likely face competition from natural

gas, particularly in the power, residential, and commercial sectors, during the next several years, especially if demand for exports of petroleum and petroleum products increases.

Figure 3. Iran's petroleum and other liquids production and consumption, 2011–2020



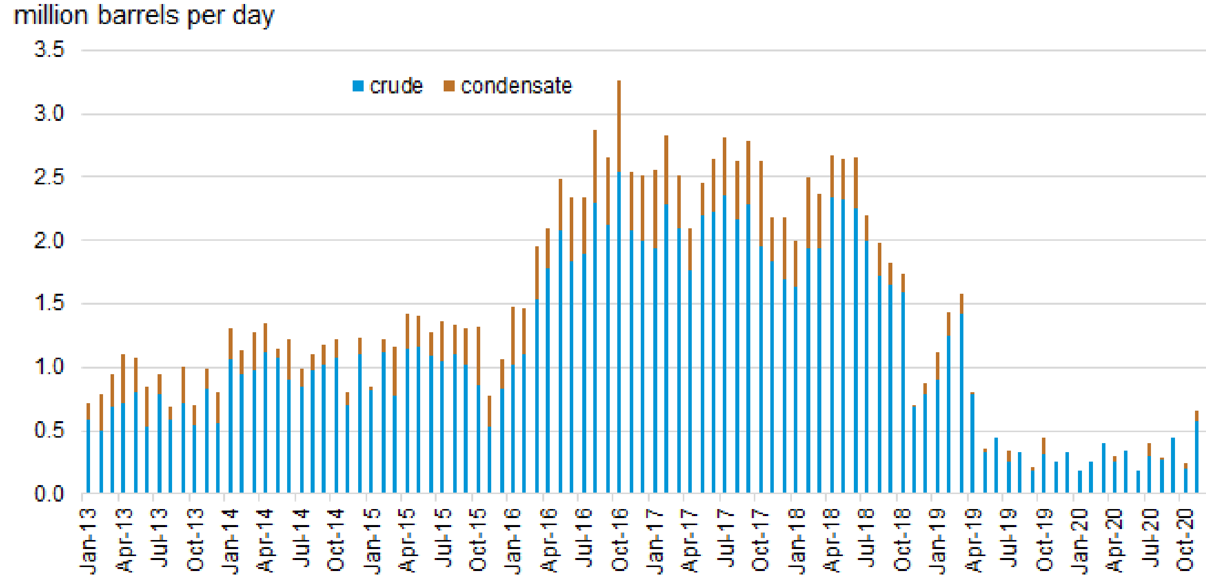
Source: U.S. Energy Information Administration, *Short-Term Energy Outlook*, June 2021.
Note: Iran's petroleum and other liquids production includes crude oil, condensate, and hydrocarbon gas liquids (HGLs).

Oil trade

- We estimate Iran's crude oil and condensate exports fell from more than 2.5 million b/d in 2017, the year before the United States re-imposed sanctions, to an average of less than 0.4 million b/d in 2020 (Figure 4). We base these estimates on tanker-tracking data reported by ClipperData, LLC. Iran's exports began to rise in November 2020 and reached an average of nearly 0.7 million b/d in the last two months of the year as Iran sent more crude oil to China.[6] Estimates based on ClipperData show that Iran's oil exports averaged more than 0.5 million b/d in the first few months of 2021. Other industry analysts and trade press vary in their range of estimates for Iran's oil exports from less than 0.6 million b/d to more than 0.8 million b/d during the first quarter of 2021.[7] The use of ship-to-ship (STS) transfers and switching off Iranian ship identification transponders, have made it difficult to track Iran's crude oil exports.
- Although Iran supplied crude oil and condensates to a variety of countries in Europe and Asia in 2017, Iran sent nearly all of its crude oil and condensate exports to China and Syria in 2020 (Figure 5). Industry analysts assess that shipments of oil to several countries were transferred ship to ship and blended with crude oil grades that did not originate in Iran before the volumes were sent to China. According to analysis from ClipperData, much of the oil that was shipped from Iran to China was relabeled from countries such as Malaysia, Singapore, the United Arab Emirates, Iraq, and Oman to escape detection from customs authorities and compliance with sanctions.[8] Syria has been receiving small amounts of crude oil and oil products mostly through a line of credit with Iran and through barter deals.[9]
- Iran's exports of petroleum products were 680,000 b/d in 2020. LPG, fuel oil, and gasoline accounted for about 61% of total petroleum product exports, according to FGE estimates, which was an increase from 2018 at 620,000 b/d.[10] Petroleum products are generally shipped on

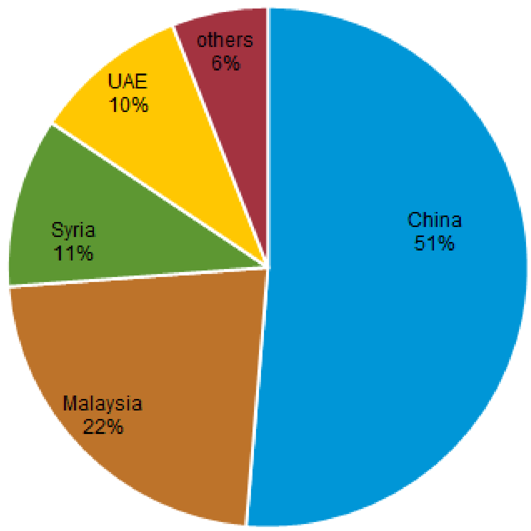
smaller vessels that have been able to avoid detection more easily than crude oil cargoes. In addition, when the new Persian Gulf Star refinery was commissioned, the added refining capacity resulted in Iran becoming a net exporter of gasoline in 2019.[11] Historically, Iran relied on petroleum product imports to meet domestic demand.

Figure 4. Iran's monthly crude oil and condensate exports



Source: Graph by U.S. EIA, based on data from ClipperData, LLC

Figure 5. Iranian crude oil and condensate exports by destination, 2020



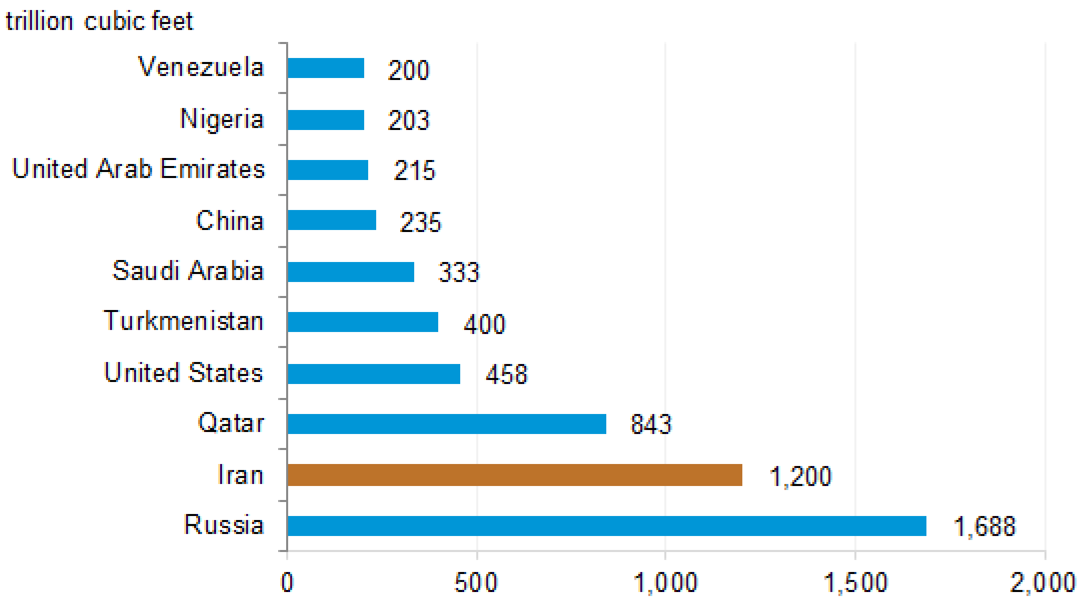
Source: Graph by U.S. EIA, based on data from ClipperData, LLC

Natural gas

- Iran's estimated proved natural gas reserves were 1,200 trillion cubic feet (Tcf) as of December 2020, second only to Russia, according to *Oil & Gas Journal* (Figure 6). Iran holds 16% of the world's proved natural gas reserves and almost half of OPEC's reserves.[12]
- Iran was the world's third-largest dry natural gas producer after the United States and Russia in 2019.[13] Dry natural gas production nearly doubled between 2009 and 2019, rising to 8.4 Tcf (Figure 7). Iran has brought online several phases of the offshore South Pars natural gas field since 2014 and continues to develop natural gas fields despite challenges posed by sanctions and a lack of foreign investment. Since 2018, domestic companies have been primarily developing the natural gas fields. However, while sanctions on Iran's oil exports are in place, the country's natural gas production growth, particularly from fields that produce condensate liquids, will remain limited because of condensate storage capacity constraints.
- In 2017, the National Iranian Oil Company (NIOC) reinjected 1.2 Tcf of natural gas into oil wells for enhanced oil recovery (EOR),[14] which plays a central role in Iran's oil production. Once sanctions resumed on Iran's oil exports in 2018, reinjected natural gas volumes fell significantly to an estimated 0.2 Tcf in 2020.
- In addition to the natural gas used for EOR, Iran vented or flared approximately 0.5 Tcf of natural gas in 2019, down from 0.6 Tcf in 2018, as a result of sanctions that indirectly depressed associated natural gas production from oil fields.[15] Plans are underway to capture more flared natural gas for use in power plants, refineries, and petrochemical plants. In early 2021, the Bid Boland-2 natural gas processing plant, one of the largest plants in Iran, was commissioned, which will increase natural gas processing capacity and reduce natural gas flaring.[16] The oil ministry plans to eliminate natural gas flaring by 2023.[17] However, accomplishing this goal will depend on if sanctions are lifted, export markets are opened for natural gas liquids, and sufficient natural gas liquids processing capacity is added.[18]

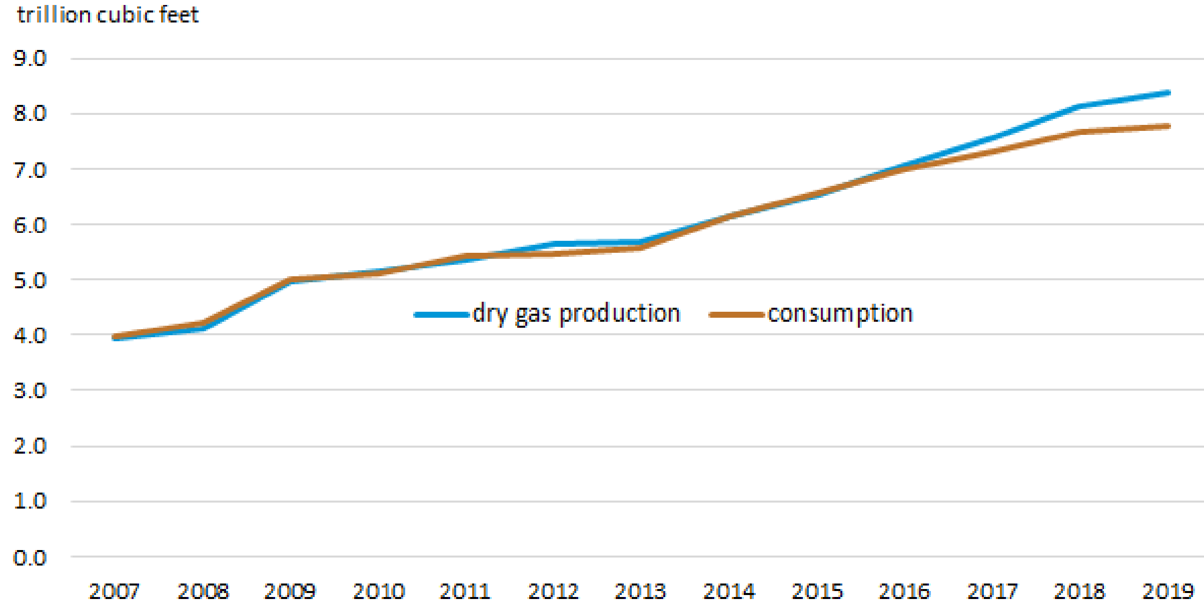
- In 2019, Iran was the world's fourth-largest consumer of natural gas after the United States, Russia, and China.[19] Most of Iran's natural gas production is consumed domestically. Iran's natural gas consumption averaged 7.8 Tcf in 2019, about 2% higher than the 2018 level (Figure 7).[20] Growth in natural gas consumption slowed in 2019 as a result of the U.S. sanctions on exports of petroleum and other liquids. Iran reduced its supply of natural gas from the South Pars field because of insufficient storage for its associated condensate production. Iran substituted some natural gas with oil products, particularly in its electric power sector, as a result of the natural gas supply constraint.
- In 2019, the residential and commercial sectors consumed the most natural gas (35%), followed by the industrial (including petrochemicals) sector (27%), and the electric power sector (26%). Natural gas consumption in the residential and commercial sector and the industrial sector has increased significantly in the past decade as natural gas replaced some liquid fuels, Iran's natural gas pipeline system expanded, and the industrial sector expanded. Although Iran's natural gas consumption for electric power generation fell in 2019, once sanctions are lifted, we assess that natural gas share in this sector will increase, which would free up more crude oil and petroleum products for exports.[21] The petrochemical industry is slated to grow in Iran during the next several years and will require more natural gas for fuel.

Figure 6. Largest proved reserve holders of natural gas, 2020



Source: Graph by U.S. EIA, based on data from *Oil & Gas Journal*, December 2020

Figure 7. Iran's dry natural gas production and consumption

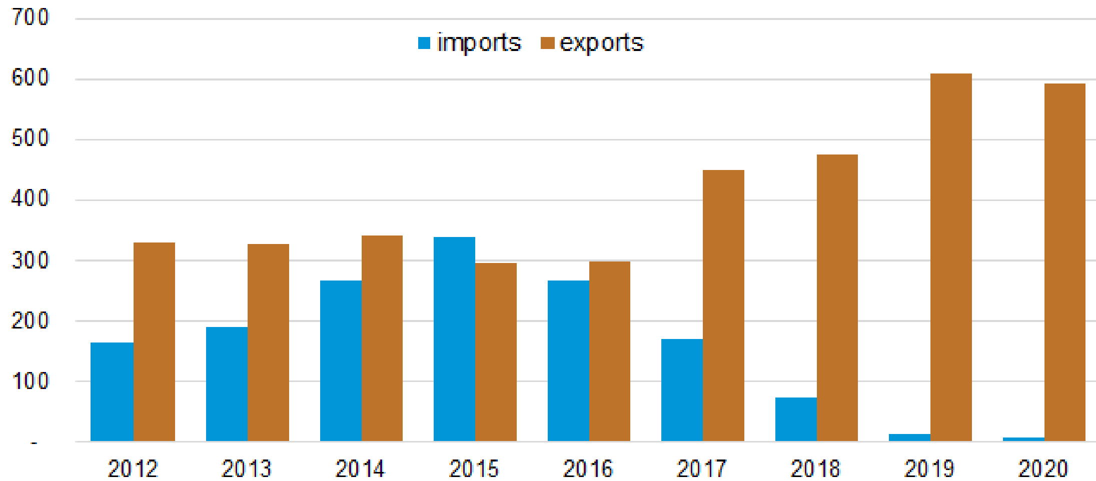


Source: U.S. Energy Information Administration

Natural gas trade

- Iran exports natural gas by pipeline to Turkey, Armenia, Azerbaijan, and Iraq, and it receives imports from Azerbaijan. In 2020, Iran exported about 590 billion cubic feet (Bcf) and imported 7 Bcf of natural gas via pipelines (Figure 8). Iran's natural gas imports decreased substantially after 2015, but exports rose sharply because of Iran's increased natural gas production from several new South Pars projects since 2014 and increased exports to Iraq. Iran stopped importing natural gas from Turkmenistan in 2019 because higher production and more pipeline coverage made it possible for domestic supplies to reach the northeastern region.
- In 2020, Iraq and Turkey accounted for 64% and 33%, respectively, of Iran's natural gas exports. Natural gas exports to Iraq increased substantially since their trade contract was implemented in mid-2017. Iraq has been relying increasingly on electricity and natural gas exports from Iran to fuel its power sector. Iran's exports to Turkey dropped in 2020 because an explosion on the Iran-Turkey natural gas pipeline stopped flows for a few months.[22] Iran's exports to Armenia and Azerbaijan are relatively small volumes and are traded on long-term agreements.

Figure 8. Iran's natural gas pipeline imports and exports, 2012–2020
billion cubic feet

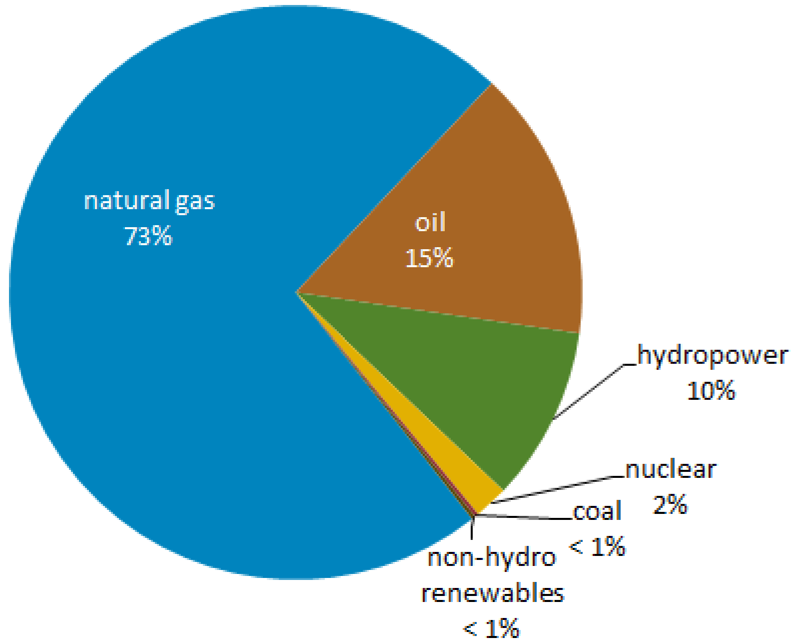


Source: Graph by U.S. EIA, based on data from Facts Global Energy

Electricity

- In 2019, Iran's electric power generation was 306 terawatthours (TWh) of net electricity, with 88% of generation coming from fossil fuel sources.[23] Natural gas is the largest source of fuel for electricity generation in Iran, accounting for nearly 73% of total generation. Oil fueled 15% of Iran's electric power production in 2019, up from 9% in 2018. Because sanctions limited Iran's oil exports, more oil production was used domestically, therefore, diesel and fuel oil replaced some of the natural gas used in the power sector.
- Coal, hydropower, nuclear, and non-hydro power renewables are the remaining fuel sources used to generate electricity in Iran (Figure 9). Iran's hydroelectric power output doubled from almost 16 TWh in 2018 to 30 TWh in 2019, the highest increase of generation on record, because of heavy, widespread rains and flooding.[24] Hydropower rose to 10% of Iran's total generation, supplanting some oil-fired and natural gas-fired power in 2019.

Figure 9. Iran's net electricity generation by fuel, 2019



Source: U.S. EIA, based on data from the International Energy Agency
Note: Total may not add to 100% because of independent rounding.

Notes

- In response to stakeholder feedback, the U.S. Energy Information Administration has revised the format of the *Country Analysis Briefs*. As of December 2018, updated briefs are available in two complementary formats: the Country Analysis Executive Summary provides an overview of recent developments in a country's energy sector and the Background Reference provides historical context. Archived versions will remain available in the original format.
- Data presented in the text are the most recent available as of April 30, 2021.
- Data are EIA estimates unless otherwise noted.

Endnotes

[1] U.S. Energy Information Administration, *Short-Term Energy Outlook*, April 2020 and International Energy Statistics.
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[3] IMF Country Report No. 17/62, page 4 and Islamic Republic of Iran (March 2018), IMF Country Report No. 18/93, page 31.
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[10] Facts Global Energy, *Iran's Oil and Gas Annual Report 2020* (December 2020), page 82.
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[15] World Bank Global Gas Flaring Tracker 2020; *Middle East Economic Survey*, "Global Gas Flaring Gets Worse in 2019", July 24, 2020, page 3; Financial Tribune, "Gas Flaring Down 40%," July 19, 2020.
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[18] Facts Global Energy, *Iran's Oil and Gas Annual Report 2020*, (December 2020), pages 105-106.
[19] BP Statistical Review of World Energy 2020.
[20] U.S. Energy Information Administration, International Energy Statistics.
[21] Facts Global Energy, *Iran's Oil and Gas Annual Report 2020*, (December 2020), pages 20-21, 31-34, and 110 and 118.
[22] Facts Global Energy, *Iran Oil and Gas Monthly,* January 2021, page 14.
[23] U.S. Energy Information Administration based on International Energy Agency, World Energy Statistics 2020.
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Independent Statistics & Analysis
U.S. Energy Information Administration

Background Reference: Iran

Last Updated: July 16, 2021

Overview

Iran holds some of the world's largest proved crude oil reserves and natural gas reserves. Despite Iran's abundant reserves, crude oil production stagnated and even declined between 2012 and 2016 as a result of nuclear-related international sanctions that targeted Iran's oil exports and limited investment in Iran's energy sector. At the end of 2011, in response to Iran's nuclear activities, the United States and the European Union (EU) imposed sanctions, which took effect in mid-2012. These sanctions targeted Iran's energy sector and impeded Iran's ability to sell oil, resulting in a nearly 1.0 million barrel-per-day (b/d) drop in crude oil and condensate exports in 2012 compared with the previous year.[1]

After the oil sector and banking sanctions eased, as outlined in the Joint Comprehensive Plan of Action (JCPOA) in January 2016, Iran's crude oil and condensate production and exports rose to pre-2012 levels. However, Iran's crude oil exports and production again declined following the May 2018 announcement that the United States would withdraw from the JCPOA. The United States reinstated sanctions against purchasers of Iran's oil in November 2018, but eight countries that are large importers of Iran's oil received six-month exemptions. In May 2019, these waivers expired, and Iran's crude oil and condensate exports fell below 500,000 b/d for the remainder of 2019 and most of 2020.

According to the International Monetary Fund (IMF), Iran's oil and natural gas export revenue was $26.9 billion in FY 2015–2016, decreasing more than 50% from $55.4 billion in FY 2014–2015. The sudden drop followed continued depressed export volumes and lower crude oil prices combined, which resulted in low total export revenue. In FY 2017–2018, oil and natural gas export revenue rose to about $63.7 billion, and crude oil export volumes also rose after JCPOA was implemented.[2] Most of the export revenues came from crude oil and condensate exports because Iran exported a relatively small volume of natural gas.

Development of Iran's natural gas resources continued and picked up pace following the JCPOA. However, production growth was slower than expected because sanctions targeting Iran's nuclear activities between 2012 and 2016 also affected investments in natural gas development. Iran's natural gas activities are centered on the South Pars natural gas field, located offshore in the Persian Gulf, which holds about 40% of Iran's proved natural gas reserves.[3] Local companies in Iran are the main developers of the field.

In addition to its relatively large energy resources, Iran plays a significant role in fossil fuel transit geographically (Figure 1). The Strait of Hormuz, off the southeastern coast of Iran, is an important route for oil exports from Iran and other Persian Gulf countries. At its narrowest point, the Strait of Hormuz is 21 miles wide, yet an estimated 20.7 million b/d of crude oil and refined products flowed through it in 2018 (about one-third of all seaborne-traded oil and more than 20% of total oil consumed globally).[4] Liquefied natural gas (LNG) volumes also flow through the Strait of Hormuz. Approximately 4.1 trillion cubic feet (Tcf) of LNG moved from Qatar through the Strait of Hormuz in 2018, accounting for more than 25% of global LNG trade.

Figure 1. Map of Iran

Source: U.S. Central Intelligence Agency

Total primary energy consumption

Despite periodic economic depression, total use of energy in Iran has grown rapidly between 2009 and 2019, increasing by about 40% over that time period.[5] To better control domestic demand growth for energy and reduce the budgetary exposure to high subsidy costs, Iran's government implemented energy subsidy reforms, which resulted in increasing domestic prices for domestic petroleum, natural gas, and electricity between 2010 and 2014.

Management of oil and natural gas sectors

The state-owned National Iranian Oil Company (NIOC) is responsible for all upstream oil and natural gas projects. Iran's constitution prohibits foreign or private ownership of natural resources. However, international oil companies (IOCs) can participate in the exploration and development phases through

Iran's petroleum contract, a relatively new model for its upstream oil and natural gas fiscal regime, implemented in 2016.

The Supreme Energy Council, established in July 2001 and chaired by the president of Iran, oversees the energy sector. The Council includes the Ministers of Petroleum, Economy, Trade, Agriculture, and Mines and Industry, among others. Under the supervision of the Ministry of Petroleum, state-owned companies dominate the activities in the oil and natural gas upstream and downstream sectors, in addition to Iran's petrochemical industry. The four key state-owned enterprises are NIOC, the National Iranian Gas Company (NIGC), National Oil Refining and Distribution Company (NIORDC), and the National Petrochemical Company (NPC).

Table 1. Iran's state-owned energy companies

Company	Responsibility
National Iranian Oil Company (NIOC)	NIOC controls oil and natural gas upstream activities through its 11 subsidiaries.
National Iranian Gas Company (NIGC)	NIGC controls natural gas downstream activities. The company processes, delivers, and distributes natural gas for domestic use. NIGC operates through several subsidiaries.
National Iranian Oil Refining and Distribution Company (NIORDC)	NIORDC is responsible for all refining and distribution activities related to crude oil and petroleum products, including construction of refining and storage facilities and oil pipelines and operations of gasoline stations. NIORDC conducts these operations through its four major subsidiaries.
National Petrochemical Company (NPC)	NPC manages Iran's petrochemical industry, including operations of several petrochemical complexes, through its subsidiaries.

Source: U.S. Energy Information Administration, Facts Global Energy, Arab Oil & Gas Directory, and NIOC

Foreign investment

To attract much-needed foreign investment and technology in its oil and natural gas sector, Iran's government implemented a petroleum contract that allows IOCs to participate in all phases of upstream projects. This fiscal regime took effect in 2016 and offers more attractive terms than the previously available buyback contracts.

Iran's constitution prohibits foreign or private ownership of natural resources, and before late 2016, the government only permitted buyback contracts, which allowed IOCs to enter exploration and development contracts through an Iranian subsidiary. A buyback contract is similar to a service contract and requires the contractor (or an IOC) to invest its own capital and expertise to develop oil and natural gas fields.

After the field was developed and production started, the project's operatorship reverted to NIOC or to the relevant subsidiary. The IOC did not get equity rights to the oil and natural gas fields. NIOC used revenue from the sale of oil and natural gas to pay back the capital costs to the IOC. The annual repayment rates to the IOC were based on a predetermined percentage of the field's production and rate of return. According to Facts Global Energy (FGE), the rate of return on buyback contracts ranged between 12% and 17%, and the payback period was between five and seven years.[6]

In late 2016, Iran implemented the new oil contract model called the Iranian (or Integrated) Petroleum Contract (IPC). The goal of the IPC is to attract more foreign investment and technology to spur development of upstream oil and natural gas projects. The IPC terms combine terms from buyback contracts and production sharing agreements (PSA). The IPC encompasses exploration, development, and production phases, along with the possibility to extend into EOR phases. The contract term is set at a maximum of 20 years, with the possibility to extend the term by 5 years for EOR projects. The IPC retains the previous local content requirement of 51% of the value of work, and the foreign investor must submit plans for knowledge and technology development transfer as part of its annual operational financial plan.[7]

International sanctions have limited the foreign investment, technology, and expertise needed to expand capacity at oil and natural gas fields and to reverse declines at mature oil fields. Iran has depended mainly on local companies to develop oil and natural gas fields since 2018. Although the IPC may reverse this trend, Iran has had limited success in attracting IOCs to its oil and natural gas upstream sector.

By 2020, Iran had signed six IPC contracts, although all of the recent contracts were with domestic firms.[8] Iran finalized two IPC contracts with foreign firms before sanctions on Iran were re-imposed, but these companies withdrew from the projects to avoid sanctions. The first project was the July 2017 agreement with French company Total and China National Petroleum Corporation (CNPC) to develop Phase 11 of the South Pars field. The development was not slated to produce any crude oil but was expected to produce about 80,000 b/d of condensate.[9] Russian state-controlled Zarubezhneft signed an oil development contract under the IPC, reportedly with Rosneft, Lukoil, Gazprom Neft, and Tatneft, who were all considering upstream agreements with Iran. Zarubezhneft, NIOC, and Dana Energy signed the latest agreement in mid-March 2018 to develop the West Paydar and Abadan onshore fields near Iraq. The 10-year contract called for improved recovery rates and increased production from the fields to 48,000 b/d.[10]

Petroleum and other liquids

Reserves

Most of Iran's crude oil reserves are located onshore (about 86%) in the Khuzestan Basin (located on the southwest border of Iraq), which contains about 80% of total onshore reserves. Offshore reserves are mainly located in the Persian Gulf. Condensate reserves are split more evenly between onshore and offshore deposits.[11] Iran also has 0.5 billion barrels of proved and probable reserves in the Caspian Sea, but to date, very limited upstream activity has occurred in Iran's portion of the Caspian Sea.[12] Iran also shares a number of onshore and offshore fields with neighboring countries, including Iraq, Qatar, Kuwait, the United Arab Emirates (UAE), and Saudi Arabia.

