Energy Tidbits

Liberals Emissions Reduction Plan Is Setting Up the Oil & Gas Sector for Failure

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Table 1. Summary of natural gas supply and disposition in the United States, 2017-2022
(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]
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 Total	**40,780**	**36,447**	**2,548**	**33,899**	**61**	**-1,916**	**-503**	**-408**	**31,132**
2020									
January	3,597	3,194	240	2,954	6	-248	581	8	3,300
February	3,363	2,985	224	2,761	5	-216	545	-53	3,041
March	3,582	3,196	240	2,956	6	-284	53	-24	2,707
April	3,374	3,012	226	2,786	5	-231	-311	-8	2,241
May	3,285	2,927	220	2,707	5	-209	-454	18	2,067
June	3,217	2,873	216	2,657	5	-151	-363	-18	2,131
July	3,374	3,021	227	2,795	5	-139	-165	-7	2,489
August	3,350	3,012	226	2,786	5	-148	-232	-9	2,401
September	3,265	2,918	219	2,699	5	-221	-329	18	2,172
October	3,364	2,992	225	2,767	5	-282	-96	-74	2,320
November	3,352	2,985	224	2,761	5	-316	-6	-8	2,435
December	3,490	3,089	232	2,857	5	-287	597	-5	3,168
Total	**40,614**	**36,202**	**2,717**	**33,485**	**63**	**-2,732**	**-180**	**-164**	**30,472**
2021									
January	3,506	3,110	233	2,877	5	-279	707	-18	3,292
February	2,924	2,586	172	2,415	5	-152	781	-7	3,042
March	3,482	3,092	231	2,861	5	-357	59	47	2,616
April	3,409	3,036	239	2,797	5	-356	-174	-33	2,238
May	3,510	3,130	247	2,883	5	-373	-416	-5	2,094
June	3,391	3,036	239	2,797	4	-331	-248	-6	2,215
July	3,491	3,151	247	2,904	5	-338	-170	-13	2,388
August	3,531	3,173	251	2,922	5	-343	-159	R-14	R2,411
September	3,413	3,050	241	2,809	4	-315	-391	R3	2,110
October	3,595	3,220	257	2,963	5	-317	-361	-52	2,238
November	R3,552	3,161	251	R2,910	6	-315	132	R-73	R2,660
December	R3,688	R3,275	258	R3,017	5	-368	323	R4	2,980
Total	**R41,492**	**R37,020**	**2,866**	**R34,154**	**59**	**-3,845**	**83**	**R-167**	**30,284**
2022									
January	3,594	3,187	245	2,943	6	-314	994	-36	3,592

[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 2017 through 2020 include underground storage and liquefied natural gas storage. Data for January 2021 forward include underground storage only. See Appendix A, Explanatory Note 5, for discussion of computation procedures.

[e] Represents quantities lost and imbalances in data due to differences among data sources. Net imports and balancing item excludes net intransit deliveries. These net intransit deliveries were (in billion cubic feet): -24 for 2020; -8 for 2019; -12 for 2018; and 14 for 2017. 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.

Notes: Data for 2017 through 2019 are final. All other data are preliminary unless otherwise indicated. Geographic coverage is the 50 states and the District of Columbia. Totals may not equal sum of components because of independent rounding.

Sources: 2017-2020: U.S. Energy Information Administration (EIA), *Natural Gas Annual 2020*. January 2021 through current month: Form EIA-914, *Monthly Crude Oil and Lease Condensate, and Natural Gas Production Report*; Form EIA-857, *Monthly Report of Natural Gas Purchases and Deliveries to Consumers*; Form EIA-191, *Monthly Underground Gas Storage Report*; EIA computations and estimates; and Office of Fossil Energy and Carbon Management, *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

Table 5. U.S. natural gas exports, 2020-2022

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

	2022					2021
	January	Total	December	November	October	September
Exports						
Volume (million cubic feet)						
Pipeline						
Canada	81,420	937,124	108,568	85,136	62,464	72,023
Mexico	174,997	2,155,205	167,057	165,546	184,539	178,823
Total Pipeline Exports	**256,417**	**3,092,329**	**275,625**	**250,683**	**247,003**	**250,846**
LNG						
Exports						
By Vessel						
Antigua and Barbuda	2	8	3	2	0	3
Argentina	0	83,449	2,077	0	0	1,950
Bahamas	34	486	36	34	36	43
Bangladesh	0	37,734	0	0	0	3,276
Barbados	28	297	34	27	25	33
Belgium	13,786	5,584	0	0	0	0
Brazil	17,322	307,714	24,246	10,715	40,769	38,282
Chile	3,162	121,881	2,938	2,956	6,364	7,929
China	0	449,667	17,050	50,228	42,202	48,584
Colombia	486	2,247	0	0	0	436
Croatia	9,084	36,133	3,117	9,416	0	0
Dominican Republic	6,647	53,095	5,969	2,780	5,619	0
Egypt	0	0	0	0	0	0
France	50,084	170,780	33,892	10,021	9,333	6,578
Greece	1,802	39,708	5,305	7,629	1,515	799
Haiti	20	137	4	8	17	10
India	6,866	196,218	3,203	14,807	10,548	23,941
Indonesia	0	3,269	1,218	456	477	1,118
Israel	0	8,906	0	0	0	2,855
Italy	7,037	34,210	0	0	0	0
Jamaica	86	25,276	113	715	1,858	2,931
Japan	21,527	354,948	24,297	33,947	37,666	10,290
Jordan	0	0	0	0	0	0
Kuwait	0	34,476	0	0	6,193	10,333
Lithuania	3,518	30,919	0	0	0	3,282
Malaysia	0	0	0	0	0	0
Malta	0	5,427	0	0	0	2,498
Mexico	0	15,200	0	0	1,088	0
Netherlands	16,279	174,339	23,354	8,829	17,157	10,424
Nicaragua	0	1	0	0	0	0
Pakistan	0	45,818	0	2,490	3,138	9,642
Panama	3,255	8,436	0	0	911	0
Poland	3,695	56,320	7,159	7,068	3,270	0
Portugal	2,868	65,865	9,630	5,380	10,459	3,696
Singapore	0	24,555	0	3,728	0	0
South Korea	21,824	453,483	38,201	30,787	33,836	31,375
Spain	49,379	215,062	32,579	22,821	35,638	31,274
Taiwan	6,211	99,350	12,034	3,404	7,123	5,789
Thailand	3,490	14,548	0	0	0	0
Turkey	45,081	188,849	38,420	47,330	19,385	24,176
United Arab Emirates	0	0	0	0	0	0
United Kingdom	60,060	195,046	60,315	30,648	3,302	3,099
By Truck						
Canada	13	128	20	8	8	19
Mexico	148	1,250	148	160	182	150
Re-Exports						
By Vessel						
Argentina	0	0	0	0	0	0
Brazil	0	0	0	0	0	0
Japan	0	0	0	0	0	0
South Korea	0	0	0	0	0	0
United Kingdom	0	0	0	0	0	0
Total LNG Exports	**353,791**	**3,560,818**	**345,363**	**306,397**	**298,119**	**284,813**
CNG						
Canada	0	211	0	0	0	0
Total CNG Exports	**0**	**211**	**0**	**0**	**0**	**0**
Total Exports	**610,208**	**6,653,357**	**620,988**	**557,080**	**545,121**	**535,660**

See footnotes at end of table.

Table 5. U.S. natural gas exports, 2020-2022

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

	2021					
	August	July	June	May	April	March
Exports						
Volume (million cubic feet)						
Pipeline						
Canada	71,586	68,264	69,528	70,561	74,567	91,301
Mexico	193,788	197,702	198,329	192,625	183,004	183,051
Total Pipeline Exports	**265,374**	**265,966**	**267,857**	**263,186**	**257,571**	**274,352**
LNG						
Exports						
By Vessel						
Antigua and Barbuda	0	0	0	0	0	0
Argentina	14,363	22,798	19,312	16,226	4,485	2,238
Bahamas	56	46	48	45	46	39
Bangladesh	7,085	0	3,493	6,948	10,219	3,566
Barbados	27	31	22	19	30	14
Belgium	0	0	0	2,100	0	3,484
Brazil	34,204	39,637	32,293	19,726	11,615	21,977
Chile	16,262	19,913	0	17,598	10,293	21,320
China	51,662	42,222	42,319	37,731	46,837	28,476
Colombia	919	0	0	0	892	0
Croatia	2,980	3,299	2,923	3,364	3,666	7,367
Dominican Republic	5,901	1,806	4,670	5,283	2,905	5,577
Egypt	0	0	0	0	0	0
France	7,111	0	3,683	11,926	36,120	33,678
Greece	3,607	6,651	0	6,796	0	6,805
Haiti	24	8	18	12	3	10
India	20,592	13,090	16,503	28,259	13,752	17,381
Indonesia	0	0	0	0	0	0
Israel	0	0	0	0	3,225	2,826
Italy	3,401	6,826	3,425	2,923	6,896	10,739
Jamaica	2,907	0	2,927	2,925	2,370	2,458
Japan	19,979	24,895	39,783	25,058	28,756	27,673
Jordan	0	0	0	0	0	0
Kuwait	3,298	0	7,126	0	3,705	3,821
Lithuania	1,677	6,469	3,285	3,049	3,078	3,228
Malaysia	0	0	0	0	0	0
Malta	0	0	0	0	2,928	0
Mexico	0	758	0	0	0	0
Netherlands	7,347	10,597	3,030	26,611	17,060	24,204
Nicaragua	0	1	0	0	0	0
Pakistan	3,319	13,428	3,376	0	3,323	3,421
Panama	1,390	0	0	2,341	0	3,279
Poland	0	6,619	10,635	3,581	7,382	3,507
Portugal	6,382	3,296	5,538	10,765	7,358	0
Singapore	0	3,449	0	3,089	7,297	3,303
South Korea	50,101	39,314	55,918	46,033	21,683	32,203
Spain	23,068	8,630	7,833	5,234	22,974	13,900
Taiwan	6,728	20,653	3,097	10,157	6,594	13,450
Thailand	3,707	0	0	3,453	7,388	0
Turkey	0	5,591	0	3,017	0	3,619
United Arab Emirates	0	0	0	0	0	0
United Kingdom	0	0	0	10,586	13,877	17,440
By Truck						
Canada	18	16	7	18	15	0
Mexico	147	97	105	48	48	19
Re-Exports						
By Vessel						
Argentina	0	0	0	0	0	0
Brazil	0	0	0	0	0	0
Japan	0	0	0	0	0	0
South Korea	0	0	0	0	0	0
United Kingdom	0	0	0	0	0	0
Total LNG Exports	**298,262**	**300,143**	**271,368**	**314,922**	**306,818**	**321,023**
CNG						
Canada	14	16	27	25	29	36
Total CNG Exports	**14**	**16**	**27**	**25**	**29**	**36**
Total Exports	**563,650**	**566,125**	**539,252**	**578,132**	**564,418**	**595,411**

See footnotes at end of table.

Table 5. U.S. natural gas exports, 2020-2022

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

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

See footnotes at end of table.

Table 5. U.S. natural gas exports, 2020-2022

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

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

See footnotes at end of table.

Table 5. U.S. natural gas exports, 2020-2022

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

	2020		
	March	February	January
Exports			
Volume (million cubic feet)			
Pipeline			
Canada	86,579	77,354	99,231
Mexico	166,550	151,071	160,875
Total Pipeline Exports	**253,130**	**228,425**	**260,106**
LNG			
Exports			
By Vessel			
Antigua and Barbuda	0	0	0
Argentina	0	0	0
Bahamas	20	13	15
Bangladesh	0	0	3,640
Barbados	28	26	33
Belgium	3,724	9,872	6,761
Brazil	6,891	10,433	8,438
Chile	3,216	10,731	6,087
China	17,699	0	0
Colombia	0	1,003	525
Croatia	0	0	0
Dominican Republic	2,872	0	0
Egypt	0	0	0
France	23,491	20,520	6,563
Greece	8,892	0	11,276
Haiti	9	11	7
India	17,245	0	3,309
Indonesia	0	0	0
Israel	3,197	0	0
Italy	9,895	16,616	6,308
Jamaica	1	2,914	869
Japan	21,845	21,360	31,975
Jordan	0	0	0
Kuwait	0	0	0
Lithuania	0	0	0
Malaysia	0	0	0
Malta	0	48	2,600
Mexico	7,037	3,167	6,764
Netherlands	13,772	14,099	6,681
Nicaragua	0	0	0
Pakistan	0	3,567	3,323
Panama	906	3,408	0
Poland	3,583	6,677	3,282
Portugal	0	6,187	0
Singapore	10,610	0	0
South Korea	28,095	11,071	44,320
Spain	23,657	20,240	24,412
Taiwan	6,987	7,115	9,317
Thailand	3,783	3,435	0
Turkey	6,489	24,303	32,637
United Arab Emirates	0	0	0
United Kingdom	20,202	28,884	30,428
By Truck			
Canada	0	0	2
Mexico	123	87	122
Re-Exports			
By Vessel			
Argentina	0	0	0
Brazil	0	0	0
Japan	0	0	305
South Korea	0	0	305
United Kingdom	0	0	0
Total LNG Exports	**244,269**	**225,786**	**250,305**
CNG			
Canada	38	34	33
Total CNG Exports	**38**	**34**	**33**
Total Exports	**497,437**	**454,245**	**510,444**

See footnotes at end of table.

Table 7

Table 7. Marketed production of natural gas in selected states and the Federal Gulf of Mexico, 2017-2022
(million cubic feet)

Year and Month	Alaska	Arkansas	California	Colorado	Kansas	Louisiana	Montana	New Mexico	North Dakota	Ohio
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 Total	**329,361**	**524,757**	**196,823**	**1,986,916**	**183,087**	**3,212,318**	**43,534**	**1,769,086**	**850,826**	**2,651,631**
2020										
January	30,018	42,187	15,908	178,066	14,623	274,755	3,527	162,016	78,798	203,701
February	28,537	39,093	14,649	166,620	13,636	255,885	3,340	155,323	77,940	190,559
March	29,219	43,677	15,376	175,202	14,486	276,544	3,527	169,244	83,892	203,701
April	27,513	39,748	14,906	168,438	13,595	264,869	3,148	156,722	72,059	193,050
May	27,076	40,463	15,172	163,768	14,012	281,636	2,692	147,782	52,874	199,485
June	25,545	38,742	14,837	159,601	13,321	264,072	2,667	153,276	52,626	193,050
July	26,779	39,855	15,061	167,105	13,674	264,875	3,322	165,335	64,860	201,686
August	26,846	40,295	13,344	165,091	13,504	260,226	3,248	168,311	74,940	201,686
September	26,978	38,734	12,857	162,531	13,030	255,690	3,009	165,008	78,195	195,180
October	29,080	40,172	13,059	164,462	13,461	263,120	3,204	171,376	82,649	201,097
November	29,575	38,565	12,934	159,409	12,917	267,312	3,143	167,213	80,112	194,610
December	31,161	39,452	12,475	160,168	13,097	277,178	3,135	166,561	83,498	201,097
Total	**338,329**	**480,982**	**170,579**	**1,990,462**	**163,356**	**3,206,163**	**37,963**	**1,948,168**	**882,443**	**2,378,902**
2021										
January	31,632	[E]39,964	[E]12,033	[E]159,820	[E]12,578	[E]271,751	[E]3,214	[E]179,574	[E]77,021	[E]206,660
February	28,365	[E]30,061	[E]10,749	[E]143,416	[E]9,965	[E]221,051	[E]2,790	[E]151,970	[E]65,685	[E]170,668
March	31,481	[E]39,947	[E]12,028	[E]156,534	[E]12,340	[E]281,406	[E]3,144	[E]187,274	[E]77,032	[E]189,405
April	29,514	[E]37,926	[E]11,685	[E]156,009	[E]12,316	[E]276,931	[E]3,096	[E]184,890	[E]76,209	[E]183,444
May	29,005	[E]38,775	[E]12,215	[E]162,200	[E]12,648	[E]284,347	[E]3,226	[E]196,174	[E]80,479	[E]187,668
June	27,715	[E]37,125	[E]11,787	[E]154,405	[E]12,276	[E]272,759	[E]2,932	[E]190,003	[E]78,111	[E]183,602
July	26,280	[E]38,273	[E]12,014	[E]160,065	[E]12,780	[E]284,504	[E]3,151	[E]201,572	[E]79,150	[E]189,223
August	27,864	[E]38,000	[E]11,930	[E]158,380	[E]12,793	[E]288,489	[E]3,168	[E]206,178	[E]81,659	[E]188,396
September	28,534	[E]36,706	[E]11,499	[E]153,067	[E]12,371	[E]285,313	[E]3,127	[E]203,500	[E]80,634	[E]180,630
October	30,458	[E]37,791	[E]11,565	[E]160,130	[E]12,775	[E]302,250	[E]3,249	[E]212,065	[E]83,166	[E]192,556
November	30,735	[RE]36,440	[RE]11,177	[RE]155,466	[RE]12,488	[RE]301,451	[RE]3,110	[RE]209,466	[RE]82,402	[E]194,200
December	33,038	[RE]38,267	[RE]11,313	[RE]156,530	[RE]12,646	[RE]312,720	[RE]3,038	[RE]213,755	[RE]83,883	[E]200,174
Total	**[R]354,622**	**[RE]449,277**	**[E]139,994**	**[RE]1,876,023**	**[RE]147,975**	**[RE]3,382,973**	**[RE]37,246**	**[RE]2,336,422**	**[RE]945,429**	**[E]2,266,627**
2022										
January	32,689	[E]37,278	[E]11,266	[E]151,081	[E]12,234	[E]310,626	[E]3,028	[E]204,548	[E]78,627	[E]192,972

See footnotes at end of table.

Table 7. Marketed production of natural gas in selected states and the Federal Gulf of Mexico, 2017-2022

(million cubic feet) – continued

Year and Month	Oklahoma	Pennsylvania	Texas	Utah	West Virginia	Wyoming	Other States	Federal Gulf of Mexico	U.S. Total
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 Total	**3,036,052**	**6,896,792**	**9,378,489**	**271,808**	**2,155,214**	**1,488,854**	**456,024**	**1,015,343**	**36,446,918**
2020									
January	263,734	603,836	843,432	21,944	209,896	124,274	37,391	86,071	3,194,177
February	243,139	569,721	783,094	20,373	198,090	108,722	34,782	81,114	2,984,616
March	257,387	607,689	841,347	21,765	210,559	117,977	36,689	87,955	3,196,236
April	235,642	586,955	783,283	20,379	204,826	111,744	34,389	80,574	3,011,842
May	217,154	592,126	734,176	20,326	212,646	107,288	33,986	64,374	2,927,037
June	222,324	560,390	741,401	19,244	212,831	103,890	32,957	62,227	2,873,001
July	226,843	604,716	775,851	20,312	220,032	108,679	34,568	67,778	3,021,331
August	226,344	607,221	782,436	19,814	223,208	107,320	33,757	43,988	3,011,580
September	222,010	567,029	755,253	19,283	218,893	104,520	30,468	48,900	2,917,569
October	219,403	595,653	773,720	20,042	226,064	104,787	31,775	38,702	2,991,827
November	224,327	605,244	751,562	19,200	223,428	103,236	31,246	60,496	2,984,528
December	228,057	647,714	770,555	19,307	231,845	103,933	32,383	67,085	3,088,701
Total	**2,786,366**	**7,148,295**	**9,336,110**	**241,989**	**2,592,319**	**1,306,368**	**404,391**	**789,262**	**36,202,446**
2021									
January	[E]221,544	[E]657,704	[E]774,497	[E]19,235	[E]234,432	[E]106,649	[E]33,651	[E]68,393	3,110,352
February	[E]163,094	[E]585,221	[E]588,035	[E]17,815	[E]208,571	[E]96,543	[E]30,083	[E]62,325	2,586,408
March	[E]220,130	[E]647,681	[E]771,346	[E]20,356	[E]227,218	[E]107,236	[E]34,338	[E]72,867	3,091,762
April	[E]214,334	[E]618,509	[E]775,796	[E]19,861	[E]229,075	[E]103,470	[E]33,044	[E]69,696	3,035,804
May	[E]223,372	[E]640,431	[E]798,311	[E]20,312	[E]234,118	[E]105,441	[E]33,844	[E]67,642	3,130,208
June	[E]213,314	[E]621,905	[E]781,294	[E]19,587	[E]227,987	[E]100,983	[E]32,490	[E]67,779	3,036,055
July	[E]221,002	[E]642,894	[E]821,587	[E]20,363	[E]229,376	[E]104,558	[E]33,626	[E]70,488	3,150,909
August	[E]222,329	[E]655,525	[E]820,135	[E]20,335	[E]241,373	[E]102,121	[E]33,126	[E]61,046	3,172,847
September	[E]216,455	[E]633,963	[E]798,167	[E]19,841	[E]216,452	[E]102,262	[E]31,895	[E]35,503	3,049,920
October	[E]223,093	[E]657,651	[E]833,481	[E]20,509	[E]240,446	[E]104,250	[E]33,056	[E]61,121	3,219,612
November	[RE]214,361	[RE]651,361	[RE]809,934	[RE]20,061	[E]229,812	[RE]101,430	[E]32,083	[RE]65,329	[R]3,161,306
December	[RE]219,187	[RE]680,706	[RE]843,633	[RE]20,624	[E]242,327	[RE]102,767	[RE]32,693	[RE]67,730	[R]3,275,030
Total	**[RE]2,572,217**	**[RE]7,693,550**	**[RE]9,416,215**	**[RE]238,900**	**[E]2,761,187**	**[RE]1,237,708**	**[RE]393,929**	**[RE]769,919**	**[R]37,020,213**
2022									
January	[E]213,886	[E]659,720	[E]826,902	[E]20,889	[E]234,795	[E]100,139	[E]31,514	[E]65,062	3,187,255

[R] Revised data.

[E] Estimated data.

[RE] Revised estimated data.

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

Sources: 2017-2020: U.S. Energy Information Administration (EIA), *Natural Gas Annual 2020*, Bureau of Safety and Environmental Enforcement (BSEE), IHS Markit, and Enverus. January 2021 through current month: Form EIA-914, *Monthly Crude Oil and Lease Condensate, and Natural Gas Production Report*; and EIA computations.

https://www.businesswire.com/news/home/20220328005955/en/Energy-Transfer-and-ENN-Sign-20-Year-LNG-Sale-and-Purchase-Agreements-for-Lake-Charles-LNG/?feedref=JjAwJuNHiystnCoBq_hl-bV7DTIYheT0D-1vT4_bKFzt_EW40VMdK6eG-WLfRGUE1fJraLPL1g6AeUGJlCTYs7Oafol48Kkc8KJgZoTHgMu0w8LYSbRdYOj2VdwnuKwa

Energy Transfer and ENN Sign 20-Year LNG Sale and Purchase Agreements for Lake Charles LNG

March 29, 2022 08:30 AM Eastern Daylight Time

DALLAS & LANGFANG, China--(BUSINESS WIRE)--Energy Transfer LP (NYSE: ET), ENN Natural Gas (ENN NG 600803.SH) and ENN Energy Holdings Limited (ENN Energy 2688.HK) today announced that ENN NG and ENN Energy have entered into LNG Sale and Purchase Agreements with Energy Transfer LNG Export, LLC (ET LNG), a subsidiary of Energy Transfer LP, related to its Lake Charles LNG project.

Under the two SPAs, ET LNG is expected to supply 1.8 million tonnes of LNG to ENN NG, and 0.9 million tonnes of LNG to ENN Energy, per annum on a free-on-board (FOB) basis. The purchase price is indexed to the Henry Hub benchmark plus a fixed liquefaction charge. Both SPAs are for a term of 20 years, and first deliveries are expected to commence as early as 2026. The SPAs will become fully effective upon the satisfaction of the conditions precedent by ET LNG, including reaching FID.

“The signing of these long-term SPAs will further enrich ENN’s LNG resources, expand resource supply channels, and improve ENN’s natural gas supply capacity to meet the rapidly growing natural gas demand in the domestic market,” said Zheng Hongtao, President of ENN NG and Vice Chairman of the Board of Directors of ENN Energy Holdings. “It also provides our customers with better resources and services, ensures natural gas supply nationwide, and contributes to the low-carbon transformation of energy structure.”

“We are very pleased to have ENN as a customer. The execution of these two SPAs represents a significant event in moving the Lake Charles LNG project towards FID. We are experiencing strong demand for long-term offtake contracts for Lake Charles LNG and we are optimistic that we will be in a position to take a positive FID by year end,” said Tom Mason, President of ET LNG. “The Lake Charles LNG project is expected to be financed primarily through infrastructure funds and strategic partners, with Lake Charles LNG retaining an equity stake and operatorship of the liquefaction facility.”

Energy Transfer is one of the largest and most diversified midstream energy companies in North America, with a strategic footprint in all of the major U.S. production basins. The core operations include complementary natural gas midstream, intrastate and interstate transportation and storage assets; crude oil, natural gas liquids (NGL) and refined product transportation and terminalling assets; and NGL fractionation. The company owns and operates approximately 120,000 miles of pipelines and associated energy infrastructure across 41 states transporting approximately 30% of the United States’ oil and natural gas.

Lake Charles LNG will be constructed on the existing brownfield regasification facility and will capitalize on four existing LNG storage tanks, two deep water berths and other LNG infrastructure. Lake Charles LNG will also benefit from its direct connection to Energy Transfer’s existing Trunkline pipeline system that in turn provides connections to multiple intrastate and interstate pipelines. These pipelines allow access to multiple natural gas producing basins, including the Haynesville, the Permian and the Marcellus Shale.

ENN NG has an annual LNG distribution capacity of over 10 bcm and runs the first large-scale private LNG terminal in China -- Zhoushan LNG Terminal. Its business layout covers the entire natural gas value chain, including distribution, trading, storage and transportation, and production and engineering.

Relying on industry best practices, ENN NG has built an intelligent operation platform for the natural gas industry – GreatGas.cn, which accelerates the aggregation of demand, resources, reserves, and delivery ecology of the natural gas industry. It also innovates and develops digital intelligence services, and promotes the digital intelligence upgrade of the natural gas industry. In 2021, ENN NG's total natural gas sales volume was 37.2 bcm, accounting for approximately 10% of China's total natural gas consumption.

About Energy Transfer

Energy Transfer LP (NYSE: ET) owns and operates one of the largest and most diversified portfolios of energy assets in North America, with a strategic footprint in all of the major U.S. production basins. Energy Transfer is a publicly traded limited partnership with core operations that include complementary natural gas midstream, intrastate and interstate transportation and storage assets; crude oil, natural gas liquids (NGL) and refined product transportation and terminalling assets; and NGL fractionation. Energy Transfer also owns Lake Charles LNG Company, as well as the general partner interests, the incentive distribution rights and 28.5 million common units of Sunoco LP (NYSE: SUN), and the general partner interests and 46.1 million common units of USA Compression Partners, LP (NYSE: USAC). For more information, visit the Energy Transfer LP website at energytransfer.com.

About ENN Natural Gas

As one of the largest independent energy companies in China, ENN Natural Gas's business layout covers the full natural gas value chain, from downstream distribution, to midstream transportation and storage, and upstream production and procurement. As of 31 December 2021, through its subsidiary, ENN Energy Holdings Limited, one of the largest natural gas distributors in China, ENN Natural Gas owns 252 city-gas projects in China, serving a population of 124 million. ENN Natural Gas owns and operates Zhoushan LNG Terminal in Zhejiang Province, China. During 2021, ENN Natural Gas's total natural gas sales volume was 37.2 bcm, accounting for about 10% of China's total consumption.

Google translate of https://pdf.dfcfw.com/pdf/H2_AN202203311556320851_1.pdf?1648748764000.pdf

Stock Abbreviation: Guangzhou Development Stock Code: 600098 Lin No. 2022-023

Corporate Bond Abbreviation: G17 Development 1 Corporate Bond Code: 127616

Abbreviation of corporate bonds: 21 Suifa 01, 21 Suifa 02 Corporate bond codes: 188103, 188281

Guangzhou Development Group Co., Ltd.

About Wholly Owned Subsidiaries and Mexico Pacific LNG

Marketing and Sales Pte Ltd signed a major contract for day-to-day operations

the same announcement

The board of directors and all directors of the company guarantee that there is no false record in the content of this announcement

information, misleading statements or material omissions, and the truthfulness, accuracy and completeness of its contents

Integrity assumes individual and joint responsibility.

Important content reminder:

 Contract type: LNG purchase and sale contract

 Amount: annual contract volume × contract term × price formula linked to the US natural gas index

 Conditions for the contract to take effect: MPL LNG facility completes financing arrangement and starts construction

 Contract performance period: from the date when the effective conditions of the contract are met, to the date of commercial operation of the project

until 20 years

 Impact on the current performance of the listed company: The performance of this contract does not affect the performance of the company in the current year.

It will have a significant impact, which will help the company to enrich the company's gas source procurement channels and further improve the

natural gas supply capacity.

 Special risk warning: During the performance of the contract, there may be fluctuations in the linked index,

industry policies, downstream sales, exchange rate fluctuations and trade controls, the seller’s LNG facility cannot be

Investors are advised to pay attention to investment risks due to the risks caused by factors such as financing and operation in the future.

I. Review procedure

On March 31, 2022, Guangzhou Development Group Co., Ltd. (hereinafter

referred to as the "Company") held the 42nd meeting of the 8th Board of Directors to review

Through the "About Wholly-owned Subsidiary and the Mexico Pacific LNG Market Sales"

Proposal for a Private Limited Company to Sign a LNG Purchase and Sale Agreement. to open up the sea

To stabilize long-term gas source channels and ensure long-term stable supply of natural gas, the entire company

The directors unanimously agreed that Guangzhou Development Natural Gas Trading Co., Ltd., a wholly-owned subsidiary of the company

Company (hereinafter referred to as the "Gas Trading Company") and MEXICO PACIFIC LNG

MARKETS PTE LTD (Mexico Pacific LNG Market Sales Private

Co., Ltd., referred to as "MPL") signed the LNG Purchase and Sale Agreement (referred to as "MPL")

same").

This agreement does not involve connected transactions. According to the company's "Articles of Association", this proposal has no

It needs to be submitted to the general meeting of shareholders for consideration.

2. The subject matter of the contract and the circumstances of the other party

(1) The subject matter of the contract

From the date of commercial operation of the project to the commercial operation of the project, the natural gas trading company

Sales to the Mexican Pacific LNG market during the next 20 years

It purchases liquefied natural gas from a private sales company, with a purchase volume of about 2 million tons per year.

(2) Situation of the parties to the contract

1. Basic situation

Company name: MEXICO PACIFIC LNG MARKETS PTE LTD (MEXICO PACIFIC LNG MARKETS PTE LTD

West Go Pacific LNG Marketing and Sales Pte Ltd)

Enterprise nature: limited liability company

Place of registration: Singapore

Main office location: 12 Marina View, Asia Square Tower 2,

#23-01, Singapore 018961

Person in charge: DOUGLAS DEAN SHANDA

Main business: LNG marketing and sales.

Major shareholder or actual controller: The ultimate parent company is MEXICO PACIFIC

LIMITED HOLDINGS LLC (Mexico Pacific Limited)

2. Mexico Pacific Co., Ltd. has no relationship with the company and its holding subsidiaries.

There is an association relationship.

3. Main terms of the contract

1. Contract volume: 2 million tons/year (1 million tons/year for each of the first and second phases).

2. Contract period: from the date when the contract effective conditions are met, to the project commercial

Expires 20 years after the date of operation.

3. Contract price: a formula linked to the US Natural Gas Index.

4. Guarantee: provide standby letter of credit or the company's guarantee as performance guarantee.

5. Contract dispute resolution: New York State (United States) law applies. Place of Arbitration of Disputes

Should be New York City, NY.

4. Follow-up arrangements of the contract

1. In order to provide the credit support arrangement for the contract, the company will first

Yi Company provides standby letters of credit as credit support, and at the same time initiates international credit

Rating work. After the rating results meet the requirements, the contract subject change will be processed, and the contract will be

The same buyer was changed from Guangzhou Development Natural Gas Trading Co., Ltd. to Guangzhou Development Group

Company limited by shares, then there is no need to open a valid letter of credit. The company will specify

Natural gas trading company as the main body of contract execution.

2. The natural gas trading company has the right to pay to those who meet the contract requirements for the second phase contract

Subject transfer.

3. The seller will make two production line investments together in the second half of 2022

Positive investment decisions.

V. The impact of contract performance on listed companies

(1) The contract is a procurement contract for the daily operation of the company, and the signing of the contract is beneficial

In order to enrich the company's gas source procurement channels, enhance the company's ability to control upstream resources, and

Further improve the natural gas supply capacity while meeting the natural gas demand of downstream users

Seek and ensure the stable supply of natural gas and increase the scale of low-carbon energy supply. favorable

As the company improves the utilization efficiency of natural gas facilities, it is beneficial for the company to build an integrated natural gas

Natural gas industry chain, enhance the company's comprehensive competitiveness. performance of the contract to the company

There was no significant impact on the total assets, net assets and net profit of the year.

(2) The performance of the contract does not affect the independence of the company's business.

The main business will not be dependent on the counterparty of the contract due to the performance of the agreement.

6. Risk analysis of contract performance

1. Fluctuation risk of the U.S. natural gas index. Hired internationally renowned business institutions

Evaluate historical data and forecast future gas prices, unless extreme market conditions occur, refer to

The fluctuation range is relatively small compared to the oil price.

2. Risk of contract performance. In the process of contract performance, there may be due to industry policy

Risks caused by factors such as policy adjustment and downstream sales. The company will pay close attention to the country

For changes in natural gas policy, timely adjust the company's sales strategy.

3. Exchange rate risk. The RMB exchange rate is affected by the fundamentals of China's economy, and it is expected that

In the medium and long term, the basic stability will prevail, but the exchange rate of RMB against the US dollar will remain

There may be two-way fluctuations in a certain range.

4. The seller's LNG facilities fail to obtain financing and put into operation risks as agreed. contract has

Set effective conditions, that is, the seller makes a positive investment decision after completing the financing arrangement.

And the company hired an internationally renowned technical consulting agency to do project design and risk

out evaluation. The company will actively follow up the progress of the seller's facilities and make replacements when necessary.

Alternate gas source arrangement.

Special announcement.

Guangzhou Development Group Co., Ltd.

April 1, 2022

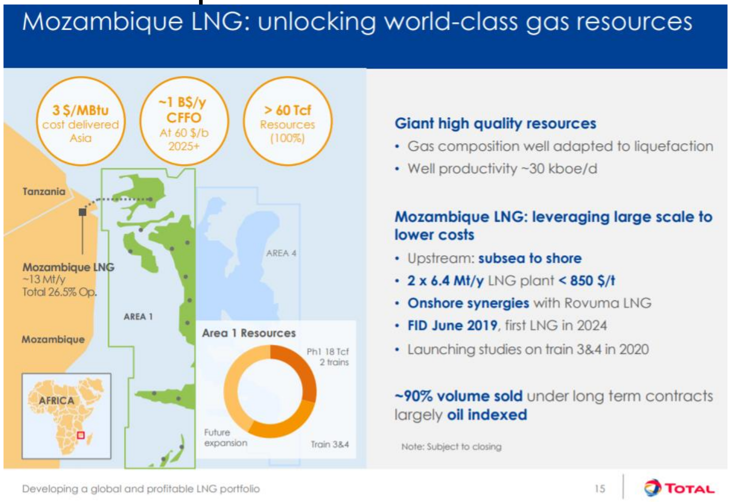
Multiple Brownfield LNG FIDs Now Needed To Fill New LNG Supply Gap From Mozambique Chaos? How About LNG Canada Phase 2?

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

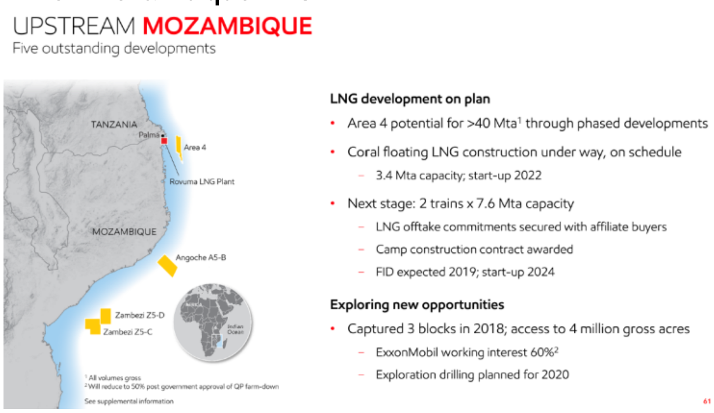
<u>Total's Mozambique force majeure is no surprise, especially the need to the restoration of security and stability "in a sustained manner"</u>. Yesterday, Total announced [LINK] "*Considering the evolution of the security".* No one should be surprised by the force majeure or the sustained manner caveat. 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

<u>Won't LNG and natural gas get hit by Biden's push for carbon free electricity?</u> 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.

<u>Will Cdn natural gas be similarly hit by if Trudeau move to "emissions free" and not "net zero emissions" electricity?</u> 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.

<u>Biden's global climate summit reminded there is too much risk to skip over natural gas as the transition fuel.</u> 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

<u>We expect the IEA's blunt message that the gap is getting wider will be reinforced on May 18</u>. 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

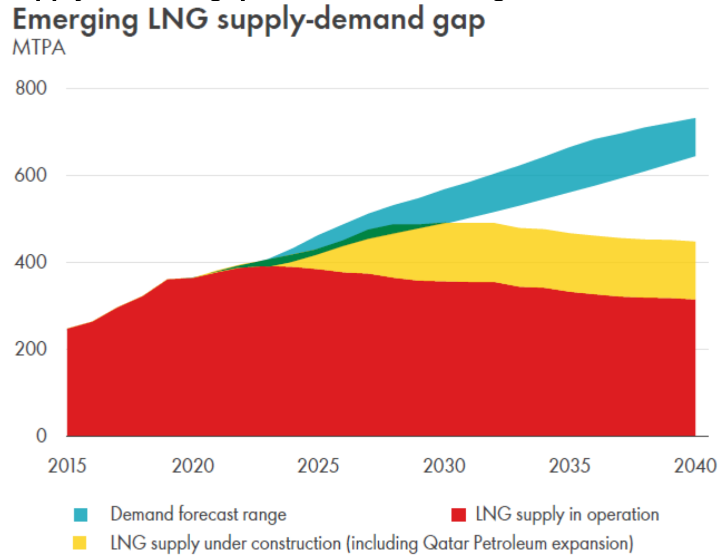
Source: IEA Tracking Clean Energy Progress, June 2020

<u>We are referencing Shell's long term outlook for LNG</u> 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.

<u>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</u> 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

<u>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..</u> 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.

<u>And does this bigger, nearer supply gap force LNG players to look at what brownfield LNG projects they could advance?</u> 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.

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? 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

A LNG Canada Phase 2 would be a big plus to Cdn natural gas. 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.

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

Posted 11am on July 14, 2021

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

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

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

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

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

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

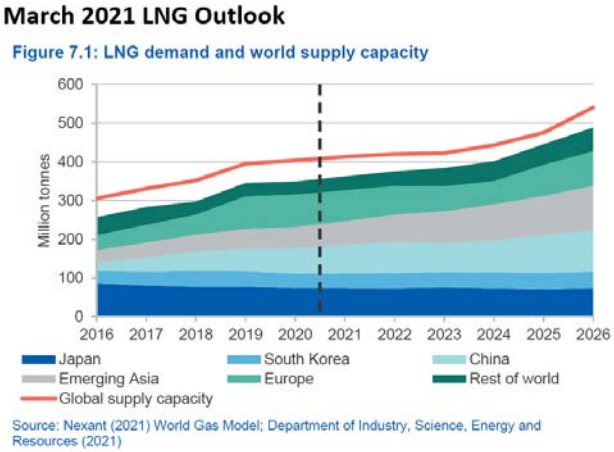
Common theme - new LNG supply is being delayed ie. [Total] Mozambique. Don't forget need capacity>demand due to normal maintenance, etc. Positive for LNG." (ii) Chevron's Gorgon. A big LNG story in H2/20 was the emergence of weld quality issues in the propane heat exchangers at Train 2, which required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

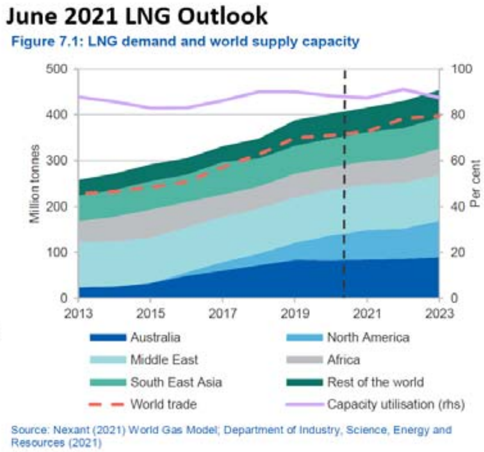
<u>Cheniere stopped the game playing the game on June 30</u>. Our July 4, 2021 Energy Tidbits memo noted that it looks like Cheniere has stopped playing stupid with respect to the strengthening LNG market in 2021. We can't believe they thought they were fooling anyone, especially their competitors. Bu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

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

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

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



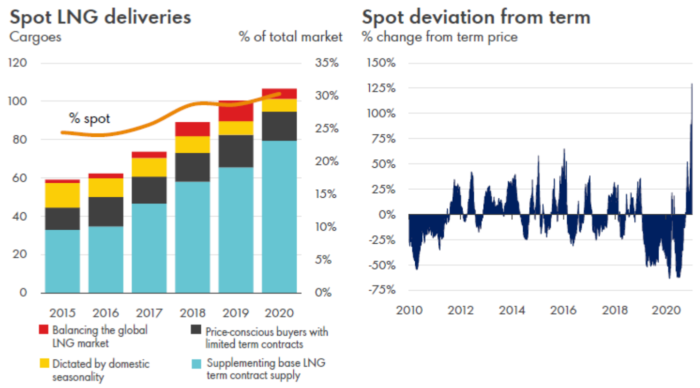


Source: Australia Resources and Energy Quarterly

<u>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.</u> 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.

<u>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</u>. 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.

https://tass.ru/ekonomika/14243381

MAR 31, 07:33

Decree of the President of Russia on the rules of gas trade with unfriendly countries. Full text

On March 31, Russian President Vladimir Putin signed a decree "On a special procedure for the fulfillment by foreign buyers of obligations to Russian suppliers of natural gas."

TASS publishes the full text of the document, which is also posted on the website of the President of Russia.

In addition to the measures provided for by Decrees of the President of the Russian Federation of February 28, 2022 No. 79 "On the application of special economic measures in connection with the unfriendly actions of the United States of America and foreign states and international organizations that have joined them", dated March 1, 2022 No. 81 "On additional temporary economic measures to ensure the financial stability of the Russian Federation", dated March 5, 2022 No. 95 "On the temporary procedure for fulfilling obligations to certain foreign creditors" and dated March 18, 2022 No. 126 "On additional temporary measures of economic character to ensure the financial stability of the Russian Federation in the field of currency regulation", I decide:

1. Establish that from April 1, 2022:

a) payment for the supply of natural gas in a gaseous state (hereinafter referred to as natural gas) carried out after April 1, 2022 by residents participating in foreign economic activity who, in accordance with Federal Law No. 117-FZ of July 18, 2006 "On Gas Export" the exclusive right to export natural gas in a gaseous state (hereinafter referred to as Russian suppliers), is made in rubles:

under foreign trade contracts for the supply of natural gas (hereinafter referred to as contracts for the supply of natural gas) concluded with foreign persons, if the supply of natural gas is carried out to foreign states that commit unfriendly actions in relation to the Russian Federation, Russian legal entities and individuals;

under contracts for the supply of natural gas concluded with foreign persons whose place of registration is foreign states that commit unfriendly actions against the Russian Federation, Russian legal entities and individuals;

b) further supply of natural gas by a Russian supplier to foreign persons named in paragraphs two and three of subparagraph "a" of this paragraph (hereinafter referred to as foreign buyers) under a contract for the supply of natural gas is prohibited, if the payment deadline for the gas supplied under this contract has come, payment by a foreign buyer is not made or is made in foreign currency, and (or) not in full, and (or) to an account in a bank that is not an authorized bank in accordance with paragraph 2 of this Decree, and such a delivery is carried out to foreign states that commit in relation to the Russian Federation, Russian legal entities and individuals, unfriendly actions. Information on compliance with the procedure for payment for the supply of natural gas established by this Decree shall be submitted to the customs authority.