Exploration and production

Iran is one of the founding members of OPEC, which was established in 1960. Since the 1970s, Iran's oil production has varied greatly. Iran's oil production averaged more than 5.0 million b/d between 1972 and 1978, and production topped 6.0 million b/d in 1974. Since the 1979 revolution, however, a combination of war, limited investment, sanctions, and a high rate of natural decline in production at Iran's mature oil fields has prevented a return to those production levels.

Sanctions imposed in late 2011 and mid-2012 related to Iran's nuclear activities led to a large and unexpected decrease in Iran's oil production in 2013, and crude oil output fell to 2.7 million b/d. These sanctions targeted Iran's petroleum exports and imports, prohibited large-scale investment in the country's oil and natural gas sector, and cut off Iran's access to European and U.S. sources for financial transactions. Further sanctions targeting the Central Bank of Iran were implemented against institutions doing business with the bank, while the EU imposed an embargo on Iran's oil and banned European Protection and Indemnity Clubs (P&I Clubs) from providing Iran's oil tankers with insurance and reinsurance. Before the 2012 sanctions, Iran was the second-largest producer in OPEC after Saudi Arabia.

Following JCPOA's start in January 2016 and Iran's renewed ability to export oil to Europe, Iran's exports immediately rose, and as a result, Iran's crude oil production once again exceeded pre-2012 levels. In 2017, Iran produced 4.8 million b/d of petroleum and other liquids, and more than 3.8 million b/d was crude oil and the remainder was condensate and hydrocarbon gas liquids (HGLs). Iran's total liquids production rose between 2015 and 2017 by 1.2 million b/d, supported by continued increases in exports.

After the United States withdrew from the JCPOA in 2018, Iran's crude oil production substantially declined. The United States' and Iran's governments reportedly began discussions in early 2021 that may result in the return to the agreement. If oil sanctions are lifted on oil exports, Iran's crude oil production could increase to its capacity of 3.8 million b/d within about 18 months.

Crude oil streams and oil fields

Most of Iran's crude oil production comes from the country's southwestern onshore fields, where Iran Heavy and Iran Light grades are produced. This area accounted for about 88% of Iran's total crude oil production capacity in 2019.[13] Iran Heavy is a medium-heavy, high-sulfur crude oil (29.6° API, 2.24% sulfur) and is sourced from some of Iran's largest oil fields, including the Gachasaran, Marun, Ahwaz, and Bangestan. Iran Light is similar in quality to Arab Light, with 33.6° API and 1.46% sulfur content. Iran Light is produced at several onshore fields in the Khuzestan province, but two-thirds of the Iran Light volume comes from three fields—Ahwaz, Karanj, and Aghajari.[14] All of these fields are decades old and have large decline rates. Sustaining production capacity will require EOR techniques, including the injection of natural gas into oil reservoirs to boost recovery rates.

In addition to its Heavy and Light grades, Iran also produces Azadegan, Doroud, Foroozan, Lavan Blend, Soroush/Nowruz, and Sirri. Azadegan is a relatively new stream, with production totaling about 0.2 million b/d in 2020 (down from 0.3 million b/d in 2017), from the Azadegan oil field (called Majnoon on the Iraqi side). Azadegan's plateau production will likely reach nearly 0.7 million b/d.[15]

While Iran developed the giant South Pars natural gas field, it also increased condensate output, which averaged 0.7 million b/d between 2018 and 2020. Condensate production of 0.7 million b/d is below Iran's production capacity of nearly 0.9 million b/d because of limiting export sanctions and lack of storage. However, Iran has managed to increase its condensate production capacity by developing South Pars, despite sanctions. We assess that Iran could produce more than 0.8 million b/d of condensate within one year without sanctions or other limiting factors.

Upstream Projects

Iran's medium-term plans to expand production capacity and crude oil output are ambitious and depend on the available international funding, expertise, and technology. The lack of foreign investment during the past few years as a result of sanctions prompted Iran to turn to local companies to develop its oil projects. However, local firms are limited in the capital and technology they need to maintain production at mature fields. The plans are focused on developing the West Karun oil fields located in the southwestern region, including Azadegan, Yadavaran, and Yaran. These fields straddle fields in neighboring Iraq. In addition, Iran plans to maintain and increase production capacity at fields with high-decline rates.

According to Iran's petroleum ministry, production from the West Karun fields was about 400,000 b/d in 2020, and target output is 1.2 million b/d.[16] In July 2020, Iran awarded contracts to local firms to raise output in the South Azadegan and Yaran fields. PetroPars, a subsidiary of NIOC, won a contract to double the production of South Azadegan from 140,000 b/d to 320,000 b/d by 2023.[17] Iran awarded local firm Persia Oil a contract to increase production from the North and South Yaran fields by 11,000 b/d over 10 years, from about 50,000 b/d in mid-2020.[18] Yadavaran is producing about 110,000 b/d of crude oil, which already surpassed its Phase 1 capacity of 85,000 b/d. A second phase will likely bring production capacity up to 180,000 b/d.[19]

To improve recovery rates at a number of mature fields, NIOC signed 28 contracts with several local companies in three phases between 2019 and 2021. These contracts are meant to bolster crude oil production from onshore and offshore fields by about 350,000 b/d.[20]

Exports

Iran's exports of crude oil and condensate increased sharply in 2016. However, Iran's exports have fallen at a faster rate than its production since the United States announced in May 2018 its withdrawal from the JCPOA. In 2017 (and before sanctions were imposed), buyers of Iran's crude oil and condensates were China (25%), India (17%), Turkey (9%), South Korea (13%), and Europe (20%). South Korea began to import much condensate from Iran to fuel its new condensate refineries.

Before the 2011 and 2012 sanctions, European refiners had been purchasing and processing Iran's crude oil, but they stopped their imports in early 2012. In 2016 and 2017, some European countries—Croatia, France, Greece, Italy, Malta, Netherlands, Poland, and Spain—resumed their purchases of Iran's oil after the JCPOA was implemented. The United States has not imported crude oil and condensate from Iran in several decades.

In addition to crude oil and condensate, Iran also exports petroleum products. According to FGE, Iran had a supply surplus of all petroleum products starting in 2019. Most of the petroleum product exports went to Asia, neighboring countries, and Syria.[21]

Oil terminals

The terminals at Kharg, Lavan, and Sirri Islands, located in the Persian Gulf, handle almost all of Iran's crude oil exports. Iran also has two small crude oil terminals at Cyrus and Bahregansar, one terminal along the Caspian Sea, and other terminals that handle mostly refined product exports and imports. Iran exports condensate from the South Pars natural gas field through the Assaluyeh terminal.

Kharg Island, the largest export terminal in Iran, is located in the northeastern part of the Persian Gulf. Most of Iran's crude oil exports are sent through Kharg, which includes a main terminal and a four-berth sea island (three of which are operational). The terminal processes all onshore production (the Iran Heavy and Iran Light Blends) and offshore production from the Foroozan field (the Foroozan Blend). NIOC has reportedly upgraded the terminal to handle a maximum loading capacity of 7 million b/d.[22]

Lavan Island mostly handles exports of the Lavan Blend, sourced from offshore fields. Lavan is Iran's highest-quality export grade (35.4° API, 1.67% sulfur) and one of Iran's smallest streams, at a production volume of about 115,000 b/d in 2018. Lavan's storage capacity is 5.5 million barrels and has a loading capacity of 200,000 b/d.[23]

Sirri Island serves as a loading port for the medium-gravity, high-sulfur Sirri Blend produced in the offshore fields. Its storage capacity is 4.5 million barrels.[24]

Neka is Iran's Caspian Sea port, which was built in 2003 to receive crude oil imports from the Caspian-region producers under swap agreements. The port's loading capacity is about 150,000 b/d. The terminal facilitates swap agreements with Azerbaijan, Kazakhstan, and Turkmenistan. Under these agreements, Iran receives crude oil that is processed in the Tehran and Tabriz refineries at its Caspian Sea port of Neka. In return, Iran exports the same amount of crude oil from Kharg Island. The terminal operations stopped when sanctions on Iran began in 2018.[25]

Assaluyeh terminal is where Iran's South Pars condensate is loaded for exports, mainly to China, India, Japan, South Korea, and UAE. In addition to condensate, the port also loads liquefied petroleum gas (LPG), sulfur, and petrochemical products.[26]

Qeshm oil terminal, located on Qeshm Island near the Strait of Hormuz, began operations in mid-2020 with 3.2 million barrels of storage capacity for either crude oil, condensates, or oil products. A second phase is slated to add another 3.2 million barrels of storage capacity in late 2021.[27]

Jask oil terminal and the accompanying 620-mile Goreh-Jask pipeline project, which will transport crude oil from Goreh, Iran, to the terminal, are under construction. This oil terminal will be Iran's first oil export facility east of the Strait of Hormuz, allowing the country to bypass any disruption that may occur within the Persian Gulf. Ultimately, Iran plans to install a total loading capacity of 2 million b/d and storage capacity of 20 million barrels at the project. Initially, at least 2 million barrels of storage capacity and 1 million b/d of loading capacity will be available at the terminal, and the Goreh-Jask oil pipeline is scheduled to come online by 2022.[28]

The export terminals **Bandar Mahshahr** and **Abadan** (also known as Bandar Imam Khomeini), near the Abadan refinery, are used to export refined product from the Abadan refinery. **Bandar Abbas**, located near the northern end of the Strait of Hormuz, is Iran's main fuel oil export terminal.

Consumption

Iran has the second-largest oil-consuming economy in the Middle East after Saudi Arabia. Domestic petroleum products used in Iran are mainly diesel, gasoline, and fuel oil. Starting in 2019, Iran's oil product consumption was completely met with domestically refined product. Historically, Iran's consumers relied on imported gasoline because of limited refining capacity to meet domestic needs.

However, following upgrades to existing refineries and the start of the third phase of the Persian Gulf Star refinery at the beginning of 2019, Iran's gasoline production grew significantly, which allowed export of gasoline that year.[29]

Refining sector

In the past, Iran had limited domestic oil refining capacity, and domestic demand relied on imports of refined products, especially gasoline. In response to international sanctions and the resulting difficulty in purchasing refined products, Iran's domestic refining capacity expanded. As of 2020, total crude oil distillation and condensate splitter capacity in Iran was more than 2.4 million b/d. The Persian Gulf Star condensate refinery, which processes condensates from Iran's South Pars natural gas field, came online in phases, starting in 2017 and continuing through 2019, with an initial design capacity of 360,000 b/d. More processing capacity to produce lighter petroleum products such as gasoline allowed Iran to substantially increase its gasoline output and become self-sufficient in all petroleum products by 2019. In early 2020, NIORDC, the state oil refiner, raised the capacity of Persian Gulf Star to 420,000 b/d, and it has plans to increase capacity by another 60,000 b/d to process more condensates from the South Pars field.[30]

Although Iran does not expect to add any significant crude oil distillation capacity in the next several years, it has plans to upgrade existing refineries that would produce lighter products such as diesel and gasoline and reduce output of fuel oil. However, some of these projects are currently on hold as a result of U.S. sanctions.[31]

Table 2. Oil refineries in Iran, 2020

Refinery	Nameplate crude oil distillation capacity (thousand b/d)
Abadan	360
Isfahan	360
Bandar Abbas	330
Tehran	250
Arak	250
Borzuyeh	120
Persian Gulf Star	420
Tabriz	110
Shiraz	60
Lavan	60
BooAli Sina	40
Kermanshah	22
Aras 2	10

Bushehr	10
Aras 1	5
Yazd	3
Total	**2,410**

Source: Created by the U.S. Energy Information Administration, based on data from Facts Global Energy, December 2020, and *Middle East Economic Survey*

Pipelines

An extensive domestic oil pipeline network exists in Iran, including 20 crude oil and product pipelines ranging in length from 93 miles to 525 miles. The longest pipeline in Iran is the product line that runs between Rey and Mashahad. The longest crude oil pipeline transports oil between Ahavaz and Rey and supplies feedstock to the Tehran, Arak, and Tabriz refineries. In addition, a new 36-inch condensate pipeline (Assaluyeh-Bandar Abbas) ships feedstock from Assaluyeh to the Persian Gulf Star refinery.[32]

Iran's future plans include construction of four additional petroleum product pipelines, including a new line that will transport gasoline throughout Iran from the Persian Gulf Star refinery.

Natural gas

Reserves

Iran has a high success rate of natural gas exploration, which is estimated at 80% compared with the world average success rate of 30% to 35%, according to FGE.[33] In late 2019, NIOC discovered Eram, a large independent onshore natural gas field with 12 trillion cubic feet of recoverable reserves.[34] However, because of its vast amounts of undeveloped known reserves, Iran prioritizes developing those that are adjacent to currently producing fields.

Iran is the second-largest holder of natural gas reserves in the world, and most reserves are located in the offshore southwestern region.[35] The largest natural gas field (by reserves) in Iran is South Pars, a non-associated natural gas field located offshore in the Persian Gulf. South Pars is part of a larger natural gas structure that straddles the territorial water of Iran and Qatar called the North Field in Qatar. South Pars reserves account for almost 40% of Iran's total natural gas reserves. Other major natural gas fields in Iran include Kish, North Pars, Sardar-e-Jangal, Forouz-B, Aghar, Golshan, and Kangan. These fields and others also hold large amounts of condensate reserves. About 81% of Iran's natural gas reserves are nonassociated.[36]

Production

Iran is one of the world's largest dry natural gas producers. Iran's natural gas prospects have improved since production began in the South Pars field in 2003, and one additional phase is expected to come online by 2024.

Iran's use of natural gas in EOR increased 27% between 2007 and 2017. As natural gas production increases, the use of natural gas for EOR will likely continue to rise. After 2017, natural gas reinjection declined substantially because of strict U.S. sanctions on Iran's oil exports and the subsequent fall in oil production.[37] Use of EOR in the future will be key to stemming declines in Iran's existing oil fields, which have relatively high natural decline rates. Natural gas is flared when no infrastructure exists to capture, transport, and process gas associated with oil production. Iran was the fourth-largest source country of flared natural gas in 2019 behind Russia, Iraq, and the United States.[38]

South Pars is Iran's largest field by production volume; approximately 66% of Iran's production originated from this field in 2019. In addition to South Pars, other major sources of Iran's natural gas production include the Tabnak, Nar, Kangan, Khangiran, Homa, and Shanoul fields.[39]

South Pars Natural Gas Field

Natural gas production from South Pars is critical for meeting increasing domestic consumption and Iran's plans and obligations for exports. The development plan includes 24 phases. Because NIOC has commissioned several South Pars phases since 2014, Iran's natural gas production has increased significantly.

Discovered in 1990 and located 62 miles offshore in the Persian Gulf, South Pars has a 24-phase development plan, with 23 phases already operational, although not all of these phases have reached maximum production capacity. Currently, Phase 11 is under development, and four phases began operations in 2019. Each of the 24 phases has a combination of natural gas with condensate and/or HGLs. Pars Oil and Gas Company (POGC), a subsidiary of NIOC, manages the project.[40] According to FGE, development of the South Pars natural gas field has so far required $80 billion in investment, and an additional $20 billion is needed to complete the remaining phase and sustain production from several other phases.[41]

After the U.S. re-imposed sanctions, China's CNPC and France's Total withdrew from South Pars Phase 11 development. As a result, in 2020, local companies led by PetroPars, resumed work to develop the block. The first stage of development involves installing all of the offshore equipment and drilling 30 wells. Field drilling began in late 2020, and production could begin as early as 2023. To maintain production capacity for 20 years, Iran will need to set up offshore compression stations to maintain natural gas flow. However, this stage is on hold for now.[42]

Table 3: South Pars natural gas field development

Phase	Natural gas capacity (Bcf/d)	Condensate capacity (b/d)	Start-up year
1	1	40,000	2004
2 3	2	80,000	2003
4 5	2	80,000	2005
6 7 8	3	120,000	2008

9 10	2	80,000	2009
11	2	80,000	2023
12	3	120,000	2014
13	2	75,000	2019
14	2	75,000	2018
15 16	2	75,000	2015
17 18	2	75,000	2016
19	2	75,000	2017
20 21	2	75,000	2017
22 23 24	2	75,000	2019
Total	**29**	**1,125,000**	

Source: Table created by the U.S. Energy Information Administration, based on data from Facts Global Energy, December 2019 and December 2020
Note: billion cubic feet per day=Bcf/d; barrels per day=b/d.

Iran has identified several undeveloped natural gas fields, such as Farzad A and B, Balal, and Kish, although sanctions have slowed any efforts to advance these projects.

Imports and exports

Natural gas pipeline exports from Iran accounted for about 2% of global trade in 2019.[43] Iran trades relatively small volumes of natural gas regionally via pipelines, although since 2017, exports have risen substantially. In 2020, all of Iran's imports came from Azerbaijan, and about 97% of Iran's exports went to Iraq and Turkey.[44]

Iran's natural gas exports to Iraq started in June 2017 to fuel electric power plants near Baghdad. In July 2018, natural gas from Iran to Basrah began through a second export pipeline. Iraq's power plants will likely continue to depend on natural gas from Iran to help meet growing electricity consumption needs until natural gas production in Iraq increases sufficiently to meet domestic demand.

Iran and Armenia trade small volumes of natural gas and electric power through a 20-year swap contract that began in 2004.[45] Azerbaijan and Iran have been trading natural gas under a natural gas swap contract since 2004. Iran exports natural gas to Azerbaijan's Nakhchivan province, and in return, Azerbaijan exports natural gas via pipeline connections to Iran's northwestern city of Astara.

Iran's imports of natural gas from Turkmenistan began in 1997 in response to a lack of domestic infrastructure that would deliver natural gas from southern Iran to the major consuming centers in the north. Turkmenistan's natural gas volumes filled this critical gap for years, especially during winter months. Iran's imports of Turkmenistan's natural gas peaked in 2015 at about 330 Bcf, but they gradually declined and ultimately stopped in 2019. The decrease is partly the result of contractual disputes between Iran and Turkmenistan, which have at times resulted in a complete stop of natural gas trade between the two countries. In January 2017, Turkmenistan halted natural gas exports to Iran over a reported nonpayment for deliveries. In response, Iran built a pipeline between the city of Damghan and Neka in the north, reducing the need for Turkmenistan's natural gas.[46]

No infrastructure exists in Iran to export or import LNG, despite Iran's aspirations, dating back to the 1970s, to build a liquefaction facility. In past years, NIOC started construction projects to build an LNG export plant, but most of the work has stopped. The lack of technology and foreign investment, stemming from decades-old international sanctions, made obtaining foreign financing and purchasing necessary technology difficult. NIOC has spent over $2 billion on developing the Iran LNG project in Tombak, near the city of Assaluyeh. This facility has a design capacity of 520 Bcf per year, but sanctions have prevented continued work on this project. NIOC is offering shares in the ownership for foreign assistance to finish the project. In addition to these large-scale LNG projects, plans existed to construct small- and medium-sized LNG plants in 2017. However, development has not moved forward because the companies involved cannot agree on the contract terms and natural gas prices.[47]

Proposed regional pipelines

Iran's potential to become an important natural gas supplier is significant, and some agreements exist with neighboring countries to export natural gas via planned regional pipelines. However, several challenges related to Iran's natural gas sector remain that may complicate the expected volumes from these projects. Some of these challenges include:

- Iran's domestic growth in natural gas demand
- Iran's reliance on reinjecting domestic natural gas to augment oil recovery
- International sanctions that have hindered Iran's access to technology and foreign investment
- Disagreements between Iran and potential buyers over natural gas prices

In addition, competition from other supply sources such as LNG or new domestic natural gas production present major obstacles for some of these projects.

Iran-Oman Pipeline: In March 2014, Iran and Oman agreed to form a joint venture that would deliver more than 365 Bcf per year of Iran's natural gas to Oman. Some of Iran's natural gas volumes were planned to be exported as LNG from Oman. However, Oman's development of its domestic natural gas resources, including tight gas development projects, has removed some of the need to import natural gas from Iran. The project would require a new pipeline (half of which would be at subsea levels), and little progress has been made so far on its construction.

Iran-Pakistan Pipeline: Construction of one leg on Iran's side of the pipeline is complete, but construction on Pakistan's side has been repeatedly delayed and has yet to start. In 2009, when the agreement was signed, Pakistan agreed to import 274 Bcf per year of natural gas, and the trade was supposed to commence in December 2014. Given the lack of progress on Pakistan's side and increasing LNG imports into Pakistan, this project is not likely to materialize.[48]

Iran-UAE Gas Contract: Although Iran's natural gas pipeline system is connected to the UAE, Iran has so far refused to sell its natural gas to UAE. Iran and UAE's Crescent Petroleum had signed an agreement to trade natural gas on a 20-year term with Iran shipping natural gas produced at the Salman field to the city of Sharjah. However, after repeated cancellations, the contract was referred for international arbitration. The court ruled that the contract was valid and that Crescent Petroleum had a right to terminate the contract and receive compensation from NIOC. The parties are waiting on a final court decision on whether NIOC is liable for damages for the full period of the agreement.[49]

Electricity

Natural gas is Iran's primary fuel source for electricity generation. Nuclear and renewables (mostly hydropower) make up the remaining fuel sources used to generate electricity in Iran.

Iran's government has ambitious plans to expand electric power generation capacity, including natural gas-fired, renewable, and nuclear facilities. Natural gas-fired generation likely will continue to play an important role in the electric power sector in Iran, and a number of natural gas-fired projects are in various stages of development. Since 2012, Iran converted several of its simple gas-fired power plants to more efficient combined-cycle natural gas-fired units. The government plans to construct several more combined-cycle power units and continues to rely on natural gas for its primary electricity generation fuel.[50]

Iran's ambitious plans also extend to nuclear electric power generation. The government plans to construct two additional units to the Bushehr facility, Iran's only nuclear power plant, which became fully operational in late 2013. Currently, Bushehr has 915 megawatts (MW) of net capacity.[51] One of these units is under construction and expected to begin operations in 2024 at the earliest, and the third Bushehr reactor is scheduled to begin operations in 2026. Combined, these units will add 1,948 MW to Iran's current net nuclear-powered capacity.[52]

Construction at the Bushehr power plant originally began in the mid-1970s, but the project was repeatedly delayed by the Iranian Revolution, the Iran-Iraq war, and then by problems associated with the Russian consortium that was awarded the construction contract. Iran's government took control of the plant's management in late 2013, about the same time the nuclear power plant began producing commercial power.

Iran's government also plans to add 5 gigawatts (GW) of new non-hydropower renewable capacity by 2022. According to Fitch Solutions, Iran has adopted a feed-in tariff to offer a fixed rate for renewable projects to promote these types of projects. [53] Although non-hydropower renewable capacity has increased gradually over the past few years to nearly 1 GW by 2021, it remains well below the 5 GW target because many projects have been shelved as a result of U.S. sanctions and a lack of investment.[54]

Notes

- In response to stakeholder feedback, the U.S. Energy Information Administration has revised the format of the *Country Analysis Briefs*. As of December 2018, updated briefs are available in two complementary formats: the Country Analysis Executive Summary provides an overview of recent developments in a country's energy sector and the Background Reference provides historical context. Archived versions will remain available in the original format.
- Data presented in the text are the most recent available as of April 30, 2021.
- Data are EIA estimates unless otherwise noted.

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India to commercialise strategic oil reserve capacity

Published date: 26 July 2021
Share:

India is planning to commercialise its strategic petroleum reserves (SPR) for the first time, including by generating revenue from leasing capacity and freeing up some of its stocks for trading.

State-controlled Indian Strategic Petroleum Reserves (ISPRL), which manages the country's strategic stocks, will trade the equivalent of 20pc of the reserves' capacity to hedge against price inflation or to supply refiners that are in urgent need of crude, ISPRL's chief executive HPS Ahuja told *Argus*.

Another 30pc will be leased to all third-party entities, Ahuja said. The commercialisation plans were approved by the cabinet.

The 50pc of capacity available for commercialisation is an addition to the government-to-government agreement between India and UAE, under which Abu Dhabi's state-owned Adnoc stores crude in the SPR at Mangalore. Adnoc has access to half the 11mn bl of capacity at Mangalore and can re-export the stored crude to third countries.

Two more strategic reserves will be constructed as part of the phase 2 expansion plan approved by the government. One is at Chandikhole in Odisha, with a capacity of 4mn t or about 29mn bl, while the other will be built at Padur in Karnataka with a capacity of 2.5mn t (about 18mn bl), Ahuja said.

"The Request for Proposal for building these storage facilities is under finalisation. An amount of 210 crore rupees ($28mn) was allocated in the budget of FY2020-21 under Phase II for land acquisition, and same has been disbursed to ISPRL," Rameswar Teli, India's oil and gas minister said in a written reply today in the Lok Sabha, the lower house of India's parliament.

Phase II covers commercial and strategic storage and will be done on a public-private partnership model, Ahuja added.

India's SPR has around 39mn bl of capacity, which Ahuja said meets about 9½ days of demand, with two other units at Vishakhapatnam (9.8mn bl) and Padur (18.4mn bl). India imports about 84pc of its crude needs.

By Sathya Narayanan

OIL DEMAND MONITOR: Air Travel Has a Relapse; Roads Get Busier
2021-07-27 11:29:58 GMT

- Commercial flights worldwide still lag 2019 by one quarter
- Toll road volumes gain w/w in Italy, Chile, Spain, Mexico

By Stephen Voss

(Bloomberg) -- Air traffic globally ebbed in the most recent industry data as coronavirus restrictions resulted in fewer travelers boarding planes in countries including Australia and Japan. Several gauges of European road traffic pointed to improving fuel demand from drivers.

Scheduled airline seats worldwide fell by 1 million in the week ended July 26, bucking a trend seen in prior weeks for more people to return to the skies. Jet fuel has been the petroleum product hardest hit by the pandemic, and travel restrictions in various nations continues to impede the demand recovery.

Seat capacity plunged by about 23% in Australia and 11% in Japan, despite the latter country hosting the Olympic Games, according to OAG Aviation. There also were small declines in China and the U.K. but increases in the U.S., South Korea, Germany and South Africa.

In the U.S., the world's biggest air-travel market, seat capacity has risen to 19.62 million a week, or 17% below the 2019 level, the OAG data show.

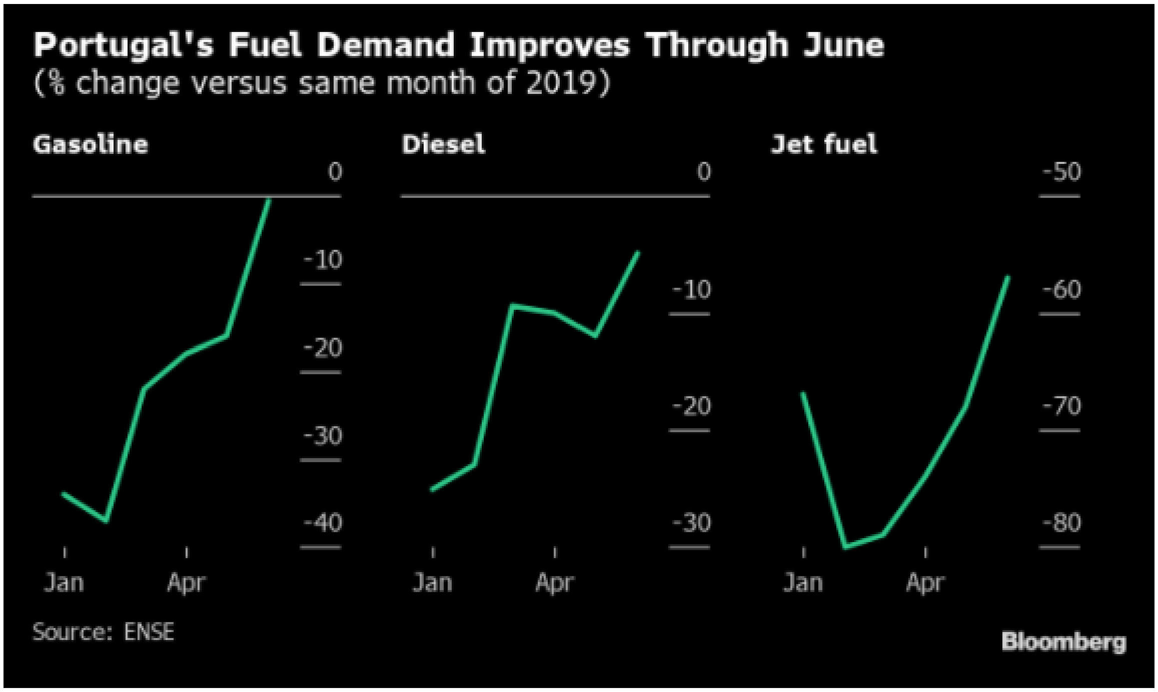
Across the world as a whole, the number of commercial flights still lags the 2019 level by 25%, using a seven day moving average calculated by FlightRadar24. Using OAG's seat capacity data, the worldwide figure is 31% lower than in 2019.