2. Joint-stock company "Gazprombank", which for the purposes of this Decree is an authorized bank (hereinafter referred to as the authorized bank), opens, on the basis of applications from foreign buyers, special ruble accounts of type "K" and special currency accounts of type "K" for payments for supplied natural gas.

3. The authorized bank has the right to open special ruble accounts of type "K" and special currency accounts of type "K" without the personal presence of a representative of a foreign buyer. The authorized bank identifies a new client - a foreign buyer, his representative, beneficiary, beneficial owner in accordance with the requirements of the Federal Law of August 7, 2001 No. 115-FZ "On countering the legalization (laundering) of proceeds from crime and the financing of terrorism" and the regulations of the Central Bank of the Russian Federation adopted in accordance with it on the basis of documents and information about these persons available in the circumstances no later than 45 days after the date of opening a special ruble account of type "K" for such a client

4. Pending an amendment to the Tax Code of the Russian Federation and other federal laws, special ruble accounts of type "K" and special currency accounts of type "K" are not subject to paragraph 12 of Article 76, paragraph 1 of Article 86

of part one of the Tax Code of the Russian Federation and Part 27 of Article 77 of Federal Law No. 289-FZ of August 3, 2018 "On Customs Regulation in the Russian Federation and on Amendments to Certain Legislative Acts of the Russian Federation".

5. It is not allowed to suspend operations on a special ruble account of type "K" and a special currency account of type "K", arrest or write-off of funds on these accounts as part of the fulfillment of obligations of a foreign buyer not related to payment under a contract for the supply of natural gas .

6. A foreign buyer transfers funds to a special type "K" currency account in the foreign currency specified in the contract for the supply of natural gas, and the authorized bank, on the basis of the foreign buyer's instruction received in the manner prescribed by the rules of the authorized bank, sells foreign currency, received from a foreign buyer to such an account, in organized trading conducted by the public joint-stock company "Moscow Exchange MICEX - RTS", credits the proceeds in rubles to a special ruble type "K" account of this foreign buyer and transfers the credited funds in rubles to an open Russian supplier in an authorized bank ruble account.

7. The obligation for the foreign buyer to pay for the supply of natural gas in accordance with subparagraph "a" of paragraph 1 of this Decree is considered fulfilled from the moment the funds received from the sale of foreign currency are credited, carried out in the manner provided for in paragraph 6 or subparagraph "a" of paragraph 10 of this Decree , to a ruble account opened by a Russian supplier in an authorized bank.

8. If a foreign buyer has transferred the obligation to pay for the supply of natural gas to another person, it shall fulfill this obligation in the manner prescribed by this Decree.

9. Grant the Government Commission for the Control of Foreign Investments in the Russian Federation the authority to issue permits for foreign buyers to fulfill obligations to Russian suppliers to pay for natural gas supplies without complying with the procedure established by this Decree.

10. Grant the following powers to the Board of Directors of the Central Bank of the Russian Federation:

a) determine other than the procedure for the sale of foreign currency provided for in paragraph 6 of this Decree;

b) establish the regime of a special ruble account of type "K" and the regime of a special currency account of type "K".

11. The Government of the Russian Federation, within 10 days, approve the procedure for issuing permits by the Government Commission for Control over Foreign Investments in the Russian Federation, provided for in paragraph 9 of this Decree.

12. The Board of Directors of the Central Bank of the Russian Federation, within 10 days, make the decisions necessary to exercise the authority provided for by subparagraph "b" of paragraph 10 of this Decree.

13. Decisions of the Board of Directors of the Central Bank of the Russian Federation provided for by this Decree are subject to official publication in accordance with Article 7 of Federal Law No. 86-FZ of July 10, 2002 "On the Central Bank of the Russian Federation (Bank of Russia)".

14. Grant the Central Bank of the Russian Federation the right to issue official clarifications on the application of this Decree.

15. The Federal Customs Service, in agreement with the Central Bank of the Russian Federation and with the participation of an authorized bank, within 10 days, approve the procedure for submitting information to the customs authority in accordance with subparagraph "b" of paragraph 1 of this Decree on compliance with the procedure for paying for the supply of natural gas.

16. Recommend to the authorized bank within 10 days to determine the rules in accordance with paragraph 6 of this Decree.

17. This Decree comes into force from the day of its official publication.

https://www.energy.gov/articles/doe-announces-second-emergency-notice-sale-crude-oil-strategic-petroleum-reserve-address

DOE Announces Second Emergency Notice of Sale of Crude Oil From The Strategic Petroleum Reserve to Address Putin's Energy Price Hike

APRIL 1, 2022

WASHINGTON, D.C. — The U.S. Department of Energy's (DOE) Office of Fossil Energy and Carbon Management (FECM) today announced a **Notice of Sale** of crude oil from the Strategic Petroleum Reserve (SPR). This Notice of Sale follows President Biden's **announcement** yesterday authorizing the sale of crude oil from the SPR to address the significant market supply disruption caused by Putin's war on Ukraine and aid in lowering energy costs for American families.

The SPR will release approximately one million barrels of crude oil per day over the next six months. Crude oil in this emergency sale will enter the market in two releases.

The first 90 million barrels will be released between May and July, through two notices of sale totaling 70 million barrels, and 20 million barrels already scheduled to be released in May 2022. The remaining 90 million barrels will be released between August and October 2022. DOE must receive bids for the first notice of sale no later than 10:00 a.m. Central Time on April 12, 2022, and will award contracts to successful offerors no later than April 21, 2022.

The May through July sales will be conducted with crude oil from the following four SPR sites:

- Up to 20.5 million barrels from Big Hill
- Up to 21.5 million barrels from West Hackberry
- Up to 18 million barrels from Bryan Mound
- Up to 10 million barrels from Bayou Choctaw

The SPR is the world's largest supply of emergency crude oil, and the federally owned oil stocks are stored in underground salt caverns at four storage sites in Texas and Louisiana. The SPR has a long history of protecting the economy and American livelihoods in times of emergency oil shortages.

Any company registered in the SPR's Crude Oil Sales Offer Program is eligible to participate in this and other SPR crude oil sales. Other interested companies may register through the SPR's website: **Crude Oil Sales Offer Program**.

For more information on the SPR please visit **Infographic: Strategic Petroleum Reserve** and **Fact Sheet: Strategic Petroleum Reserve**. Sign up to receive future FECM news alerts **here**.

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https://www.energy.gov/fecm/articles/us-department-energy-announces-contract-awards-crude-oil-sales-strategic-petroleum

U.S. Department of Energy Announces Contract Awards for Crude Oil Sales From the Strategic Petroleum Reserve

MARCH 16, 2022

WASHINGTON, D.C. – Today, the U.S. Department of Energy's (DOE) Office of Fossil Energy and Carbon Management announced that contracts have been awarded for ALL 30 million barrels put up for sale from the U.S. Strategic Petroleum Reserve. This fully-subscribed sale is part of **a coordinated action** with the 30 member countries of the International Energy Agency to collectively release an initial 60 million barrels of oil from strategic petroleum reserves. This effort reflects a common focus and willingness to address significant market and supply disruptions related to President Putin's war on Ukraine, as the Administration continues to take action to help lower energy prices for Americans.

On March 2, 2022, DOE issued a **Notice of Sale** for a price-competitive sale of 30 million barrels of SPR crude oil. A total of 13 companies responded to this notice, submitting 109 bids for evaluation. Contracts were awarded to the following seven companies:

- Atlantic Trading & Marketing, Inc. (1.05 million barrels);
- Chevron USA (1.265 million barrels);
- Gunvor USA, LLC (0.350 million barrels);
- Marathon Petroleum Supply and Trading, LLC (16.06 million barrels);
- Motiva Enterprises, LLC (2.55 million barrels);
- Phillips 66 Company (4.2 million barrels); and
- Valero Marketing and Supply Company (4.75 million barrels)

From this sale the SPR sold a total of 30.225 million barrels, and of that amount 8.33 million barrels will be sold from the SPR's Bryan Mound site (near Freeport, TX), 10 million barrels from the West Hackberry site (near Hackberry, LA), 10 million barrels from the Bayou Choctaw site (near Baton Rouge, LA), and 1.895 million barrels from the Big Hill site (near Winnie, TX). The SPR plans to schedule deliveries between April 1–May 31, 2022, with early deliveries available in March if arrangements can be made.

Visit **DOE's website** for more information on the SPR.

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https://www.energy.gov/fecm/articles/doe-awards-additional-strategic-petroleum-reserve-exchange

DOE Awards Additional Strategic Petroleum Reserve Exchange

MARCH 7, 2022

WASHINGTON, D.C. — The U.S. Department of Energy (DOE) has approved a twelfth exchange of 2,700,000 barrels of crude oil for release to ExxonMobil from the Strategic Petroleum Reserve (SPR). This release falls under the authorization published in **the DOE announcement** on November 23, 2021.

Combined, DOE has provided 24.4 million barrels of SPR crude oil available for exchange to **boost the nation's fuel supply**. As with all exchanges, companies that receive SPR crude oil through the exchange agree to return the amount of crude oil received, as well as an additional amount, dependent upon the length of time in which they hold the oil. Since September, 2021, 38 million barrels of crude oil from the SPR has been sold through sales mandated by Congress and including sales accelerated by the administration (**19.9 million barrels awarded** in September and **18.1 million barrels awarded** in January), for a total of 62.4 million barrels put on the market through sales and the exchange so far. The President has now announced an emergency sale of an additional **30 million barrels**.

Additional information about SPR exchanges can be found **here**. Those interested in receiving future announcements from DOE's Office of Fossil Energy and Carbon Management can sign up **here**.

AMLO Says Mexico to Refine Less Crude and Export More on Rally
2022-03-31 16:29:20.122 GMT

By Amy Stillman and Max de Haldevang
(Bloomberg) -- Mexico will refine less of its oil this year to take advantage of an international price rally, putting on hold the nationalist president's goal of producing all of its own fuel at home.
"We launched a new plan because the price of crude oil is high and we are in the process of modernizing the refineries, so we are taking advantage now that the price is high to dedicate more resources and time to the rehabilitation of the plants," President Andres Manuel Lopez Obrador said during his daily press conference on Thursday.
Mexico will reduce its crude processing to 850,000 barrels a day from a goal of about one million barrels a day, he said. The country processed 846,329 barrels a day of crude in February, and it averaged 711,612 barrels a day last year, according to data from Pemex.
Bloomberg News previously reported that the price rally due Russia's invasion of Ukraine has temporarily delayed Lopez Obrador's plan to halve crude exports as part of his energy self-sufficiency goal. The president, known as AMLO, has sought to reverse the liberalizing reforms of his predecessor and cast off the country's dependence on foreign interests by increasing Mexico's refining output and reducing its reliance on fuel imports.
Higher prices have thrown a spanner in the works, as AMLO has been forced to use the additional revenues from Petroleos Mexicanos's oil sales abroad to offset the higher cost of importing fuel to avoid a gasoline price spike for consumers, known in Mexico as a "gasolinazo".
Read more: Mexico finance chief says subsidies work even with $155 oil (1)
AMLO campaigned on a promise to end high electricity and fuel prices for Mexicans by building a new refinery to process more of the country's crude at home and reigning in foreign companies, which he's blamed for overcharging consumers and pillaging the country's oil riches.
The government calculates that it can afford to subsidize fuel with prices up to $155 per barrel without hurting public finances, Finance Minister Rogelio Ramirez de la O told Bloomberg News last week. West Texas Intermediate crude oil for May delivery fell Thursday, trading near $104, but was still heading for a monthly gain.

--With assistance from Carolina Gonzalez.

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To view this story in Bloomberg click here:

https://blinks.bloomberg.com/news/stories/R9M8KYDWX2PZ

https://www.forbes.com.mx/estados-tendran-hasta-10-mil-mdp-mas-que-en-2021-por-alto-precio-del-petroleo/

Forbes Staff

March 31, 2022 @ 11:11 am

States will have up to 10 billion pesos more than in 2021 due to high oil prices

The president reported that the surplus obtained from the sale of oil will be used to increase the resources of the states.

President Andrés Manuel López Obrador reported that the surpluses obtained from the sale of oil prices will be used to increase federal resources sent to the states, so that each entity will have between 8 and 10 billion pesos more than in 2021.

"With what we are obtaining from the surplus due to the high prices of crude oil, it is enough for the gasoline subsidy. It doesn't mean that we have to sell gasoline to our friendly neighbors in the United States, our consumption is increasing, it doesn't, it's enough for us to sell gasoline cheaper than it is sold in the United States. The subsidy is enough for us, we have more than enough; that is to say, we have utility and we are going to divide it, a part is for the states and it is a shareable income", said the president.

Due to these surpluses, he pointed out that he has already informed the governors of Nuevo León, Samuel García, and of Jalisco, Enrique Alfaro, that they will have 10 billion pesos more than in 2021.

“This means that if a crude oil price was established in the approved Revenue Law and the price is higher, if there is a surplus, it is divided and delivered to the states. Now that the governors of Nuevo León and Jalisco have been there, they have been informed that they will have approximately 10 billion pesos in participation increases in Nuevo León and Jalisco compared to last year,” he said.

The head of the Executive mentioned that from the rest of the entities, each one will have between 8 to 10 billion additional pesos compared to last year.

He also pointed out that another part of the surplus will be to continue subsidizing the price of gasoline so that the cost of these to users is not increased.

In addition, he reported that his government is applying an "emerging plan" to take advantage of high crude oil prices to modernize refineries.

“Yes, we are maintaining a plan that we started, an emerging plan, because the price of crude oil is high and we are in the process of modernizing the refineries. We are taking advantage now that the price is high to dedicate more resources and time to the rehabilitation of the plants. So, that's why from about one million barrels per day processed in the refineries it will decrease to 850 thousand, because we are taking advantage to rehabilitate them”, he mentioned.

https://www.opec.org/opec_web/en/press_room/6845.htm

27th OPEC and non-OPEC Ministerial Meeting

No 08/2022
Vienna, Austria
31 Mar 2022

Following the conclusion of the 27th OPEC and non-OPEC Ministerial Meeting, held via videoconference on March 31, it was noted that continuing oil market fundamentals and the consensus on the outlook pointed to a well-balanced market, and that current volatility is not caused by fundamentals, but by ongoing geopolitical developments.

The OPEC and participating non-OPEC oil-producing countries decided to:

1. Reaffirm the decision of the 10th OPEC and non-OPEC Ministerial Meeting on 12th April 2020 and further endorsed in subsequent meetings including the 19th OPEC and non-OPEC Ministerial Meeting on the 18th July 2021.
2. Reconfirm the baseline adjustment, the production adjustment plan and the monthly production adjustment mechanism approved at the 19th OPEC and non-OPEC Ministerial Meeting and the decision to adjust upward the monthly overall production by 0.432 mb/d for the month of May 2022, as per the attached schedule.
3. Reiterate the critical importance of adhering to full conformity and to the compensation mechanism taking advantage of the extension of the compensation period until the end of June 2022. Compensation plans should be submitted in accordance with the statement of the 15th OPEC and non-OPEC Ministerial Meeting.
4. Hold the 28th OPEC and non-OPEC Ministerial Meeting on 5 May 2022.

	May 2022 Required Production
Algeria	1013
Angola	1465
Congo	312
Eq.Guinea	122
Gabon	179
Iraq	4461
Kuwait	2694
Nigeria	1753
Saudi Arabia	10549
UAE	3040
Azerbaijan	688
Bahrain	197
Brunei	98
Kazakhstan	1638
Malaysia	571
Mexico	1753
Oman	846
Russia	10549
Sudan	72
South Sudan	124
OPEC 10	25589
Non-OPEC	16537
OPEC+	42126

https://www.opec.org/opec_web/en/press_room/6512.htm

19th OPEC and non-OPEC Ministerial Meeting concludes

No 21/2021
Vienna, Austria
18 Jul 2021

The 19th OPEC and non-OPEC Ministerial Meeting (ONOMM), held via videoconference, concluded on Sunday 18 July 2021.

The Meeting noted the ongoing strengthening of market fundamentals, with oil demand showing clear signs of improvement and OECD stocks falling, as the economic recovery continued in most parts of the world with the help of accelerating vaccination programmes.

The Meeting welcomed the positive performance of Participating Countries in the Declaration of Cooperation (DoC). Overall conformity to the production adjustments was 113% in June (including Mexico), reinforcing the trend of high conformity by Participating Countries.

In view of current oil market fundamentals and the consensus on its outlook, the Meeting resolved to:

Reaffirm the Framework of the Declaration of Cooperation, signed on 10 December 2016 and further endorsed in subsequent meetings, including on 12 April 2020.

Extend the decision of the 10th OPEC and non-OPEC Ministerial Meeting (April 2020) until the 31st of December 2022.

Adjust upward their overall production by 0.4 mb/d on a monthly basis starting August 2021 until phasing out the 5.8 mb/d production adjustment, and in December 2021 assess market developments and Participating Countries' performance.

Continue to adhere to the mechanism to hold monthly OPEC and non-OPEC Ministerial Meetings for the entire duration of the Declaration of Cooperation, to assess market conditions and decide on production level adjustments for the following month, endeavoring to end production adjustments by the end of September 2022, subject to market conditions.

Adjust, effective 1st of May 2022, the baseline for the calculations of the production adjustments according to the attached table (table 1).

Reiterate the critical importance of adhering to full conformity and taking advantage of the extension of the compensation period until the end of September 2021. Compensation plans should be submitted in accordance with the statement of the 15th OPEC and non-OPEC Ministerial Meeting.

The meeting decided to hold the 20th OPEC and non-OPEC Ministerial Meeting on 1 September 2021.

	Reference Production up to end of April 2022	Reference Production effective May 2022
Algeria	1057	1057
Angola	1528	1528
Congo	325	325
Eq.Guinea	127	127
Gabon	187	187
Iraq	4653	4803
Kuwait	2809	2959
Nigeria	1829	1829
Saudi Arabia	11000	11500
UAE	3168	3500
Azerbaijan	718	718
Bahrain	205	205
Brunei	102	102
Kazakhstan	1709	1709
Malaysia	595	595
Mexico*	1753	1753
Oman	883	883
Russia	11000	11500
Sudan	75	75
South Sudan	130	130
OPEC 10	26683	27815
Non-OPEC	17170	17670
OPEC+	43853	45485

SAF Group created transcript of CNBC's Hadley Gamble with UAE Energy Minister Suhail Mohamed Al Mazrouei on March 28, 2022 https://twitter.com/themmagraham/status/1508473389580705799

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

Al Marzouei "…*because what we want to do is be friend with everyone. we're friends with the US. we're friends with the*" Gamble "*but you're not taking a call from President Biden*." Al Marzouei "*No, I think". Gamble "that's what you told me the last time we spoke*". Al Marzouei "*no, President Biden doesn't call me."* Gamble "*but if the United States were to call you, you'd take the call?*" Al Marzouei "*I had a meeting today with some envoys from the United States, the United States"*. Gamble "*but it doesn't't' necessarily sway your opinion one way or another*." Al Marzouei *"I don't think we should take it that way. the United States is a very important partner to us. And we have significant investments. We have much more in common with the United States, but that doesn't mean that we would have to agree on everything. I mean we would agree on the things that we think we can agree. And there are things that we could disagree. And we're not going to be told what to do. We know what is sensible for us. and in the field of energy, I haven't received any call or any request for a call from the Secretary of Energy*" Gamble "*nothing*?" Al Marzouei "*No, she didn't call me, she didn't approach me*." Gamble "*Huh"*. Al Marzouei "*And if she wanted to call, she is always going to be welcome. I will not say no to, I speak with everyone. So, I think taking it that way is not the right approach. but If taking a call means that we have to listen to something that is, that we cannot do, then that is not how it should be interpreted. US is important, it Is an important friend, we are investing there, they are investing here, we have lots of collaboration with them. And cooperation. So, it's the largest economy in the world*".

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

In the spotlight: China's road congestion levels

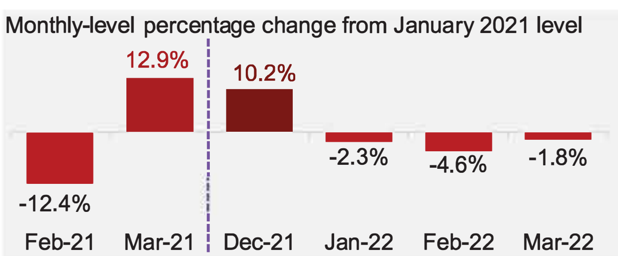
List of 99 cities available at the back of this report

Congestion in China fell to lowest since Lunar New Year

- Charts to the **right** display, in alphabetical order, the 15 cities with the highest number of car registrations. The chart to the **top left** is derived by taking the weighted average of the congestion levels in the 15 cities and their vehicle registration numbers. An index value below 100 indicates a decrease from January 2021 levels.

China congestion index

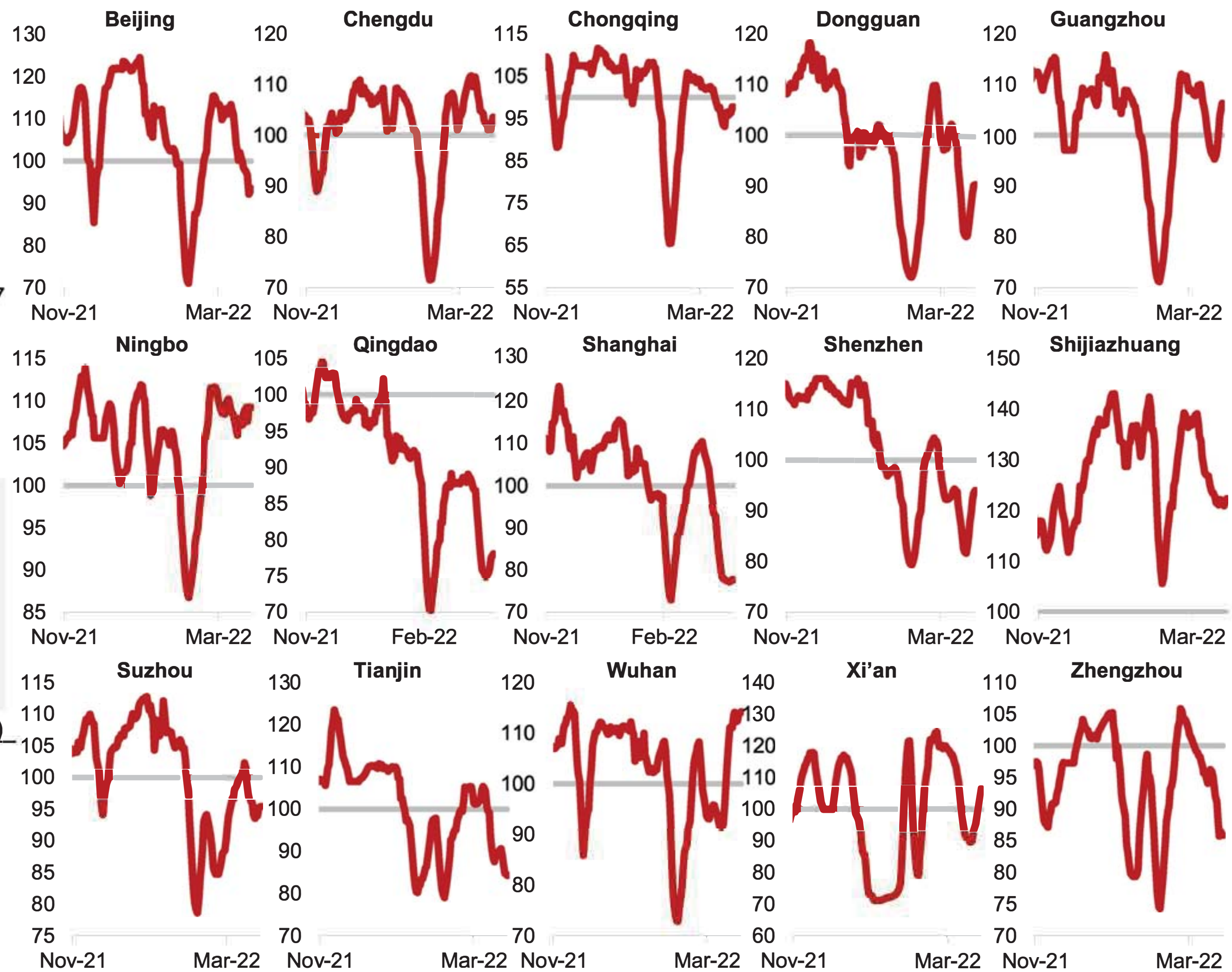
Daily peak congestion levels, indexed to January 2021 (seven-day MA)



China's 15 cities with highest car registrations (in millions)

Beijing	6.03	Shenzhen	3.54
Chengdu	5.46	Dongguan	3.41
Chongqing	5.04	Tianjin	3.29
Suzhou	4.43	Qingdao	3.14
Shanghai	4.40	Shijiazhuang	3.02
Zhengzhou	4.04	Guangzhou	2.99
Xi'an	3.74	Ningbo	2.98
Wuhan	3.66		

Daily peak congestion levels, indexed to January 2021 (seven-day MA)



*Source: BloombergNEF, calculated from Baidu's data. Note: Data updated to **March 27**. Note: Month-to-date change shown for March 2022*

Oil price outlook – Snapshot: March 28, 2022

Disclaimer: Please note that BNEF does not offer investment advice. Clients must decide for themselves whether current market prices fully reflect the issues discussed in this note.

Category	Indicator	Signal	Comment
Fundamentals	**Refinery margins**	↑	• Refinery margins rose over the past week due to stronger middle distillate cracks.
	Crude stocks	↔	• In the week ending March 18, land crude-oil storage levels in BloombergNEF's tracked regions (U.S., ARA, Japan) were virtually flat at 522.6 million barrels (m bbl). The stockpile **deficit** against its five-year average (2015-19) **widened from 83.1m bbl to 84.2m bbl**. • Including global floating crude stockpiles from the same week, total crude oil inventories increased by 1.2% to 620.5m bbl, with the stockpile **deficit narrowing from 49.6m bbl to 39.5m bbl.** However, initial data shows floating crude stocks falling considerably in the week to March 25.
	Product stocks	↔	• In the week ending March 18, gasoline and light distillate stockpiles in BNEF's tracked regions (U.S., ARA, Singapore, Japan and Fujairah) were down 0.4% week-on-week to 281.7m bbl, with the stockpile **deficit** against its three-year average (2017-19) **narrowing from 3.2m bbl to 0.4m bbl**. Gasoil and middle distillate stockpiles in BNEF's tracked regions dropped by 1.2% to 141.5m bbl, with the stockpile **deficit** against its three-year average **widening from 40.5m bbl to 41.2m bbl**. • Total oil product stockpiles in tracked regions decreased by 0.5% to 878.7m bbl, with the stockpile **deficit** against its three-year seasonal average **widening from 72.3m bbl to 74.4m bbl**. Altogether, crude and product stockpiles grew by 0.2% to 1,499.2m bbl, with the stockpile **deficit narrowing from 121.9m bbl to 113.9m bbl.**
	Demand indicators	↔	• In the week to March 22, global jet fuel demand from commercial passenger flights fell by 20,700 barrels per day (or 0.5%) week-on-week to 4.39 million barrels per day. Jet fuel consumption by international passenger departures was down by 16,100 barrels per day (or 0.7%) week-on-week, while consumption by domestic passenger departures fell by 4,600 barrels per day (or 0.2%). • Global mobility indices were mixed over the past week. Apple's global driving activity index increased by 0.9% in the week to March 26, driven by growth in Asia Pacific ex-China (+4.2%) and Europe (+3.5%). Google's global mobility index was down 0.2% in the week to March 24, as growth in Europe (+1.8%) was nullified by the decline in Asia Pacific ex-China (-2.1%). Road congestion in China's key 15 cities increased by 2.3 percentage points to 96.2% of January 2021 levels in the week to March 27, according to BNEF's calculation based on Baidu data. Month-to-date, congestion is about 13% lower than March 2021. • Daily average Covid-19 cases fell by 17% to 1.5 million in the week to March 26. Europe was down 10% to 650,000 daily cases, Asia Pacific fell by 17% to 740,000 daily cases, and the Americas fell by 14% to 92,000 daily cases. All numbers shown are the daily averages for the week ending March 26. • Weather forecasts showed that temperatures in key Asian cities are becoming warmer. Temperatures in European cities, however, got significantly colder.
Financial	**Macro indicators**	↔	• The dollar index averaged 0.1% higher than the week before. U.S. flash manufacturing PMI rose to 56.5 in March, the highest in seven months.
	Hedge fund positioning	↑	• In the week to March 22, Managed Money net positioning in the oil complex increased by 16.0m bbl (or 2.9%) week-on-week to 568.6m bbl, and rose to the 26th percentile of the past five years (versus the 23rd percentile last week) .
	Options chains and volatility	↓	• There was a significant decline in open interest for Brent and WTI Dec-22 calls. Brent and WTI 1M volatility skews fell over the past week.
Outlook	**Weekly call**	↔	• BNEF is neutral on oil prices for the week ahead, with Brent Jun-22 trading at $109.53/bbl and WTI May-22 trading at $105.58/bbl at the time of writing. The market continues to contend with short-term supply shortages and rising demand risks in China as Shanghai locks down half the city to fight a Covid-19 outbreak. Talks to revive the Iran nuclear deal hit a stumbling block as the U.S. re-evaluated the risks of declassifying the Islamic Revolutionary Guard Corps as a foreign terrorist organization given the current geopolitical situation. The revival of the Iran deal could boost Iranian exports by 500,000 barrels a day (b/d) within a month and 1.3m b/d by the end of 2022. The UAE has also reaffirmed its support for Russia's role within OPEC+, and BNEF expects OPEC+ to ease its production quota by the usual pace of 400,000 b/d for May 2022 in the group's upcoming meeting on March 31.

Past outlooks

Disclaimer: Please note that BNEF does not offer investment advice. Clients must decide for themselves whether current market prices fully reflect the issues discussed in this note

Date of report	Refinery margins	Crude stocks	Product stocks	Demand indicators	Commitment of traders	Options chain and volatility	BNEF week ahead call	Brent/WTI price at time of writing ($/bbl)	Web Link
March 28	↑	↔	↔	↔	↑	↓	↔	Brent-**Jun**: 109.53 WTI-May: 105.58	
March 21	↔	↔	↔	↓	↓	↔	↔	Brent-May: 112.35 WTI-May: 107.56	
March 14	↑	↑	↑	↔	↓	↓	↔	Brent-May: 108.66 WTI-Apr: 104.77	
February 28	↔	↔	↔	↑	↔	↔	↔	Brent-May: 99.00 WTI-Apr: 96.38	
February 21	↔	↔	↑	↑	↔	↔	↑	Brent-May: 91.50 WTI-Apr: 90.17	
February 14	↑	↔	↑	↑	↓	↔	↑	Brent-Apr: 93.75 WTI-Mar: 92.46	
February 7	↑	↑	↔	↑	↔	↔	↔	Brent-Apr: 92.83 WTI-Mar: 91.43	
January 31	↑	↔	↔	↑	↓	↔	↑	Brent-Apr: 89.17 WTI-Mar: 87.55	
January 24	↔	↑	↔	↔	↑	↓	↑	Brent-Mar: 87.19 WTI-Mar: 85.25	
January 17	↑	↑	↔	↔	↑	↑	↔	Brent-Mar: 85.78 WTI-Mar: 83.22	
January 10	↑	↓	↔	↓	↑	↑	↔	Brent-Mar: 81.71 WTI-Feb: 78.82	
January 3	↔	↔	↑	↓	↔	↔	↑	Brent-Mar: 78.84 WTI-Feb: 76.14	
December 13	↑	↑	↔	↑	↓	↔	↑	Brent-Feb: 75.25 WTI-Jan: 71.62	
December 6	↑	↔	↔	↔	↓	↑	↔	Brent-Feb: 71.63 WTI-Jan: 68.05	

To view past reports on terminal, go to NI BNEFOIL, search for the report and click on the icon to the far right:

BloombergNEF

Fundamentals | Financial

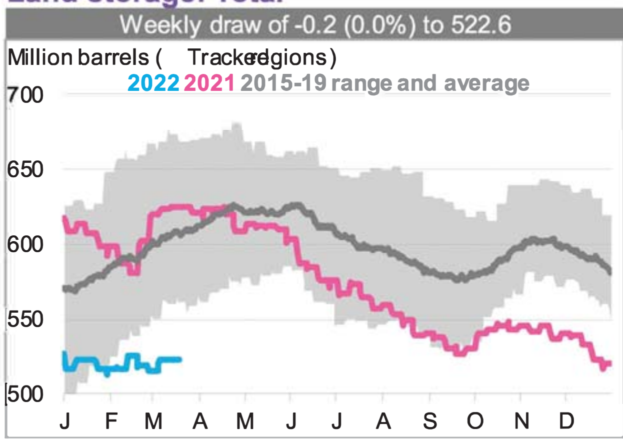
Crude stocks: Land

Note: We will continue to compare current inventory levels with the three-year (2017-19) seasonal average for the time being. Crude inventory data for Shandong teapots were excluded since January 10.

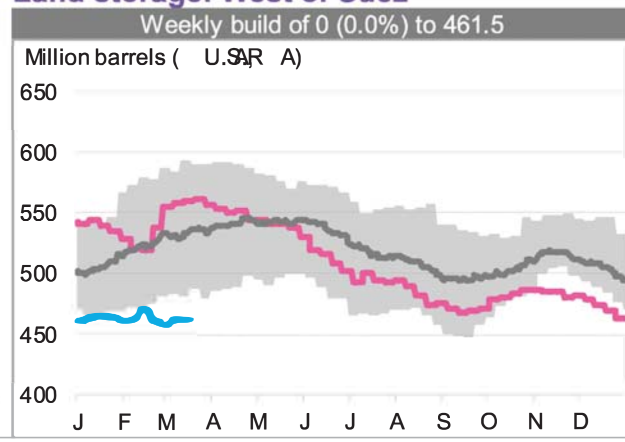
Neutral: Deficit widened from 83.1m bbl to 84.2m bbl against seasonal average

- Crude inventory rises when supply outstrips demand (meaning more physical oil is available than is needed). High or rising inventories are therefore a bearish factor for oil prices. Every year, storage levels fluctuate due to seasonal demand trends. The intra-year directional movement of stockpile levels is somewhat predictable, yet the magnitude of movement can differ significantly from expectations.
- A useful way to gauge if the intra-year storage levels differ from the norm is to measure the difference between the current and seasonal average inventory levels.

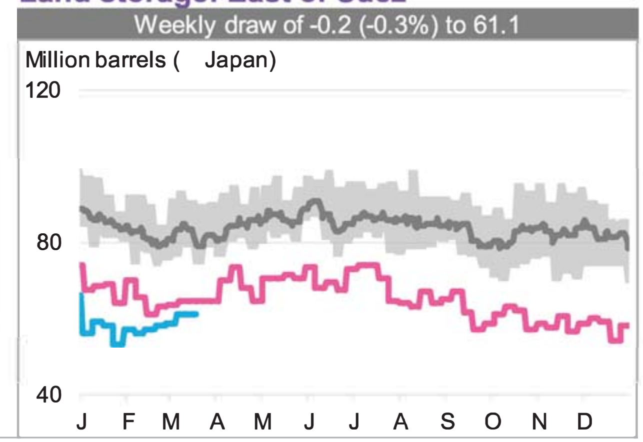
Land storage: Total



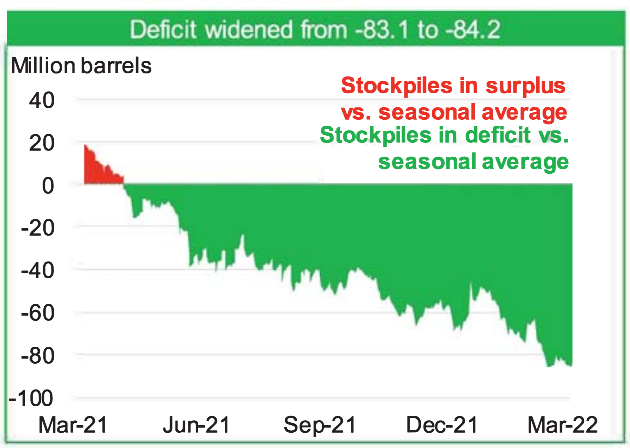
Land storage: West of Suez

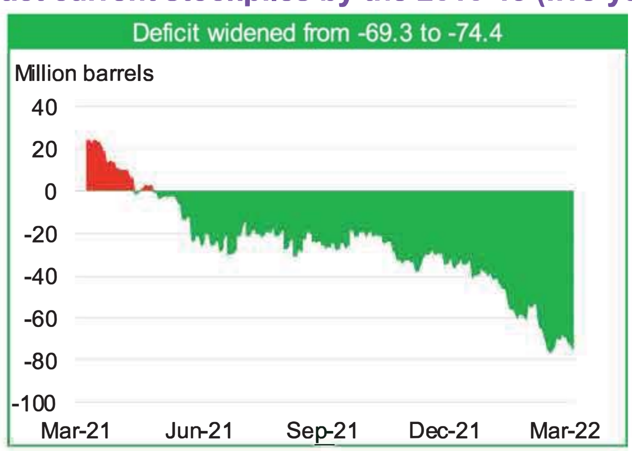


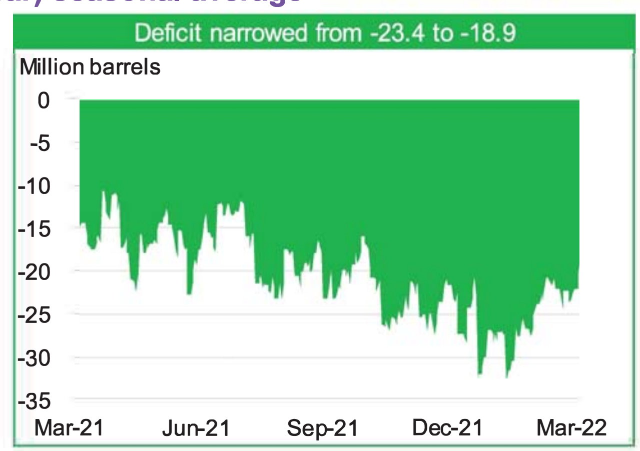
Land storage: East of Suez



Charts below subtract current stockpiles by the 2015-19 (five-year) seasonal average







*Source: BloombergNEF, U.S. EIA, Genscape, PAJ, SCIG. Note: As of the **week ending March 18.***

Crude stocks: Floating

Bullish: Surplus narrowed over the recent week

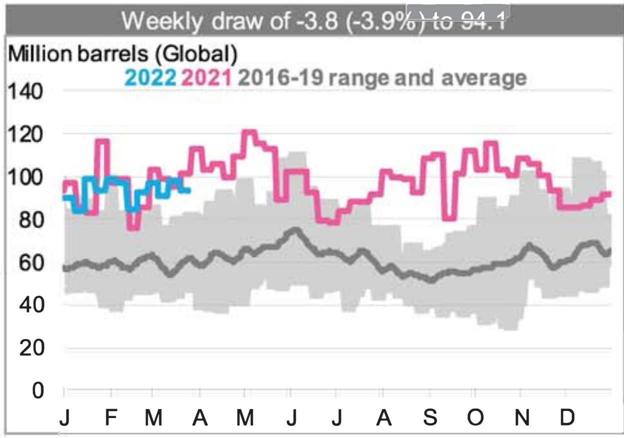
- Floating storage is only profitable if the strength of contango (future vs. prompt price) is greater than the tanker costs. Therefore, tankers become floating storage when the profit from a storage play exceeds the cost of the forward freight agreement (FFA).
- The floating storage data used in the "Oil Price Outlook" slide is for the previous week (i.e. the week before the latest data shown below). That data are available in the table to the right.

Vortexa's revision to global floating crude inventories

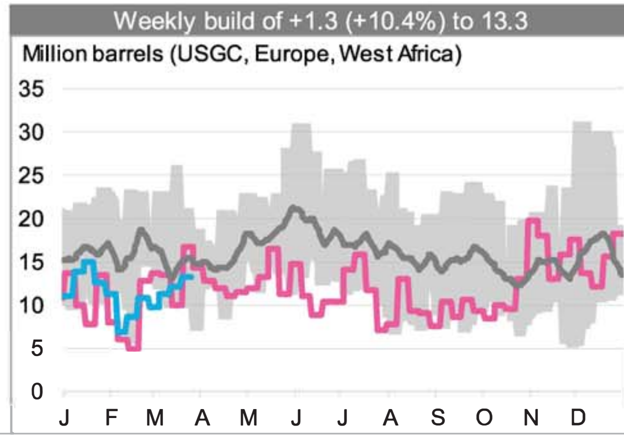
Million barrels	Previous report	Current report	Vortexa's revision
Inventories in week of Mar. 18	94.6	**97.9***	+3.3
Inventories in week of Mar. 11	93.2	90.6	-2.6

*Note: *Figure used to aggregate total oil inventories on page 12.*

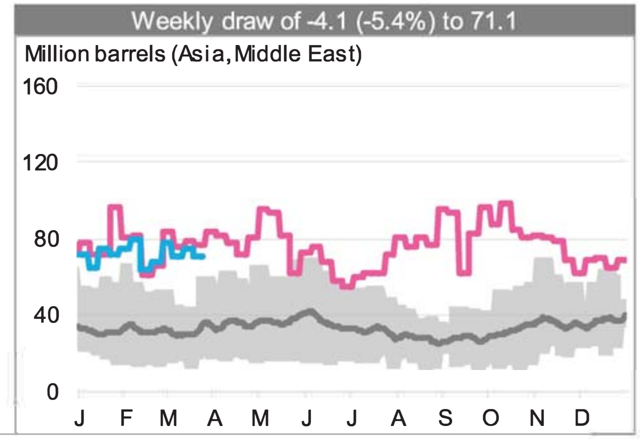
Floating storage: Total



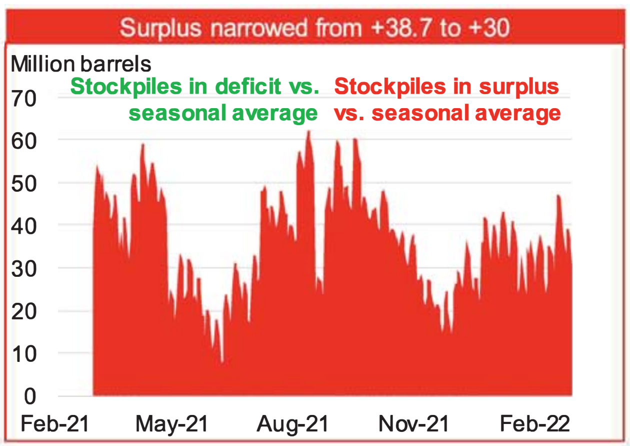
Floating storage: West of Suez

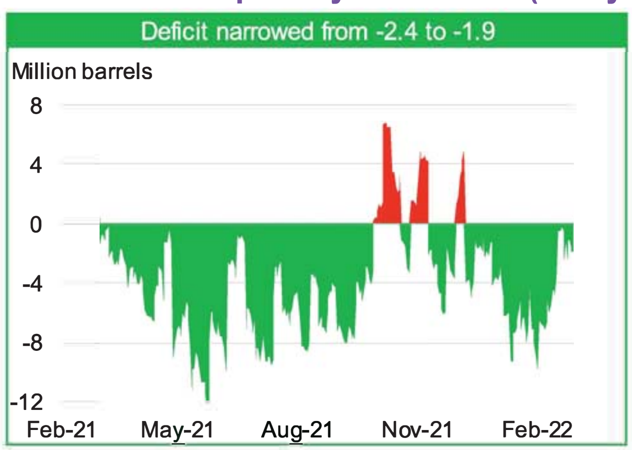


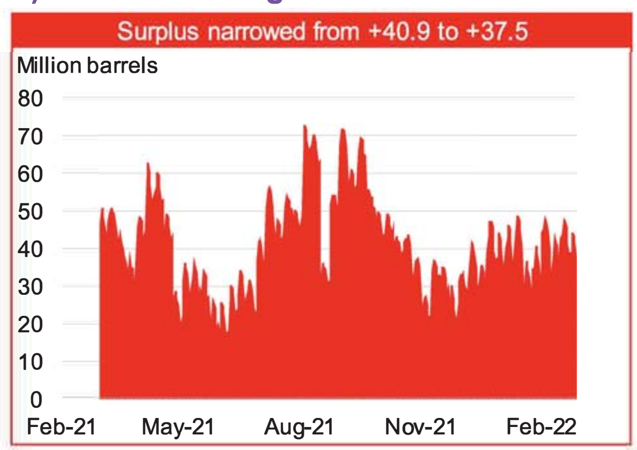
Floating storage: East of Suez



Charts below subtract current stockpiles by the 2016-19 (four-year) seasonal average