Busy Roads

In Europe, gasoline demand rose to a nine-month high in Portugal in June, and was just 0.6% below the same period of 2019, before the pandemic emerged, according to government reserves agency ENSE. More recent toll-road data showed traffic in Italy as close to 2019 levels as at any point this year.

Travel restrictions persist across Europe as governments weigh peaks and troughs in infection rates against a desire to allow the full resumption of hospitality and travel industries. The European Union announced earlier Tuesday that it achieved a target of giving at least one vaccination to 70% of adults before the end of July.

Traffic volumes versus 2019 improved noticeably in Chile and Italy in the latest week of toll gate data from Atlantia Group. Italy, Mexico and Brazil are all within 3% either side of the equivalent week of 2019. France and Spain made very small improvements and were 4.7% and 6.3% below, respectively, for the week ended July 25, according to Atlantia, which manages about 13,000 kilometers of toll motorways in Europe and Latin America.



Trucks Do Better

Separately, the most recent government-compiled traffic volume data for the U.S., U.K. and Poland showed passenger car use respectively down 2%, down 5% and up 3% versus 2019. Truck volumes are generally higher, benefiting from the increase in home deliveries during the pandemic. The number of miles traveled by U.S. trucks on interstate highways was 7% more than two years ago.

The U.K. government's weekly experimental statistics on road fuel sales, from sampled filling stations, will now be published once a month, starting Aug. 5, instead of once a week. The latest available data point, for July 4, showed total road fuel sales 7% below the normal level of several weeks before March 2020, when the nation's first pandemic lockdown began.

Traffic congestion has tailed off in recent weeks in many major cities in Europe, according to a weekly snapshot at 8 a.m. local time on Monday, using data from location technology company TomTom NV. Summer vacations and the end of school terms may be contributing to the decline in urban centers. Congestion remains fairly steady in New York, Los Angeles, Sao Paulo and Mexico City.

The Bloomberg weekly oil-demand monitor uses a range of high-frequency data series to help identify trends that may become clearer later in more comprehensive monthly figures.

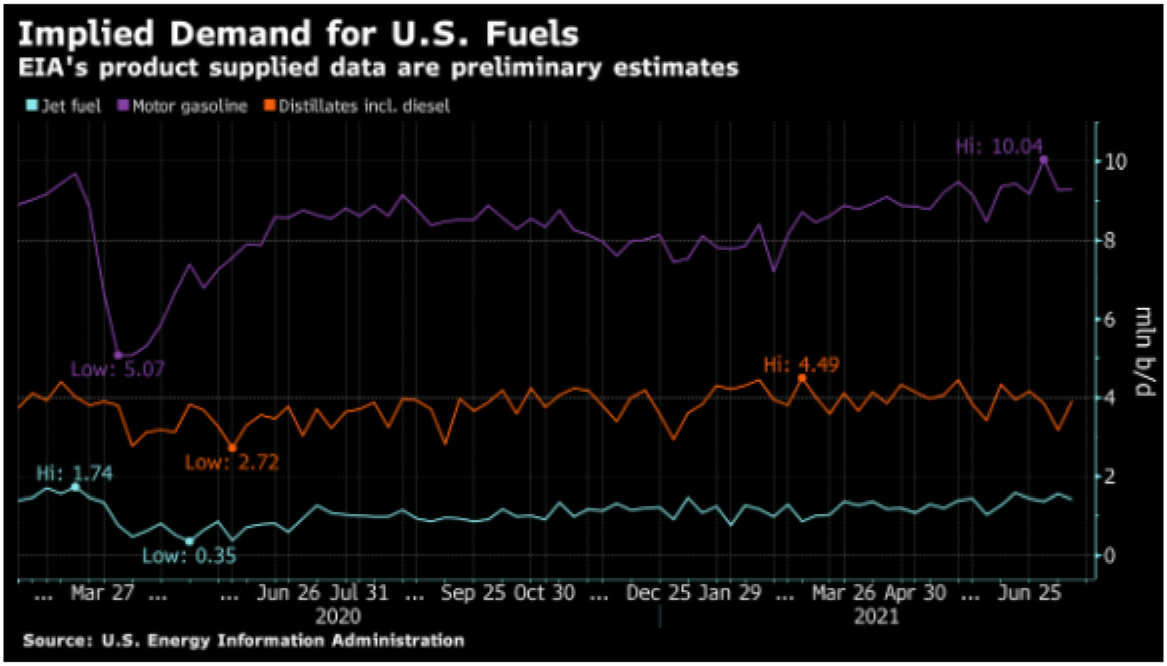
Following are the latest indicators, in the four tables below. The first two show fuel demand and mobility, the next shows air travel globally and the last is refinery activity:

Measure	Location	% y/y	% vs 2019	% m/m	Freq.	Latest as of Date	Latest Value	Source
Gasoline demand	U.S.	+8.7	-3.9	-1.5	w	July 16	9.3m b/d	EIA
Distillates demand	U.S.	+22	-8	-0.6	w	July 16	3.93m b/d	EIA
Jet fuel demand	U.S.	+30	-23	-11	w	July 16	1.41m b/d	EIA
Total oil products demand	U.S.	+17	-4.5	-0.8	w	July 16	20.6m b/d	EIA
All vehicles miles traveled	U.S.		+1		w	July 18	17.2b miles	DoT
Passenger car VMT	U.S.		-2		w	July 18	n/a	DoT
Truck VMT	U.S.		+8		w	July 18	n/a	DoT
All motor vehicle use index	U.K.	+12	-1	+2.1	d	July 19	99	DfT
Car use	U.K.	+13	-5	+2.2	d	July 19	95	DfT
Heavy goods vehicle use	U.K.	+8.1	+7	-0.9	d	July 19	107	DfT
Gasoline (petrol) avg sales per filling station	U.K.	+28	-6	-3	m	July 4	6,828 liters/d	BEIS
Diesel avg sales per station	U.K.	+16	-7.8	+2.9	m	July 4	9,614 liters/d	BEIS
Total road fuels sales per station	U.K.	+21	-7.1	+0.4	m	July 4	16,442 liters/d	BEIS
Gasoline	India	+18	+3.4	+14	2/m	July 1-15	1.03m tons	Bberg
Diesel	India	+13	-11	unch	2/m	July 1-15	2.49m tons	Bberg
Jet fuel	India	+20	-56	+19	2/m	July 1-15	132k tons	Bberg
Total Products	India	+1.5	-7.6	+8	m	June 2021	16.34m tons	PPAC
Passenger car traffic	Poland	+6	+3	+12	w	July 19-25	26,927	GDDKiA
Heavy goods traffic	Poland	+9	+13	-3.1	w	July 19-25	4,613	GDDKiA

Toll roads volume	France	-0.2	-4.7		w	July 18	n/a	Atlantia
Toll roads volume	Italy	+14	-2.4		w	July 18	n/a	Atlantia
Toll roads volume	Spain	+13	-6.3		w	July 18	n/a	Atlantia
Toll roads volume	Brazil	+22	-2.4		w	July 18	n/a	Atlantia
Toll roads volume	Chile	+140	+8.7		w	July 18	n/a	Atlantia
Toll roads volume	Mexico	+27	+1.3		w	July 18	n/a	Atlantia
All vehicles traffic	Italy	+15	+12	+13	m	June	n/a	Anas
Heavy vehicle traffic	Italy	+17	-1	+9	m	June	n/a	Anas
Gasoline	Portugal	+9.6	-0.6	+6.3	m	June	84k tons	ENSE
Diesel	Portugal	+2.2	-4.9	-1.3	m	June	375k tons	ENSE
Jet fuel	Portugal	+314	-57	+40	m	June	65k tons	ENSE
Gasoline	Spain	+40	+1.1		m	June	500k m3	Exolum
Diesel	Spain	+15	-8		m	June	2199k m3	Exolum
Jet fuel	Spain	+371	-61		m	June	268k m3	Exolum

The frequency column shows d for data updated daily, w for weekly, 2/m for twice a month and m for monthly.

* In DfT 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, 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.



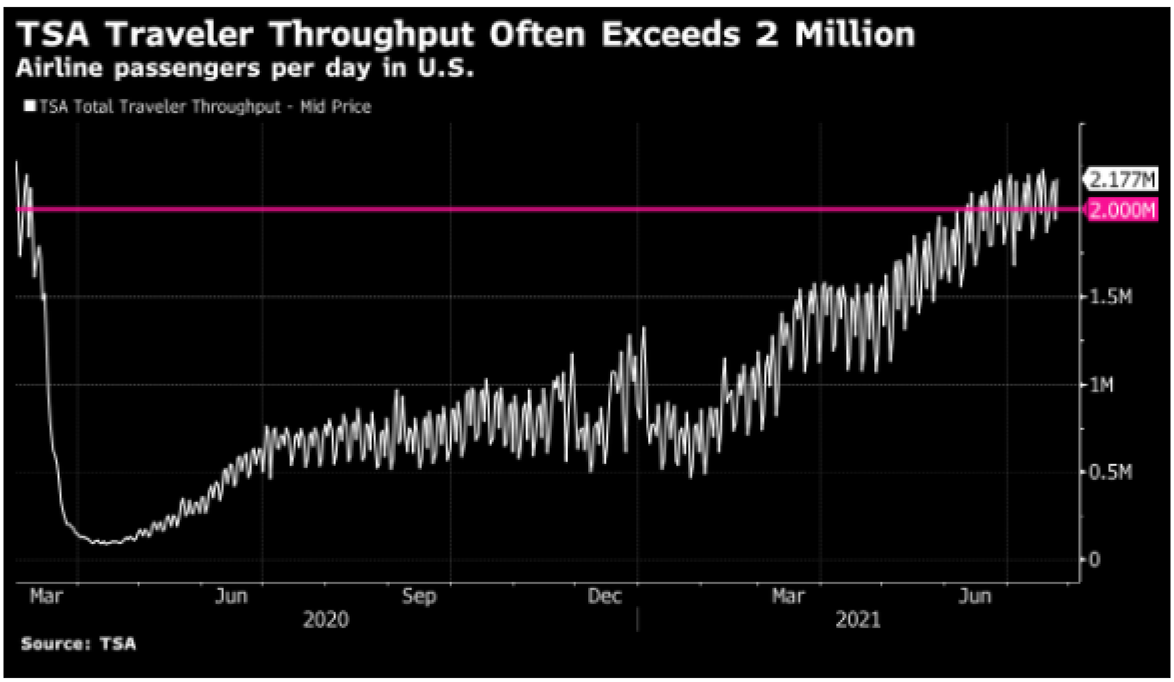
City Congestion:

Measure	Location	% chg vs 2019	% chg m/m	July 26	Jul. 19	Jul 12	Jul. 5	Jun. 28	Jun. 21	Jun. 14	Jun. 7	May 31	May 24
		(July 26)		Minutes of congestion at 8am local time									
Congestion	Tokyo	-24	+4	28	29	31	36	27	28	30	27	26	29
Congestion	Mumbai	-80	+50	7	9	5	6	5	5	4	4	2	2
Congestion	New York	-50	-4	16	14	18	0	16	16	22	23	2	20
Congestion	Los Angeles	-54	-7	16	18	17	3	17	16	19	20	3	21
Congestion	London	-49	-50	19	25	19	34	38	37	39	40	3	41
Congestion	Rome	-56	+71	22	23	23	35	13	36	34	49	24	38
Congestion	Madrid	-85	-65	5	8	13	14	16	18	22	27	22	23
Congestion	Paris	-64	-56	16	22	29	39	37	44	42	42	37	3
Congestion	Berlin	-59	-26	14	13	16	16	19	28	28	28	26	3
Congestion	Mexico City	-62	-23	19	20	22	23	24	21	26	24	22	23
Congestion	Sao Paulo	-50	-5	22	22	22	20	23	26	23	26	28	23

Source: TomTom. Note: M/m comparison is July 26 vs June 28. 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.	+190	-11	+0.4	d	July 25	2.18m people	TSA
Commercial flights	Worldwide	+48	-25	+8	d	July 26	94,045	FlightRadar24
Air traffic (flights)	Europe		-33	+13	d	July 26	22,558	Eurocontrol
Seat capacity	Worldwide	+42	-31		w	July 26	81.67m	OAG
Seat cap.	China	+21	+6.2		w	July 26	18.26m	OAG
Seat cap.	U.S.	+70	-17		w	July 26	19.62m	OAG
Seat cap.	India	+95	-32		w	July 26	2.70m	OAG
Seat cap.	Japan	-23	-54		w	July 26	1.99m	OAG
Seat cap.	Australia	+63	-70		w	July 26	624k	OAG
Seat cap.	Brazil	+200	-32		w	July 26	1.74m	OAG
Seat cap.	France	+48	-33		w	July 26	1.70m	OAG
Seat cap.	Germany	+54	-50		w	July 26	1.67m	OAG
Seat cap.	Spain	+59	-27		w	July 26	2.68m	OAG
Seat cap.	U.K.	+33	-61		w	July 26	1.53m	OAG
Seat cap.	S. Africa	+226	-68		w	July 26	185k	OAG



Refineries:

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.

Measure	Location	y/y chg	vs 2019 chg	m/m chg	Latest as of Date	Latest Value	Source
Crude intake	U.S.	+13%	-6%	-0.7%	July 16	16m b/d	EIA
Utilization	U.S.	+14 ppt	-1.7 ppt	-0.8 ppt	July 16	91.4 %	EIA
Utilization	Gulf Coast U.S.	+11 ppt	+1.2 ppt	-0.2 ppt	July 16	92.3 %	EIA
Utilization	East Coast U.S.	+44 ppt	+3 ppt	-7.2 ppt	July 16	80.4 %	EIA
Utilization	Midwest U.S.	+10 ppt	-3.4 ppt	-0.5 ppt	July 16	96.1 %	EIA
Apparent Oil Demand	China	-1.7%		+1.7%	June 2021	13.81m b/d	NBS
Indep. refs run rate	Shandong province, China	-3.2 ppt	+10 ppt	-3.1 ppt	July 23	71.5 %	SCI99
State refs run rate	East China	+4.7 ppt	+7 ppt	+5.6 ppt	July 15	82.2 %	SCI99
State refs run rate	South China	-3.4 ppt	+2.9 ppt	-3.1 ppt	July 15	80.7 %	SCI99

ROYAL DUTCH SHELL PLC
SECOND QUARTER 2021 RESULTS

BEN VAN BEURDEN, CHIEF EXECUTIVE OFFICER OF ROYAL DUTCH SHELL PLC

Welcome to our second quarter 2021 results presentation. Today, Jessica and I will talk about how we are delivering on our Powering Progress strategy, we will share an update on our financial framework and then we will provide insights into our strong Q2 performance.

The past year has proven to be challenging. In this environment, our operations, our supply chains and our people have shown immense resilience and we have continuously delivered safe operations, robust business performance and unmatched cash flows. So, although volatility in commodity prices and demand recovery might still continue for some time, we are confident in the strength of our cash generation potential.

Therefore, we are moving to the next phase of our capital allocation framework and we are stepping up distributions to our shareholders. We are rebasing our dividend and launching share buybacks this quarter, which Jessica will cover in more detail in a moment.

In our Powering Progress strategy, we are moving at pace to a net-zero emissions company purposefully and profitably. We are providing energy that the world needs today, while also building the energy business of the future. That is what Powering Progress is about.
So today, I will share the progress we are making in three areas: hydrogen, refining and carbon capture and storage technology - or CCS.

In hydrogen, we are building on our leading position. By 2035, we aim to achieve a double-digit share of sales of clean hydrogen, which is a market poised for growth.
We are currently offering our customers the opportunity to fuel with hydrogen across 50 sites for light-duty vehicles globally. And recently, we opened the first hydrogen station for trucks in the United States, and in the Netherlands, buses can refuel within 10 minutes. With a full tank of 25 kilos of hydrogen, buses can travel over 400 kilometres.
These are the first steps in building an extensive hydrogen network. In Europe, we are partnering with Daimler to roll out a hydrogen-refuelling network of 1200 kilometres which will join three green hydrogen production hubs. We have also started up Europe's largest PEM electrolyser in Germany for the production of green hydrogen with 10 megawatts capacity and plans are under way to expand it to 100 megawatts.

In refining, our strategy is to concentrate our portfolio into 5 Energy & Chemicals parks by the end of the decade, and that's from 8 refineries as of today. Our updated target reflects the sale of the Deer Park refinery. And, even in a challenging environment for refining, we have been making great progress in rationalising our portfolio and divesting refineries for value. And, by divesting, closing or converting our refineries, we are reducing Shell's Scope 1 and 2 emissions from refining by around 50% since 2018.

With CCS, as part of our strategy to reduce our own carbon emissions and those of our customers, we aim to capture and store an additional 25 million tonnes of CO2 a year by 2035.

And we have recently made announcements on two important CCS projects – Polaris at our Scotford facility in Canada, and the Acorn project in the UK. These will help us deliver low-carbon energy solutions to our customers and they make important contributions to our 2035 CCS ambition.

This is tremendous progress across our business pillars in delivering our strategy and while we transform and build the business of the future, our financial delivery remains strong.
Jessica, over to you.

JESSICA UHL, CHIEF FINANCIAL OFFICER OF ROYAL DUTCH SHELL PLC

Thank you, Ben.

With strong results in the previous quarters and outstanding cash generation from our businesses, we have reduced net debt by $12 billion since Q2 last year. This resilient performance gives us the confidence to move to the next phase of our capital allocation framework.

We committed to increase shareholder distributions once we reduced net debt. And today we are delivering on that commitment. Starting from Q2 2021, we are rebasing our dividend to 24 US cents per share, an increase of 38% from Q1 2021. This rebased dividend is now at a more meaningful level, and more in line with our cash generation track record. In addition, we will buy back up to $2 billion of our shares in the second half of 2021. As a result, we expect the full year 2021 shareholder distributions to be around the middle of the 20 to 30%

range of our cash flow from operations. And, from 2022, we plan to announce distributions on a quarterly basis.
As we move into the next phase of our capital allocation, let me emphasise that our cash priorities remain unchanged.
The first priority is disciplined base Cash capex and paying ordinary progressive dividends to our shareholders. Base Cash capex is the minimum spend that allows us to sustain our strategy… balancing between maintaining our assets, sustaining cash flows and investing for growth. We expect base Cash capex to be between $19 and 22 billion per year. And we will also grow our dividend per share by about 4% a year, subject to Board approval, in line with our progressive dividend policy.

The second priority is ensuring we have a strong balance sheet. For that, we will target AA credit metrics through the cycle.

That brings me to the third priority of our financial framework: additional shareholder distributions. These incremental distributions may be in the form of share buybacks and/or dividends. Every quarter, the Board will decide the amount of distributions above the ordinary dividend level, looking to optimise capital allocation between shareholder returns, balance sheet strength and accretive growth. The total distribution amount will then be tested to ensure it falls within the 20 to 30% range of the previous four-quarter rolling CFFO, rather than being determined by a target percentage within this range.

And finally, our fourth priority any cash surplus will be allocated in a balanced way between additional Cash capex and continued strengthening of the balance sheet. We will allocate the additional Cash capex in a measured and disciplined manner, and we expect to spend more than half of it on our Growth pillar.

This brings me to our performance in Q2 2021. Once again, we delivered strong financial results for the quarter. Our Adjusted Earnings increased to $5.5 billion, from $3.2 billion in Q1. Our Adjusted EBITDA, was $13.5 billion on a current cost of supplies basis. And we delivered $14.2 billion of cash flow from operations excluding working capital movements… one of the highest levels of cash generation on record. This shows we are well positioned to benefit from the global economic recovery. Our performance was particularly strong in Marketing, boosted by outstanding performance in Retail. Good margin management and growing convenience retail resulted in one of the best quarterly results for Retail in the last decade. And our cash conversion was once again robust, across all businesses, which shows the quality of our portfolio.

To demonstrate our strategy in action, I will highlight an important achievement from our Upstream joint venture BGC, in Basrah, Iraq. BGC will bring energy to around a million more homes than today, by capturing, processing and selling gas that companies in the region would otherwise flare. And, to support this development, the IFC of the World Bank, together with 8 international banks, is providing essential funding, a first of its kind in the Iraqi oil and gas sector, helping the country to access international capital markets. This funding will increase BGC's ability to reduce greenhouse gas emissions by around 10 million tons per annum, while materially improving local air quality. This is a great example of how our businesses contribute to our goals of Powering Lives, by providing energy and Respecting Nature, by reducing emissions.
And with that, let's return to Ben.

BEN VAN BEURDEN, CHIEF EXECUTIVE OFFICER OF ROYAL DUTCH SHELL PLC

Thank you, Jessica.
Today, I hope we have shown you how Shell is changing, progressing on the goals of our strategy and delivering value. Value today. Value tomorrow and value for decades to come. To shareholders and to wider society. Helping society heading towards net-zero emissions. That is our strategy. That is Powering Progress.
Thank you.

Royal Dutch Shell plc
July 29, 2021
www.shell.com/investors

DEFINITIONS AND CAUTIONARY NOTE

Adjusted Earnings is the income attributable to RDS plc shareholders for the period, adjusted for the after-tax effect of oil price changes on inventory and for identified items. In this presentation, "earnings" refers to "Adjusted Earnings" unless stated otherwise. Adjusted EBITDA (FIFO basis) is the income/(loss) attributable to Royal Dutch Shell plc shareholders adjusted for identified items; tax charge/(credit); depreciation, amortisation and depletion; exploration well write-offs and net interest expense. Adjusted EBITDA on a CCS basis is used to remove the impact of price changes on our inventories in our Oil Products and Chemicals segments, therefore enabling comparisons over time. In this presentation, "operating expenses", "costs" and "underlying costs" refer to "Underlying operating expenses" unless stated otherwise. Underlying operating expenses represent "operating expenses excluding identified items". Operating expenses consist of the following lines in the Consolidated Statement of Income: (i) production and manufacturing expenses; (ii) selling, distribution and administrative expenses; and (iii) research and development expenses. Cash flow from operating activities excluding working capital movements is defined as "Cash flow from operating activities" less the sum of the following items in the Consolidated Statement of Cash Flows: (i) (increase)/decrease in inventories, (ii) (increase)/decrease in current receivables, and (iii) increase/(decrease) in current payables.

In this presentation, "capex" refers to "Cash capital expenditure" unless stated otherwise. Cash capital expenditure comprises the following lines from the Consolidated Statement of Cash Flows: Capital expenditure, Investments in joint ventures and associates and Investments in equity securities. Free cash flow is defined as the sum of "Cash flow from operating activities" and "Cash flow from investing activities". Organic free cash flow is defined as free cash flow excluding inorganic cash capital expenditure, divestment proceeds and tax paid on divestments. In this presentation, "divestments" refers to "divestment proceeds" unless stated otherwise. Divestment proceeds are defined as the sum of (i) proceeds from sale of property, plant and equipment and businesses, (ii) proceeds from sale of joint ventures and associates, and (iii) proceeds from sale of equity securities. Net debt is defined as the sum of current and non-current debt, less cash and cash equivalents, adjusted for the fair value of derivative financial instruments used to hedge foreign exchange and interest rate risks relating to debt, and associated collateral balances. Reconciliations of the above non-GAAP measures are included in the Royal Dutch Shell plc Unaudited Condensed Financial Report for the second quarter and half year ended June 30, 2021.

This presentation contains the following forward-looking non-GAAP measures: Cash capital expenditure and Underlying operating expenses. We are unable to provide a reconciliation of the above forward-looking non-GAAP measures to the most comparable GAAP financial measures because certain information needed to reconcile the above non-GAAP measures to the most comparable GAAP financial measures is dependent on future events some of which are outside the control of the company, such as oil and gas prices, interest rates and exchange rates. Moreover, estimating such GAAP measures with the required precision necessary to provide a meaningful reconciliation is extremely difficult and could not be accomplished without unreasonable effort. Non-GAAP measures in respect of future periods which cannot be reconciled to the most comparable GAAP financial measures are estimated in a manner which is consistent with the accounting policies applied in Royal Dutch Shell plc's consolidated financial statements.

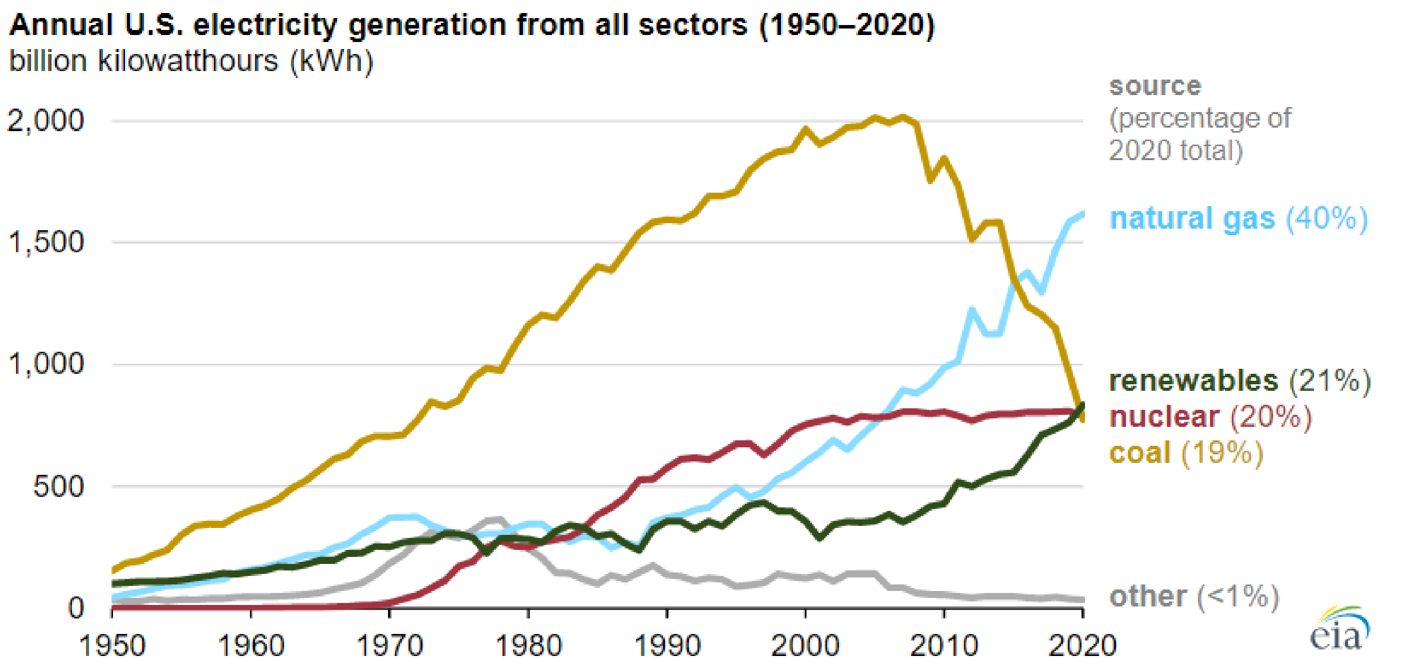
The companies in which Royal Dutch Shell plc directly and indirectly owns investments are separate legal entities. In this presentation "Shell", "Shell Group" and "Group" are sometimes used for convenience where references are made to Royal Dutch Shell plc and its subsidiaries in general. Likewise, the words "we", "us" and "our" are also used to refer to Royal Dutch Shell plc and its subsidiaries in general or to those who work for them. These terms are also used where no useful purpose is served by identifying the particular entity or entities. "Subsidiaries", "Shell subsidiaries" and "Shell companies" as used in this presentation refer to entities over which Royal Dutch Shell plc either directly or indirectly has control. Entities and unincorporated arrangements over which Shell has joint control are generally referred to as "joint ventures" and "joint operations", respectively. Entities over which Shell has significant influence but neither control nor joint control are referred to as "associates". The term "Shell interest" is used for convenience to indicate the direct and/or indirect ownership interest held by Shell in an entity or unincorporated joint arrangement, after exclusion of all third-party interest.