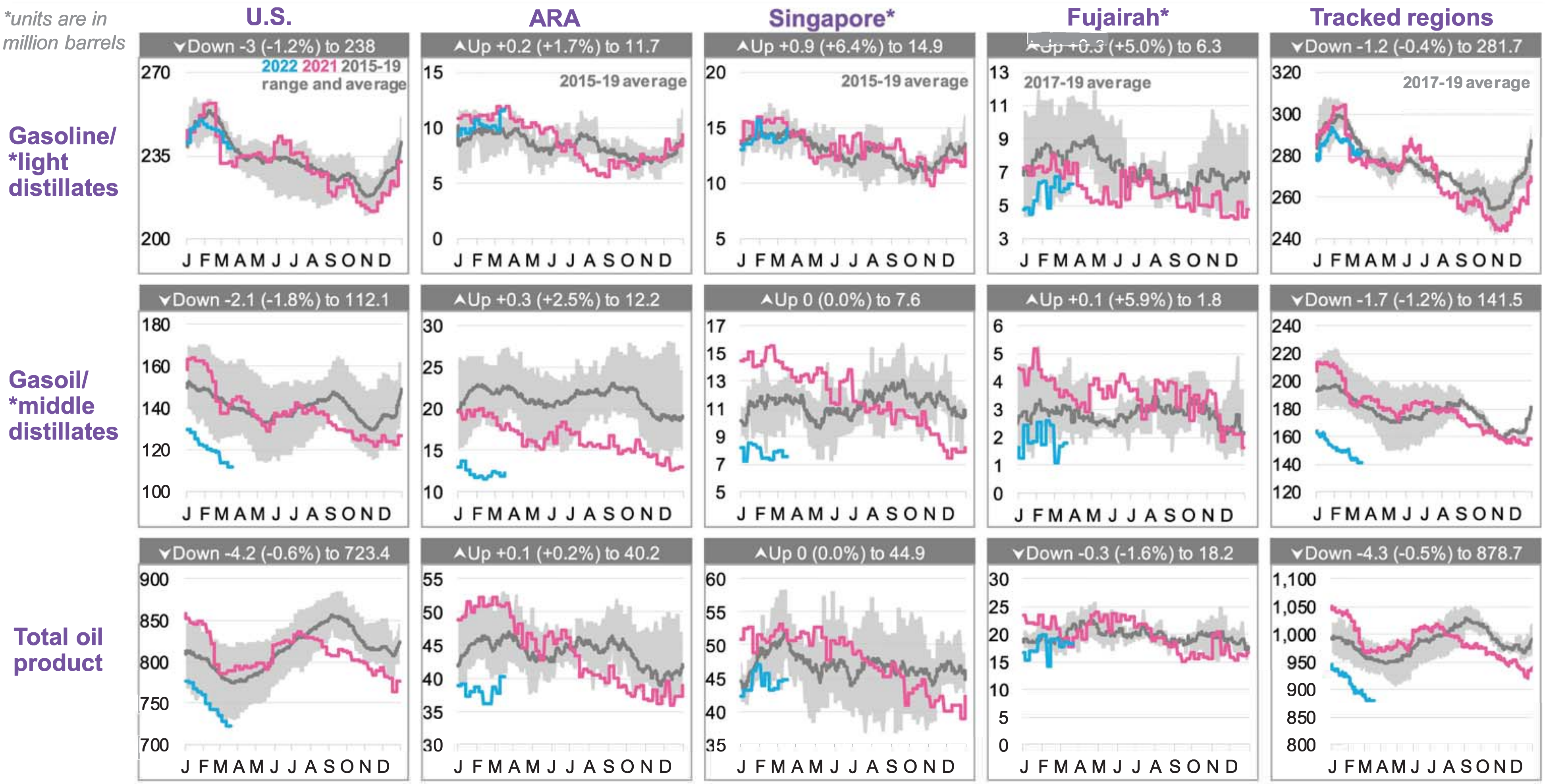


*Source: BloombergNEF, Vortexa. Note: As of the **week ending March 25. *Raw data from Vortexa is revised frequently, so the data in this report might change week-to-week.***

Product stocks: Current vs. seasonal average

Neutral: Oil product stockpiles in tracked regions fell by 0.5% week-on-week

- Chart legend are as follows: 2021, 2020 and the 2015-19 range and average. For Fujairah and tracked regions, the **2017-19 (three-year) seasonal range** is shown. Tracked regions include U.S., ARA, Singapore, Japan and Fujairah

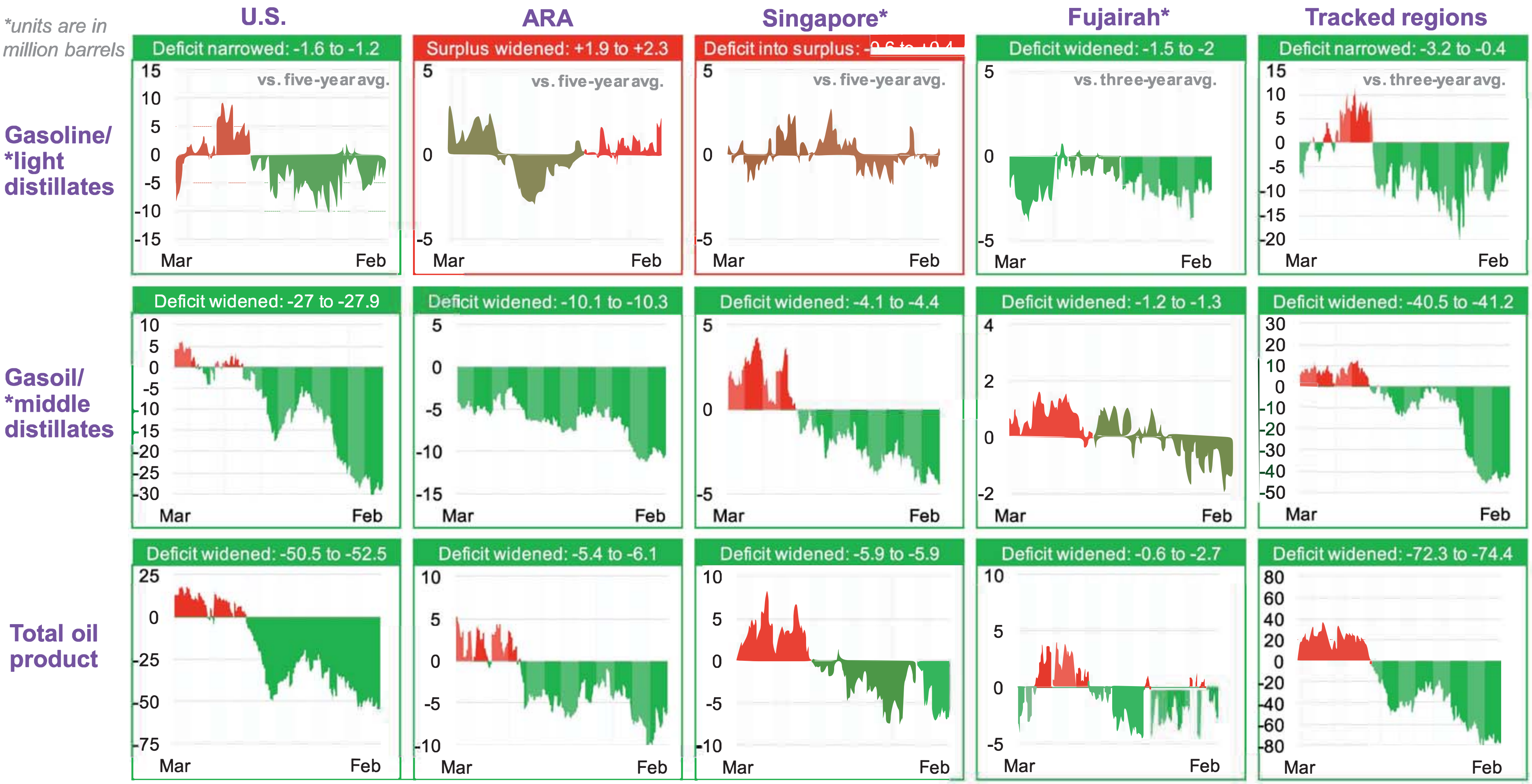


Source: BloombergNEF, U.S. EIA, PJK, IE Singapore, FEDCom/Platts, PAJ. Note: As of the ***week ending March 18.***

Product stocks: Current vs. seasonal average

Neutral: Oil product stockpile deficit against the seasonal average widened from 72.3m bbl to 74.4m bbl

- The charts below compare each respective regional product stockpile level against the seasonal average defined in the previous slide.
- **Red** signifies that the current stockpile levels are higher (in surplus) than the seasonal average, while **green** signals that the current stockpiles are lower (in deficit).



*Source: BloombergNEF, U.S. EIA, PJK, IE Singapore, FEDCom/Platts, PAJ. Note: As of the **week ending March 18.***

Fundamentals Financial

Note: We will continue to compare current inventory levels with the three-year (2017-19) seasonal average for the time being. Crude inventory data for Shandong teapots were excluded since January 10.

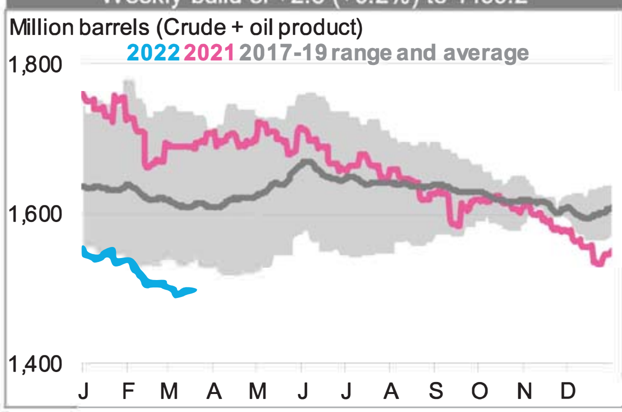
Aggregated oil stockpiles

Neutral: Stockpiles deficit narrowed from 121.9m bbl to 113.9m bbl

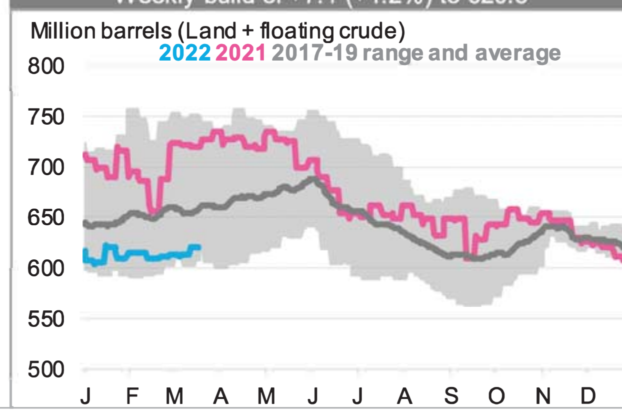
- Charts below use the **2017-19** (three-year) seasonal stockpiles. All calculations are recalibrated to measure against their respective three-year seasonal averages, so the values below might differ from the previous slides.
- Land crude inventories include the U.S., ARA, Japan and Shandong Teapots. Floating storage data are global. Oil product storage includes the U.S., ARA, Japan, Singapore, Shandong Teapots and Fujairah. Floating crude inventories may have been adjusted since the previous report – see slide 8 for more info.

Total oil and product stocks = Total crude stocks (land + floating) + Total oil product stockpiles

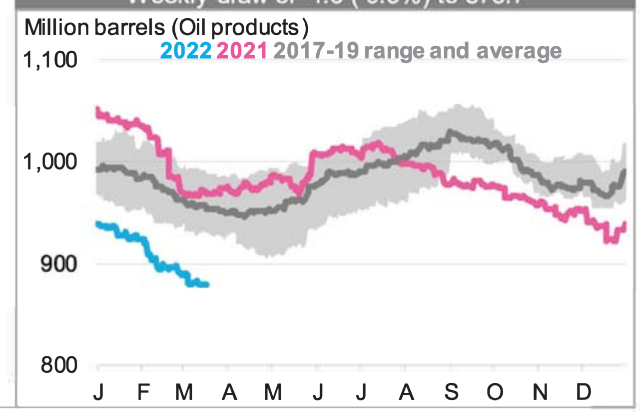
Weekly build of +2.8 (+0.2%) to 1499.2



Weekly build of +7.1 (+1.2%) to 620.5



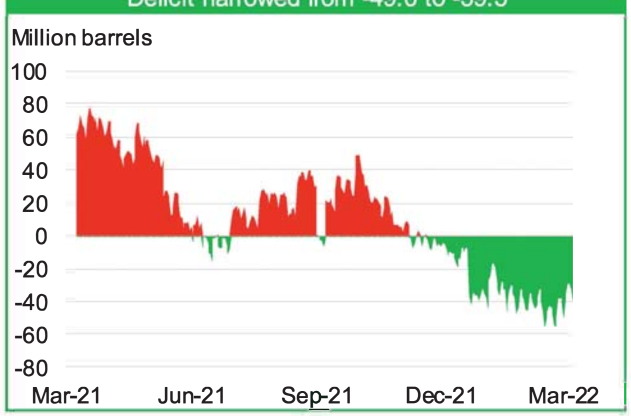
Weekly draw of -4.3 (-0.5%) to 878.7



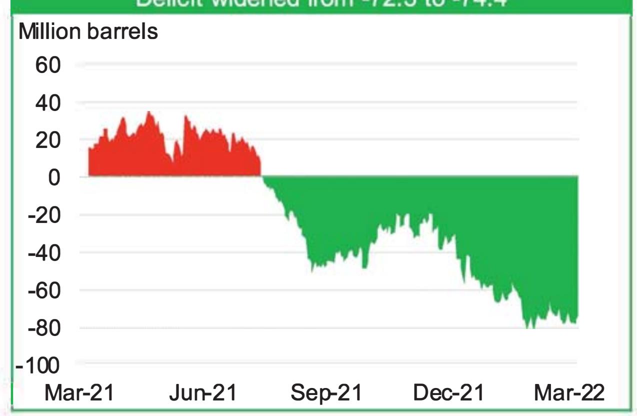
Charts below subtract current stockpiles by the 2017-19 (three-year) seasonal average

Deficit narrowed from -121.9 to -113.9

Deficit narrowed from -49.6 to -39.5



Deficit widened from -72.3 to -74.4



Source: BloombergNEF, U.S. EIA, PJK, IE Singapore, FEDCom/Platts, PAJ ,Vortexa, Genscape, SCIG. As of the ***week ending March 18.***

BloombergNEF

Mar 29, 2022 11:18:36

OIL DEMAND MONITOR: Road Fuel Use Weaker From London to Shanghai

- Traffic congestion tumbles in Shanghai amid strict lockdown
- Air travel improves in Europe, DAG and Eurocontrol data show

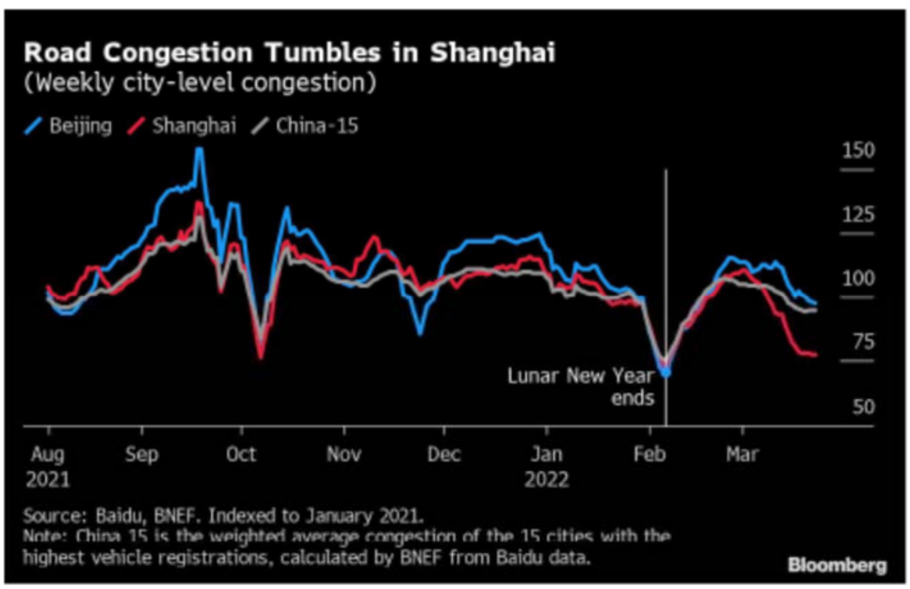
By Stephen Voss

(Bloomberg) -- Pockets of weakness are appearing in road traffic and fuel consumption due to a mixture of high prices, economic shocks and a resurgent coronavirus. Air travel though is slowly gathering pace, especially in Europe.

U.K. road fuel sales have continued to slide through mid-March after a brief bout of panic buying in late February when Russia invaded Ukraine. Gasoline and diesel sales in the seven days ended March 20 have now slipped about 15% below the pre-pandemic average just before the country's first national lockdown in 2020.

Gasoline demand in the U.S. in the week ended March 18 was about 8% below the same week of 2019, and is veering toward the bottom end of its five-year range. Nevertheless, such estimates from the U.S. Energy Information Administration are notoriously volatile from week to week and total oil product demand -- including gasoline, diesel and other fuels -- remains near the top of its range.

Urban traffic congestion data in China collected by Baidu show a recent decline across the biggest cities. There was an especially steep drop in Shanghai, down to levels comparable with the Lunar New Year holiday, as the city endures a strict lockdown following a jump in infections. In some parts of the city, people are only allowed to leave their homes to get a Covid-19 test.



Pump prices remain stubbornly high in most countries around the world. The U.S. national average for regular gasoline is about 9 cents off its recent record high, yet still well above the $4 mark at $4.244 a gallon on March 28, according to auto club AAA.

After a month of high prices, data suggest consumers are starting to react, JPMorgan Chase & Co. analysts said in a report. Spain last week offered financial aid to truckers in an attempt to end protests over expensive fuel. With European energy traders avoiding Russian diesel shipments where they can, the retail price of diesel is now higher than gasoline in a majority of EU countries.

Still, the actual war in Ukraine, the financial sanctions targeting Russia and the spread of the omicron variant in China have all had even more of a direct impact on oil demand than elevated prices, according JPMorgan, which cut its second-quarter world oil demand forecast by 1.1 million barrels a day.

"High prices are clearly not the only demand-destructive force in the world at the moment," JPMorgan analysts including Natasha Kaneva wrote in a note Thursday. The "revisions are heavily concentrated in Europe, which remains the epicenter of the geopolitical shock," they said.

Turning to car travel, only one out of 13 world cities regularly examined in this monitor, Taipei, showed more congestion this Monday morning than the 2019 average for that time of week, according to data collected from in-car navigation devices by TomTom NV. Of the five European cities in that list, four of them showed a decline in congestion over the past week, and the fifth, Berlin, was unchanged.

Furthermore, this was the first Monday out of six in which London has shown less congestion than its 2019 average.

Broader measures of fuel use and traffic intensity for several European nations are only published on a monthly basis, and with March not yet available, the February data doesn't yet take into account the full impact of higher prices and Russia's Feb. 24 invasion of Ukraine.

Right Numbers Rising

Air travel continues to slowly improve, however, according to most measures. The global number of commercial flights has remained relatively flat through March, according to AightRadar24, and was about 15% below 2019 levels. When one includes all types of flights, adding in helicopters, military craft and private jets, the tally is slightly above the equivalent 2019 level, as it has been for most of the year so far.

Global seat capacity for domestic and international flights -- the number of seats on scheduled flights -- has recovered to 83.4 million this week, up from last week's 80.8 million, according to OAG Aviation. That's still 23% below 2019 levels but 70% above the figure for this time of the year in 2020, when flight activity was plunging due to the virus.

"This week finally saw a resurgence in global airline capacity," OAG said in a note on its website. "The overall number masks the scale of the increase in Western Europe which has been partially offset by more than a million seats being removed from the Chinese market in response to new lockdowns in Shanghai."

Seat capacity jumped by 20% in one week in western Europe, and fell almost 8% in North East Asia, the OAG data show. A similar trend is seen in Eurocontrol data, which measures flight arrivals and departures in Europe, including a 13% gain in the week ended March 28.

The Bloomberg weekly oil-demand monitor uses a range of high-frequency data to help identify emerging trends.

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

Demand Measure	Location	% y/y	% vs 2020	% vs 2019	% m/m	Freq	Latest Date	Latest Value	Source
Gasoline	U.S.	+0.2	-2.3	-8.2	-0.2	w	March 18	8.64m b/d	EIA
Distillates	U.S.	+26	+19	-4	+6.7	w	March 18	4.52m b/d	EIA
Jet fuel	U.S.	+68	+19	-3.2	+18	w	March 18	1.74m b/d	EIA
Total oil products	U.S.	+13	+8.8	-1.6	-1.7	w	March 18	21.1m b/d	EIA
All vehicles miles traveled	U.S.			-3.5		w	March 20	15.0b miles	DoT
Passenger car VMT	U.S.			-6.6		w	March 20	n/a	DoT
Truck VMT	U.S.			+7.7		w	March 20	n/a	DoT
All motor vehicle use index	U.K.	+20		-4	+4.3	w	March 21	96	DfT
Car use	U.K.	+25		-9	+4.6	w	March 21	91	DfT
Heavy goods vehicle use	U.K.	+0.9		+7	+4.9	w	March 21	107	DfT
Gasoline (petrol) avg sales per filling station	U.K.	+21		-14	-1.6	w	March 20	6,266 liters/d	BEIS
Diesel avg sales per station	U.K.	+3.7		-16	-4.5	w	March 20	8,761 liters/d	BEIS
Total road fuels sales per station	U.K.	+10		-15	-3.3	w	March 20	15,027 liters/d	BEIS
Gasoline	India	+18			+19	2/m	March 1-15	1.24m tons	Bberg
Diesel	India	+24			+33	2/m	March 1-15	3.53m tons	Bberg
LPG	India	+17			-1.9	2/m	March 1-15	1.29m tons	Bberg
Jet fuel	India	+7			+20	2/m	March 1-15	233k tons	Bberg
Total Products	India	+5.4	-2.9	+0.8	-0.2	m	February	17.6m tons	PPAC
Toll roads volume	France	+23		+0.2		m	February	n/a	Atlantia
Toll roads volume	Italy	+19		-1.7		m	February	n/a	Atlantia
Toll roads volume	Spain	+52		-1.5		m	February	n/a	Atlantia
Toll roads volume	Brazil	+2.1		+5.8		m	February	n/a	Atlantia
Toll roads volume	Chile	+23		+9.5		m	February	n/a	Atlantia
Toll roads volume	Mexico	+16		+11		m	February	n/a	Atlantia
Gasoline	Spain	+43			+6.8	m	February	425k m3	Exolum
Diesel (and heating oil)	Spain	+20			+3.9	m	February	2283k m3	Exolum
Jet fuel	Spain	+171			-6.8	m	February	307k m3	Exolum

Road fuel sales	France	+10	-1.8		+3.3	m	February	3.749m m3	UFIP
Jet fuel	France	+74	-31		-5.5	m	February	413k m3	UFIP
Gasoline	France	+22	+7.5			m	February	n/a	UFIP
Road diesel	France	+6.8	-4.4			m	February	n/a	UFIP
All petroleum products	France	+11	-5.6		+1.3	m	February	4.285m tons	UFIP
Total fuel sales	Italy	+11		-2.5	+6	m	February	3.9m tons	Ministry
Gasoline	Italy	+18		+3.7	+7.4	m	February	539k tons	Ministry
Diesel /gasoil	Italy	+9.3		+1.5	+12	m	February	2.06m tons	Ministry
Jet fuel	Italy	+130		-45	-8.7	m	February	179k tons	Ministry
All vehicles traffic	Italy	+14			+12	m	February	n/a	Anas
Heavy vehicle traffic	Italy	-3.4			+17	m	February	n/a	Anas
Gasoline	Portugal	+52	-8.5	-4.1	-0.8	m	February	72k tons	ENSE
Diesel	Portugal	+27	-2.7	-2.3	+4.1	m	February	370k tons	ENSE
Jet fuel	Portugal	+313	-28	-18	-8.6	m	February	75k tons	ENSE

Notes: Click here for a PDF with more information on sources, methods. The frequency column shows w for data updated weekly, 2/m for twice a month and m for monthly. The column showing "vs 2020" is used for some data, such as comparing Indian fuel demand for Feb. 2022 vs Feb. 2020.
In Dfr U.K. daily data, which is updated once a week, 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. daily data, which is updated once a week, 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.
Atlantia is publishing toll road data on a monthly basis, rather than the weekly format seen in 2021.

City congestion:

Measure	Location	% chg vs avg 2019	% chg m/m	March 28	Mar. 21	Mar. 14	Mar. 7	Feb. 28	Feb. 21	Feb. 14	Feb. 7	Jan. 31
		(March 28)		Congestion minutes added to 1 hr trip at 8am* local time								
Congestion	Tokyo	-10	-2	34	8	36	35	34	35	25	31	28
Congestion	Taipei	+41	+1560	50	34	31	49	3	44	47	23	2
Congestion	Jakarta	-5	n/a	37	30	29	23	zero	12	11	19	14
Congestion	Mumbai	-54	+23	22	22	22	20	18	19	17	8	13
Congestion	New York	-4	-2	30	28	29	29	31	5	28	33	36
Congestion	Los Angeles	-47	-42	19	29	29	31	32	6	29	32	26
Congestion	London	-5	-17	36	40	44	42	43	47	21	45	43
Congestion	Rome	-32	-7	33	35	43	37	35	35	34	35	25
Congestion	Madrid	-36	+171	23	35	34	43	8	24	25	18	14
Congestion	Paris	-18	+53	37	39	46	43	24	29	46	43	35
Congestion	Berlin	-21	-4	26	26	25	11	28	29	26	25	16
Congestion	Mexico City	-20	+14	40	zero	39	37	35	32	29	zero	22
Congestion	Sao Paulo	-30	+188	28	30	31	35	10	29	28	33	28

Source: TomTom. Click here for a PDF with more information on sources, methods.
* Mumbai and Sao Paulo use 9am statistics rather than 8am.
NOTE: m/m comparisons are March 28 vs Feb. 28. There was little or no congestion on the month-ago dates for Taipei, Jakarta, Madrid and Mexico City due to holidays. Also, Tokyo and Mexico City had holidays on March 21, reducing traffic that day. TomTom has been unable to provide Chinese data since April 2021. Taipei and Jakarta were added to the table in December 2021.

Air Travel:

Measure	Location	y/y	vs 2 yrs ago	vs 2019	m/m	w/w	Freq.	Latest Date	Latest Value	Source
		changes shown as %								
Airline passenger throughput	U.S.	+64	+1182	+7.2	+7.5	-2.5	d	March 27	2.31m	TSA
Airline passenger throughput (7-day moving avg)	U.S.	+59	+842	-9	+10	+1.3	d	March 27	2.18m	TSA
Commercial flights	Worldwide	+20	+91	-15	-1.5	+4.1	d	March 28	92,255	FlightRadar24
All flights	Worldwide	+18	+107	+4.9	+4.9	+1.3	d	March 28	191,514	FlightRadar24
Air traffic (flights)	Europe			-24	+18	+13	d	March 28	24,164	Eurocontrol
Seat capacity	Worldwide	+34	+70	-23	+1.6	+3.2	w	March 28-April 3	83.4m	OAG
Seat capacity	North America			-12		+0.7	w	March 28-April 3	n/a	OAG
Seat capacity	North East Asia			-41		-7.8	w	March 28-April 3	n/a	OAG
Seat capacity	South East Asia			-43		+3.9	w	March 28-April 3	n/a	OAG
Seat capacity	South Asia			+9.5		+5.3	w	March 28-April 3	n/a	OAG
Seat capacity	Western Europe			-20		+20	w	March 28-April 3	n/a	OAG

NOTE: Comparisons versus 2019 are a better measure of a return to normal for most nations, rather than y /y comparisons.
FlightRadar24 data shown above, and comparisons thereof, all use 7-day moving averages, except for w/w which uses single day data.

Refineries:

Measure	Location/area	y/y	chg vs 2019	m/m chg	Latest as of Date	Latest Value	Source
		Changes are in ppt unless noted					
Crude intake	U.S.	+10%	-2%	+4.1%	March 18	15.9m b/d	EIA
Apparent Oil Demand	China	+2.9%		+0.5%	Jan.-Feb. 2022	13.71m b/d	NBS
Utilization	U.S.	+9.5	+2.2	+3.7	March 18	91.1 %	EIA
Utilization	U.S. Gulf	+15	+4.3	+8.5	March 18	94.3 %	EIA
Utilization	U.S. East	+2.2	+3.2	-10	March 18	80.6 %	EIA
Utilization	U.S. Midwest	+1.5	+1.2	-7.3	March 18	88.7 %	EIA

NOTE: All of the refinery data is weekly, except NBS apparent demand, which is usually monthly. Changes are shown in percentages for the rows on crude intake and Chinese apparent oil demand, while refinery utilization changes are shown in percentage points. SCI99 data on Chinese refinery run rates was discontinued in late 2021.
NOTE: lhe latest NBS data is an average for January and February, and the m/m change is the comparison of that average versus December's level

Caixin China
General Manufacturing
PMI Press Release

2022.03

财新
Caixin

Caixin China General Manufacturing PMI™

Manufacturing performance dampened by latest COVID-19 wave in March

The introduction of tighter restrictions to contain the spread of the latest wave of COVID-19 in China weighed heavily on manufacturing performance in March. Companies registered the quickest falls in output and new business since the initial onset of the pandemic in February 2020, with restrictions around mobility also leading to a steeper deterioration in supplier performance. Cost pressures meanwhile intensified, with input costs and output charges both rising at the sharpest rates for five months. The ongoing disruption to business operations, rising costs and recent invasion of Ukraine all weighed on business confidence for the year ahead, which slipped to a three-month low in March.

The headline seasonally adjusted *Purchasing Managers' Index™ (PMI™)* – a composite indicator designed to provide a single-figure snapshot of operating conditions in the manufacturing economy – fell from 50.4 in February to 48.1 in March, to signal a renewed deterioration in business conditions. Though modest overall, the pace of decline was the quickest seen since February 2020.

The drop in the headline PMI was partly driven by a renewed and solid fall in production at Chinese manufacturing firms in March. Furthermore, the rate of contraction was the steepest seen for 25 months. Companies frequently mentioned that the measures to contain the spread of COVID-19 had disrupted operations, supply and dampened customer demand.

New orders likewise fell at the sharpest rate since February 2020 in March. Companies commented that both domestic and foreign demand had waned, with new export business declining at the fastest pace for 22 months. The pandemic, and difficulties shipping items to clients, as well as greater market uncertainty due to the Ukraine war had dampened sales, according to panellists.

Disruption to business operations and logistics due to containment measures led to a further deterioration in average supplier performance. Notably, the rate at which delivery times increased was the fastest since last October.

Higher COVID-19 case numbers and increased restrictions also added pressure to capacities, as backlogs of work rose slightly for the second month in a row. This was despite a marginal increase in staffing levels.

Greater market uncertainty and lower sales led firms to cut back on their purchasing activity, though the rate of contraction was only marginal. At the same time, stocks of both inputs and finished goods fell as firms made greater usage of current inventories amid softer demand conditions. There were also reports that high purchasing costs had contributed to greater utilisation of current stocks.

Overall input costs rose at a sharp and accelerated pace in March, with the rate of inflation hitting a five-month high. Firms sought to pass on additional expenses to clients in the form of higher selling prices. The rate of charge inflation was the quickest since last October and solid overall.

Business expectations regarding future output waned to a three-month low in March. Companies cited a number of headwinds to the outlook, most notably, uncertainty relating to the pandemic, the war in Ukraine and steep rises in costs. Optimism was generally attributed to company expansion plans and hopes that global economic conditions will strengthen as the pandemic recedes.

China General Manufacturing PMI

sa, >50 = improvement since previous month

Sources: Caixin, S&P Global

Key findings:

Production falls at quickest rate for just over two years amid tighter pandemic restrictions

Steep declines in total new work and foreign demand

Suppliers' delivery times worsen, cost pressures intensify

New Export Orders Index

sa, >50 = growth since previous month

Sources: Caixin, S&P Global

Employment Index

sa, >50 = growth since previous month

Sources: Caixin, S&P Global

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

"The Caixin China General Manufacturing PMI came in at 48.1 in March, down from 50.4 the previous month. The index fell to its lowest since February 2020 amid the new wave of Covid-19 flare-ups.

"In the manufacturing sector, both supply and demand shrank. In March, Covid-19 flared up in several regions across China, disrupting manufacturing supply chains and impacting production. Market demand weakened, especially for consumer goods. In March, both the gauges of output and total new orders came in at the lowest levels since February 2020. Overseas demand fell sharply, and global transportation conditions deteriorated. The gauge for new export orders hit its lowest in 22 months in March.

"The job market improved marginally in March. The employment gauge climbed into positive territory for the first time since July 2021, though the rate of expansion was limited. Some enterprises said they added new employees, while some reported a suspension of recruitment due to the impact of the epidemic.

"Inflationary pressures increased. The war between Russia and Ukraine and subsequent sanctions against the former disrupted supply chains and largely pushed up commodity prices. The measures of both input costs and output prices rose to five-month highs in March. The growth in prices of energy and metals was relatively steep, with the high cost partly passed on to downstream producers.

"Manufacturing enterprises' quantity of purchases decreased, deliveries took longer. Affected by the epidemic, the measure of suppliers' delivery times fell further in contractionary territory, indicating longer delivery times in March. Due to the weak supply and demand, manufacturing enterprises reduced their purchases of raw materials, with the measure of quantity of purchases falling into negative territory. Stocks of finished goods and purchased items also fell.

"Manufacturers still held on to a positive outlook for their businesses. Surveyed entrepreneurs remained confident that authorities would get the domestic epidemic under control. However, the degree of their optimism was limited. The measure of future output expectations in March was over 2 points lower than its long-term average.

"Overall, impacted by factors including the Covid-19 outbreaks in multiple parts of China, manufacturing activity largely weakened in March. Supply contracted. Demand was also under pressure, and external demand worsened. The job market was more or less stable. Inflationary pressure continued to rise. And market optimism weakened.

"At present, China is facing the most severe wave of outbreaks since the beginning of 2020. Meanwhile, uncertainty increased abroad. The prospect of the war between Russia and Ukraine is uncertain, and the commodity market convulsed. A variety of factors resonate, aggravating the downward pressure on China's economy and underscoring the risk of stagflation.

"Policymakers are facing double challenges of "precision" — improving the level of precision of epidemic control measures, to strike a balance between maintaining the normal order of production and life and guarding safety and health of the people; ensuring fiscal policy and monetary policy are implemented precisely. Policymakers should care about vulnerable groups, enhancing supports for key industries and small and micro businesses, to stabilize market expectations."

Survey methodology

The Caixin China General Manufacturing PMI™ is compiled by S&P Global from responses to questionnaires sent to purchasing managers in a panel of around 500 private and state-owned manufacturers. The panel is stratified by detailed sector and company workforce size, based on contributions to GDP. For the purposes of this report, China is defined as mainland China, excluding Hong Kong SAR, Macao SAR and Taiwan.

Survey responses are collected in the second half of each month and indicate the direction of change compared to the previous month. A diffusion index is calculated for each survey variable. The index is the sum of the percentage of 'higher' responses and half the percentage of 'unchanged' responses. The indices vary between 0 and 100, with a reading above 50 indicating an overall increase compared to the previous month, and below 50 an overall decrease. The indices are then seasonally adjusted.

The headline figure is the Purchasing Managers' Index™ (PMI). The PMI is a weighted average of the following five indices: New Orders (30%), Output (25%), Employment (20%), Suppliers' Delivery Times (15%) and Stocks of Purchases (10%). For the PMI calculation the Suppliers' Delivery Times Index is inverted so that it moves in a comparable direction to the other indices.

Underlying survey data are not revised after publication, but seasonal adjustment factors may be revised from time to time as appropriate which will affect the seasonally adjusted data series.

For more information on the survey methodology, please contact: economics@ihsmarkit.com.

Survey dates and history

Data were collected 11-23 March 2022.

Data were first collected April 2004.

About PMI

Purchasing Managers' Index™ (PMI™) surveys are now available for over 40 countries and also for key regions including the eurozone. They are the most closely watched business surveys in the world, favoured by central banks, financial markets and business decision makers for their ability to provide up-to-date, accurate and often unique monthly indicators of economic trends.

https://ihsmarkit.com/products/pmi.html

About Caixin

Caixin is an all-in-one media group dedicated to providing financial and business news, data and information. Its multiple platforms cover quality news in both Chinese and English. Caixin Insight Group is a high-end financial research, data and service platform. It aims to be the builder of China's financial infrastructure in the new economic era.

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PMI™ by S&P Global

Aviation Indicators Weekly

BloombergNEF is tracking the evolution of passenger flight schedules and departures globally. This note provides a weekly update of these data points to guide expectations of the demand for aviation fuel.

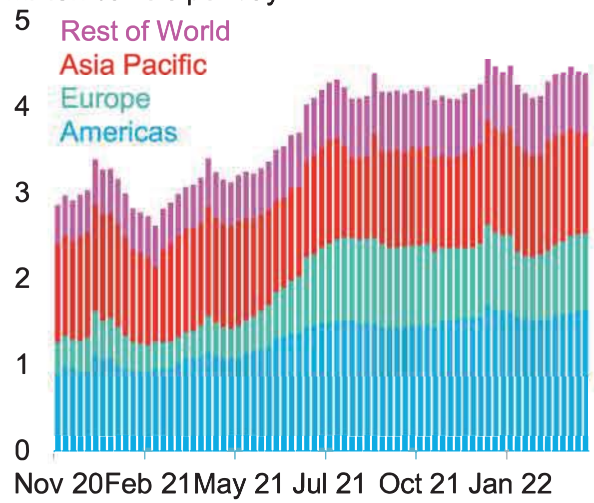
Metric	Frequency	March 17 to March 23
Passenger flight schedule	Weekly	Week-on-week scheduled departures decreased by a small amount
Implied fuel consumption	Weekly	Week-on-week implied fuel consumption decreased by a small amount
APAC jet fuel demand	Weekly	APAC jet fuel demand declined week-on-week and also year-on-year
Europe jet fuel demand	Weekly	Europe jet fuel demand rose week-on-week and year-on-year
Americas jet fuel demand	Weekly	Americas jet fuel demand rose week-on-week and year-on-year
Rest of World jet fuel demand	Weekly	Rest of world jet fuel demand declined week-on-week, but rose year-on-year

Source: DATA FLY<GO>, BloombergNEF. Note: Green signals an upturn from the disruption caused by Covid-19, red indicates no upturn, orange indicates a possible upturn.

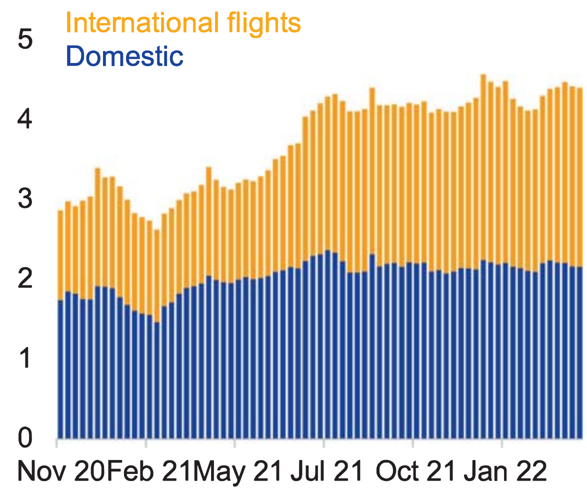
- Global passenger jet fuel demand decreased by 0.5% week-on-week, led by Asia Pacific. Based on the number of passenger flights scheduled, jet fuel demand over the next four weeks will average 4.95 million barrels per day.
- Cancellations since last week have removed on average 230,522 barrels per day of jet fuel demand over the same four weeks, largely driven by Asia Pacific.
- In Europe, departures in the Eurocontrol area increased by 3% week-on-week. Iberia, KLM and TAP Portugal were among carriers to increase activity this week.
- Global aviation sanctions continue to impact activities in Russia, with Aeroflot and S7 most impacted. The number of flights scheduled to depart Russian airports this week is down by over 3.8% since last week, due to repercussions of the Russia-Ukraine war and the resulting sanctions.
- U.S. passenger numbers decreased by 1% week-on-week due to flight cuts from major airlines. Passenger numbers are at 89% of 2019 levels.
- In Asia Pacific, China has reduced flights for the week ahead by 17.9% compared to what was scheduled to depart this time last week, as regional lockdowns, including one imposed in Shanghai, are in full swing amid a rise in Covid-19 cases. Both international and domestic passenger flights scheduled for the next month in the area have seen increased cancellations.

Commercial passenger flight jet fuel demand

Demand by departure region



Demand by flight type



- Global passenger jet fuel demand decreased 0.5% week-on-week.
- Asia Pacific experienced the largest decline, followed by the rest of the world.
- Both international and domestic flights decreased week-on-week.
- Similar to last week, the Americas led growth, followed by Europe.
- For more cuts of this data see DATA FLY<GO>.

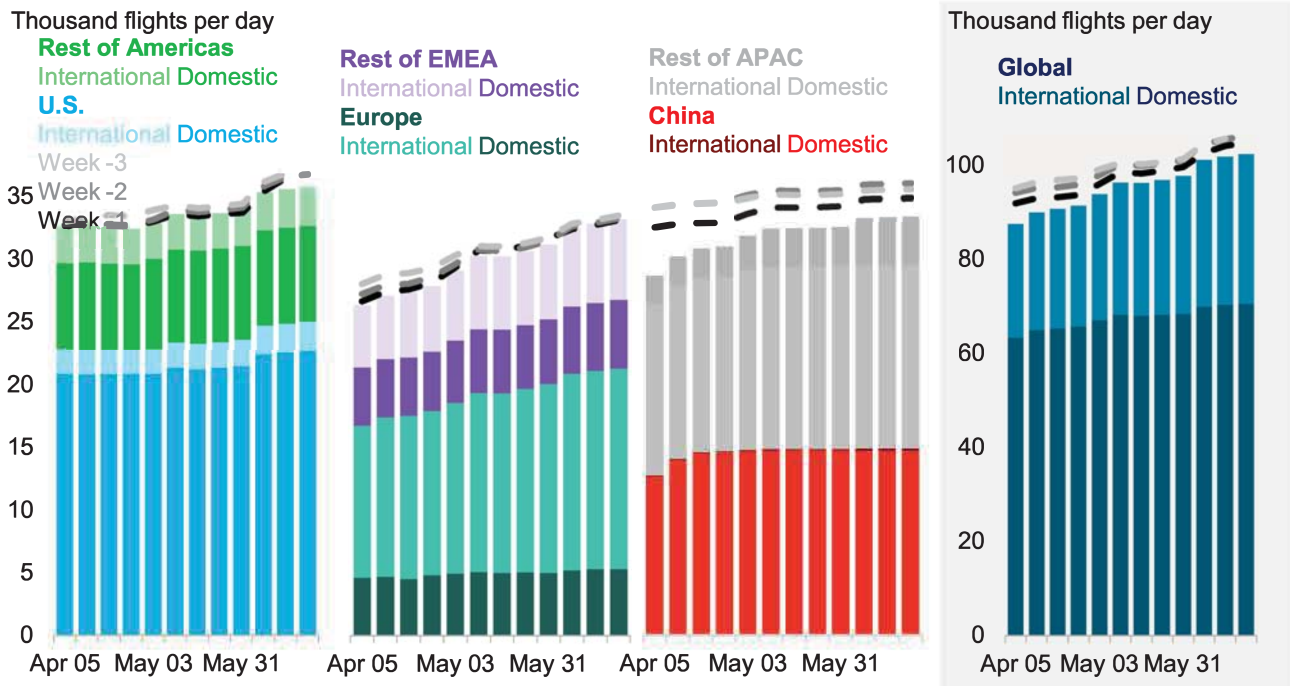
For more on demand and pricing fundamentals see Oil Price Indicators Weekly

K bbl per day	Latest	Week Δ	Four-week Δ	Year-on-year Δ
World	**4,390**	-20.7 (-0.5%)	11.0 (+0.3%)	1296.8 (+41.9%)
Americas	**1,635**	4.9 (+0.3%)	61.1 (+3.9%)	553.7 (+51.2%)
Asia Pacific	**1,170**	-13.8 (-1.2%)	-112.2 (-8.8%)	-33.1 (-2.8%)
Europe	**891**	1.6 (+0.2%)	67.5 (+8.2%)	579.5 (+185.9%)
Rest of World	**694**	-13.4 (-1.9%)	-5.3 (-0.8%)	196.7 (+39.6%)

K bbl per day	Latest	Week Δ	Four-week Δ	Year-on-year Δ
International	**2,237**	-16.1 (-0.7%)	93.3 (+4.3%)	1052.0 (+88.8%)
Domestic	**2,153**	-4.6 (-0.2%)	-82.2 (-3.7%)	244.8 (+12.8%)

Source: BloombergNEF, Bloomberg terminal DATA FLY<GO>. Note: The model does not account for load factors of aircraft, route inefficiencies or cargo flights.