This presentation contains forward-looking statements (within the meaning of the U.S. Private Securities Litigation Reform Act of 1995) concerning the financial condition, results of operations and businesses of Shell. All statements other than statements of historical fact are, or may be deemed to be, forward-looking statements. Forward-looking statements are statements of future expectations that are based on management's current expectations and assumptions and involve known and unknown risks and uncertainties that could cause actual results, performance or events to differ materially from those expressed or implied in these statements. Forward-looking statements include, among other things, statements concerning the potential exposure of Royal Dutch Shell to market risks and statements expressing management's expectations, beliefs, estimates, forecasts, projections and assumptions. These forward-looking statements are identified by their use of terms and phrases such as "aim", "ambition", "anticipate", "believe", "could", "estimate", "expect", "goals", "intend", "may", "milestones", "objectives", "outlook", "plan", "probably", "project", "risks", "schedule", "seek", "should", "target", "will" and similar terms and phrases. There are a number of factors that could affect the future operations of Shell and could cause those results to differ materially from those expressed in the forward-looking statements included in this presentation, including (without limitation): (a) price fluctuations in crude oil and natural gas; (b) changes in demand for Shell's products; (c) currency fluctuations; (d) drilling and production results; (e) reserves estimates; (f) loss of market share and industry competition; (g) environmental and physical risks; (h) risks associated with the identification of suitable potential acquisition properties and targets, and successful negotiation and completion of such transactions; (i) the risk of doing business in developing countries and countries subject to international sanctions; (j) legislative, fiscal and regulatory developments including regulatory measures addressing climate change; (k) economic and financial market conditions in various countries and regions; (l) political risks, including the risks of expropriation and renegotiation of the terms of contracts with governmental entities, delays or advancements in the approval of projects and delays in the reimbursement for shared costs; (m) risks associated with the impact of pandemics, such as the COVID-19 (coronavirus) outbreak; and (n) changes in trading conditions. No assurance is provided that future dividend payments will match or exceed previous dividend payments. All forward-looking statements contained in this presentation are expressly qualified in their entirety by the cautionary statements contained or referred to in this section. Readers should not place undue reliance on forward-looking statements. Additional risk factors that may affect future results are contained in Shell's plc's Form 20-F for the year ended December 31, 2020 (available at www.shell.com/investors and www.sec.gov). These risk factors also expressly qualify all forward-looking statements contained in this presentation and should be considered by the reader. Each forward-looking statement speaks only as of the date of this presentation, July 29, 2021. Neither Royal Dutch Shell plc nor any of its subsidiaries undertake any obligation to publicly update or revise any forward-looking statement as a result of new information, future events or other information. In light of these risks, results could differ materially from those stated, implied or inferred from the forward-looking statements contained in this presentation.

The content of websites referred to in this announcement do not form part of this announcement. We may have used certain terms, such as resources, in this presentation that the United States Securities and Exchange Commission (SEC) strictly prohibits us from including in our filings with the SEC. Investors are urged to consider closely the disclosure in our Form 20-F, File No 1-32575, available on the SEC website www.sec.gov.

https://www.eia.gov/todayinenergy/detail.php?id=48896#

Renewables became the second-most prevalent U.S. electricity source in 2020



Source: U.S. Energy Information Administration (EIA), *Monthly Energy Review*
Note: This graph shows electricity net generation in all sectors (electric power, industrial, commercial, and residential) and includes both utility-scale and small-scale (customer-sited, less than 1 megawatt) solar.

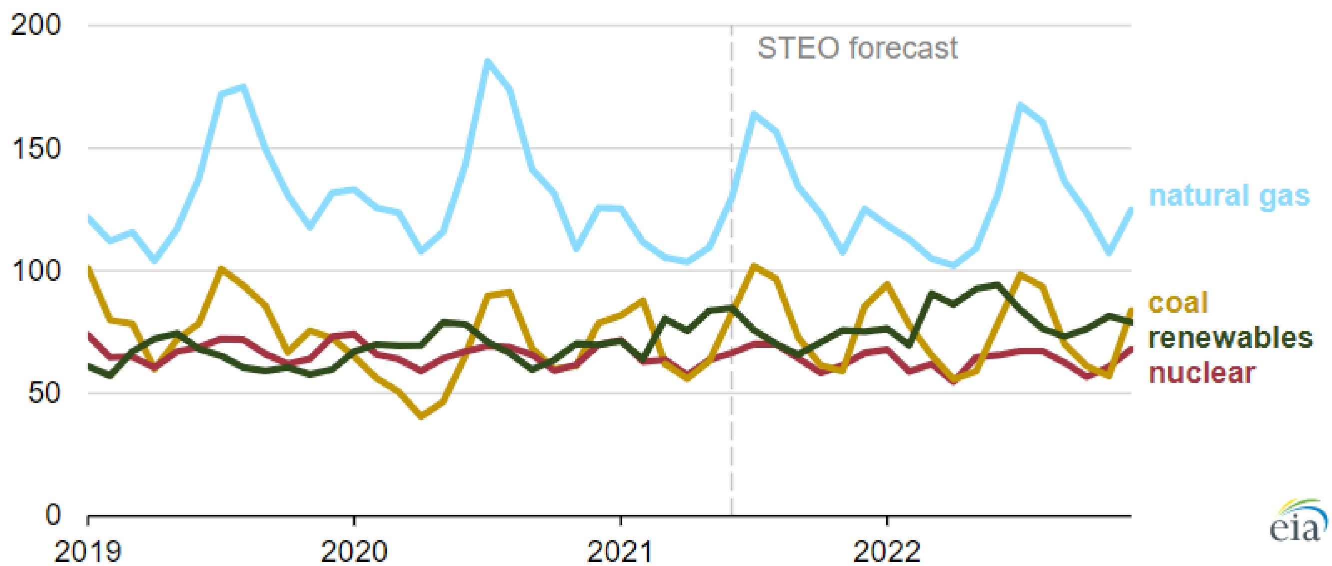
In 2020, renewable energy sources (including wind, hydroelectric, solar, biomass, and geothermal energy) generated a record 834 billion kilowatthours (kWh) of electricity, or about 21% of all the electricity generated in the United States. Only natural gas (1,617 billion kWh) produced more electricity than renewables in the United States in 2020. Renewables surpassed both nuclear (790 billion kWh) and coal (774 billion kWh) for the first time on record. This outcome in 2020 was due mostly to significantly less coal use in U.S. electricity generation and steadily increased use of wind and solar.

In 2020, U.S. electricity generation from coal in all sectors declined 20% from 2019, while renewables, including small-scale solar, increased 9%. Wind, currently the most prevalent source of renewable electricity in the United States, grew 14% in 2020 from 2019. Utility-scale solar generation (from projects greater than 1 megawatt) increased 26%, and small-scale solar, such as grid-connected rooftop solar panels, increased 19%.

Coal-fired electricity generation in the United States peaked at 2,016 billion kWh in 2007 and much of that capacity has been replaced by or converted to natural gas-fired generation since then. Coal was the largest source of electricity in the United States until 2016, and 2020 was the first year that more electricity was generated by renewables and by nuclear power than by coal (according to our data series that dates back to 1949). Nuclear electric power declined 2% from 2019 to 2020 because several nuclear power plants retired and other nuclear plants experienced slightly more maintenance-related outages.

We expect coal-fired electricity generation to increase in the United States during 2021 as natural gas prices continue to rise and as coal becomes more economically competitive. Based on forecasts in our *Short-Term Energy Outlook* (STEO), we expect coal-fired electricity generation in all sectors in 2021 to increase 18% from 2020 levels before falling 2% in 2022. We expect U.S. renewable generation across all sectors to increase 7% in 2021 and 10% in 2022. As a result, we forecast coal will be the second-most prevalent electricity source in 2021, and renewables will be the second-most prevalent source in 2022. We expect nuclear electric power to decline 2% in 2021 and 3% in 2022 as operators retire several generators.

Monthly U.S. electricity generation from all sectors, selected sources (Jan 2019–Dec 2022)
billion kilowatthours



Source: U.S. Energy Information Administration, *Monthly Energy Review* and *Short-Term Energy Outlook* (STEO)
Note: This graph shows electricity net generation in all sectors (electric power, industrial, commercial, and residential) and includes both utility-scale and small-scale (customer-sited, less than 1 megawatt) solar.

Principal contributor: Mickey Francis

Tags: generation, coal, electricity, natural gas, nuclear, renewables

https://www.dailymail.co.uk/news/article-9828441/Boris-Johnson-puts-ban-new-gas-boilers-five-years-2040.html

Boris Johnson 'puts ban on new gas boilers back by five years to 2040' after backlash over soaring heating costs

- **Britons are set to be allowed up to five more years before a ban on sales of all new gas boilers comes into force**
- **Prime Minister Boris Johnson is looking at delaying the ban by five years to 2040 over soaring 'net zero' cost**
- **Move would give millions of households more time for new hydrogen boilers and heat-pumps to fall in price**
- **It comes amid a mounting backlash over the spiralling cost of Mr Johnson's so-called green revolution**

By JACK WRIGHT FOR MAILONLINE
PUBLISHED: 19:46 EDT, 26 July 2021 | **UPDATED:** 19:49 EDT, 26 July 2021

Britons are set to be allowed up to five more years before a ban on sales of all new gas boilers comes into force, in a major row-back for Boris Johnson amid a backlash over the soaring cost of 'net zero' ahead of the COP26 climate conference in Glasgow later this year.

The Prime Minister is looking at delaying the ban by five years to 2040, in a move which would give millions of UK households more time for new hydrogen boilers and heat-pumps to fall in price, and for businesses to pump more money into shifting people over gradually.

The public is set to be incentivised to buy an eco-friendly heat-pump next time their boiler breaks down - but the delay to introducing the ban means working boilers could have to be taken out before 2050, or the UK could fail to hit its 'net zero' carbon emission targets.

It comes amid a mounting backlash over the spiralling cost of Mr Johnson's so-called green revolution, with Government insiders fearful that the proposals could add another £400billion on top of the enormous sums accrued during the Covid pandemic.

Hydrogen boilers are one of the possible replacements for gas boilers, with others including ground source or air source heat pumps, but these cost upwards of £14,000 or £11,000 respectively.

Other options include solar photovoltaic panels or solar water heating which both come in at about £5,000 for a full fitting. A hydrogen-ready boiler is intended to be a like-for-like swap for an existing gas boiler, but the cost is unknown, with estimates ranging from £1,500 to £5,000.

Britons are set to be allowed up to five more years before a ban on sales of all new gas boilers comes into force, in a major row-back for Boris Johnson amid a backlash over the soaring cost of 'net zero' ahead of the COP26 climate conference in Glasgow later this year (stock image)

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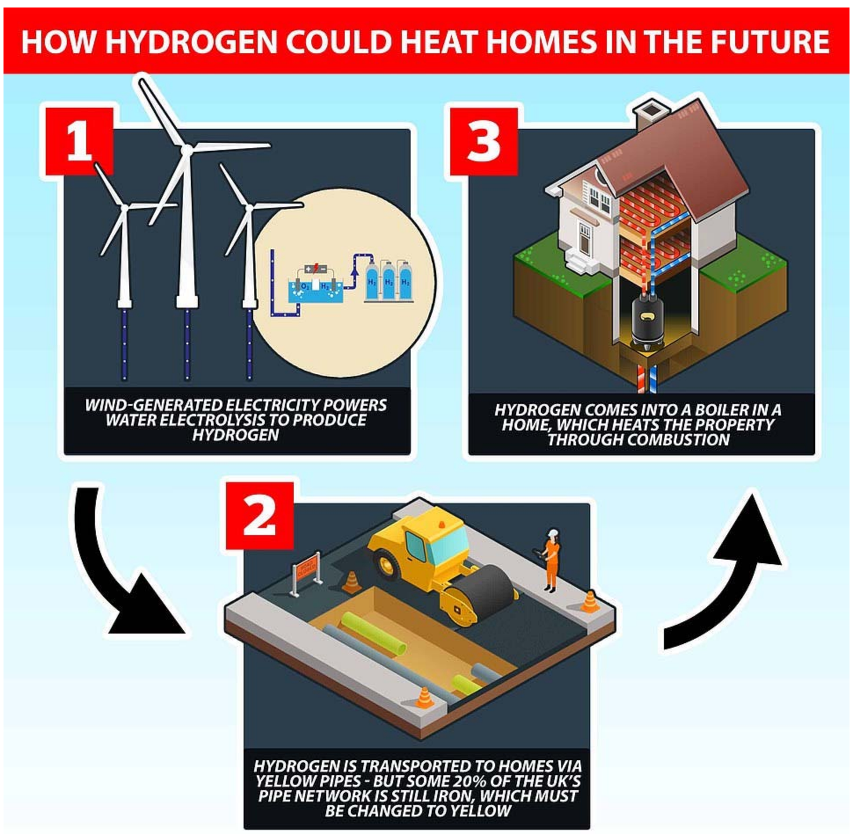
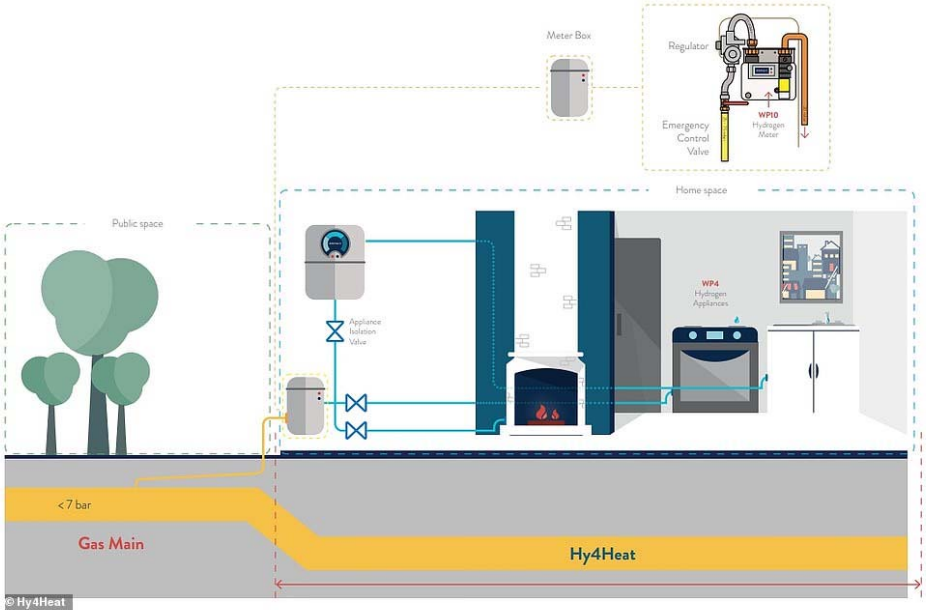
The Prime Minister is looking at delaying the ban by five years to 2040, in a move which would give millions of UK households more time for new hydrogen boilers and heat-pumps to fall in price, and for businesses to pump more money into shifting people over gradually



If hydrogen is part of a zero-carbon future, it could have to be produced by electrolysis (as shown above), which sees electric currents passed through water. Another option is for the plants to capture the carbon emissions and pump them underground



The Hy4Heat innovation programme has shown how hydrogen homes would be powered

The 28 million homes in the UK contribute more than a third towards the country's carbon emissions, which must be slashed to 'net zero' by 2050 under the Government's legal obligations.

Ministers had considered issuing millions of households with so-called 'green cheques' worth hundreds of pounds to compensate them for making their homes more eco-friendly and offset the cost of higher gas bills - but now only the poorest people in society are set to get grants to cover the cost of swapping.

As part of the net zero plan - which would decarbonise the economy by 2050 - No10 had been expected to publish in the spring details of the strategy for moving away from gas boilers ahead of Glasgow's COP26 climate change conference in November. But this has been delayed until the autumn amid mounting alarm about the bill.

The Chancellor - who is already looking for ways to pay back the £400billion cost of the Covid crisis and the £10billion a year required to reform long-term care for the elderly - is understood to have baulked at estimates of hitting net zero at more than £1.4trillion.

The independent Office For Budget Responsibility calculated the cost of making buildings net zero at £400billion, while the bill for vehicles would be £330billion, plus £500billion to clean up power generation and a further £46billion for industry. After energy savings across the economy, this would leave a £400billion bill for the Treasury.

The OBR also warned that the Government would need to impose carbon taxes to make up for the loss of fuel duty and other taxes.

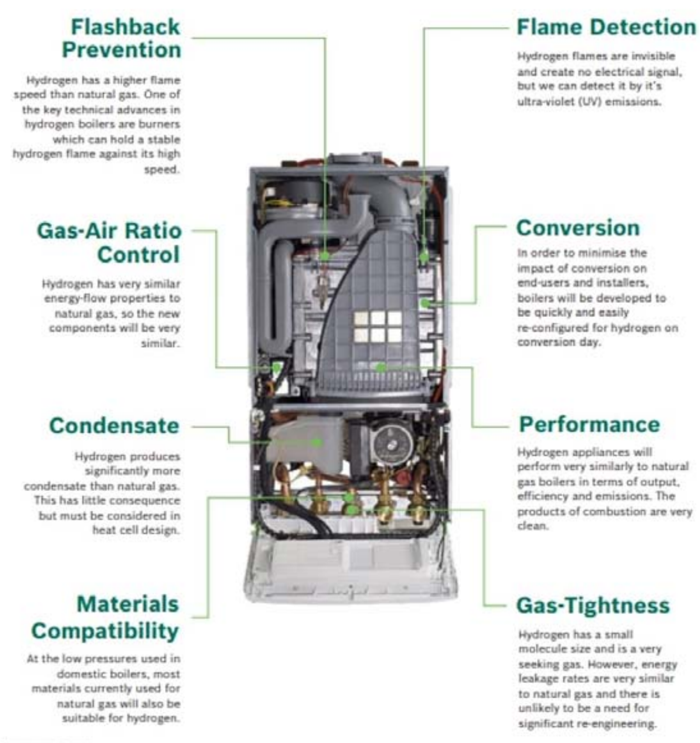
It is the latest claim of tensions between No10 and No11 over the strains on the public purse.

Last week, The Mail on Sunday revealed Mr Sunak had warned that reforms to social care would not be affordable without the introduction of a new dedicated tax, equivalent to an extra 1 per cent on National Insurance. After a backlash, No 10 shelved the plans until the autumn.

There are also ongoing discussions about how to reduce the predicted £4 billion cost of the 'triple lock' protecting the value of the state pension, amid fears that a surge in average earnings figures will push it unaffordably high.

Both the increase on National Insurance and extra green costs are controversial within Government because the burden of both fall more heavily on younger people and lower income households.

The summit is expected to bring together more than 100 world leaders to make commitments on how they intend to reach global net zero and limit global warming to 1.5C.



Hydrogen boilers have not yet hit the market, with Worcester Bosch building this prototype

Smart meters will become redundant if Britain ditches gas boilers in an effort to go green

New smart meters that work on hydrogen boilers will have to be installed in the future

Allegra Stratton, Mr Johnson's COP26 spokeswoman, promised that the details will be published before November's meeting. She said the Prime Minister believed that 'if we are going to transition to net zero it needs to be in a way the British public understand and are comfortable with'.

A Treasury spokesman said that No10 and No11 were 'on the same page' on both the triple lock and the need for an effective, affordable net zero strategy.

Business Secretary Kwasi Kwarteng provoked anger after admitting smart meters will become redundant if Britain ditches gas boilers in an effort to go green. He said new smart meters that work on hydrogen boilers - a possible future greener alternative to conventional gas boilers - would have to be installed.

The 46-year-old told MPs on the science and technology committee: 'We are developing prototype smart meters that can be installed to be adapted to hydrogen.'

He said current trials looking into the safety and viability of hydrogen boilers will determine whether all homes in Britain with gas boilers can be switched over. But Mr Kwarteng accepted this would mean the end for current smart meters, which measure the flow of gas, because hydrogen and methane are different chemicals.

If deemed safe and effective, hydrogen boilers could replace gas boilers to help the UK meet its target of decarbonising home heating by 2050. But this would make the multi-billion pound, much-delayed rollout of smart meters largely redundant because they cannot measure the flow of hydrogen.

How much will alternatives to gas boilers cost you to install at home?

GROUND SOURCE HEAT PUMPS (£14,000 - £19,000)

+13

Ground source heat pumps use pipes buried in the garden to extract heat from the ground, which can then heat radiators, warm air heating systems and hot water.

They circulate a mixture of water and antifreeze around a ground loop pipe. Heat from the ground is absorbed into the fluid and then passes through a heat exchanger.

Installation costs between £14,000 to £19,000 depending on the length of the loop, and running costs will depend on the size of the home and its insulation.

Users may be able to receive payments for the heat they generate through the Government's renewable heat incentive. The systems normally come with a two or three year warranty - and work for at least 20 years, with a professional check every three to five years.

AIR SOURCE HEAT PUMPS (£11,000)

+13

Air source heat pumps absorb heat from the outside air at low temperature into a fluid to heat your house and hot water. They can still extract heat when it is as cold as -15C (5F), with the fluid passing through a compressor which warms it up and transfers it into a heating circuit.

They extract renewable heat from the environment, meaning the heat output is greater than the electricity input – and they are therefore seen as energy efficient.

There are two types, which are air-to-water and air-to-air, and installing a system costs £9,000 to £11,000, depending on the size of your home and its insulation.

A typical three-bedroom home is said to be able to save £2,755 in ten years by using this instead of a gas boiler.

HYDROGEN BOILERS (£1,500 - £5,000)

+13

Hydrogen boilers are still only at the prototype phase, but they are being developed so they can run on hydrogen gas or natural gas – so can therefore convert without a new heating system being required.

The main benefit of hydrogen is that produces no carbon dioxide at the point of use, and can be manufactured from either water using electricity as a renewable energy source, or from natural gas accompanied by carbon capture and storage.

A hydrogen-ready boiler is intended to be a like-for-like swap for an existing gas boiler, but the cost is unknown, with estimates ranging from £1,500 to £5,000.

The boiler is constructed and works in mostly the same way as an existing condensing boiler, with Worcester Bosch – which is producing a prototype – saying converting a hydrogen-ready boiler from natural gas to hydrogen will take a trained engineer around an hour.

SOLAR PHOTOVOLTAIC PANELS (£4,800)

+13

Solar photovoltaic panels generate renewable electricity by converting energy from the sun into electricity, with experts saying they will cut electricity bills.

Options include panels fitted on a sloping south-facing roof or flat roof, ground-standing panels or solar tiles – with each suitable for different settings. They are made from layers of semi-conducting material, normally silicon, and electrons are knocked loose when light shines on the material which creates an electricity flow.

The cells can work on a cloudy day but generate more electricity when the sunshine is stronger. The electricity generated is direct current (DC), while household appliances normally use alternating current (AC) – and an inverter is therefore installed with the system.

The average domestic solar PV system is 3.5 kilowatts peak (kWp) - the rate at which energy is generated at peak performance, such as on a sunny afternoon. A 1kWp set of panels will produce an average of 900kWh per year in optimal conditions, and the cost is £4,800.

SOLAR WATER HEATING (£5,000)

+13

Solar water heating systems, or solar thermal systems, use heat from the sun to warm domestic hot water.

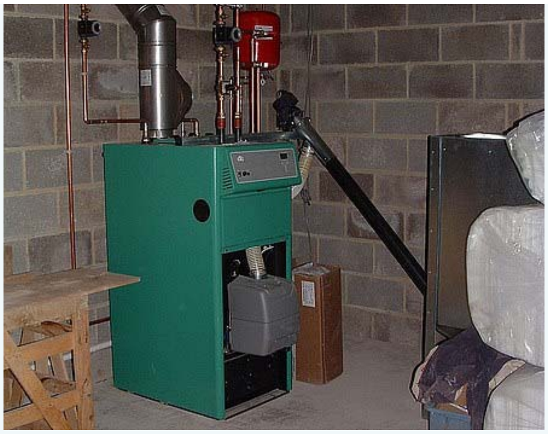
A conventional boiler or immersion heater can then be used to make the water hotter, or to provide hot water when solar energy is unavailable.

The system works by circulating a liquid through a panel on a roof, or on a wall or ground-mounted system.

The panels absorb heat from the sun, which is used to warm water kept in a cylinder, and those with the system will require a fair amount of roof space receiving direct sunlight for much of the day to make it effectively.

The cost of installing a typical system is between £4,000 and £5,000, but the savings are lower than other options because it is not as effective in the winter months.

BIOMASS BOILERS (£5,000 - £19,000)



+13

The renewable energy source of biomass is generated from burning wood, plants and other organic matter such as manure or household waste. It releases carbon dioxide when burned, but much less than fossil fuels.

Biomass heating systems can burn wood pellets, chips or logs to heat a single room or power central heating and hot water boilers.

A stove can also be fitted with a back boiler to provide water heating, and experts say a wood-fuelled biomass boiler could save up to £700 a year compared to a standard electric heating system.

An automatically-fed pellet boiler for an average home costs between £11,000 and £19,000, including installation, flue and fuel store. Manually fed log boiler systems can be slightly cheaper, while a smaller domestic biomass boiler starts at £5,000.

https://committees.parliament.uk/committee/153/transport-committee/news/156943/transport-committee-charging-an-electric-vehicle-should-be-convenient-straightforward-and-inexpensive-owners-should-not-face-a-postcode-lottery/

Transport Committee: Charging an electric vehicle should be convenient, straightforward, and inexpensive; owners should not face a postcode lottery

28 July 2021

A clear policy framework is essential to ensure that industry can deliver the vehicles and charging infrastructure required to deliver the Government's ambition.

- Read the report summary
- Read the report's conclusions and recommendations
- Read the full report

In Zero emission vehicles, published today, MPs on the Transport Committee deliver a set of recommendations to Government to boost the production and purchase of electric vehicles as the net zero deadline approaches.

Questions remain on whether the Government's current plans are enough to deliver the public charging infrastructure needed across all regions of the UK and whether it will benefit everyone, says the report.

Accessible and reliable charging infrastructure must be available by 2030 but drivers who live in rural or remote areas or who don't have off-street parking risk being left behind.

Unless charging habits change, or the National Grid is strengthened, concerns exist that the charging needs from millions of new electric vehicles will cause blackouts to parts of the country.

The Government must:

- Work with the National Grid to map national coverage to eradicate ‘not-spot’ areas and identify locations where the Grid will not cope with additional usage
- Make public charge provision a requirement of local development and provide funding for local planning and transport bodies to hire staff with a mandate to deliver charging infrastructure
- Protect the consumer from excessive charges and multiple accounts when charging in public
- Address the discrepancy between the 5% VAT incurred for home charging and 20% VAT for on-street
- Insist that industry uses price to change consumer charging behaviour to a ‘little but often’ approach and at times when the National Grid can meet total demand
- Boost the manufacturing and sales of new electric vehicles by requiring those who sell the fewest electric vehicles to buy credits from those who produce the most; such credit to then be used to reduce the purchase price of electric vehicles (the ‘ZEV Mandate’).

With charging at home substantially cheaper than on-street charging, pricing must be fair for people who charge their electric vehicles in public spaces. The Committee welcomes the Government’s commitment to regulate interoperability between charge points and pricing transparency for public charge points later this year. However, mandating industry to use pricing to move consumer behaviour towards a ‘little and often’ refuelling habit will also help.

Government must also introduce a zero emission vehicle mandate as a matter of priority if it is to hit its target of 100% new zero emission vehicles (ZEVs) by 2035. A ZEV mandate would incentivise car manufacturers to steadily increase sales of zero emission vehicles towards the 2030 target for all new vehicles to have ‘significant zero emission capability’. This would bring ZEV vehicles within reach of more consumers encouraged by cost-effective ways to support purchases compared to taxpayer-funded incentives. A stronger marketplace generated by an increased vehicle supply from global manufacturers to the UK market would also bring down costs.

Chair's comment

Chair of the Transport Committee, Huw Merriman MP said:

“As car usage returns to pre-pandemic levels, we must keep our sights locked on the target: all new cars and vans should be electric by 2035 at the latest. To help consumers see their route to a zero emission world, choosing to run an electric vehicle must be as seamless as possible. Today we offer a set of recommendations to help Government hit the accelerator on its ambition.

“Putting guarantees in place on infrastructure is crucial but one report after another flags concerns to Government about the provision of electric car charging infrastructure. Let ours be the last: it’s time that ministers set out the route map to delivering a network of services for everyone across the UK.

“The Government's inclusion of a ZEV mandate in a recent consultation is welcome but not enough on its own. Charging electric vehicles should be convenient, straightforward and inexpensive and drivers must not be disadvantaged by where they live or how they charge their vehicles. Shifting the subsidy from the taxpayer to the manufacturer will incentivise those who deliver the fewest electric vehicles in our showrooms to up their game.

“Unless the National Grid gains more capacity, consumer behaviour will have to alter so that charging takes place when supply can meet the additional demand. The alternative will be blackouts in parts of the country. We also cannot have a repeat of the broadband and mobile ‘not spot’ lottery which would mean those in remote parts cannot join the electric vehicle revolution.”

The report notes that the move to electric vehicles can only be one strand in the UK’s net zero ambitions. The Government has now published its Transport Decarbonisation Plan and further papers are expected. Having considered zero emission vehicles, the Committee will turn its attention to road pricing. The Committee will continue to scrutinise government work in this area, particularly in the run up to the UK hosting COP26 in the Autumn.