12-week-ahead passenger departure schedule

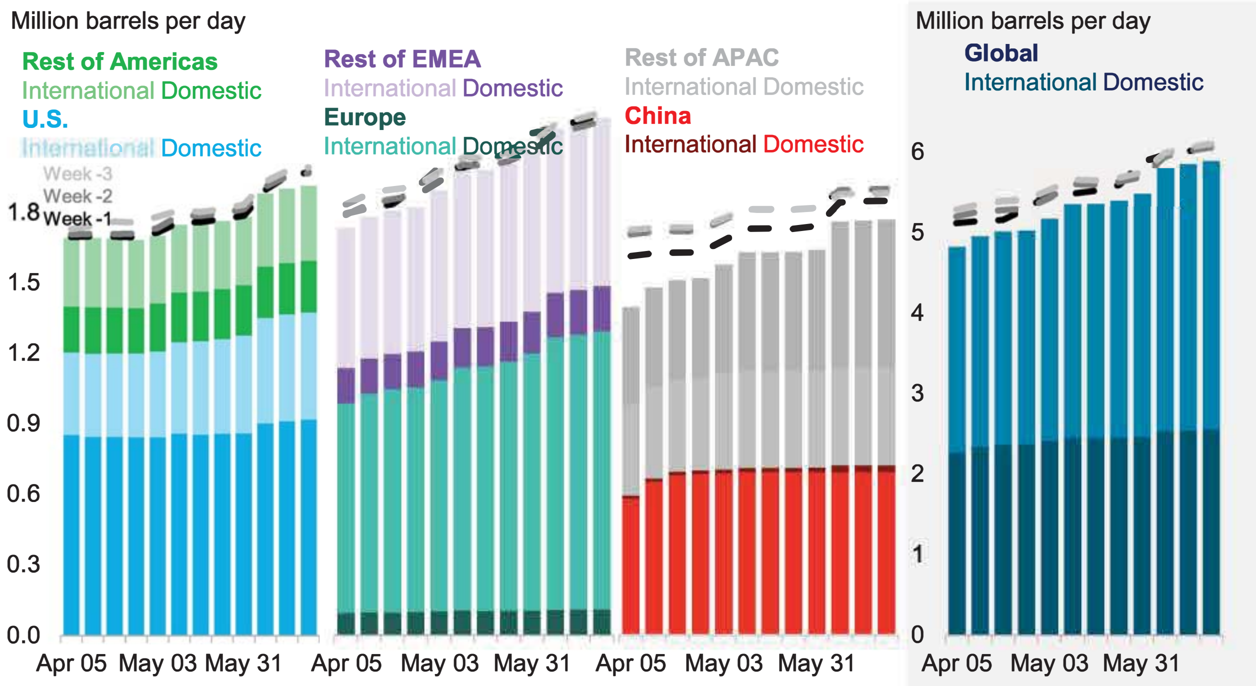


- Globally, the passenger flight schedule for the 12 weeks ahead is 2.5% lower week-on-week, with cuts remaining minimal for almost two months.
- The number of flights scheduled to depart Russian airports this week is down by over 3.8% since last week, with global sanctions biting Russia's aviation market.
- Similarly, the number of flights scheduled to depart Chinese airports decreased by 17.9% as a result of mass cancellations and local-level lockdowns across the region, with China Eastern and China Southern among the most impacted.
- Terminal users can track the Chinese and Russian aviation market here.

Source: BloombergNEF, Bloomberg terminal DATA FLY<GO>.

Note: As of March 23. Based on more than 11,000 commercial airports, taking the average daily scheduled flight departures per week. Excludes cargo flights. Europe is defined as the EU 27, EFTA and the U.K. Intra-Europe flights are defined as international.

Jet fuel demand implied by scheduled flights



- Based on the number of passenger flights scheduled, jet fuel demand over the next four weeks will average 4.95 million barrels per day (b/d). Fuel consumed in cargo flights is not included in this number.
- Cancellations since last week have removed on average more than 230,522 b/d of jet fuel demand over the same four weeks.
- For more cuts of this data see DATA FLY<GO>.

Source: BloombergNEF, Bloomberg terminal DATA FLY<GO>.

Note: As of March 23. Oil consumption is based on the aircraft model, distance between origin and destination airport and the fuel efficiency of each aircraft type. Consumption is allocated to the departure airport and does not account for load factor, or inefficiencies such as longer routes or circling at an arrival airport. Intra-Europe flights are defined as international.

https://www.transportation.gov/briefing-room/usdot-announces-new-vehicle-fuel-economy-standards-model-year-2024-2026

USDOT Announces New Vehicle Fuel Economy Standards for Model Year 2024-2026

Friday, April 1, 2022

Standards to require fleet average of 49 mpg by 2026, save consumers money, and advance U.S. energy independence

WASHINGTON – The U.S. Department of Transportation's National Highway Traffic Safety Administration today announced new, landmark fuel economy standards which follow President Biden's executive order to drive American leadership forward on clean cars. The new standards will make vehicle miles per gallon more efficient, save consumers money at the pump, and reduce transportation emissions.

The new Corporate Average Fuel Economy standards require an industry-wide fleet average of approximately 49 mpg for passenger cars and light trucks in model year 2026, the strongest cost savings and fuel efficiency standards to date. The new standards will increase fuel efficiency 8% annually for model years 2024-2025 and 10% annually for model year 2026. They will also increase the estimated fleetwide average by nearly 10 miles per gallon for model year 2026, relative to model year 2021.

Strong fuel economy standards strengthen U.S. energy independence and help reduce reliance on fossil fuels. Since CAFE was signed into law in 1975, the standards have reduced American oil consumption by 25%, or approximately 5 million barrels a day since then.

The new CAFE standards for model year 2024-26 will reduce fuel use by more than 200 billion gallons through 2050, as compared to continuing under the old standards.

Increasing vehicle efficiency and reducing fuel use will save American families and consumers money at the pump. Americans purchasing new vehicles in 2026 will get 33% more miles per gallon as compared to 2021 vehicles. This means new car drivers in 2026 will only have to fill up their tanks three times as compared to every four times that new car drivers today do for the same trips.

"Today's rule means that American families will be able to drive further before they have to fill up, saving hundreds of dollars per year," said U.S. Transportation Secretary Pete Buttigieg.
"These improvements will also make our country less vulnerable to global shifts in the

price of
oil, and protect communities by reducing carbon emissions by 2.5 billion metric tons."

The new standards will also reduce greenhouse gas emissions and air pollution. These reductions will improve public health and provide environmental justice for communities who live near freeways and other heavily trafficked roadways, which are disproportionately low-income communities of color.

"NHTSA is helping American families by making life more affordable – and the air cleaner for their children. These vehicles will be better for the environment, safer than ever, and cost less to fuel over their lifetimes. We are proud to fulfill President Biden's mission to move us to a more sustainable future, one that strengthens American energy independence and helps put more money in American families' pockets," said Dr. Steven Cliff, NHTSA's Deputy Administrator.

This announcement of new standards comes as the automobile industry is retooling production for future models in response to rapidly growing market demand for cleaner, more fuel-efficient vehicles. Nearly all auto manufacturers have announced new electric vehicle models.

More robust fuel economy standards will encourage the industry to continue improving the fuel economy of cars powered by internal combustion engines as the transportation sector transitions to electrification.

Today's final fuel economy standards follow President Biden's Executive Order 13990, which directed NHTSA to review the 2020 "The Safer Affordable Fuel-Efficient (SAFE) Vehicles Rule for Model Years 2021-2026 Passenger Cars and Light Trucks" final rule. These CAFE standards also support the Biden-Harris Administration's priorities to cut costs for American families, improve public health, combat climate change, and create and sustain good-paying jobs with a free and fair choice to join a union.

For the final Corporate Average Fuel Economy rule, please click here. For more on today's announcement, please visit www.NHTSA.gov/CAFE.

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Pump Your Own Gas? No Thanks, Say New Jerseyans
2022-03-31 16:32:28.808 GMT

By Tracey Tully

(New York Times) -- A brief but intense push to change a law that forbids self-service gas stations stalled before it even revved up.

Sabrina Banks, an 18-year-old college freshman, has never pumped her own gasoline. Growing up in New Jersey, she never had to.

“I don’t even know how,” Ms. Banks said with a quick laugh before heading into a Bed Bath & Beyond store in Brick, N.J.

For now, she need not learn: A brief but intense push to abolish a law that bars drivers in New Jersey from pumping their own fuel at gas stations has hit a speed bump, if not a complete dead-end.

Nicholas Scutari, the Democratic president of the State Senate whose backing would be crucial to any law change, put an end to speculation earlier this month when he said he did not support changing the state’s unique policy.

New Jersey is the only state in the country that requires attendants to pump gas for all customers, a law that has been in place for 73 years and that a majority of residents have repeatedly told pollsters they support. The idiosyncrasy is often worn as a badge of honor on T-shirts and bumper stickers that proudly proclaim “Jersey Girls Don’t Pump Gas.”

Earlier this month, proponents of self-service gas reintroduced a bill that would permit drivers to pump their own fuel, an effort backed by a gas station industry group that resurfaces regularly. Widely seen as a third rail for politicians, the proposal has never gone far.

But proponents of the legislation, who have framed it as an issue of driver choice at a time when most major grocery and retail stores offer self-service checkout options, said they believed that a confluence of circumstances had given it better odds.

Gas prices are high, making the promise of even pennies in savings more potent. Workers have become harder to find during the pandemic, a shortage that station owners say forces them to regularly close down fuel pumps. And the governor, in a televised news conference, suggested a new openness to the proposal as a way of making New Jersey more affordable.

“It’s ridiculous that we actually go out of our way to prohibit something that virtually all the rest of the world allows,” said State Senator Declan O’Scanlon Jr., a Republican from Monmouth County and a longtime supporter of self-service gasoline.

Voters — especially Democrats — appear to disagree. A recent Rutgers Eagleton poll found that 73 percent of people surveyed said they preferred having someone else pump their gas. Roughly 82 percent of Democrats preferred full-service, compared with 64 percent of Republicans. And nearly 90 percent of women said they would rather have an attendant pump their gas, compared with 55 percent of men, the poll found.

The bill would require owners of stations with more than four pumps to offer a full-service option between 8 a.m. and 8 p.m. It was introduced in the Assembly, but is unlikely to advance in the Senate without Mr. Scutari's support.

"The people of New Jersey are very clear in wanting to keep the system we have now," Mr. Scutari said in a policy position first reported by the New Jersey Monitor. He also said he was not convinced that the addition of self-service lanes would lead to lower gas prices.

Still, he did leave open a small window of hope for supporters of self-service gasoline. "If the public sentiment changes or there is in fact data showing that it would dramatically reduce costs," Mr. Scutari said in a text message. "I would reconsider."

In 2016, a former Republican governor, Chris Christie, offered a similar argument for not supporting self-service gas.

"The last poll we did on this question, 78 percent of New Jersey women said they were opposed to self-service gas. Seventy-eight percent!" he reportedly said at the time. "You can't find 78 percent of people in New Jersey who agree on anything!"

Three years later, Mr. Murphy similarly demurred.

"I will not commit political suicide this morning in East Orange," the governor said in 2019 when asked about self-service gas.

But when asked about the proposed legislation earlier this month, he did not rule out authorizing a self-service gas option, although he remained noncommittal.

"I'm not necessarily signing up for that, because I need to understand what impact it would have," Mr. Murphy said.

In 2016, the price of gas in New Jersey was the second lowest in the country, hovering close to $2 a gallon. That year, Mr. Christie signed a law that raised the gas tax by 23 cents a gallon. The extra fee paid for the elimination of the state's tax on large estates, cut the sales tax slightly and created a formula-driven funding stream for transportation projects that has led to additional increases, and one decrease, in the gas tax.

The state tax on gasoline is now 42.4 cents a gallon, and there has been little discussion about temporarily suspending the charge, as several other states have done to offset the recent price spike.

On Wednesday, the average price of a gallon of gas in New Jersey was $4.20, three cents less than the nationwide average of $4.23 and roughly 14 cents less than in New York, according to the American Automotive Association.

Sal Risalvato, executive director of the New Jersey Gasoline, C-Store and Automotive Association, a trade group, said he believed allowing self-service gasoline would lower overhead costs, increase sales and drive down prices.

Perhaps more important, he said, it would alleviate the hiring challenges now facing gas stations. A self-service option would enable station owners to keep all pumps open, rather than block off lanes when there are not enough employees, a problem that can lead to longer lines for gas, he said.

“Orange cones blocking pumps in the last two years — it’s not new, it’s just become more commonplace,” Mr. Risalvato said.

The 1949 statute barring self-service in New Jersey dates to a time when the practice was rare and the justification for entrusting only station attendants to pump gas was safety. Since then, every other state except Oregon has adopted liberal use of self-service gas lanes. (Oregon stipulates that attendants at many gas stations must pump fuel for drivers, but carves out a large exception for rural counties with fewer than 40,000 residents.)

In New Jersey, the 1949 statute that Mr. Risalvato is trying to overturn actually grew out of a lobbying effort by the same group he now leads.

The owner of a gas station in Hackensack, N.J., got upset when a competitor, deviating from the custom of the day, began allowing drivers to pump their own gas. This enabled the station to sell gas for less than the 22 cents a gallon competitors were charging, Mr. Risalvato said.

“All of the competing gas stations were up in arms, saying, ‘Hey, he’s going to steal all our customers,’” Mr. Risalvato said.

Levent Sertbas owns three family-run Exxon stations in Bergen County, N.J. His wife, daughters and brother often work at the stations, but he said he was desperate for additional employees. He said he could hire three people on the spot if anyone showed up to apply for the jobs that pay $14 an hour.

“Everybody is looking for employees now,” said Mr. Sertbas, 54. “This is something that people don’t want to do anymore. They’ve got to work outside, deal with the environment — hot, cold.

“How am I going to compete with Amazon or Target?” he said. “There’s no way.”

When he is short-staffed, he shuts down certain pumps to make the work more manageable for a single employee. Frustrated drivers regularly climb out of their cars, he said, to remove the nozzle from their filled tanks rather than wait for an employee attending to another car.

Three times in the last year, he said he had to close a station altogether for several hours because of staff shortages.

“If I close, I’m not making money,” Mr. Sertbas said, who also operates convenience stores next to the filling stations. “And if you’re not coming into the station, you don’t come into the store either.”

Click Here to see the story as it appeared on the New York Times website.

-0- Mar/31/2022 16:32 GMT

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MODIFY FOSSIL FUEL TAXATION

ELIMINATE FOSSIL FUEL TAX PREFERENCES

Current Law

Current law provides several credits, deductions, and other special provisions that are targeted towards encouraging oil, gas, and coal production.

Credit for enhanced oil recovery

The general business credit includes a 15 percent credit for eligible costs attributable to enhanced oil recovery (EOR) projects. Eligible costs include the cost of constructing a gas treatment plant to prepare Alaskan natural gas for pipeline transportation, the cost of depreciable or amortizable tangible property that is integral to a qualified EOR project, intangible drilling and development costs (IDCs), and any allowable qualified tertiary injectant expenses that are paid or incurred in connection with a qualified EOR project. A qualified EOR project must be located in the United States and must involve the application of one or more of nine tertiary recovery methods. The allowable credit is phased out over a $6 range for a taxable year if the annual reference price exceeds an inflation adjusted threshold.

Credit for oil and natural gas produced from marginal wells

In addition, the general business credit includes a credit for crude oil and natural gas produced from marginal wells. For taxable years beginning after 2005, the full potential credit rate is determined by the annual inflation adjustment applied to a starting credit rate of $3.00 per barrel of oil and $0.50 per 1,000 cubic feet of natural gas. The credit per well is limited to 1,095 barrels of oil or barrel-of-oil equivalents per year. The credit rates for crude oil and natural gas are phased out for a taxable year if the reference price exceeds the applicable thresholds. The crude oil phase-out range and the applicable threshold at which phase-out begins in 2020 are $3.97 and $19.87 respectively. The natural gas phase-out range and the applicable threshold at which phase-out begins are $0.44 and $2.21. Both sets of rates are adjusted annually for inflation. In 2020, the credit amount was the full rate of $0.66 per 1,000 cubic feet of natural gas and the credit for oil was completely phased out.

Expensing of intangible drilling costs (IDCs)

IDCs include all expenditures made by an operator for wages, fuel, repairs, hauling, supplies, and other expenses incident to and necessary for the drilling of wells and the preparation of wells for the production of oil and natural gas. Generally, IDCs do not include expenses for items which have a salvage value or items related to the acquisition of the property. An operator who pays or incurs IDCs in the development of an oil or natural gas property located in the United States, including certain wells drilled offshore, may elect either to expense or capitalize those costs. If a taxpayer elects to expense IDCs, the amount of the IDCs is deductible as an expense in the taxable year the cost is paid or incurred. For any particular taxable year, a taxpayer may deduct some portion of its IDCs and capitalize the rest under the provision.

Deduction of costs paid or incurred for any tertiary injectant used as part of tertiary recovery method

Taxpayers are allowed to deduct the cost of qualified tertiary injectant expenses for the taxable year. Qualified tertiary injectant expenses are amounts paid or incurred for any tertiary injectants, except for recoverable hydrocarbon injectants, that are used as a part of a tertiary recovery method to increase the recovery of crude oil. The deduction is treated as an amortization deduction in determining the amount subject to recapture upon disposition of the property.

Exception to passive loss limitations provided to working interests in oil and natural gas properties

Deductions attributable to passive activities, to the extent they exceed income from passive activities, generally may not be used against other income, such as wages, portfolio income, or business income that is derived from a nonpassive activity. A similar rule applies to credits. Passive activities are defined to include trade or business activities in which the taxpayer does not materially participate. An exception is provided, however, for any working interest in an oil or natural gas property that the taxpayer holds directly or through an entity that does not limit the liability of the taxpayer with respect to the interest. Suspended deductions and credits are carried forward and treated as deductions and credits from passive activities in the next year. The suspended losses and credits from a passive activity are allowed in full when the taxpayer completely disposes of the activity.

Use of percentage depletion with respect to oil and natural gas wells

The capital costs of oil and natural gas wells are recovered through the depletion deduction. Under the cost depletion method, the basis recovery for a taxable year is proportional to the exhaustion of the property during the year and cannot exceed basis. A taxpayer may also qualify for percentage depletion, under which the amount of the deduction is a statutory percentage of the gross income from the property. In general, only independent producers and royalty owners, in contrast to integrated oil companies, qualify for the percentage depletion deduction. A qualifying taxpayer determines the depletion deduction for each oil and natural gas property under both the percentage depletion method and the cost depletion method then deducts the larger of the two amounts. Because percentage depletion is computed without regard to the taxpayer's basis in the depletable property, a taxpayer may continue to claim percentage depletion after all the expenditures incurred to acquire and develop the property have been recovered.

Two-year amortization of independent producers' geological and geophysical expenditures

Geological and geophysical expenditures are costs incurred for the purpose of obtaining and accumulating data that will serve as the basis for the acquisition and retention of mineral properties. The amortization period for geological and geophysical expenditures incurred in connection with oil and natural gas exploration in the United States is two years for independent producers and seven years for major integrated oil companies.

Expensing of mine exploration and development costs

A taxpayer may elect to expense the exploration costs incurred for the purpose of ascertaining the existence, location, extent, or quality of a domestic ore or mineral deposit, including a deposit of coal or other hard mineral fossil fuel. After the existence of a commercially marketable deposit has been disclosed, costs incurred for the development of a mine to exploit the deposit are deductible in the year paid or incurred unless the taxpayer elects to deduct the costs on a ratable basis as the minerals or ores produced from the deposit are sold.

Percentage depletion for hard mineral fossil fuels

The capital costs of coal mines and other hard-mineral fossil-fuel properties are recovered through the depletion deduction. Under the cost depletion method, the basis recovery for a taxable year is proportional to the exhaustion of the property during the year. A taxpayer may also qualify for percentage depletion; hence, the amount of the deduction is a statutory percentage of the gross income from the property. A qualifying taxpayer determines the depletion deduction for each property under both the percentage depletion method and the cost depletion method and deducts the larger of the two amounts. Because percentage depletion is computed without regard to the taxpayer's basis in the depletable property, a taxpayer may continue to claim percentage depletion after all the expenditures incurred to acquire and develop the property have been recovered.

Treatment of capital gains for royalties

Royalties received on the disposition of coal or lignite generally qualify for treatment as long-term capital gain, and the royalty owner does not qualify for percentage depletion with respect to the coal or lignite. This treatment does not apply unless the taxpayer has been the owner of the mineral in place for at least one year before it is mined.

Exemption from the corporate income tax for fossil fuel publicly traded partnerships

Publicly traded partnerships are generally subject to the corporate income tax. Partnerships that derive at least 90 percent of their gross income from depletable natural resources, real estate, or commodities are exempt from the corporate income tax. Instead, they are taxed as partnerships. They pass through all income, gains, losses, deductions, and credits to their partners, with the partners then being liable for income tax (or benefitting from the losses) on their distributive shares.

Oil Spill Liability Trust Fund (OSTLF) excise tax exemption for crude oil derived from bitumen and kerogen-rich rock

Crudes such as those that are produced from bituminous deposits as well as kerogen-rich rock are not treated as crude oil or petroleum products for purposes of the OSTLF tax. They are exempt from the oil spill liability excise tax of $0.09 per barrel of crude oil received at a United States refinery, and on petroleum products entered into the United States for consumption, use, or warehousing.