Further information

- About Parliament: Select committees
- Visiting Parliament: Watch committees

Image: H. Kashioka

Conclusions and recommendations

Uptake of zero emission vehicles

1.A healthy used electric vehicle market is critical to ensuring that electric vehicles are not the sole preserve of people who can afford new models. The Government's position is that current incentives to stimulate the sale of new EVs are sufficient to support the development of the second-hand EV market. However, electric vehicles that will be traded on the second-hand market in three to five years' time are likely to be more expensive to buy upfront than comparable ICE models. To drive mass consumer uptake of ZEVs, the Government must ensure that the market facilitates the supply of affordable new and used electric vehicles. (Paragraph 17)

2.In order to ensure that the Government achieves the targets set out in the Transport Decarbonisation Plan, it may need to intervene to support the second-hand market in electric vehicles until price parity with comparable ICE vehicles is reached. (Paragraph 18)

3.A zero emission vehicle mandate would:

- be revenue neutral;
- provide certainty to allow manufacturers to invest in the UK and supply a sufficient volume of ZEVs to meet the UK's decarbonisation commitments;
- reduce costs for consumers by increasing the supply of electric vehicles; and
- free taxpayers from the annual £135 million cost of the plug-in car grant. (Paragraph 26)

4.*In order to achieve its 2030 and 2035 targets, the Government must introduce a ZEV mandate to incentivise manufacturers to sell an increasing proportion of ZEVs or to purchase tradeable credits year-on-year, reaching some 100% ZEV sales by 2030.* (Paragraph 27)

5.*The Government must define 'significant zero emissions capability' for the automotive manufacturing industry, while ensuring that only the cleanest possible hybrid technology is available until 2035. It should also maintain a technology-neutral approach to the transition to ZEVs and explore the potential of alternative fuels, such as hydrogen or other alternatives to petrol and diesel, where possible*. (Paragraph 32)

Charging infrastructure

6.Drivers who do not have access to off-street parking and who live in rural or remote areas may struggle to charge their vehicles. To ensure that a comprehensive network of electric vehicle charging infrastructure is in place by 2030, sub-national transport bodies and local authorities will need to implement strategies to deliver a range of practical and accessible charging solutions to suit local needs. (Paragraph 44)

7.*As part of its electric vehicle charging infrastructure strategy, the Government must explain:*

a) how it will support all regions and local authorities to deliver sufficient and well-maintained charging infrastructure solutions tailored to local needs, so that no area is left behind; and

b) how it will ensure that the roll-out of charging infrastructure keeps pace with the increase in EVs and that the right types of chargers are in the right locations. (Paragraph 45)

8.*To facilitate the roll-out of charging infrastructure, the Government must:*

a) use the upcoming Planning Bill to make public charge point provision a requirement of local plans;

b) make funding for the on-street residential charging scheme dependent upon local authorities having detailed charge point plans in place which support rapid charging options; and

c) ring-fence a portion of the £90 million local charging scheme to allow local authorities to employ dedicated 'charge point champions' to deliver local charging infrastructure strategies. (Paragraph 46)

9.*The Government must work with National Grid to map the electricity network to assess potential weak areas, especially in rural locations, and to develop a plan to prevent 'not-spots' from emerging similar to those during the roll-out of broadband and mobile coverage*. (Paragraph 47)

10.Project Rapid, which specifies the number of charge points on the strategic road network by 2023 and beyond, is welcome. However, the spending priorities for the £950 million rapid charging fund are currently obscure. Given the time and expense involved in upgrading grid connections, it is crucial that this money is distributed to unlock investment, provide fully future-proofed grid capacity and secure public confidence in charging infrastructure. (Paragraph 58)

11.*The electric vehicle charging infrastructure strategy must set out:*

a) how the £950 million rapid charging fund will be spent to facilitate the implementation of charging infrastructure; and

b) the measures that the Government is taking to identify and address under-provision at locations outside the strategic road network, where grid connection costs and grid upgrades are expensive and the business case for investment is weak. (Paragraph 59)

12.*The Government must amend the wayleave regime for installing charging infrastructure to ensure that that regime does not act as a barrier to roll-out.* (Paragraph 60)

13.Charging an electric vehicle should be convenient, straightforward, and inexpensive. To boost consumer confidence in the charging network, to maximise convenience and value for motorists and to facilitate connectivity, all charge points should be interoperable and provide a seamless experience for drivers. We welcome the Government's commitment to regulate interoperability and pricing transparency for public charge points later in 2021. (Paragraph 69)

14.*In the charging infrastructure strategy, the Government must explain how it will improve the consumer experience at public charge points and ensure that*

a) drivers can seamlessly access any charging network in any location at any time; and

b) charge point operators are not disincentivised from investing in charging infrastructure. (Paragraph 70)

15.People who rely on public charging infrastructure should get value for money and should not be disadvantaged by unfair pricing mechanisms. (Paragraph 71)

16.*The Government must explain how it plans to tackle the potential price differential faced by people who cannot charge their vehicles at home and are compelled to rely on on-street public charge points. It could do this by:*

a) protecting the consumer from excessive costs where there are risks of local monopolies emerging; and

b) addressing the discrepancy between the 5% VAT incurred on electricity at home compared with the 20% VAT incurred at public charge points. (Paragraph 72)

Managing energy demand and smart charging

17.We welcome the Government's commitment to mandate that all new private charge points should be equipped with smart functionality and to introduce the relevant legislation later in 2021. (Paragraph 78)

18.*The Government must mandate industry to*:

a) use price as a lever to shift consumer behaviour away from conventional refuelling habits towards 'a little but often' approach; and

b) incentivise consumers to charge at times when there is less demand on the electricity grid. (Paragraph 79)

< Back

Next >

Published: 28 July 2021

System margins / Early view of winter 2021/22

Following tighter margins in winter 2020/21 compared to previous winters, we have decided to publish an early view of the margin for winter 2021/22. We believe this will help to inform the electricity industry and support preparations for the winter ahead. We published the Winter Review and Consultation on 24 June 2021. This year's consultation is currently open and we welcome responses from stakeholders by 30 July 2021. This will help inform our analysis for the Winter Outlook Report, which will also include our more detailed operational view of winter, that is due to be published in October 2021. Responses to the consultation are invited via email to: marketoutlook@nationalgrideso.com

1 De-rated margin

Our base case view of de-rated margin for winter 2021/22 is currently 4.3 GW or 7.3%. This is slightly lower than last year, but the associated loss of load expectation (LOLE) of around 0.1 hours / year is well within the Reliability Standard of 3 hours set by Government.

While we remain confident there is sufficient supply to meet peak demand, we should prepare for some tight periods during the winter. For example this could be when plant outages are higher than expected (often experienced in the shoulder months), wind is low, or there is tightness in Europe at the same time that reduces imports. We may expect similar challenges this winter. We have a well-functioning market that responds to market signals. and the ESO may need to use its tools, including issuing margins notices, to manage these periods.

2 Supply

There is still some uncertainty in our view of de-rated margin for the winter, driven mainly by available supply. This could potentially see the de-rated margin range from 3.1 – 5.4 GW or 5.3 – 9% – still within the Reliability Standard of 3 hours LOLE set by Government.

One nuclear station has announced closure ahead of the winter, with a second one expected to close during winter. Coal availability dropped in winter 2020/21 and there remains uncertainty as these stations approach the end of their operational lives. The IFA2 interconnector to France came online during last winter and we expect the NSL interconnector to Norway to be operational from October 2021.

3 Demand

Our base case forecast for underlying average cold spell (ACS) peak demand is 59.5 GW, including operational reserve. This assumes that there is no suppression of peak demand in winter 2021/22 due to the ongoing COVID-19 pandemic.

The ACS peak demand forecast represents the total underlying demand in GB met by generation on the transmission and distribution networks. Last winter we assumed a 3 – 4% reduction in peak demand due to suppression from the ongoing COVID-19 pandemic. Given the intention to relax COVID-19 restrictions, the roll-out of the vaccination program and our assessment of out-turn demand in the Winter Review and Consultation for last winter, we have not forecast any suppression in peak demand for this winter coming.

nationalgridESO

EMN Case Studies / 4th & 5th November 2020

On the 4th and 5th November 2020, demands were forecast to be **43.2GW** and **43.1GW** respectively (much higher than can be seen from the green bars in the *Winter Outlook Report* chart – Figure 1 in this publication - which assume average weather conditions). Wind generation was also forecast to be at lower-than-expected levels.

Unplanned generation outages were slightly higher than expected for the time of year, but well within the range of variability for this time of year.

Although network reconfiguration and circuit rating enhancements could alleviate some of the active constraints on the system, there remained some generation constrained by circuit outages on the Scottish network. The tightness of margin for 4th and 5th November were consistently forecast from 30th October onwards. EMNs were cancelled on both days ahead of each darkness peak as the contingency requirement moved to zero as we approached real-time operation.

Day ahead prices reached **£132/MWh** on 4 November and **£192/MWh** on 5 November, with comparable intraday prices. Analysis of the underlying basic demand used by the demand forecast models shows that there was no detectable price response in the distributed generation market. This could either be because distributed generators were not expecting to be called upon, and generation was not ready to run, or because in recent days all available generation had been running over the peak, and there was no extra pool of generation to draw on.

Settlement Period	CET/CEST Time	Price (£/MWh)
00 - 01	23 - 00	36.92
01 - 02	00 - 01	36.67
02 - 03	01 - 02	36.95
03 - 04	02 - 03	34.20
04 - 05	03 - 04	28.93
05 - 06	04 - 05	30.97
06 - 07	05 - 06	38.08
07 - 08	06 - 07	43.29
08 - 09	07 - 08	46.33
09 - 10	08 - 09	50.54
10 - 11	09 - 10	50.90
11 - 12	10 - 11	41.10
12 - 13	11 - 12	40.70
13 - 14	12 - 13	40.50
14 - 15	13 - 14	40.58
15 - 16	14 - 15	41.36
16 - 17	15 - 16	43.09
17 - 18	16 - 17	56.00
18 - 19	17 - 18	132.00
19 - 20	18 - 19	99.91
20 - 21	19 - 20	63.00
21 - 22	20 - 21	46.60
22 - 23	21 - 22	37.00
23 - 00	22 - 23	32.44

Table 15. Day ahead auction prices on 04/11/20 from the N2EX dataset

Settlement Period	CET/CEST Time	Price (£/MWh)
00 - 01	23 - 00	43.27
01 - 02	00 - 01	36.42
02 - 03	01 - 02	34.00
03 - 04	02 - 03	31.89
04 - 05	03 - 04	28.09
05 - 06	04 - 05	30.79
06 - 07	05 - 06	34.40
07 - 08	06 - 07	40.96
08 - 09	07 - 08	43.44
09 - 10	08 - 09	50.00
10 - 11	09 - 10	50.36
11 - 12	10 - 11	44.00
12 - 13	11 - 12	39.66
13 - 14	12 - 13	42.80
14 - 15	13 - 14	42.99
15 - 16	14 - 15	42.00
16 - 17	15 - 16	49.75
17 - 18	16 - 17	60.00
18 - 19	17 - 18	192.25
19 - 20	18 - 19	150.00
20 - 21	19 - 20	66.20
21 - 22	20 - 21	45.10
22 - 23	21 - 22	44.90
23 - 00	22 - 23	39.60

Table 16. Day ahead auction prices on 05/11/20 from the N2EX dataset

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EMN Case Study / 6th December 2020

A third EMN was issued for the darkness peak on Sunday 6th December 2020. Historically, it is highly unusual to have tight margins over a weekend. Like the previous two EMNs, higher than expected demand and low wind were drivers but additionally there was lower Balancing Mechanism generation availability too as some power stations continued to take weekend outages. Lower than average temperatures resulted in demand forecasts of **44GW** and wind generation was at extremely low levels.

Unplanned generation outages were at the high end of normal variability for the time of year, but again, within the range of variability we have seen over the past five years.

No generation was constrained on the GB network, there were minimal exports on the Irish interconnectors and continental interconnectors were importing. The tightness of margin was consistently reported from 1st December onwards, with the impact increasing day on day as the wind forecast was consistently revised downwards. The EMN was cancelled ahead of the darkness peak as the situation improved and contingency margin requirement reduced. The demand outturn was in line with forecasts indicating minimal price response from other distribution connected generators and high Balancing Mechanism prices were setting imbalance prices up to **£720/MWh**.

Day ahead prices peaked at **£350/MWh** on 6 December, and intraday prices at **£380/MWh**. Analysis of the underlying basic data showed no evidence of price response from distributed generators, although increased uncertainty in level of Sunday peak demand, coupled with the effects of the recent lifting of the lockdown may have partially masked this. The demand forecast did not factor in any allowance for price response and was 100MW below the outturn. Any under forecast, however slight, does not give any evidence for demand suppression driven by price.

Settlement Period	CET/CEST Time	Price (£/MWh)
00 - 01	23 - 00	44.55
01 - 02	00 - 01	43.05
02 - 03	01 - 02	42.54
03 - 04	02 - 03	39.57
04 - 05	03 - 04	33.00
05 - 06	04 - 05	31.25
06 - 07	05 - 06	31.98
07 - 08	06 - 07	39.53
08 - 09	07 - 08	34.80
09 - 10	08 - 09	41.86
10 - 11	09 - 10	46.27
11 - 12	10 - 11	50.82
12 - 13	11 - 12	51.62
13 - 14	12 - 13	56.92
14 - 15	13 - 14	56.89
15 - 16	14 - 15	60.82
16 - 17	15 - 16	65.00
17 - 18	16 - 17	189.96
18 - 19	17 - 18	350.00
19 - 20	18 - 19	150.49
20 - 21	19 - 20	77.80
21 - 22	20 - 21	53.68
22 - 23	21 - 22	44.73
23 - 00	22 - 23	42.02

Table 17. Day ahead auction prices on 06/12/20 from the N2EX dataset

EMN Case Study / 6th January 2021

A fourth EMN was issued for the darkness peak on Wednesday 6th January 2021. Lower than average temperatures (approx. 2°C) resulted in a high demand forecast of **46.4GW** (including **1.5GW** of customer response demand reduction due to an expected triad) and wind generation was at low levels.

Unplanned generation outages were at the high end of normal variability for the time of year, but again, within the range of variability we have seen over the past five years.

No generation was constrained on the GB network, the Irish interconnectors were partially importing, and the continental interconnectors were fully importing. The tightness of margin was consistently reported from 1st January onwards. The EMN was cancelled ahead of the darkness peak as the situation improved and contingency margin requirements reduced. The demand outturn was in line with forecasts which included approx. **1.5GW** of customer response demand reduction. Analysis of the underlying basic data showed approx. **1.6GW** of customer response demand reduction on 6th January which was close to expected as it was a forecast triad.

Day ahead prices peaked at **£1000/MWh** on 6th January. High Balancing Mechanism prices were setting imbalance prices of up to **£1000/MWh**.

Settlement Period	CET/CEST Time	Price (£/MWh)
00 - 01	23 - 00	46.49
01 - 02	00 - 01	46.41
02 - 03	01 - 02	45.99
03 - 04	02 - 03	42.41
04 - 05	03 - 04	41.55
05 - 06	04 - 05	42.59
06 - 07	05 - 06	48.00
07 - 08	06 - 07	55.03
08 - 09	07 - 08	57.63
09 - 10	08 - 09	75.00
10 - 11	09 - 10	96.60
11 - 12	10 - 11	99.30
12 - 13	11 - 12	97.59
13 - 14	12 - 13	128.47
14 - 15	13 - 14	103.88
15 - 16	14 - 15	90.39
16 - 17	15 - 16	75.00
17 - 18	16 - 17	563.04
18 - 19	17 - 18	1000.04
19 - 20	18 - 19	383.28
20 - 21	19 - 20	156.74
21 - 22	20 - 21	80.30
22 - 23	21 - 22	55.06
23 - 00	22 - 23	51.06

Table 18. Day ahead auction prices on 06/01/21 from the N2EX dataset

EMN Case Study / 8th January 2021

A fifth EMN was issued for the darkness peak on Friday 8th January. Lower than average temperatures (approx. 2°C) resulted in a high demand forecast of **46.2GW** and wind generation was at very low levels.

Unplanned generation outages were at the high end of normal variability for the time of year, but again, within the range of variability we have seen over the past five years.

No generation was constrained on the GB network, the Irish interconnectors were partially importing, and the continental interconnectors were fully importing. The tightness of margin was consistently reported from 1st January onwards. The EMN was cancelled ahead of the darkness peak as the situation improved and contingency margin requirements reduced. The demand outturn was in line with forecasts. The demand forecast from Energy Forecasting did not factor in any allowance for price response and was approx. 700MW below the outturn.

Day ahead prices peaked at **£670/MWh** on 8th January. High Balancing Mechanism prices were setting imbalance prices of up to **£4000/MWh**.

A CMN was also issued for 8th January 2021 (as well as the one on 3rd December 2020).

Settlement Period	CET/CEST Time	Price (£/MWh)
00 - 01	23 - 00	56.62
01 - 02	00 - 01	55.52
02 - 03	01 - 02	51.59
03 - 04	02 - 03	48.75
04 - 05	03 - 04	46.98
05 - 06	04 - 05	46.94
06 - 07	05 - 06	52.45
07 - 08	06 - 07	58.56
08 - 09	07 - 08	78.17
09 - 10	08 - 09	89.73
10 - 11	09 - 10	92.94
11 - 12	10 - 11	93.85
12 - 13	11 - 12	93.14
13 - 14	12 - 13	89.77
14 - 15	13 - 14	87.49
15 - 16	14 - 15	84.22
16 - 17	15 - 16	81.74
17 - 18	16 - 17	163.30
18 - 19	17 - 18	670.39
19 - 20	18 - 19	167.31
20 - 21	19 - 20	90.73
21 - 22	20 - 21	75.68
22 - 23	21 - 22	62.11
23 - 00	22 - 23	59.44

Table 19. Day ahead auction prices on 08/01/21 from the N2EX dataset

nationalgridESO

EMN Case Study / 13th January 2021

A sixth EMN was issued for the darkness peak on Wednesday 13th January. Lower than average temperatures resulted in a demand forecast of **45.4GW** and wind generation was at very low levels.

Unplanned generation outages were at the high end of normal variability for the time of year, but again, within the range of variability we have seen over the past five years.

No generation was constrained on the GB network, the Irish and continental interconnectors were fully importing. The tightness of margin was consistently reported from 8th January onwards. The EMN was cancelled ahead of the darkness peak as the situation improved and contingency margin requirements reduced. The demand outturn was in line with forecasts. The demand forecast from Energy Forecasting did not factor in any allowance for price response.

Day ahead prices peaked at **£1,500/MWh** on 13th January. High Balancing Mechanism prices were setting imbalance prices of up to **£990/MWh**.

Settlement Period	CET/CEST Time	Price (£/MWh)
00 - 01	23 - 00	66.51
01 - 02	00 - 01	65.09
02 - 03	01 - 02	61.58
03 - 04	02 - 03	60.59
04 - 05	03 - 04	59.02
05 - 06	04 - 05	58.09
06 - 07	05 - 06	60.50
07 - 08	06 - 07	66.53
08 - 09	07 - 08	66.53
09 - 10	08 - 09	88.65
10 - 11	09 - 10	142.16
11 - 12	10 - 11	167.70
12 - 13	11 - 12	199.93
13 - 14	12 - 13	195.60
14 - 15	13 - 14	167.28
15 - 16	14 - 15	145.59
16 - 17	15 - 16	103.18
17 - 18	16 - 17	411.61
18 - 19	17 - 18	1499.62
19 - 20	18 - 19	694.54
20 - 21	19 - 20	175.19
21 - 22	20 - 21	99.99
22 - 23	21 - 22	60.52
23 - 00	22 - 23	54.98

Table 20. Day ahead auction prices on 13/01/21 from the N2EX dataset

nationalgridESO

1.

https://www.politico.eu/article/eu-government-climate-and-coal-lawsuits/

EU governments whipsawed by climate and coal lawsuits

Some EU governments are trying to escape an energy investment treaty that could see them sued for billions.

German utility RWE this week slapped the Dutch government with a €1.4 billion lawsuit over its plans to end coal power | Patrik Stollarz/AFP via Getty Images
BY KARL MATHIESEN, SARAH ANNE AARUP AND KALINA OROSCHAKOFF
February 4, 2021 8:38 pm

Fighting climate change could become a sued if you do, sued if you don't problem for governments.

German utility RWE this week slapped the Dutch government with a €1.4 billion lawsuit over its plans to end coal power.

But the coal phaseout itself was compelled by the Dutch Supreme Court, which found in 2019 that the government was failing in its duty to protect citizens from climate change and mandated that it speed up emissions cuts.

It's the wicked problem facing EU members. They are under pressure from lawsuits holding them to climate pledges that require huge drops in fossil fuel use, but are all signed up to a 55-country investment protection deal called the Energy Charter Treaty (ECT). That treaty allows foreign investors in the energy sector to claim compensation for profits deemed unfairly lost due to government regulation.

"It's not inconceivable that there will be more cases" from both fossil fuel and renewable energy investors, said Johannes Tropper, international law lecturer at the University of Vienna.

RWE, which operates the Eemshaven power station in the Netherlands, triggered the treaty claiming that the Netherlands had failed to offer adequate time or money for the plant built in 2015 to be converted to burn biomass instead of coal.

Green groups said the RWE case was the first time a coal operator had sued a European country over climate policy.

Such lawsuits from utilities could become more common as governments face a growing wave of climate-focused court cases compelling them to cut emissions and shut down fossil fuels faster. On Wednesday, a French court found that the government wasn't following through on its Paris Agreement promises to slash its greenhouse gas emissions. The government has two months to spell out its plans after which it could face court-mandated action.

The U.N. Environment Program reported in January that it expected the number of climate litigation cases globally to rise.

Heavily polluting coal plants are often the first victims of climate policy. Sixteen EU countries have already pledged to stop using coal in their power systems. Ending coal is usually accompanied by lavish payments; Germany plans to end coal use by 2038 and is budgeting €4.3 billion to compensate utilities.

But RWE spokesperson Vera Bücker said the Dutch coal phaseout was "not legal."

"Unlike the German coal phaseout law, the Dutch law does not include an adequate compensation for this interference with the company's property," she said.

The legal basis for companies to sue countries really depends on how countries enact legislative changes, Tropper said. Investment courts do recognize a state's sovereign right to regulate, but it all depends on how laws are changed, he said.

A spokesperson said the Dutch economy and climate ministry would fight the RWE case "on both the jurisdiction of the tribunal as well as the content of the dispute."

It's not the only such threat facing The Hague.

There are five coal power stations in the Netherlands. Eemshaven and one other operated by Uniper, another German utility, are less than six years old. Uniper has said the Dutch government encouraged the companies to build the plants to cut reliance on gas. Uniper has threatened to also sue the government under the ECT. A spokesperson said the company and government were having "constructive discussions" over compensation.

Rethinking the Energy Charter

Those kinds of cases are fueling a push among EU countries to minimize the threat of lawsuits or even withdraw from the ECT.

There's a lively discussion over whether the treaty allows lawsuits among EU countries. The Netherlands, along with 20 other EU countries, concluded in 2019 that intra-EU investor-state dispute settlements are indeed illegal and chose to terminate all cases between each other.

Last year, Belgium asked for an opinion from the Court of Justice of the EU on the issue, which it's still awaiting.

"I would expect the ECT to be in violation of EU law in intra-EU disputes," Tropper said.

The EU could choose to quit the ECT altogether out of fear that it undermines its green agenda. Although the EU's current position is to negotiate for reforms to the treaty, chances are that conservative treaty members such as Japan may block any substantial change.

EU member countries are taking varying positions. France and Spain have called for Brussels to prepare to withdraw. Last January, the Dutch government said leaving the treaty would expose Dutch companies investing in energy projects abroad — something that could harm oil major Royal Dutch Shell.

A spokesperson for the German energy ministry said the ECT needed "numerous clarifications" to prevent "unjustified complaints against legitimate state measures for the common good."

But if Brussels were to pull out of the ECT, it wouldn't stop applying for 20 years under a sunset clause. This has been the fate of Russia, which withdrew from the agreement in 2009 but has since faced billions in claims from energy giant Yukos on the basis of the ECT.

Most claims brought under the treaty stay within the EU, so the reasoning is that Brussels and member countries could simply agree among themselves to cancel the sunset clause for cases brought within the bloc.

The question is whether such an agreement is feasible. That hinges on EU courts ruling that the ECT contradicts Union law, something that's “not unrealistic," said Andreas Gunst, a partner at law firm DLA Piper.

The fight could determine the future of Europe’s Green Deal. Wendel Trio, director of the NGO network Climate Action Network Europe, said: “It’s outrageous that fossil fuel firms can use this powerful treaty to obstruct the clean energy transition.”

https://biv.com/article/2021/07/efforts-decarbonize-long-haul-trucking-face-literal-uphill-battle

Efforts to decarbonize long-haul trucking face literal uphill battle

Converting long-haul trucks to clean sources of power remains a challenge

By Nelson Bennett | July 23, 2021, 8:00am

"In the long-haul world, this is where it gets scary," says Dave Earle, president of the BC Trucking Association | Chung Chow

This article was originally published in *BIV Magazine*'s *Trade* issue.

When it comes to decarbonizing the economy, pretty much everyone in the sustainable energy field agrees aviation and long-haul trucking will be the last mile on the road to net-zero by 2050.

"Of the on-road applications, long-haul trucking is probably the single most challenging," says Gordon McTaggart-Cowan, professor of sustainable energy engineering at Simon Fraser University.

Transportation accounts for 25% of Canada's greenhouse gas (GHG) emissions, with heavy trucking accounting for 35% of that, or 9% of total national emissions. Globally, it's estimated that heavy-duty trucking accounts for only 4% of the vehicles on the road, but 27% of road emissions.

There are 60,000 heavy-duty trucks (vehicles that weigh at least 25 tonnes) registered in B.C. and 156,000 medium-duty trucks, according to the BC Trucking Association. They emit slightly more carbon dioxide (CO_2) than the 2.2 million light-duty vehicles in B.C.

Converting buses and medium-duty trucking to battery electric or natural gas engines that run on ever-increasing amounts of renewable natural gas is feasible, says Dave Earle, president of the BC Trucking Association. In fact, it's already starting.

"In the long-haul world, this is where it gets scary," he says. "We are literally decades away in the long-haul world."

Indeed, projections by Bloomberg New Energy Finance and IHS Markit suggest that 70% to 80% of heavy-duty trucks will still be running on diesel or natural gas in 2040, with only about 19% electrified.

The long-haul sector faces a mountain of barriers – including actual mountains – when it comes to switching from diesel to zero-emission fuels or power sources.

One is physics, notably energy and power densities and energy transfer. The longer the range, the heavier the load and the steeper the grade, the more that energy density and energy transfer become limitations, and there are few fuels as energy dense and efficient as diesel or gasoline.

Then there's the chicken-and-egg problem of fueling infrastructure – regardless of whether that fuel is electricity, hydrogen or biofuel – and the range anxiety that goes with it. But the biggest hurdle is fleet turnover, Earle says.

A diesel engine for a Class 8 semi truck can last up to one million miles (1.6 million kilometres) for an average lifetime of 15 years. The average year for a heavy commercial truck in B.C. is 2008, Earle says, with a 3% turnover per year. Even if the technology, infrastructure and fuels were widely available today, which they're not, it would take 25 years to convert the entire fleet, Earle estimates.

"That assumes you start turning it over today," he adds.

The medium-duty and, in some instances, heavy-duty trucking sector can switch to battery electric or natural gas (which could be displaced with renewable natural gas, as it becomes available) for local and regional routes.

Fleet operators with return-to-base operations would be able to charge or refuel their trucks at base each night, without needing to find recharging or fueling stations in the communities they serve.

ColdStar Solutions, which operates a fleet of refrigerator trucks, has already begun making the switch. Of a fleet of 35 company-owned trucks, 25 run on compressed natural gas (CNG), which produces fewer emissions – including CO2 – than diesel. The company has also put in its first order for a battery-electric reefer truck.

"Our goal is, by the end of 2023, our trucks will be 100% natural gas or electric," says ColdStar CEO Kelly Hawes.

One advantage of CNG and liquefied natural gas (LNG) is that no engine modifications would be needed, should a sufficient supply of renewable natural gas (RNG) become available as a zero-emission drop-in fuel.

"There just isn't enough supply at this point," Hawes says.

While starting with CNG and LNG, and converting eventually to 100% RNG, is a solution for some sectors of trucking, long-haul trucking once again poses a problem. Natural gas is not as energy dense as diesel, so it has limitations when it comes to heavy loads and long distances.

"We've got carriers where the bulk of their fleet is natural gas because it works," Earle says. "We've got other carriers that have tried it and said it just doesn't work because it doesn't have the energy density."

As for biodiesel, it can reduce emissions intensity, but at a certain percentage it can gel and foul engines.

"Biodiesel is a nightmare," Earle says. "Because of the chemical makeup of it, it gels in cold weather."

So what about battery-electric trucks? Despite efforts by Tesla, Inc. to develop a battery-electric semi truck, battery electric has some serious limitations for long-haul trucking.

After visiting PACCAR Inc.'s research and development division in Washington State, which builds prototypes for low- and zero-emission trucks, Earle came away fairly skeptical about the prospects of applying battery-electric solutions to long-haul trucking.

A major problem is the weight of the batteries needed to power a semi truck – a problem that gets compounded in cold weather, which reduces battery efficiency. While Tesla says its semi would have a range of 475 to 800 kilometres before needing to be recharged, a typical diesel semi truck has a range of 1,000 to 1,500 kilometres.

Earle has done the math, which looks like this: 1,200 metres, vertically, with perfect fuel efficiency requires 100 kilowatt hours of power, which is the vertical lift of a run from Hope to the Coquihalla Summit.

"That's about two Tesla model threes," Earle says. "If you look at the current batteries that are available, you could conceivably run a load from the Fraser Valley to the top of the Coquihalla summit on a 400-kilowatt battery and need to charge at the summit. That ain't going to work."

One carrier is currently trialling an electric semi truck between Vancouver and Puget Sound, Earle says. To date, those trials suggest that what now takes four trucks would require six electric semis to move the same amount of freight.

At a recent forum on decarbonizing transportation hosted by the Greater Vancouver Board of Trade, Randy MacEwan, CEO of Ballard Power Systems, said hydrogen fuel cells can addresses the decarbonization problem for the long-haul sector.

“When you have heavy vehicles, heavy payloads that have long range and high utilization requirements, we see an opportunity for hydrogen fuel cells to decarbonize these segments, and to date they’ve been very difficult to abate,” he said.

He’s not the only one who thinks fuel cells may win over battery electric for the long-haul sector, or at least some segments of it.

“We also see, for long-haul, there’s a few challenges with the battery electric technology,” says Joanna Kyriazis, senior policy advisor for Clean Energy Canada. “As much as battery technology is kind of winning the race in a lot of these other vehicle segments, a lot of people are holding out for hydrogen on the long-haul side.”

To date, there are no fuel cell semis on the road, except in trials. Daimler recently announced its new GenH2 semi truck, powered by hydrogen fuel cells, with a range of 1,000 kilometres. The company will begin customer trials in 2023, with production scheduled for 2027.

This article was originally published in the July 2021 issue of BIV Magazine under the title 'In it for the long haul.' The digital magazine can be read in full here.

nbennett@biv.com

@nbennett_biv

https://www.whatcar.com/news/range-test-how-far-can-electric-cars-go-in-the-real-world/n23331

Range test: how far can electric cars go in the real world?

We've named our 2021 Electric Car Awards winners. But now it's time to find out how close they can get to matching their official ranges...

By **What Car? team**

28 Jul 2021 09:20

The line from the car industry is that the latest official range tests (called WLTP) are reflective of real-world driving, so you can rely on them when choosing an electric car to suit your needs. But is that really true?

To find out, we lined up all six of the fully electric winners from the new-car side of our 2021 Electric Car Awards, plus four wildcards – the Audi Q4 e-tron, Ford Mustang Mach-E, Mazda MX-30 and Renault Zoe – and drove them until they died.

How we did it

For fairly obvious reasons, it wouldn't have been safe to deliberately run the cars out of charge on the public road, so we used our proving ground in Bedfordshire.

We devised a relatively simple test route of around 15 miles, which included 2.6 miles of simulated stop-start urban driving, four miles at a steady 50mph and eight miles at a constant 70mph. The rationale for the high percentage of motorway driving was that drivers who want to travel a long distance in one hit are likely to be using the motorway network.

The cars were fully charged and then left out in the open overnight – for roughly 15 hours in 13-18deg C ambient conditions. The following morning, all 10 were plugged in again to check they were fully charged before the climate control was set to 21deg and the headlights switched to auto.

Normal (or the closest equivalent) driving mode was selected (no Eco modes were allowed) and the cars were left in their default regenerative braking setting – with the exception of the Porsche Taycan, in which the default setting is off. Auto was chosen instead.

The cars were then driven repeatedly around our test route in convoy, with driver changes and a switch in running order at the end of each lap.

It was a relatively mild day with a mixture of sun and cloud and an air temperature of between 17deg C and 24deg. It was relatively still and there was no rain at all. In other words, it was near-ideal conditions for these electric cars.

The winners and losers

Unsurprisingly, the car with the smallest battery, the MX-30, was first to bow out at just 115 miles. On the plus side, that mileage was only 7% adrift of the car's official range, although efficiency (in terms of miles per kWh) was respectable rather than spectacular.

Next to fall was the Fiat 500, notching up 140 miles. That result is particularly disappointing when you consider that officially it can cover 199 miles. Indeed, it's a shortfall of almost 30% – the greatest of any car in the test by a sizeable margin.

Every other contender managed at least 200 miles, with the Zoe (which differed from our used winner in that it was the latest 52kWh battery model) beating the similar-priced Skoda Enyaq by a single digit. The Zoe proved far more efficient, too, although that's hardly surprising, given that it's a much smaller, lighter car.

It's also worth noting that the Enyaq is available with a larger battery; the Enyaq 80 is closely related to the Q4 e-tron 40 and is likely to have a similar real-world range to that car.

If you consider range versus price, the Volkswagen ID.3 looks very appealing indeed. The version we tested (our favourite) costs less than £30k once the government grant has been factored in, and yet it kept going for 226 miles.

Meanwhile, excellent efficiency of 4.0 miles per kWh saw the Kia e-Niro almost match the range of the new Q4 e-tron, although the latter's much larger battery ultimately won the day.

Perhaps the most surprising result of all was the Taycan's test range of 281 miles – only nine miles (or 3%) short of its official range. It was (by a fraction) the least efficient of the bunch, averaging just under 3.4

miles per kWh – but then it is an incredibly capable performance car with fat, sticky tyres and acceleration that can embarrass even the Tesla Model 3.

But the Model 3 edged the Taycan for range, managing 284 miles before conking out, thanks to the best efficiency (4.1 miles per kWh) of the entire bunch. It also had by far the biggest emergency buffer, continuing to drive normally for many miles after its trip computer was reading empty.

Ultimately, though, the car with the biggest battery won the day. The Ford Mustang Mach-E may not be particularly efficient in the way it uses its energy, but it has so much of it, it broke the 300-mile barrier before grinding to a halt at 302 miles. That’s impressive, particularly when you consider its sub-£50k price tag.

On the other hand, the Mach-E fell 20% short of its official range of 379 miles – and don’t forget, our tests were carried out in close to ideal conditions. On a cold, rainy day in January, the potential range of any of these cars would be much lower.

So, the answer to the question we posed at the start? The official figures shouldn’t automatically be relied upon when choosing your first (or next) electric car.

REAL-WORLD RANGE TEST: THE RESULTS

Make and model	Wheel size	Usable battery size	Official (WLTP) range	TEST RANGE	Shortfall	Miles per kWh*
Ford Mustang Mach-E Extended Range RWD	18in	88.0	379	**302**	20.2%	3.4
Tesla Model 3 Long Range	19in	70.0	360	**284**	21.1%	4.1
Porsche Taycan 4S Performance Battery Plus	20in	83.7	290**	**281**	3.0%	3.4
Audi Q4 e-tron 40 S line	20in	77.0	308	**266**	13.6%	3.5
Kia e-Niro 64kWh 3	17in	64.0	282	**257**	8.5%	4.0
Volkswagen ID.3 58kWh Pro Performance Life	18in	58.0	264	**226**	14.2%	3.9
Renault Zoe R135 GT Line	16in	52.0	238	**208**	12.4%	4.0
Skoda Enyaq 60	20in	58.0	254**	**207**	18.3%	3.6
Fiat 500 42kWh Icon	17in	37.3	198**	**140**	29.2%	3.8
Mazda MX-30 SE-L Lux	18in	30.0	124	**115**	7.1%	3.8

*Based on usable battery size **With test car’s non-standard wheels, which affect range

For all the latest reviews, advice and new car deals, sign up to the What Car? newsletter here

https://rbnenergy.com/forever-and-for-always-canadas-energy-industry-steps-up-carbon-capture-efforts-in-the-oil-sands

Forever And For Always - Canada's Energy Industry Steps Up Carbon Capture Efforts In The Oil Sands

Tuesday, 07/27/2021
Published by: Martin King

New and expanded efforts to reduce greenhouse gases, most notably carbon dioxide, have been making headlines globally on a daily basis for a while now. Canada's energy industry has been increasingly contributing to that newsfeed this year, with two large projects announced in Alberta that will capture, use, and sequester large volumes of CO_2 generated from the oil sands as well as other sources of oil and gas production in Western Canada. In today's blog, we review the emissions profile of the Canadian oil and gas sector and discuss two of the largest carbon capture, use, and sequestration projects announced to date.

It seems you cannot open your e-mail, scan a news website, or — better yet — read an RBN blog, without some mention of a new initiative to reduce greenhouse gas (GHG) emissions, especially among those who produce, transport, and refine hydrocarbons. As part of our expansion into ESG themes and our ongoing The Air That I Breathe series on using CO_2 for enhanced oil recovery, we felt it was important to consider what has been happening with respect to CO_2 reduction initiatives in Canada's energy industry, and especially the oil sands, a sector often unfairly maligned as a massive contributor to Canadian and global GHG emissions.

Given the oil sands' reputation among environmental activists, it may be surprising to hear that Canada's carbon footprint has changed very little over the past two decades — a period during which oil sands production has doubled. According to Canada's federal government, the country's overall GHG emissions didn't stray far from the 700-725-million-metric-tons-per-year-of-CO2-equivalent range between 2000 and 2019, the last year with published data available (height of stacked bar segments and left axis in Figure 1). Although not part of the government's dataset, it would be reasonable to expect that Canada's 2020 GHG emissions declined due to the suppression of economic activity tied to the COVID pandemic. In fact, BP's latest statistical review estimates that Canada's emissions fell by about 11% last year, which would place emission levels at the lowest since 1994, or about 652 million metric tons (MMT).

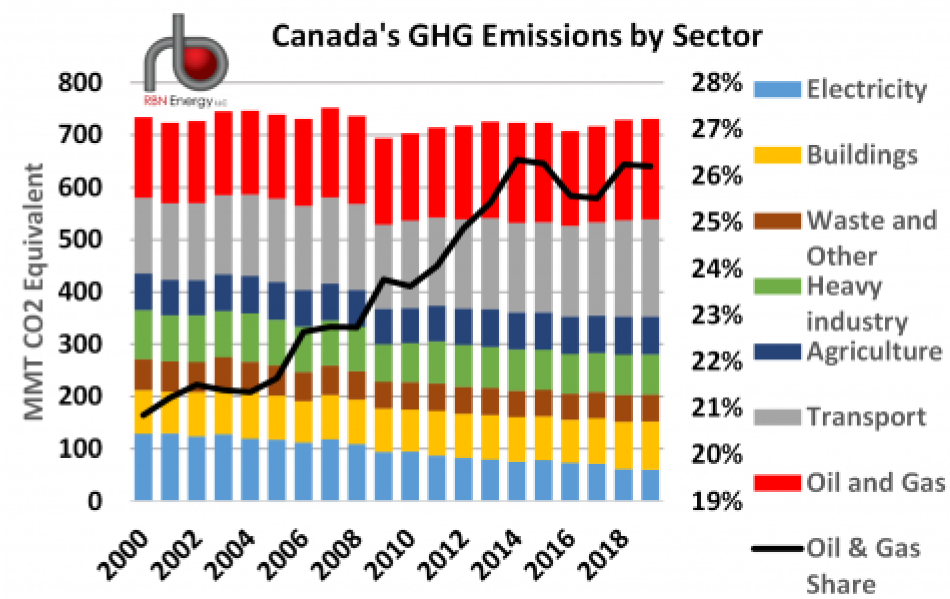

Figure 1. Canada's GHG Emissions by Sector. Source: Government of Canada

The oil and gas sector's contribution to Canada's overall emissions (red bar segments in Figure 1), has been rising since 2000: from a 21% share in 2000 to 26% in 2019 (black line and right axis). It is likely that share changed little relative to overall emissions in 2020 given the immense short-term reductions that took place in oil sands production during the spring and summer last year in response to COVID and the short-lived oil price crash. Taking the share comparison a step further, Canada's oil and gas sector contributed approximately 0.4% to total global emissions in 2019.

If we break down the oil and gas sector's emissions so that we can isolate oil sands emissions, again using data from the federal government, we can see that the oil sands' contribution has definitely been increasing since 2000 (blue bar segments in Figure 2). This is not surprising given the immense expansion that has taken place in oil sands production over the past two decades, and part of that expansion has been powered by utilizing natural gas for the extraction and processing of bitumen.

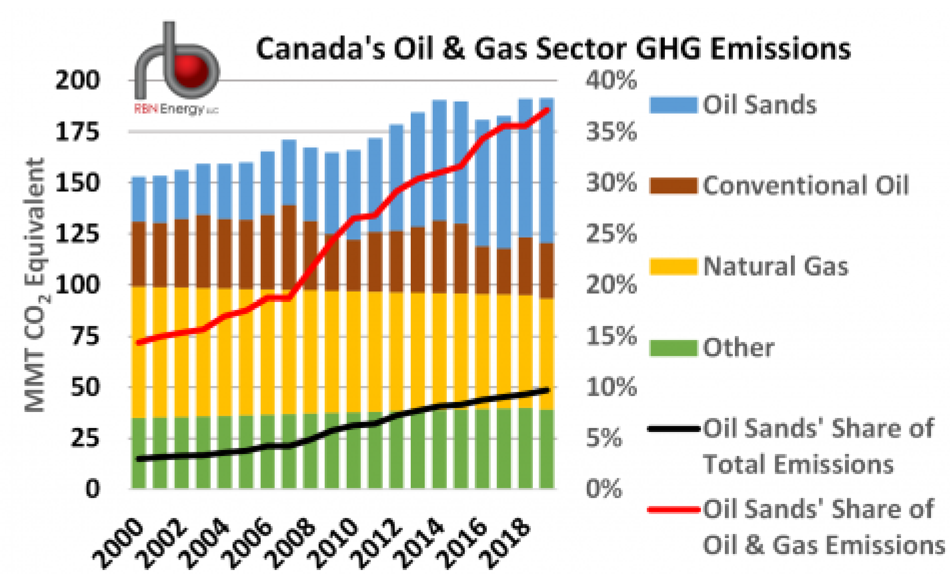

Figure 2. Canadian Oil and Gas Sector GHG Emissions. Source: Government of Canada

The oil sands' share of the total oil and gas sector's emissions has risen from 14% in 2000 to 37% in 2019 (red line in Figure 2), while its share in Canada's overall emissions has risen from 3% to 10% during the same period (black line). When placing oil sands emissions at the global scale, it becomes more of a rounding error, coming in at a miniscule 0.16% of the global total in 2019.

In April 2021, Canadian Prime Minister Justin Trudeau committed to reducing the country's GHG emissions by 40-45% by 2030 from the 2005 level, expanding on his government's earlier promise for a 36% reduction. To meet the new goal, Canada's annual GHG emissions within nine years would need to decline to about 443 MMT, a level not seen since 1977.

It is clear that while Canada's overall GHG emissions profile has been fairly steady up to 2019, emissions from the oil and gas sector have been rising, driven primarily by emissions from the oil sands. With further expansion in the oil sands output expected in the next few years, one way for the oil sands, and the oil and gas sector more generally, to address its contribution to Canada's emissions would be to undertake initiatives that explicitly reduce CO_2 and other GHG emissions, rather than just reduce the rate of emissions growth.

Now that we have some sense of the scale of emissions from Canada's energy industry, and the oil sands in particular, we will take a closer look at some recent initiatives that have been announced to capture, use, and sequester CO_2 emissions. Two of the largest to date were both announced within a week of each other in June, and although they are not related — at least not yet — they could certainly form a complementary network on an even larger scale.

The first of these, dubbed "Oil Sands Pathways to Net Zero" was announced on June 9 and involves five large oil sands companies that collectively account for about 90% of Canada's oil sands output: Canadian Natural Resources Limited, Cenovus Energy, Imperial Oil, MEG Energy, and Suncor Energy. These five companies are proposing — as part of a possible collaboration with the Alberta provincial and Canadian federal governments — to establish a network that gathers CO_2 emissions from oil sands operations and transports it on a dedicated trunk line about 300 kilometers (~185 miles) south from Fort McMurray, AB, the heart of oil sands operations, to a proposed carbon sequestration hub in Alberta's Cold Lake region (yellow arrow in Figure 3), where the CO_2 would be stored "forever and for always."

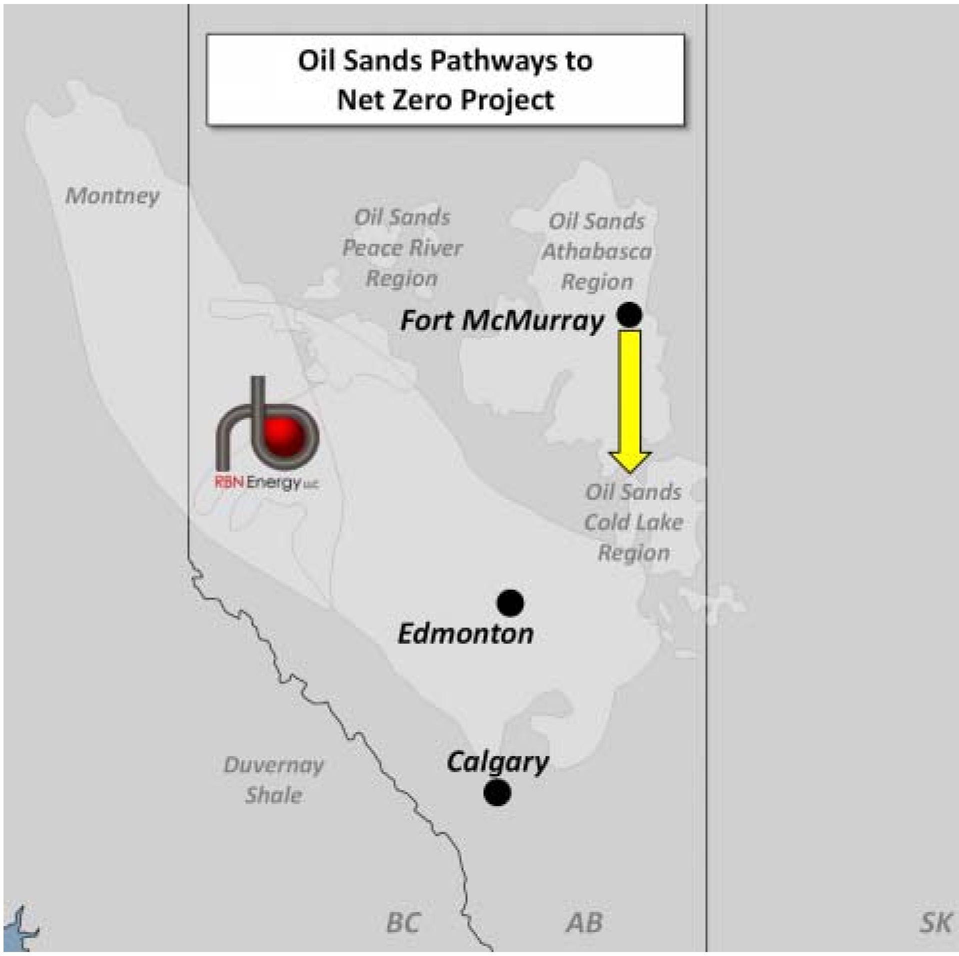

Figure 3. Oil Sands Pathways to Net Zero Project. Source: RBN

Although the Pathways project is the first of its kind to involve multiple oil sands companies, it is also short on specifics. There are no estimates provided for the amount of produced carbon that would be captured and sequestered, nor are there estimates for the cost of the project, the capacity of the dedicated CO_2 pipeline, or an in-service date.

The potential for other emitters to tie into the trunk line is mentioned in the announcement and could include blue hydrogen production, in which hydrogen is produced from natural gas (with the resulting CO_2 being sequestered); power generation plants, as well as any direct CO_2-capture technologies that might be deployed near the trunkline. The five companies are also making further commitments to change the nature of bitumen extraction by using less emission-intensive methods and focusing more on solvents that can allow the viscous bitumen to be pumped to the surface more easily. At this stage, the Pathways initiative remains more aspirational than concrete, but the companies in the collaboration have made it clear that progress will be dependent on government involvement in terms of infrastructure planning, development, and cost sharing.

Just a week later, on June 17, came the announcement for the Alberta Carbon Grid (ACG). A joint proposal by two major pipeline operators, TC Energy and Pembina Pipeline, the ACG would be a world-scale CO_2 transportation and sequestration system handling up to 20 MMT/yr (60 MT/d) by using unutilized or underutilized segments of each company's existing hydrocarbon pipeline network in Alberta, as well as newbuild pipeline expansions, for CO_2. Intended as an open access, fee-for-use system, the ACG would gather GHG emissions from the oil sands area (red-shaded North Leg in Figure 4), Alberta's industrial heartland near Edmonton (Central Leg), and power generation plants to the south and west of Edmonton (Southwest Leg). The system would transport the captured CO_2 to a proposed sequestration hub northeast of Edmonton (green dot) where it would be permanently stored in an already identified geological formation. The formation is said to be capable of storing up to 2 billion MT of CO_2, or enough to provide many decades of storage potential if fully developed.

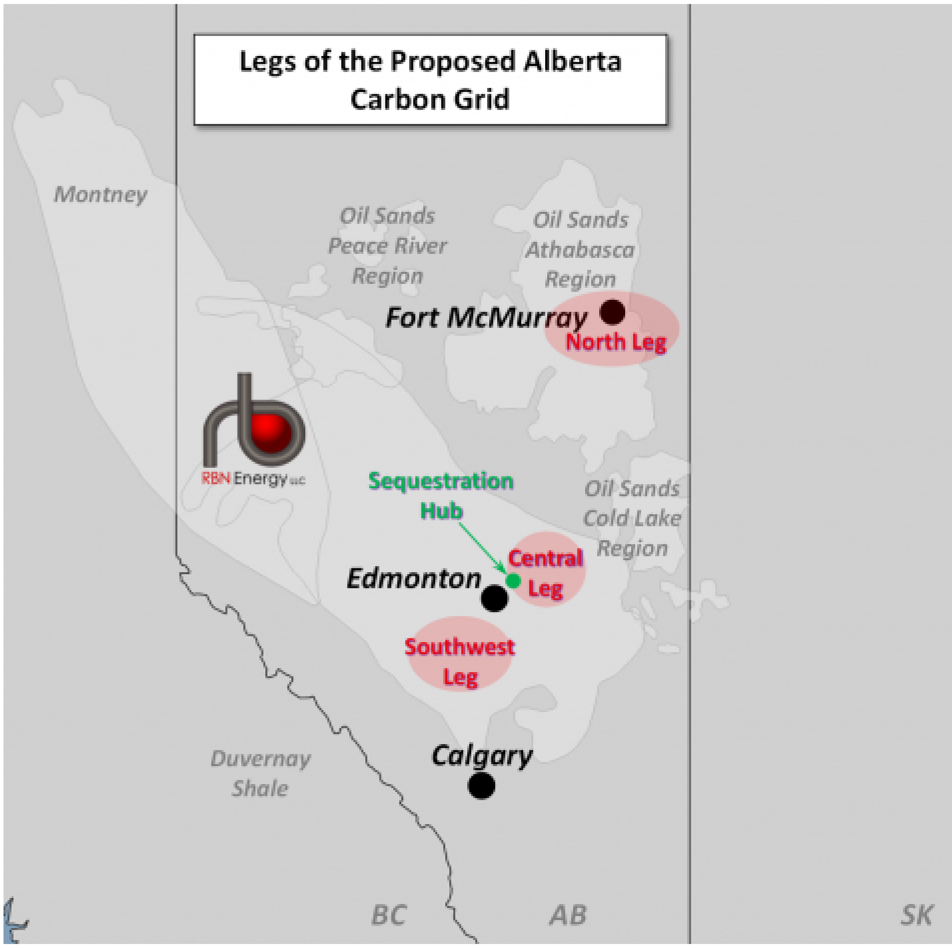

Figure 4. Legs of the Proposed Alberta Carbon Grid. Source: RBN

Although the cost of the ACG project has not been disclosed, TC Energy and Pembina have stated that fees for using the system would be materially less than the current price for carbon in Alberta, thereby creating an incentive for emitters to use AGC for transport and sequestration rather than pay for emissions they can't avoid. In addition, the system could be expanded to include CO_2 transportation from other parts of Alberta, such as heavy oil operations in the Peace River region, as well as access to any future sequestration hubs that might be developed. Currently, the first phase of the ACG is targeted to be in operation as early as 2025, with full-scale operations of 20 MMT/yr expected in early 2027.

The largest portion of CO_2 that would be moved on the ACG is expected to come from the oil sands (North Leg), with the remainder evenly split between the other two currently proposed legs of the system. The obvious connection for the ACG to the Pathways initiative is clear, although at this stage, no explicit links have been stated or implied by either the TC Energy/Pembina team or the five companies participating in the Pathways initiative. One caveat: Pembina mentioned when the ACG was unveiled that moving forward with the project as it is currently envisioned was predicated on a successful conclusion to its corporate takeover of Inter Pipeline Limited. On Monday, July 26, Pembina announced that its plan to acquire Inter Pipeline has been scrapped. Inter Pipeline indicated the same day that it intends to pursue a deal to be acquired by Brookfield Infrastructure Partners.

Time will tell if the ACG project advances in its current form. If and when the project is fully operational at 20 MMT/yr, the ACG would be transporting and sequestering a little under 30% of the oil sands total CO_2 emissions and slightly more than 10% of the Canadian oil and gas sector's GHG emissions based on the 2019 data that we mentioned previously. This would easily be the single largest contributor to a net reduction in emissions from the oil sands and oil and gas sector, and would take the Canadian government at least part of the way toward its 2030 GHG-reduction target. Note, however, that over the next nine years the government is pushing to reduce the country's annual emissions by more than 260 MMT — in other words, a lot more would need to be done, not only by Canada's oil and gas sector, but by transportation and other sectors as well.

One such project that bears mentioning was announced just a couple of weeks ago, on July 13 — Shell's proposed Polaris carbon capture project at its Scotford Refinery near Edmonton. Planned in two phases, the project will address CO_2 capture as well as blue hydrogen and help make Edmonton a leader in both the carbon and hydrogen markets. In upcoming blogs, we will review this among numerous other emission-reduction projects being proposed by the energy industry in Canada, as well as the handful of projects already in operation.

In our upcoming webinar, It's A Gas: CO2, we will discuss Edmonton's emergence as a CO2 hub and how it stacks up against other developing centers of CO2 activity in the U.S. Gulf Coast and Midwest. This is our third virtual conference in the It's a Gas series and will be held on August 10, 2021. Like our other recent conferences on propane and hydrogen, this will bridge the gap between fundamentals analysis and boots-on-the-ground market intelligence. We will bring together the views of senior executives involved in the CO2 transition along with RBN's latest analysis of CO2 production, infrastructure, pipelines, and projects. For details, click here.

"Forever and for Always" was written by Shania Twain and Mutt Lange, and appears as the fifth song on Shania Twain's fourth studio album, *Up!* Produced by Mutt Lange, the song was released as a single in April 2003, and went to #1 on the Billboard Adult Contemporary, #4 on the Hot Country Songs, and #20 on the Billboard Hot 100 Singles charts. It has been certified Platinum by the Recording Industry Association of America (RIAA). Personnel on the record were: Shania Twain (lead, backing vocals), Kevin Churko (programming), Simon Duggal (bass, drum programming), Paul Laime (drums), Paul Franklin (pedal steel guitar); Brent Mason, Michael Thompson, and Cory Churko (guitars); Diamond Duggal (keyboards), and Mutt Lange and Mauro Pagani (backing vocals).

Up! was recorded between the fall of 2001 and the summer of 2002. Produced by Mutt Lange, it was released in November 2002. The album went to #1 on the Billboard Top 200 Albums and Top Country Albums charts. It has been certified 11X Platinum by the RIAA. Different regions of the world received different versions of the LP. North America got a two-disc set, with separate album versions later released on vinyl in 2016. Eight singles were released from the album.

Shania Twain (Eileen Regina Edwards) is a Canadian singer and songwriter. She has sold more than 100 million records worldwide, making her the best-selling female country artist in history. She has released five studio albums, two live albums, two compilation albums, and 43 singles. Twain has won four Academy of Country Music Awards, six American Music Awards, 39 BMI Awards, two Country Music Association Awards, five Grammy Awards, and one World Music Award, and is a member of the Canadian Music Hall of Fame. Twain resides with her family in Corseaux, Switzerland. She will be performing her live "Let's Go!" show in Las Vegas at the Zappos Theater in December 2021 and February 2022.

https://www.shell.com/media/news-and-media-releases/2021/shell-invests-in-the-whale-development-in-the-gulf-of-mexico.html

Shell Invests in the Whale Development in the Gulf of Mexico

Jul 26, 2021

Shell Offshore Inc., a subsidiary of Royal Dutch Shell plc, today announces the final investment decision (FID) for Whale, a deep-water development in the U.S. Gulf of Mexico that features a 99% replicated hull and an 80% replication of the topsides from our Vito project.

“Whale is the latest demonstration of our focus on simplification, replication and capital projects with shorter cycle times to drive greater value from our advantaged positions,” said Wael Sawan, Shell Upstream Director. “We are building on more than 40 years of deep-water expertise to deliver competitive projects that yield high-margin barrels so that we are able to meet the energy demands of today while generating the cash required to help fund the development of the energy of the future.”

Whale will be the second Shell-operated deep-water development in the Gulf of Mexico to employ a simplified, cost-efficient host design. With this development approach, Shell anticipates an internal rate of return estimated to be greater than 25%. Our Whale development will feature energy-efficient gas turbines and compression systems. This development will be the latest addition to our Gulf of Mexico portfolio where our production is among the lowest greenhouse gas (GHG) intensity in the world for producing oil.

The Whale development, owned by Shell Offshore Inc. (60% operator) and Chevron U.S.A. Inc. (40%), is expected to reach peak production of approximately 100,000 barrels of oil equivalent per day (boe/d) and currently has an estimated, recoverable resource volume of 490 million boe. Whale will be Shell’s 12th deep-water host in the Gulf of Mexico and is currently scheduled to begin production in 2024.

Shell’s Powering Progress strategy to thrive through the energy transition includes increasing investment in lower carbon energy solutions, while continuing to pursue the most energy-efficient and highest-return Upstream investments.

Notes to editors

- The Whale production facility is in the Alaminos Canyon Block 773 and is adjacent to the Shell-operated Silvertip field, approximately 10 miles from the Shell-operated Perdido platform and approximately 200 miles southwest of Houston.
- Discovered in 2017, Whale will feature a semi-submersible production host in more than 8,600 feet of water with 15 oil producing wells.
- Whale’s design closely replicates Vito, a four-column semi-submersible host facility located in the greater Mars Corridor. Vito is scheduled to begin production in 2022.
- By leveraging the engineering, construction and supply chain of Vito, Whale is expected to achieve first oil 7.5 years after discovery.
- The cycle time includes the impact from COVID cash-preservation efforts that delayed project FID by one year.
- The estimated peak production and current estimated recoverable resources presented above are 100% total gross figures.
- The reference to our U.S. Gulf of Mexico production being among the lowest GHG intensity in the world is a comparison among other IOGP oil- and gas-producing members.
- Shell is the leading operator in the U.S. Gulf of Mexico.
- In addition to operations in Brazil and the U.S. Gulf of Mexico, Shell’s deep-water portfolio includes frontier exploration opportunities in Mexico, Suriname, Argentina and West Africa.

SAF Group created transcript of Excerpts from Bloomberg Daybreak Europe, Bloomberg's Manus Cranny interview with Equinor CEO Anders Opedal interview https://www.bloomberg.com/news/videos/2021-07-28/equinor-profit-more-than-doubles-video

Items in "i*talics*" are SAF Group created transcript

At 1:10 min mark re his view of high oil and gas prices, Opedal says "I *don't want to say exactly the prices for the gas because there will still see volatility there, but we see the fundaments are there, there is less LNG coming into Europe and there is increasing demand. For the oil price, we will continue to see prices in the level we are seeing now buyt we are expecting volatility. We are still in the pandemic, there will still be close downs in some parts of the region around the world and that might take down the demand. and the rising demand a little bit.*"

At 2:50 min mark. Cranny "*you recently reduced your renewables returns, what are the biggest headwinds in renewables?"* Opedal "… *but we also see there is strong competition. We see that there is a companies that are very ambitious about their targets. But we still need more seabeds to actually execute on a project. At the moment there are higher ambitions than seabeds available. So but we think that, based on the ambitions we see from different countries, more seabeds will be available."*

At 3:50 min mark on CCS. Cranny "*Anders on the hydrogen and carbon capture business, when will you return to profit*?" Opedal "*well, that's a little bit to early to say. Still we are now working on a lot of different options. Both in the UK, Norway, Germany and Holland. We are maturing those options. We need to see higher carbon price to make those projects profitable. It actually needs to be more expensive to pollute than actually capture and storage. The Northern Lights project is progressing well. This is the world's first project where we are actually picking up the CO2 from different places in Europe and bring it by vessel to the western coast of Norway and store it safely under the North Sea. We expect more years to see this type of projects can be profitable. At the moment we are dependent upon on support from governments".*

https://apnews.com/article/lifestyle-business-health-california-coronavirus-pandemic-5ebe70407fcd94ef712c16410f32c4b1

Bacon may disappear in California as pig rules take effect

By SCOTT McFETRIDGEtoday

DES MOINES, Iowa (AP) — Thanks to a reworked menu and long hours, Jeannie Kim managed to keep her San Francisco restaurant alive during the coronavirus pandemic.

That makes it all the more frustrating that she fears her breakfast-focused diner could be ruined within months by new rules that could make one of her top menu items — bacon — hard to get in California.

“Our number one seller is bacon, eggs and hash browns,” said Kim, who for 15 years has run SAMS American Eatery on the city’s busy Market Street. “It could be devastating for us.”

At the beginning of next year, California will begin enforcing an animal welfare proposition approved overwhelmingly by voters in 2018 that requires more space for breeding pigs, egg-laying chickens and veal calves. National veal and egg producers are optimistic they can meet the new standards, but only 4% of hog operations now comply with the new rules. Unless the courts intervene or the state temporarily allows non-compliant meat to be sold in the state, California will lose almost all of its pork supply, much of which comes from Iowa, and pork producers will face higher costs to regain a key market.

Animal welfare organizations for years have been pushing for more humane treatment of farm animals but the California rules could be a rare case of consumers clearly paying a price for their beliefs.

With little time left to build new facilities, inseminate sows and process the offspring by January, it’s hard to see how the pork industry can adequately supply California, which consumes roughly 15% of all pork produced in the country.

“We are very concerned about the potential supply impacts and therefore cost increases,” said Matt Sutton, the public policy director for the California Restaurant Association.

California’s restaurants and groceries use about 255 million pounds of pork a month, but its farms produce only 45 million pounds, according to Rabobank, a global food and agriculture financial services company.

The National Pork Producers Council has asked the U.S. Department of Agriculture for federal aid to help pay for retrofitting hog facilities around the nation to fill the gap. Hog farmers said they haven’t complied because of the cost and because California hasn’t yet issued formal regulations on how the new standards will be administered and enforced.

Barry Goodwin, an economist at North Carolina State University, estimated the extra costs at 15% more per animal for a farm with 1,000 breeding pigs.

If half the pork supply was suddenly lost in California, bacon prices would jump 60%, meaning a $6 package would rise to about $9.60, according to a study by the Hatamiya Group, a consulting firm hired by opponents of the state proposition.

At one typical hog farm in Iowa, sows are kept in open-air crates measuring 14-square-feet when they join a herd and then for a week as part of the insemination process before moving to larger, roughly 20-square foot group pens with other hogs. Both are less than the 24 square feet required by the California law to give breeding pigs enough room to turn around and to extend their limbs. Other operations keep sows in the crates nearly all of the time so also wouldn't be in compliance.

The California Department of Food and Agriculture said that although the detailed regulations aren't finished, the key rules about space have been known for years.

"It is important to note that the law itself cannot be changed by regulations and the law has been in place since the Farm Animal Confinement Proposition (Prop 12) passed by a wide margin in 2018," the agency said in response to questions from the AP.

The pork industry has filed lawsuits but so far courts have supported the California law. The National Pork Producers Council and a coalition of California restaurants and business groups have asked Gov. Gavin Newsom to delay the new requirements. The council also is holding out hope that meat already in the supply chain could be sold, potentially delaying shortages.

Josh Balk, who leads farm animal protection efforts at the Humane Society of the United States, said the pork industry should accept the overwhelming view of Californians who want animals treated more humanely.

"Why are pork producers constantly trying to overturn laws relating to cruelty to animals?" Balk asked. "It says something about the pork industry when it seems its business operandi is to lose at the ballot when they try to defend the practices and then when animal cruelty laws are passed, to try to overturn them."

In Iowa, which raises about one-third of the nation's hogs, farmer Dwight Mogler estimates the changes would cost him $3 million and allow room for 250 pigs in a space that now holds 300.

To afford the expense, Mogler said, he'd need to earn an extra $20 per pig and so far, processors are offering far less.

"The question to us is, if we do these changes, what is the next change going to be in the rules two years, three years, five years ahead?" Mogler asked.

The California rules also create a challenge for slaughterhouses, which now may send different cuts of a single hog to locations around the nation and to other countries. Processors will need to design new systems to track California-compliant hogs and separate those premium cuts from standard pork that can serve the rest of the country.

At least initially, analysts predict that even as California pork prices soar, customers elsewhere in the country will see little difference. Eventually, California's new rules could become a national standard because processors can't afford to ignore the market in such a large state.

Kim, the San Francisco restaurant owner, said she survived the pandemic by paring back her menu, driving hundreds of miles herself through the Bay Area to deliver food and reducing staff.

Kim, who is Korean-American, said she's especially worried for small restaurants whose customers can't afford big price increases and that specialize in Asian and Hispanic dishes that typically include pork.

"You know, I work and live with a lot of Asian and Hispanic populations in the city and their diet consists of pork. Pork is huge," Kim said. "It's almost like bread and butter."

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Associated Press writers David Pitt in Des Moines, Iowa, and Stephen Groves in Alvord, Iowa, contributed to this story.

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Follow Scott McFetridge on Twitter: https://twitter.com/smcfetridge https://www.afacwa.org/unruly_passengers_survey

85 percent of Flight Attendants dealt with unruly passengers, nearly 1 in 5 experienced physical incidents in 2021

After new survey, Flight Attendants Union Calls on FAA, DOJ to take action, make "zero-tolerance" policy permanent

WASHINGTON, D.C. (July 29, 2021) — A new national survey of nearly 5,000 flight attendants released today by the Association of Flight Attendants-CWA, AFL-CIO (AFA) found that over 85 percent of all respondents had dealt with unruly passengers as air travel picked up in the first half of 2021. More than half (58%) had experienced at least five incidents this year. A shocking 17 percent reported experiencing a physical incident.

AFA is calling on the FAA and DOJ to protect passengers and crew from disruptive, and verbally and physically abusive travelers. Survey data confirmed that existing measures were failing to address the problem. 71 percent of Flight Attendants who filed incident reports with airline management received no follow-up and a majority did not observe efforts to address the rise in unruly passengers by their employers.

"This survey confirms what we all know, the vitriol, verbal and physical abuse from a small group of passengers is completely out of control, and is putting other passengers and flight crew at risk. This is not just about masks as some have attempted to claim. There is a lot more going on here and the solutions require a series of actions in coordination across aviation," said Sara Nelson, President of AFA-CWA. "It is time to make the FAA 'zero tolerance' policy permanent, the Department of Justice to utilize existing statute to conduct criminal prosecution, and implement a series of actions proposed by our union to keep problems on the ground and respond effectively in the event of incidents."

"This is not a 'new normal' we are willing to accept," Nelson continued. "We know the government, airlines, airports, and all stakeholders can take actions together to keep us safe and flying friendly. We will be sharing survey findings with FAA, DOT, TSA, and FBI to help more fully identify the problems and our union's proposed actions to affect positive change."

The survey provides further documentation of the unprecedented rise in verbally abusive and physically violent passenger misconduct documented by the Federal Aviation Administration (FAA). The FAA's most recent public reporting included 3,615 incident reports and a record number of enforcement actions to enforce aviation safety rules. In March 2021, FAA Administration Steve Dickson extended the FAA "zero tolerance" policy for passenger misconduct, and the FAA has since run an aggressive public campaign to communicate consequences of violations.

It is a violation of federal law to interfere or disrupt the duties of a crewmember. Federal Aviation Regulations 91.11, 121.580 and 135.120 state that "no person may assault, threaten, intimidate, or interfere with a crewmember in the performance of the crewmember's duties aboard an aircraft being operated."

When asked what they believed to be the cause or escalating reasons for the unruly behavior, Flight Attendants cited that mask compliance, alcohol, routine safety reminders, flight delays and cancellations were all common factors in unruly passenger interactions. Many cited multiple factors contributed to incidents.

Flight attendants reported facing extensive verbal abuse, including from visibly drunk passengers, passengers yelling and swearing in response to masking directions, and often aggressively challenging flight crew working to ensure compliance with federal rules. Many respondents recounted aggressive incidents, including shoving, kicking seats, throwing trash at flight crew, defiling the restroom in response to crewmember instructions, and following flight crew through the airport to continue yelling and harassment.

One Flight Attendant wrote, “We tell them [passengers] that it is a federal offense to not comply with crew member instructions, use foul and/or threatening language onboard, and then the plane is met by airline supervisors or airport law enforcement and the passenger gets a slap on the wrist and sent on their way. I've been yelled at, cursed at and threatened countless times in the last year and the most that has come out of it has been a temporary suspension of travel for the passenger. We need real consequences if flight attendants are ever going to feel safe at work again.”

Another Flight Attendant wrote, “I was on the floor in the back of the plane and the [rest of] crew members didn't know what happened until after my attacker had already deplaned.”

Additional findings:

- **Reports to law enforcement**: 33 percent of the respondents reporting verbal incidents said that law enforcement was requested to meet their flight in response to the incident. Of the respondents that encountered physical incidents, 60 percent said law enforcement was requested to meet their flight.
- **When incidents occur**: While 84 percent of respondents reported that they experienced unruly behavior during flight, 50 percent reported witnessing misconduct during boarding, and 13 percent reported behavior beginning in the gate area.
- **Sexist, racist, homophobic language**: 61 percent of respondents reported that disruptive passengers used racist, sexist and/or homophobic slurs during incidents. Many specific examples were provided, most of which were too offensive to repeat.

“Racist, sexist, and homophobic abuse of flight crews creates a hostile environment for everyone onboard and violates federal law. It has no place anywhere, and certainly not in a workplace environment. Our union has fought discrimination and prejudice for decades, and we are not about to allow this moment to set us back. Hell no! Not on our watch. Aviation is about bringing people together, not tearing us apart. Every person matters, and we can only have the freedom of flight when we recognize the reality that we are all in this together.”

Nearly 5,000 responses from flight attendants across 30 airlines were collected from June 25, 2021 through July 14, 2021 through an online survey.

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The Association of Flight Attendants is the Flight Attendant union. Focused 100 percent on Flight Attendant issues, AFA has been the leader in advancing the Flight Attendant profession for 75 years. Serving as the voice for Flight Attendants in the workplace, in the aviation industry, in the media and on Capitol Hill, AFA has transformed the Flight Attendant profession by raising wages, benefits and working conditions. Nearly 50,000 Flight Attendants come together to form AFA, part of the 700,000-member strong Communications Workers of America (CWA), AFL-CIO. Visit us at www.afacwa.org.

https://www.wsj.com/articles/beirut-explosion-what-happened-in-lebanon-and-everything-else-you-need-to-know-11596590426

Beirut Explosion: What Happened in Lebanon and Everything Else We Know

Warehouse fire ignited a cache of explosive ammonium nitrate, authorities say, leading to more than two dozen arrests but no ministers among them

Days after a massive explosion rocked the city of Beirut, WSJ's Dion Nissenbaum visits the blast site. Photo: Dion Nissenbaum for the Wall Street Journal

By Nazih Osseiran *and* Isabel Coles

Updated Dec. 10, 2020 4:58 pm ET

Nearly 200 people were killed and more than 6,000 injured in a massive explosion at the port in Beirut on Aug. 4, ravaging the heart of residential areas and the city's vibrant commercial district. Dozens of people are unaccounted for. Here is what we know so far.

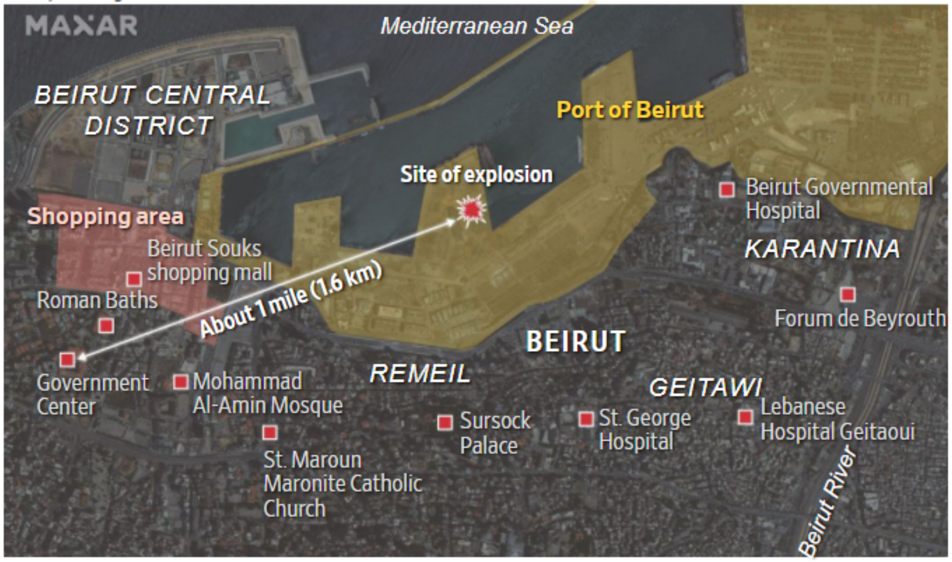
What happened in Beirut?

A giant explosion at a warehouse in the port sent a shock wave through east and downtown Beirut at about 6 p.m. local time on Aug. 4. Videos of the blast posted on social media showed smoke billowing from the warehouse on the waterfront before a massive explosion produced a dome-shaped cloud that engulfed large parts of central Beirut. The force of the blast did tremendous damage to the surrounding neighborhoods and nearby buildings. The homes of tens of thousands of people were damaged by the blast.

Beirut Blast

Beirut was rocked by an explosion felt as far as 150 miles away in Cyprus on Tuesday.

Key damaged locations



Source: Maxar Technologies (satellite image)

What caused the explosion in Beirut?

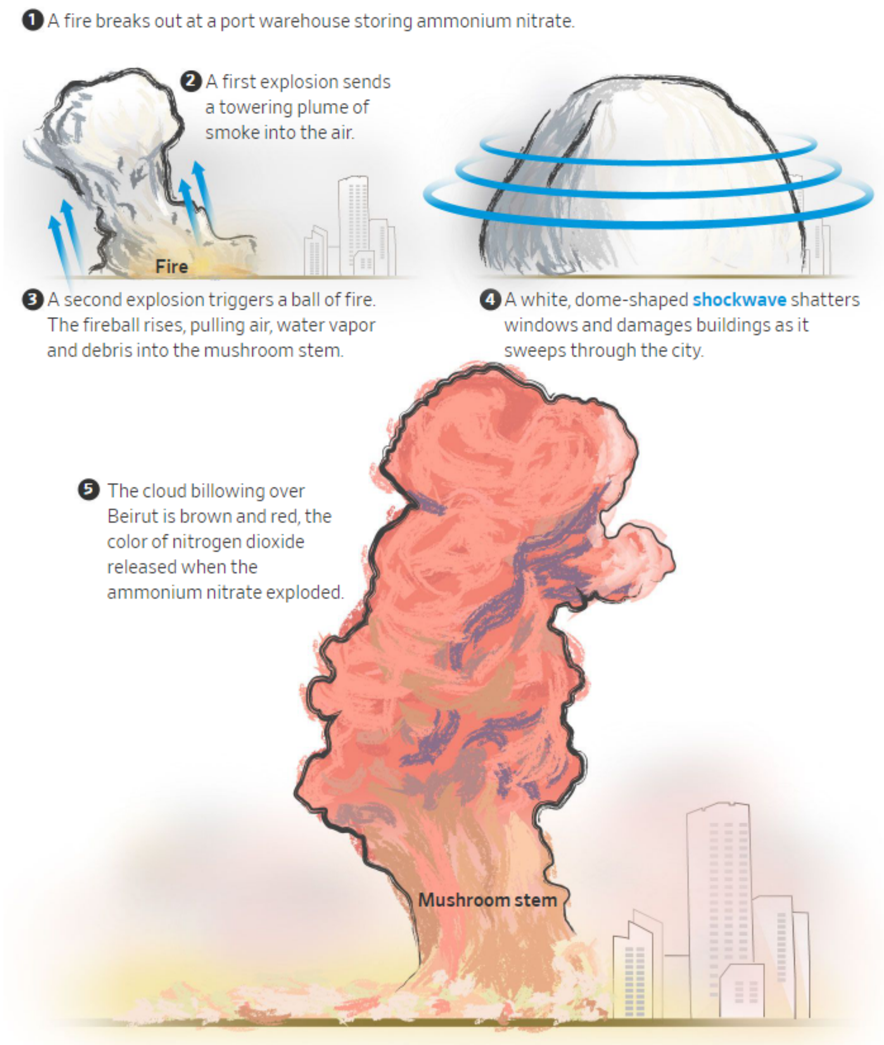
Authorities say the blast occurred when a fire at a warehouse—Hangar 12—on the city's waterfront ignited a cache of ammonium nitrate, an explosive material that had been stored at the site for more than six years.

What is ammonium nitrate?

Ammonium nitrate is a chemical compound most commonly used in fertilizers. It is also used to make explosives and was used in the Oklahoma City bombing in 1995.

Fire, Blast and Shockwave

How ammonium nitrate stored in Beirut's port caused chaos through the city



Sources: Cheryl Rofer, Los Alamos National Laboratory (retired); Jeffrey Lewis, Middlebury Institute; Vipin Narang, Massachusetts Institute of Technology; Andrea Sella, University College London
Roque Ruiz/THE WALL STREET JOURNAL

Who is responsible?

The Lebanese government is facing questions about why the explosive chemicals were stored at the port. A judge leading an investigation into the blast has charged caretaker Prime Minister Hassan Diab and three former ministers with negligence in relation to the blast. Mr. Diab has denied any wrongdoing. The former ministers couldn't be reached for comment. Many Lebanese blame years of poor governance and corruption by the entire ruling elite for the explosion.

Lebanese authorities say the explosives originally entered Beirut's port on a ship bound for Mozambique in 2013. Shiparrested.com, a shipping industry newsletter, said in 2015 that the vessel, which was carrying 2,750 tons of ammonium nitrate, was forced to dock in 2013 in Beirut due to technical problems. Its owners later abandoned it there. Local authorities transferred the explosives to a warehouse in the port and were meant to dispose of them safely, according to the newsletter, but they never did.

The Lebanese army on Sept. 3 said it found more than four tons of ammonium nitrate near Beirut's port. An engineering team discovered the chemical during a search of a warehouse that was requested by the customs agency at the port, an army official said. It wasn't immediately clear if the chemical was from the same stockpile that blew up, but it served as a reminder of the security lapses that led to the Aug. 4 blast.
Lebanese leaders have backed a probe that has focused on junior officials working at the port, but residents say they want national leaders held accountable for years of poor governance and corruption.

More than two dozen people have been arrested in connection with the explosion as on Oct. 22, according to state media. No ministers have been charged.

Escalating protests forced prime minister Mr. Diab and his cabinet to resign a week after the blast. Lebanon's ambassador to Germany, Mustapha Adib, was named the next prime minister on Aug. 31 but he also quit in September after failing to form a government. Mr. Diab remained as caretaker prime minister.

Prime Minister-designate Saad Hariri arrived to the presidential palace to meet with President Michel Aoun on Oct. 22.
PHOTO: WAEL HAMZEH/SHUTTERSTOCK

On Oct. 22, Lebanon's political elite named former Prime Minister Saad Hariri as the country's next premier a year after he quit the position under pressure from popular protests. The move angered many Lebanese who sought a complete overhaul of the political system they blame for the deadly Beirut explosion.

What is the Lebanon's economic situation now?

Lebanon's already fragile economy has deteriorated amid lockdowns imposed to halt the spread of the coronavirus. The value of the country's currency has plummeted in recent months, and its overtaxed power system has plunged the capital of Beirut into darkness for hours at a time. The economy is expected to contract by 25% this year, according to the International Monetary Fund. Meanwhile, the international community is refusing to disburse aid unless the Lebanese political class forms a government and tackles corruption in the public sector. An initiative by French President Emmanuel Macron —who has visited Lebanon twice since the blast—to expedite the formation of a government has yet to yield results.

The dominance of Hezbollah over Lebanon's political system is also a sticking point for the U.S., which has sanctioned politicians allied with the group since the blast.

How has the coronavirus pandemic affected the country?

Lebanon's health-care system has been strained by a rising number of coronavirus infections. The small Mediterranean country of 5.8 million has recorded almost 140,000 confirmed cases of Covid-19 as of Dec. 9. Beds earmarked for Covid-19 treatment are nearing capacity. Many of Beirut's hospitals were quickly overwhelmed after the blast, owing to the country's poor infrastructure and the strained resources that were devoted to combating the coronavirus.

How have Lebanese people responded to the explosion amid economic and political crises?

Critics of the Lebanese government are asking how and why the fire and resulting explosion took place. Tens of thousands of protesters converged days after the blast on central Beirut, some clashing with security forces and taking over government buildings, as they demanded revenge. More than 700 people were injured in the protests, according to first responders. The protests have since subsided.

The mass demonstration followed large protests that erupted in Lebanon in 2019 to denounce government corruption and mismanagement. Protesters took to the streets again in April as the coronavirus and financial crisis heaped economic pressure on ordinary Lebanese people. They attacked bank buildings as they vented frustration at soaring prices of food and other goods and what many Lebanese see as a sclerotic political system unwilling to fix the country's problems. The World Food Program is providing emergency support for the thousands of Beirut residents who have lost their homes. It also warned that the damage to the port—through which much of the country’s imports flow—could send food prices higher. Prices for some staples had already more than doubled this year in Lebanon.

Write to Isabel Coles at isabel.coles@wsj.com

Dan Tsubouchi @Energy_Tidbits · 3h

Time to add geopolitical risk to #Oil price? #Bennett closes with "we expect the international communtiy will make it clear to the Iranian regime that they have made a serious mistake. In any case, we know how to send a message to Iran in our own way" #OOTT

> **PM of Israel** @IsraeliPM · 3h
>
> Prime Minister Naftali Bennett, at the Cabinet meeting today:
> "The world recently received a reminder of Iranian aggression, this time on the high seas. The Iranians, who attacked the ship 'Mercer Street' with UAVs, intended to attack an Israeli target.
>
> gov.il/en/departments...
>
> Show this thread

1 2 2

Dan Tsubouchi @Energy_Tidbits · 4h

#JCPOA. has to make increasingly difficult for #Biden to achieve his moon shot of return to JCPOA unless Iran gives in on missiles. Key question/upside to #Oil - will @POTUS clamp down on Iran barrels being snuck into market? Iran up almost 0.5 mmb/d since Nov election. #OOTT

> **Dan Tsubouchi** @Energy_Tidbits · 4h
>
> Time to add some geopolitical risk to #Oil price. Israel PM @naftalibennett "I declare unequivocally: Iran is the one that carried out the attack on the ship" "We, in any case, have our own way to relay the message to Iran" #OOTT
> reuters.com/world/middle-e...

5 2

Dan Tsubouchi @Energy_Tidbits · 4h

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> **Dan Tsubouchi** @Energy_Tidbits · 12h
>
> US #AnthonyBlinken & Israel #YairLapid call, agree to work with UK, RO & other international partners to investigate the facts, provide support & "consider the appropriate next steps" regarding drone attack on #MercerStreet products tanker. #OOTT
> state.gov/secretary-blin...

5 5

Dan Tsubouchi @Energy_Tidbits · 12h

Just watched an amazing performance by #TeamCanada @lalongen in women's 3,000m steeplechase. sets new personal best & new Cdn record in what CBC just said is 37C temp and humid at @Tokyo2020. Hope she qualifies for finals. She looks deservedly pumped in #CBC post race interview.

1

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> **Dan Tsubouchi** @Energy_Tidbits · Jul 31
>
> ICYMI. US Central Command "Initial indications clearly point to a UAV-style attack" on Mercer Street oil products tanker. Have to wonder what is coming in a counter punch from Israel? #OOTT
>
> centcom.mil/MEDIA/PRESS-RE...

2

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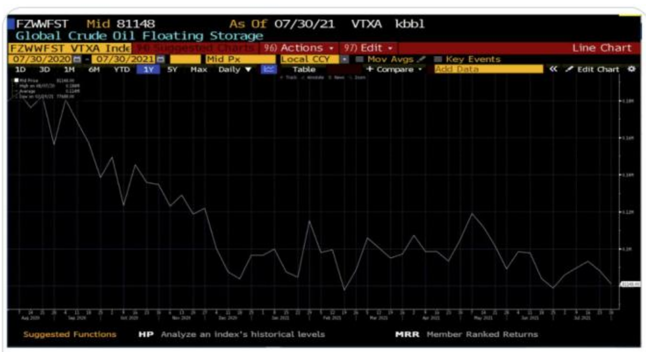
1

Dan Tsubouchi @Energy_Tidbits · 13h

#Oil markets look to be absorbing increased #OPEC+ barrels since May1. Vortexa crude #Oil in floating storage as of 07/30 was 81.15 mmb, down vs 88.18 mmb as of 07/23. Down 135.72 mmb vs 06/26/20 peak of 216.42 mmb. Thx @Vortexa for data & @TheTerminal for posting today. #OOTT



Source: Bloomberg, Vortexa

3 16

Dan Tsubouchi @Energy_Tidbits · 19h

2/2. Recall July 2018, Saudi temporarily halted tanker transit via #RedSea #BabElMandeb due attack on tanker rumored to be via rocket or drone. @EIAgov estimates >3.5 mmb/d daily transit. #OOTT

https://www.eia.gov/todayinenergy/detail.php?id=41073
AUGUST 27, 2019

The Bab el-Mandeb Strait is a strategic route for oil and natural gas shipments

Source: U.S. Energy Information Administration

The Bab el-Mandeb Strait is a sea route chokepoint between the Horn of Africa and the Middle East, connecting the Red Sea to the Gulf of Aden and Arabian Sea. Most exports of petroleum and natural gas from the Persian Gulf that transit the Suez Canal or the SUMED Pipeline pass through both the Bab el-Mandeb and the Strait of Hormuz.

Chokepoints are narrow channels along widely used global sea routes that are critical to global energy security. The Bab el-Mandeb

1

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Dan Tsubouchi @Energy_Tidbits · 19h

1/2. Saudi says thwarted armed drone attack on Saudi commercial vessel in southern #RedSea. Wonder how & what type of "commerical vessel". Are #Houthis moving from small boats w/ explosives & mines to drones? If so, elevates risks to #RedSea #BabElMandeb tankers? #OOTT

https://saudigazette.com.sa/article/609309/SAUDI-ARABIA/Arab-Coalition-foils-Houthis-bid-to-target-Saudi-commercial-ship

Arab Coalition foils Houthis' bid to target Saudi commercial ship

July 30, 2021

Saudi Gazette report

RIYADH — The Arab Coalition forces have thwarted an attempt by the Houthi militia to target a Saudi commercial vessel with an armed drone.
In a statement on Friday, the Coalition to Restore Legitimacy in Yemen said that the Iran-backed militia continues to threaten global maritime shipping routes.

The coalition added in the statement that its efforts have contributed to securing the freedom of navigation and the safety of ships transiting through the Bab Al-Mandeb Strait.

The sabotage attempt on Friday by the Houthi militia comes just a couple of days after the coalition forces intercepted and destroyed a Houthi explosive-laden drone targeting the Kingdom's southern region.

Just hours before the drone attack, the coalition forces destroyed two booby-trapped drones and three ballistic missiles launched by the militia toward the southern city of Jazan.

1 2 4

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Dan Tsubouchi @Energy_Tidbits · Jul 31

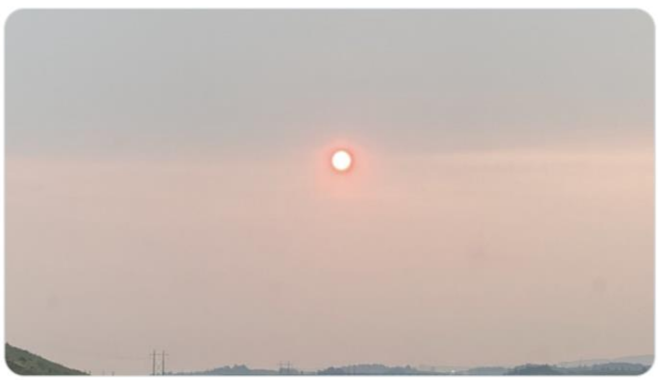
ICYMI. US Central Command "Initial indications clearly point to a UAV-style attack" on Mercer Street oil products tanker. Have to wonder what is coming in a counter punch from Israel? #OOTT

Drone strike in North Arabian Sea kills two: US Navy rendering assista
ARABIAN SEA (July 30, 2021) – U. S. naval forces responded to an emergency distress call following an attack on a merchant vessel in the...
centcom.mil

3

Dan Tsubouchi @Energy_Tidbits · Jul 31

great sunrise on trans canada highway on way back to #Calgary. unfortunately it's only because of the smoke in the air from wildfires in BC. hope everyone is doing their best to stay safe there and big thank you to all the firefighters and emergency services.



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Dan Tsubouchi @Energy_Tidbits · Jul 30

#TeamCanada🇨🇦 women's soccer just beat Brazil to get to semi finals. huge team effort and @stephlabbe1 was amazing. huge save with a minute to go in extra time, and now in penalty kicks. worth watching the replay on this one. 🇨🇦

3

Dan Tsubouchi @Energy_Tidbits · Jul 29

3/3. Don't forget #Shell Feb 25 #LNGSupplyGap outlook was 1 mth pre #TotalEnergies force majeure on Mozambique #LNG Phase 1 of 1.7 bcf/d in 2024 & delays in #Exxon Mozambique Rozuma 2.0 bcf/d originally in 2025. See SAF Group Apr 28 & July 14 LNG blogs.

Blog Summary

iple Brownfield LNG FIDs Now Needed To Fill New LNC
n Mozambique Chaos? How About LNG Canada Phase

Wednesday April 28, 2021. 9:00 MT

xt six months will determine the size and length of the new LNG supply gap that is hitting
expected six months ago. Optimists will say the Mozambique government will bring sust
to the northern Cabo Delgado province and provide the confidence to Total to quickly get
pment such that its LNG in-service delay is a matter of months and not years. We hope t
tic situation, but will it be that easy for Total's board to quickly look thru what just happen
pment for 3 months, restarted development on March 25, but then 3 days of violence led
on March 28, and announce force majeure on Monday April 26. Even if the optimists are r
d on for LNG supply and the major LNG supply project that are in LNG supply forecasts a
1 of 1.7 bcf/d and its follow on Phase 2 of 1.3 bcf/d, and Exxon's Rozuma Phase 1 of 2.0
ber this 5.0 bcf/d of major LNG supply is being counted in LNG supply forecasts and star
m, we think the more likely scenario is a delay of at least 2 years in this 5.0 bcf/d from th
s creates a much bigger and sooner LNG supply gap starting ~2025 and stronger outlool
Asia will play a role in keeping a lid on LNG prices. But there will be the opportunity for L
the potential for brownfield LNG projects to fill the growing supply gap. The thought of inc
six months ago, but there is a much stronger outlook for global oil and gas prices. Oil anc
g from cutting capex to small increases in 2021 capex and expecting for higher capex in 2
ge for looking at potential FID of brownfield LNG projects before the end of 2021 to be inc
s. Mozambique is causing an LNG supply gap that someone will try to fill. And if browní
Shell looking at 1.8 bcf/d brownfield LNG Canada Phase 2? Cdn natural gas producers h
nore Cdn natural gas will be tied to Asian LNG markets and not competing in the US aga

For Details, Please See The 7 Page Blog
http://www.safgroup.ca/insights/trends-in-the-market/

Blog Summary

ı LNG Buyers Abruptly Change and Lock in Long Terr
ates Supply Gap, Provides Support For Brownfield LN

Wednesday, July 14, 2021 at 10:00 MT

7 days has shown there is a sea change as Asian LNG buyers have made an abrupt
ing and are moving to lock in long term LNG supply. This is the complete opposite of
hen they were trying to renegotiate Qatar LNG long term deals lower and moving awa
rt term sales. Why? We think they did the same math we did in our April 28 blog "Mult
eded To Fill New LNG Supply Gap From Mozambique Chaos? How About LNG Cana
gger and sooner LNG supply gap driven by the delay of 5 bcf/d of Mozambique LNG t
supply forecasts. Asian LNG buyers are committing real dollars to long term LNG dea
idation for the LNG supply gap. Another validation, Shell, Total and others are aggres
n capital to partner in Qatar Petroleum's massive 4.3 bcf/d LNG expansion despite pl
on in the 2020s. And even more importantly to LNG suppliers, the return to long term
g capacity to commit to brownfield LNG FIDs. The abrupt change by Asian LNG buyer
hanger for LNG markets and sets the stage for brownfield LNG FIDs likely as soon as
ownfield LNG FIDs if the gap is coming bigger and sooner. And we return to our April
needed, what about Shell looking at 1.8 bcf/d brownfield LNG Canada Phase 2? LNG
pacity is already a material positive for Cdn natural gas producers. A FID on LNG Car
eaning 3.6 bcf/d of Cdn natural gas will be tied to Asian LNG markets and not compet
nd with a much shorter distance to Asian LNG markets. This is why we focus on glob
uture value of Canadian natural gas.

For Details, Please See The 8 Page Blog
http://www.safgroup.ca/research/trends-in-the-market/

1 3

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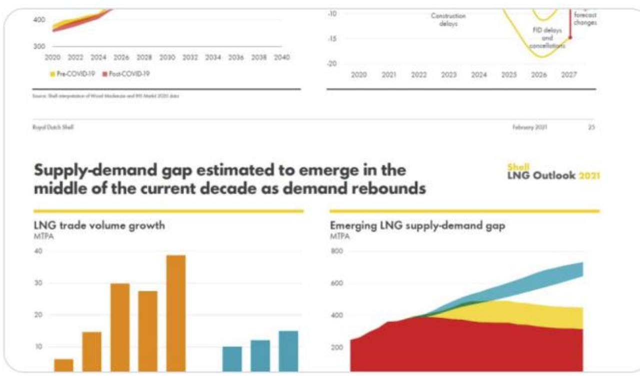
Dan Tsubouchi @Energy_Tidbits · Jul 29

2/3. #Shell says #LNG demand to nearly double by 2040, secures volumes for portfolios by the mid-2020s. same view as per Shell LNG outlook Feb 25/21 to nearly double (+340 mtpa or +45 bcf/d) by 2040 & #LNGSupplyGap in mid 2020s.



1 3 6

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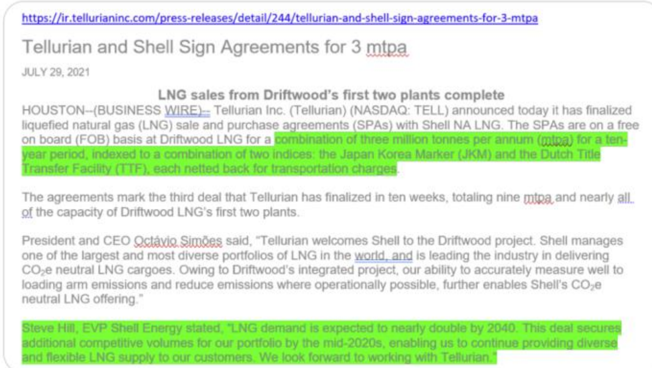
Dan Tsubouchi @Energy_Tidbits · Jul 29

1/3. #LNGSupplyGap. Great #Shell reminder of bullish #LNG outlook in 2020s. Wasn't in today's Q2 results/call, but in #Tellurian #DriftwoodLNG release Shell signed 10-yr LNG purchase deal for 0.4 bcf/d. ir.tellurianinc.com/press-releases...



https://ir.tellurianinc.com/press-releases/detail/244/tellurian-and-shell-sign-agreements-for-3-mtpa

Tellurian and Shell Sign Agreements for 3 mtpa

JULY 29, 2021

LNG sales from Driftwood's first two plants complete

HOUSTON--(BUSINESS WIRE)-- Tellurian Inc. (Tellurian) (NASDAQ: TELL) announced today it has finalized liquefied natural gas (LNG) sale and purchase agreements (SPAs) with Shell NA LNG. The SPAs are on a free on board (FOB) basis at Driftwood LNG for a combination of three million tonnes per annum (mtpa) for a ten-year period, indexed to a combination of two indices: the Japan Korea Marker (JKM) and the Dutch Title Transfer Facility (TTF), each netted back for transportation charges.

The agreements mark the third deal that Tellurian has finalized in ten weeks, totaling nine mtpa and nearly all of the capacity of Driftwood LNG's first two plants.

President and CEO Octávio Simões said, "Tellurian welcomes Shell to the Driftwood project. Shell manages one of the largest and most diverse portfolios of LNG in the world, and is leading the industry in delivering CO_2e neutral LNG cargoes. Owing to Driftwood's integrated project, our ability to accurately measure well to loading arm emissions and reduce emissions where operationally possible, further enables Shell's CO_2e neutral LNG offering."

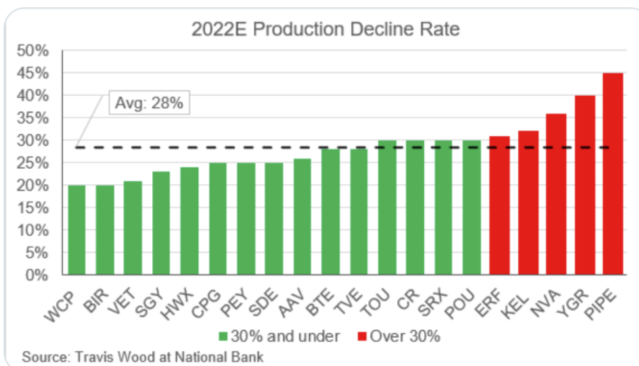
Steve Hill, EVP Shell Energy stated, "LNG demand is expected to nearly double by 2040. This deal secures additional competitive volumes for our portfolio by the mid-2020s, enabling us to continue providing diverse and flexible LNG supply to our customers. We look forward to working with Tellurian."

1 3 5

Show this thread

Dan Tsubouchi @Energy_Tidbits · Jul 29

Low decline rates are key reason why Cdn public E&P are able to take advantage of high #Oil #NatGas prices to increase shareholder distributions and drilling. Less capex was needed in 2020 to fight higher decline rates as in shale. Thx @nationalbank Travis Wood for data #OOTT



Dan Tsubouchi @Energy_Tidbits · Jul 23

Note $PD why broad group of Cdn public E&P are able to increase drilling while being highly capital disciplined. Fits SAF Group view Cdn E&P long established total return models only got stronger with high prices. Big advantage to Cdn public E&P vs US ...

8 7

Dan Tsubouchi @Energy_Tidbits · Jul 29

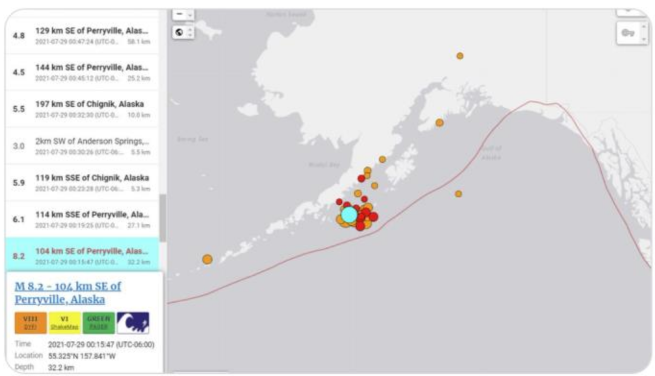
Positive for #Oil. Plays into Iran hardliner fears that return to #JCPOA under Biden doesn't return to same freedom as JCPOA under Obama. Have to add to increasing risk that no return to JCPOA? Key signal coming on #Raisi Aug 5 inauguration address. #OOTT

WSJ News Exclusive | U.S. Plans Sanctions Against Iran's Drones and G...
Western security officials say they now view Iranian precision-strike capabilities as a more immediate danger to Middle East stability than ...
wsj.com

1 3

Dan Tsubouchi @Energy_Tidbits · Jul 29

big 8.2 earthquake just off Alaska coast. BC says no tsunami threat. amazing there was similar earthquake 7.9 & cluster in same spot a year ago. hope everyone is okay.

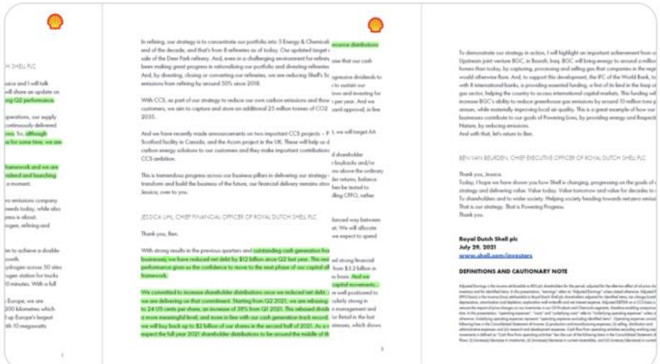


Emergency Info BC @EmergencyInfoBC · Jul 29
There is no tsunami threat to #BC as a result of the 8.2M earthquake that was detected earlier this evening southeast of Chignik, Alaska. twitter.com/NWS_NTWC/statu...

3 2

Dan Tsubouchi @Energy_Tidbits · Jul 29

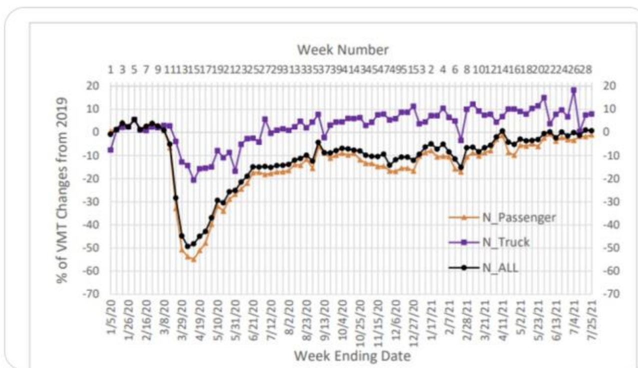
What's missing from #Shell CEO CFO 4-pg message on Q2 +38% to dividend, $2b share buybacks? Any credit that it was driven by strong #Oil #NatGas #LNG price or they expect continued strong #Oil #NatGas #LNG prices in for why have confidence in strength of cash generation. #OOTT



2 2

Dan Tsubouchi @Energy_Tidbits · Jul 28

US vehicles miles traveled for week ended July 25: Total VMT est 17.15 b vehicle miles, +1% vs same week 2019. Passenger VMT is -1% vs 2019. Truck VMT +8% vs 2019, no wonder there is truck driver shortage, better for #Oil demand for diesel guzzler trucks vs gasoline cars. #OOTT



4 4

Dan Tsubouchi @Energy_Tidbits · Jul 28

Reality check why #OffshoreWind #Renewable returns are low & #EnergyTransition will cost more -companies have made big promises to accelerate to renewables but not enough quality offshore seabeds available. Straight talk from #Equinor CEO @andop68 to @Bloomberg @ManusCranny #OOTT

SAF Group created transcript of Excerpts from Bloomberg Daybreak Europe, Bloomberg's Manus Cranny interview with Equinor CEO Anders Opedal interview https://www.bloomberg.com/news/videos/2021-07-28/equinor-profit-more-than-doubles-video

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

At 1:10 min mark re his view of high oil and gas prices, Opedal says "*I don't want to say exactly the prices for the gas because there will still see volatility there, but we see the fundaments are there, there is less LNG coming into Europe and there is increasing demand. For the oil price, we will continue to see prices in the level we are seeing now buyt we are expecting volatility. We are still in the pandemic, there will still be close downs in some parts of the region around the world and that might take down the demand. and the rising demand a little bit.*"

At 2:50 min mark. Cranny "*you recently reduced your renewables returns, what are the biggest headwinds in renewables?*" Opedal "*… but we also see there is strong competition. We see that there is a companies that are very ambitious about their targets. But we still need more seabeds to actually execute on a project. At the moment there are higher ambitions than seabeds available. So but we think that, based on the ambitions we see from different countries, more seabeds will be available.*"

At 3:50 min mark on CCS. Cranny "*Anders on the hydrogen and carbon capture business, when will you return to profit?*" Opedal "*well, that's a little bit to early to say. Still we are now working on a lot of*

Dan Tsubouchi @Energy_Tidbits · Jun 15

Good thing #Equinor has #Oil #NatGas w/ ave payback time <2.5 yrs & >20% base IRRs as they lowered expected base returns (prior to farmdowns & project financing) from #Wind to 4-8% vs 6-10% in Dec. But didn't include average payback time for wind, Hmmm!...

1 4

Dan Tsubouchi @Energy_Tidbits · Jul 28

For those not near their laptop, EIA weekly #Oil #Gasoline #Distillates inventory data as of July 23 just out. Prior to release, WTI was $71.82. #OOTT

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

Oil/Products Inventory July 23: EIA, Bloomberg Survey Expectations, API

(million barrels)	EIA	Expectations	API
Oil	-4.09	-2.50	-4.73
Gasoline	-2.25	-1.24	-6.23
Distillates	-3.09	-0.70	-1.88
	-9.43	-4.44	-12.84

Note: In addition, there was no change in the SPR for July 23 week
Note: Cushing had a draw of 1.27 mmb for July 23 week
Source EIA, Bloomberg
Prepared by SAF Group

2

Dan Tsubouchi @Energy_Tidbits · Jul 28

#JCPOA. can't wait to see what #Raisi says and signals on JCPOA after Aug 5 inauguration because Supreme Leader comments today make it seem like back to square 1. Not just #Oil markets will watch with interest, also Israel. #OOTT

Emphasizing the necessity of using the experiences of the 11th and 12th administrations (Rouhani's term), he referred to 'distrust in the West' as an importance experience of this period that should be used by generations to come.
The Leader said that it turned out in this administration's term that confidence in the West would neither work nor help, as they would harm other countries whenever they have the opportunity and if they didn't, that's because they couldn't.

Ayatollah Khamenei firmly underlined that domestic programs should not be made subject to the West's company, because they would certainly fail if they were.

President-elect Ebrahim Raisi's inauguration will be held on August 5, 5:00 pm in the venue of Iran's parliament.

Mohammad Mohseni Bandpey, a member of parliament, told IRNA on Wednesday that the parliament decided that President-elect's swearing-in ceremony would be held at 5:00 pm local time on Thursday August 5, 2021.

He also said that the parliament would be in recess next week and no legislator session would be held.

Representatives of 50 world countries has responded positive to Iran's invitations to attend the ceremony.

According to his official website, Khamenei.ir, the Supreme Leader further said: "Others should use the experience of Mr. Rouhani's govt. One experience is distrusting the West. In this administration, it became clear that trusting the West isn't helpful. They don't help and they strike a blow wherever they can. When they didn't, it was because they couldn't.

Dan Tsubouchi @Energy_Tidbits · Jul 28

#BlackRock CIO Rieder just now on @SquawkCNBC 80% of inflation is transitory but stickiness in other means inflation to stay above target. didn't commit to a specific number above target. glad we finally got #SquawkBox back on in #Calgary after mon/tues misses

Dan Tsubouchi @Energy_Tidbits · Jul 28

is this just because #BorisJohnson knows rising home heating and power costs will hurt re-election or are politicians realizing "#EnergyTransition is not ready for Prime Time" and delay? either way means demise of #NatGas will take longer. expect more reality checks!

> **Dan Tsubouchi** @Energy_Tidbits · Jul 27
>
> look for more of these reality check examples as govts realize the #EnergyTransition will take longer, be a bumpy road and cost more. demise of #NatGas wont be as quick as aspirations of #G7 plans. thx @chigrl fir flagging dailymail.co.uk/news/article-9...

2 1

Dan Tsubouchi @Energy_Tidbits · Jul 27

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Boris Johnson 'puts ban on new gas boilers back by five years to 2040'

The Prime Minister is looking at delaying the ban by five years to 2040, in a move which would give millions of UK households more time for ...

dailymail.co.uk

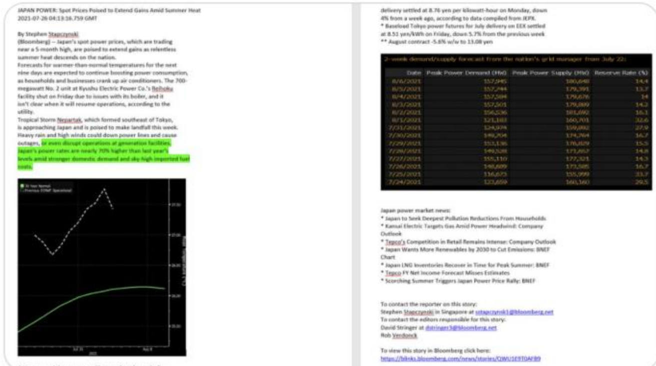
1 2 5

Dan Tsubouchi @Energy_Tidbits · Jul 27

Goal! #TeamCanada🇨🇦. great run by @AshleyLawrence and smooth calm finish by @LeonAdriana9 puts 🇨🇦 in front. now at 60 min mark

Dan Tsubouchi @Energy_Tidbits · Jul 27

Continued #LNG support from hot/humid Japan weather keeping #Electricty & #LNG demand strong. But power reserve margin is healthy, more than expected coming into summer. Would have been tight if Japan had attracted expected 40 million visitors to @Tokyo2020 ? Thx @SStapczynski



2 · 4

Dan Tsubouchi @Energy_Tidbits · Jul 27

Also suggests India is not worried about risk for any major supply interruption. Current SPR is only 39 mmb #Oil capacity or 9.5 days of demand.   Thx @ArgusMedia @Ksathya21 #OOTT

India to commercialise strategic oil reserve capacity
India is planning to commercialise its strategic petroleum reserves (SPR) for the first time, includin...
argusmedia.com

1 · 3

Dan Tsubouchi @Energy_Tidbits · Jul 26

>25% IRR, no wonder why #Shell FIDs Whale 100,000 boed GoM development. Apr 15/21, upstream IRRs "needed" to fund shareholder distributions & #EnergyTransition ie. compensate for hugely lower #Renewable IRRs. >25% IRR projects give Shell strong cash flow for plan execution. #OOTT

2 · 3

Dan Tsubouchi @Energy_Tidbits · Jul 26

ICYMI. Canada's 1st gold @Tokyo2020. big congrats to @mags_swims26 for gold in 100m butterfly. got to love her delayed reaction, didn't know she won until she could focus in on the board to see she won! 🇨🇦 Good job @CBC with posting event replays.

Maggie Mac Neil swims to Canada's 1st gold meda...
Maggie Mac Neil of London, Ont., won Canada's first gold medal of these Olympics, capturing the ...
cbc.ca

2

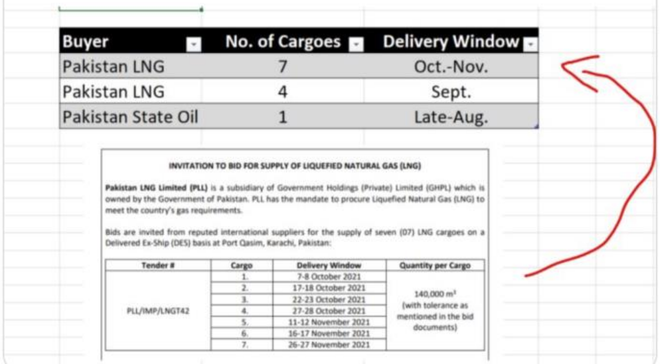
Dan Tsubouchi @Energy_Tidbits · Jul 26

good @tomkeene reminder. uncertainty on #Delta impact will cause company boards to be cautious ie. likely to hold off increases to dividend, capex, etc until sept/oct to see how it plays out. #OOTT

Dan Tsubouchi @Energy_Tidbits · Jul 26

been a good summer for #LNG with buying surprises from the unexpected areas like south america and now pakistan.

> **Stephen Stapczynski** @SStapczynski · Jul 26
>
> Pakistan dives into the LNG spot market as rival importers chill on the sidelines 🇵🇰🤿
>
> Pakistan's state-owned firms are currently seeking 12 LNG cargoes for Aug.-Nov. delivery amid dwindling domestic gas output
>
> Other nations have curbed spot buying after a recent price surge
>
> Show this thread



Buyer	No. of Cargoes	Delivery Window
Pakistan LNG	7	Oct.-Nov.
Pakistan LNG	4	Sept.
Pakistan State Oil	1	Late-Aug.

INVITATION TO BID FOR SUPPLY OF LIQUEFIED NATURAL GAS (LNG)

Pakistan LNG Limited (PLL) is a subsidiary of Government Holdings (Private) Limited (GHPL) which is owned by the Government of Pakistan. PLL has the mandate to procure Liquefied Natural Gas (LNG) to meet the country's gas requirements.

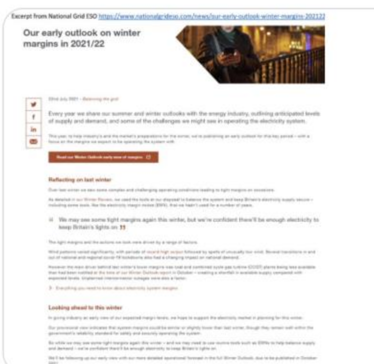
Bids are invited from reputed international suppliers for the supply of seven (07) LNG cargoes on a Delivered Ex-Ship (DES) basis at Port Qasim, Karachi, Pakistan:

Tender #	Cargo	Delivery Window	Quantity per Cargo
PLL/IMP/LNGT42	1.	7-8 October 2021	140,000 m^3 (with tolerance as mentioned in the bid documents)
	2.	17-18 October 2021	
	3.	22-23 October 2021	
	4.	27-28 October 2021	
	5.	11-12 November 2021	
	6.	16-17 November 2021	
	7.	26-27 November 2021	

1 3

Dan Tsubouchi @Energy_Tidbits · Jul 25

Hmmm! Why doesn't UK #NationalGridESO want to call out #Wind as key wildcard for reliable power? Fcast lower reserve for winter 21/22. "reflecting on last winter" say main issue #Coal #CCGT #NatGas plants. Yet common denominator for their 5 winter 20/21 bad power days is wind?



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Dan Tsubouchi @Energy_Tidbits · Jul 25

Our weekly SAF July 25, 2021 Energy Tidbits memo was just posted to our SAF Group website. This 53-pg energy research piece expands upon and covers many more items than tweeted this week. See the research section of the SAF website #Oil #OOTT #LNG #NatGas safgroup.ca/insights/trend...

SAF | GROUP

Energy Tidbits

July 25, 2021

Produced by: Dan Tsubouchi

Big Potential Upside to 2022 HH/AECO Prices, New US LNG Export Capacity Could Reduce Gas Storage By 1 Tcf in 2022

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.

1 3 8