Amortization of air pollution control facilities

Under current law, a taxpayer may elect to amortize expenses related to certain pollution control facilities over 60 months or 84 months. The 60-month period applies to property placed in service at a plant that began operation prior to January 1, 1976. The 84-month period applies to property placed in service after April 11, 2005 and used in connection with an electric generation plant or other property which is primarily coal-fired and constructed after December 31, 1975. Eligible pollution control facilities include new identifiable treatment facilities that are used to abate or control water or atmospheric pollution by removing, altering, disposing, storing, or preventing the creation or emission of pollutants, contaminants, wastes, or heat. Eligible facilities must be certified by a State certifying authority and a Federal certifying authority as being in compliance with applicable regulations and requirements. Without this special treatment, most pollution control facilities would be depreciated over 39 years as nonresidential real estate property.

Reasons for Change

These oil, gas, and coal tax preferences distort markets by encouraging more investment in the fossil fuel sector than would occur under a neutral system. This market distortion is detrimental to long-term energy security and is also inconsistent with the Administration's policy of supporting a clean energy economy, reducing our reliance on oil, and reducing greenhouse gas emissions.

Proposal

The proposal would repeal: (a) the enhanced oil recovery credit for eligible costs attributable to a qualified enhanced oil recovery project; (b) the credit for oil and gas produced from marginal wells; (c) the expensing of intangible drilling costs; (d) the deduction for costs paid or incurred for any qualified tertiary injectant used as part of a tertiary recovery method; (e) the exception to passive loss limitations provided to working interests in oil and natural gas properties; (f) the use of percentage depletion with respect to oil and gas wells; (g) two year amortization of geological and geophysical expenditures by independent producers, instead allowing amortization over the seven-year period used by major integrated oil companies; (h) expensing of exploration and development costs; (i) percentage depletion for hard mineral fossil fuels; (j) capital gains treatment for royalties; (k) the exemption from the corporate income tax for publicly traded partnerships with qualifying income and gains from activities relating to fossil fuels; (l) the

OSTLF excise tax exemption for crude oil derived from bitumen and kerogen-rich rock; and (m) accelerated amortization for air pollution control facilities.

Unless otherwise specified, the proposal provisions would be effective for taxable years beginning after December 31, 2022. In the case of royalties, the proposal provision would be effective for amounts realized after taxable years beginning after December 31, 2022. The repeal of the exemption from the corporate income tax for publicly traded partnerships with qualifying income and gains from activities relating to fossil fuels would be effective for taxable years beginning after December 31, 2027.

MODIFY OIL SPILL LIABILITY TRUST FUND FINANCING AND SUPERFUND EXCISE TAXES

Current Law

An excise tax to finance the Oil Spill Liability Trust Fund (OSLTF) is imposed on: (a) crude oil received at a U.S. refinery; (b) imported petroleum products (including crude oil) entered into the United States for consumption, use, or warehousing; and (c) any domestically produced crude oil that is used (other than on the premises where produced for extracting oil or natural gas) in or exported from the United States if, before such use or exportation, no taxes were imposed on the crude oil. The tax is eight cents per barrel before January 1, 2017, and nine cents per barrel thereafter. Crudes such as those that are produced from bituminous deposits as well as kerogen-rich rock (for example, tar sands) are not treated as crude oil or petroleum products for purposes of the tax. The tax is deposited in the OSLTF to pay costs associated with oil removal and damages resulting from oil spills, as well as to provide annual funding to certain agencies for a wide range of oil pollution prevention and response programs, including research and development. In the case of an oil spill, the OSLTF makes it possible for the Federal government to pay for removal costs up front, and then seek full reimbursement from the responsible parties.

U.S. Code Title 19 (Customs Duties), Section 1313 – Drawbacks and Refunds has been administratively interpreted to allow drawback of the tax when products subject to this tax are exported.

Before January 1, 1996, Superfund excise taxes were imposed on crude oil and imported petroleum products, specific hazardous chemicals, and imported taxable substances. The Infrastructure Investment and Jobs Act reinstates, effective July 1, 2022, the Superfund excise taxes imposed on certain hazardous chemicals and imported taxable substances and increases the tax rates for such chemicals and substances. The revenues from these taxes are dedicated to the Hazardous Substance Superfund Trust Fund. Amounts in the Trust Fund are available for expenditures incurred in connection with releases or threats of releases of hazardous substances into the environment under specified provisions of the Comprehensive Environmental Response, Compensation, and Liability Act of 1980 (as amended).

Adjusted Baseline

The Build Back Better Act reinstates, effective July 1, 2022, the Superfund excise tax on crude oil and imported petroleum products and increases the tax rate from 9.7 cents per barrel to 16.4 cents per barrel, adjusted annually for inflation. Crudes such as those that are produced from bituminous deposits as well as kerogen-rich rock are not treated as crude oil or petroleum products for purposes of the tax.

Reasons for Change

The magnitude of the Federal response to recent disasters has reinforced the importance of the OSLTF and the need to maintain a sufficient balance in the fund, particularly in order to accommodate spills of national significance. It is appropriate to extend the tax to other sources of crudes that present environmental risks comparable to those associated with crude oil and petroleum products.

The drawback of the tax is granted when the product is exported even though there is no concomitant reduction in the risk of an oil spill. A prohibition on the drawbacks of the tax will strengthen the finances of the OSLTF and remove an incentive to export crude and like products.

The Superfund excise taxes provide critical financing to remedy damages caused by releases of hazardous substances. As with the OSLTF tax, it is appropriate to extend the Superfund excise tax to other crudes such as those produced from bituminous deposits as well as kerogen-rich rock, as such crudes can also cause environmental contamination.

Proposal

The eligibility of the OSLTF for drawback would be eliminated. In addition, the proposal would extend the Superfund excise tax on crude oil and imported petroleum products to other crudes such as those produced from bituminous deposits as well as kerogen-rich rock.

The proposal would be effective after December 31, 2022.

https://www.canada.ca/en/environment-climate-change/news/2022/03/2030-emissions-reduction-plan--canadas-next-steps-for-clean-air-and-a-strong-economy.html

2030 Emissions Reduction Plan – Canada’s Next Steps for Clean Air and a Strong Economy

From: Environment and Climate Change Canada

Backgrounder

On climate change, the science is clear—we must take action now to protect our planet and secure our children’s future. But the economics are clear too: to build a strong, resilient economy for generations to come, we must harness the power of a cleaner future.

Canada’s average temperatures are rising at twice the global average, and three times in the North. Polluting less and taking steps to remove excess carbon from the air will be one of the most important undertakings in Canada’s history. Last year, Canada increased its ambition on climate change under the Paris Agreement. The 2030 Emissions Reduction Plan describes the many actions that are already driving significant reductions as well as the new measures that will ensure that we reduce emissions across the entire economy to reach our emissions reduction target of 40 to 45 percent below 2005 levels by 2030 and put us on a path to achieve net-zero emissions by 2050.

Reaching our climate goals will also help ensure that the conditions are right to seize the growing economic opportunities of a clean future. This Plan includes $9.1 billion in new investments, and reflects economy-wide measures such as carbon pricing and clean fuels, while also targeting actions sector by sector ranging from buildings to vehicles to industry and agriculture. These measures will drive reductions while creating jobs for workers and opportunities for businesses. The Government of Canada is working with Canadians in all parts of the country and all sectors of the economy to achieve Canada’s climate goals and seize new economic opportunities.

In developing the 2030 Emissions Reduction Plan, we heard from over 30,000 Canadians—young people, workers, Indigenous Peoples, business owners, and more. Their key message to the Government of Canada is that climate action must go hand in hand with keeping life affordable for Canadians and creating good jobs. This plan reflects that vision.

The 2030 plan is designed to be evergreen—a comprehensive roadmap that reflects levels of ambition to guide emissions reduction efforts in each sector. As governments, businesses, non-profits, and communities across the country work together to reach these targets, we will identify and respond to new opportunities.

This is the first Emissions Reduction Plan issued under the *Canadian Net-Zero Emissions Accountability Act*. Progress under the plan will be reviewed in progress reports produced in 2023, 2025, and 2027. Additional targets and plans will be developed for 2035 through to 2050.

Publishing this Plan fulfills a requirement under the *Act*, and presents Canada's bold next steps forward as we keep our air clean and build a strong economy for everyone.

In the 2030 plan, the Government of Canada is taking action by:

Helping to reduce energy costs for our homes and buildings, while driving down emissions to net zero by 2050 and boosting climate resiliency through the development of the $150-million Canada Green Buildings Strategy. Working with provinces, territories, and other partners, the strategy will build off existing initiatives and set out new policy, programs, incentives, and standards needed to drive a massive retrofit of the existing building stock, and construction to the highest zero-carbon standards. Under the 2030 Emissions Reduction Plan, the Canada Greener Homes Loan program will receive an additional investment of $458.5 million. Together, these measures and others outlined in the 2030 Emissions Reduction Plan, will help Canadians reduce emissions, save money on renovations and heating and cooling costs, and stimulate well-paying jobs in the economy.

Empowering communities to take climate action by expanding the Low Carbon Economy Fund through a $2.2-billion renewal. The funding aims to leverage further climate actions from provinces and territories, municipalities, universities, colleges, schools, hospitals, businesses, not-for-profit organizations, and Indigenous communities and organizations. The renewed Low Carbon Economy Fund will also support climate action by Indigenous Peoples with a new $180-million Indigenous Leadership Fund. This will support clean energy and energy efficiency projects led by First Nations, Inuit, and Métis communities and organizations. In addition, the Government of Canada will support regional growth opportunities and energy systems transformation through a $25-million investment in Regional Strategic Initiatives that will drive economic prosperity and the creation of sustainable jobs in a net-zero economy.

Making it easier for Canadians to switch to electric vehicles through additional funding of $400 million for zero-emission vehicles (ZEVs) charging stations, in support of the Government's objective of adding 50,000 ZEV chargers to Canada's network. In addition, the Canada Infrastructure Bank will also invest $500 million in ZEV charging and refueling infrastructure. The Government of Canada will provide $1.7 billion to extend the Incentives for Zero-Emission Vehicles (iZEV) program will make it more affordable and easier for Canadians to buy and drive new electric light-duty vehicles. The Government will also put in place a sales mandate to ensure at least 20 percent of new light-duty vehicle sales will be zero-emission vehicles by 2026, at least 60 percent by 2030 and 100 percent by 2035. To reduce emissions from medium- and heavy-duty vehicles (MHDVs), the Government of Canada will aim to achieve 35 percent of total MHDV sales being ZEVs by 2030. In addition, the Government will develop a MHDV ZEV regulation to require 100 percent MHDV sales to be ZEVs by 2040 for a subset of vehicle types based on feasibility, with interim 2030 regulated sales requirements that would vary for different vehicle categories based on feasibility, and explore interim targets for the mid-2020s.

Driving down carbon pollution from the oil and gas sector. The International Energy Agency's Net-Zero Scenario sees continued oil and gas use globally, but with demand declining significantly in the coming decades. Competing in this future means not only diversifying our energy mix, but also offering lower carbon oil and gas to the world. The Plan presents modelling of the most economically efficient pathway to meeting Canada's 2030 target. Drawing on that modelling, the Plan includes a projected contribution from the oil and gas sector of emission reductions to 31 percent below 2005 levels in 2030 (or to 42 percent below 2019 levels). This will guide the Government of Canada's work with industry, provinces, Indigenous partners, and civil society to define and implement the cap on oil and gas sector emissions. Following consultations, the cap will be designed to lower emissions at a pace and scale needed to achieve net zero by 2050. The government is also working to reduce oil and gas methane by at least 75 percent by 2030, supporting clean technologies to further decarbonize the sector, and working to create sustainable jobs.

Powering the economy with renewable electricity. Electrifying more activities—from vehicles to heating and cooling buildings to various industrial processes—will be needed for Canada to transition to net-zero emissions by 2050. To do that, Canada needs to both increase the supply of electricity and ensure that all electricity generation has net-zero emissions. While Canada already has one of the cleanest electricity grids in the world, with over 80 percent produced by non-emitting sources, transitioning the remaining generation to clean sources will reduce greenhouse gas (GHG) emissions, improve local air quality, and create jobs and economic growth with the construction of new power sources and retrofitting and fuel-switching existing power plants and buildings. To ensure success, the Government of Canada will work with provinces and utilities to establish a Pan-Canadian Grid Council to promote clean electricity infrastructure investments. Additionally, the Government of Canada will invest an additional $600 million in the Smart Renewables and Electrification Pathways Program to support renewable electricity and grid modernization projects and $250 million to support predevelopment work for large clean electricity projects, in collaboration with provinces.

Helping industries develop and adopt clean technology in their journey to net-zero emissions. Canada is positioning its industries to be green and competitive. This includes developing a carbon capture, utilization, and storage (CCUS) strategy; introducing an investment tax credit to incentivize the development and adoption of this important technology; and investing $194 million to expand the Industrial Energy Management System to support ISO 50001 certification, energy managers, cohort-based training, audits, and energy efficiency–focused retrofits for key small-to-moderate projects.

Investing in nature and natural climate solutions with an additional $780 million for the Nature Smart Climate Solutions Fund to deliver additional emission reductions from nature-based climate solutions. The Fund supports projects that conserve, restore, and enhance Canada's vast and globally significant endowment of wetlands, peatlands, and grasslands to store and capture carbon. To stimulate demand for other projects across Canada that reduce GHG emissions, sequester carbon, and generate economic opportunities, Canada will continue to develop protocols under the Federal GHG Offset System, including for projects that focus on nature-based climate solutions.

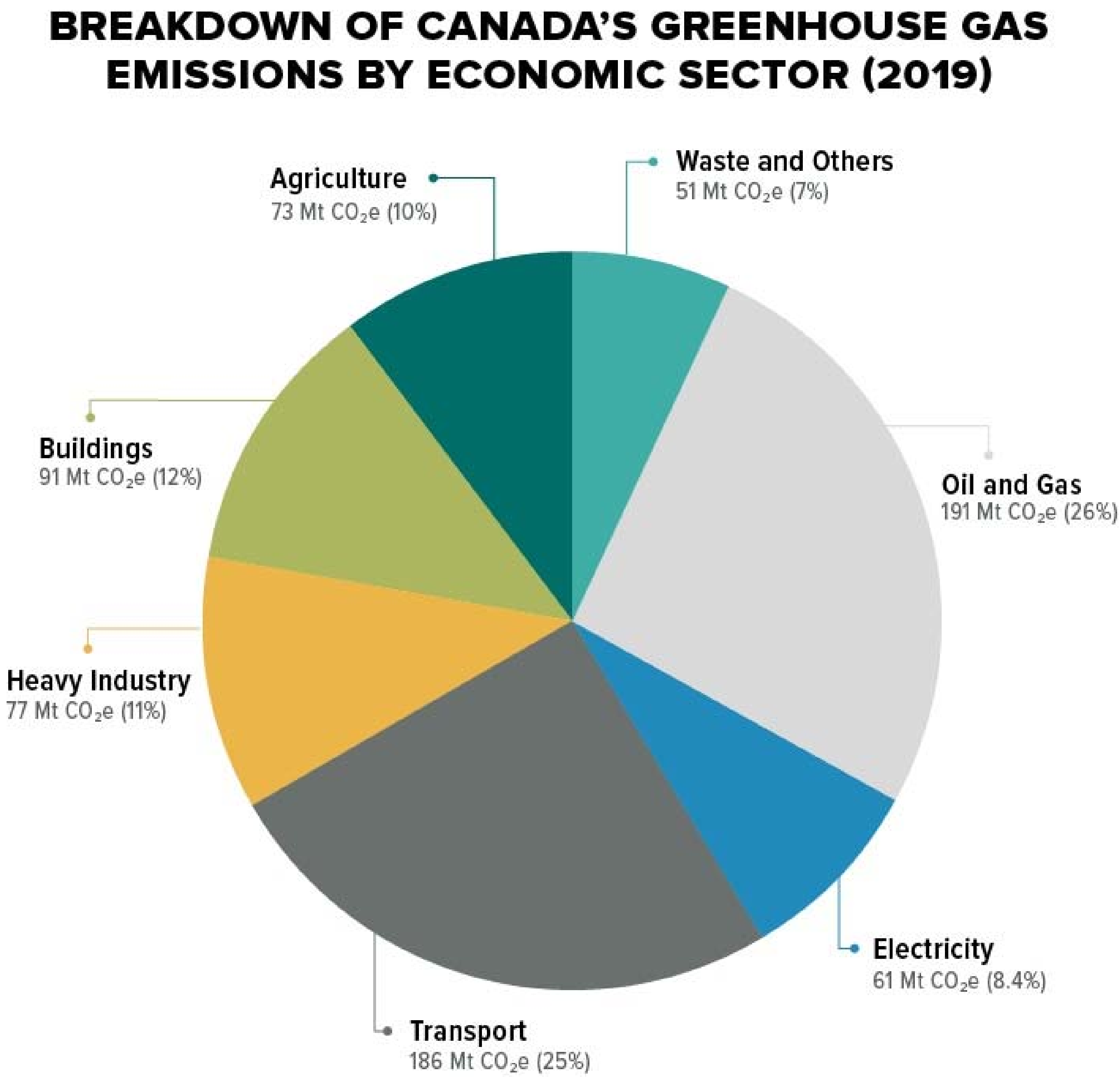
Supporting farmers as partners in building a clean, prosperous future. Farmers are key to reaching Canada's climate targets, making sure family businesses can succeed in a changing climate, and keep food on people's plates. That is why the Government of Canada is making a significant new investment to support a sustainable future for Canadian farmers. That includes an investment of $470 million in the Agricultural Climate Solutions: On-Farm Climate Action Fund to help farmers adopt sustainable practices such as cover crops, rotational grazing and fertilizer management. The Government is also investing $330 million to triple funding for the Agricultural Clean Technology Program which supports the development and purchase among farmers of more energy-efficient equipment. The Government will also invest $100 million in transformative science for a sustainable sector in a changing climate and to support the sector's role in the transition to a net-zero economy for 2050, including fundamental and applied research, knowledge transfer, and developing metrics.

Maintaining Canada’s approach to pricing pollution. Putting a price on pollution is widely recognized as the most efficient means to reduce greenhouse gas emissions. Without a strong price on pollution, achieving Canada’s environmental goals would require additional actions. To enhance long-term certainty, the 2030 Emissions Reduction Plan commits the Government of Canada to exploring measures that help guarantee the price of pollution. This includes investment approaches, like carbon contracts for differences, which enshrine future price levels in contracts between the Government and low-carbon project investors, thereby de-risking private sector low-carbon investments. This also includes exploring legislative approaches to support a durable price on pollution.

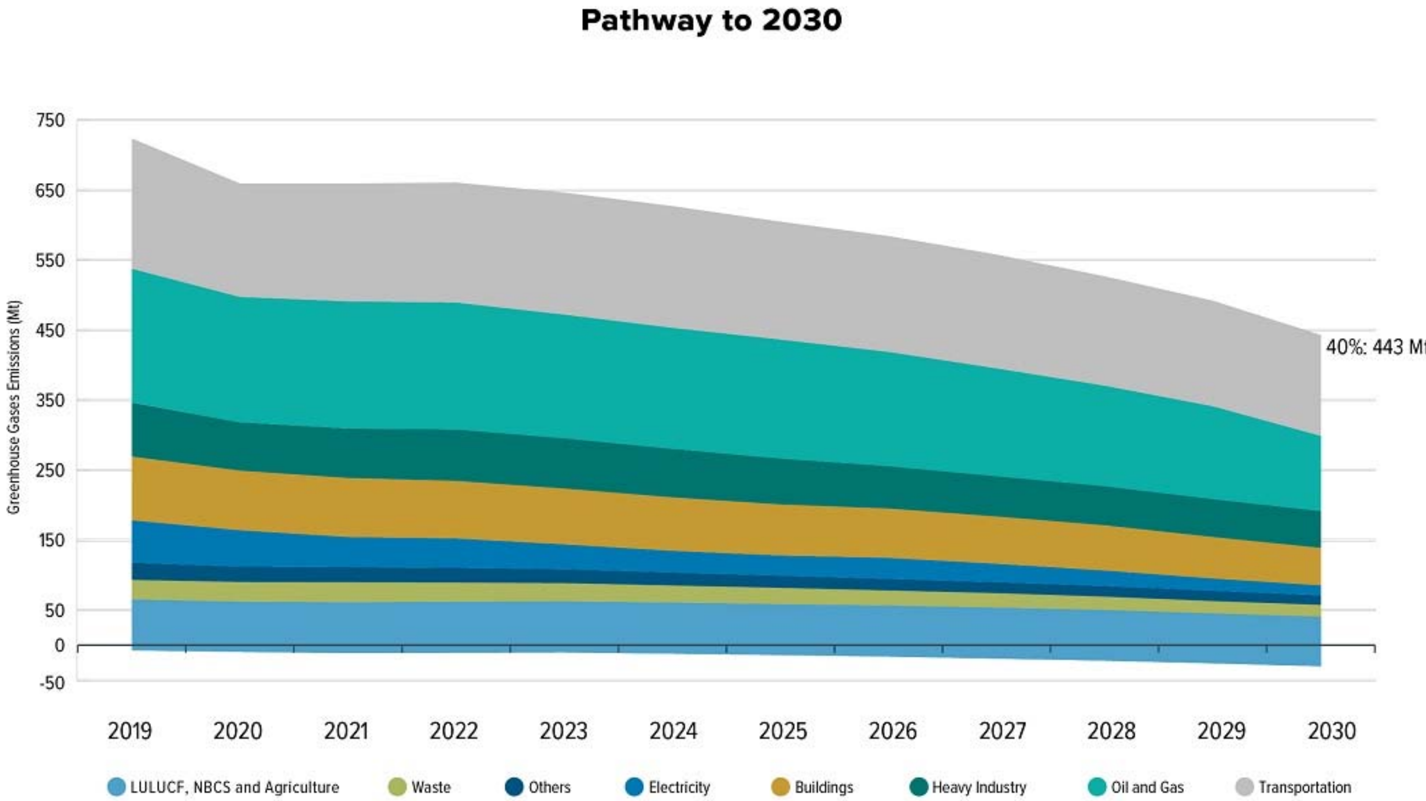
Canada’s Emissions Profile

Canada’s current emissions profile and historical trends are helpful for providing a clearer picture of where Canada needs to be by 2030 and 2050. As a party to the United Nations Framework Convention on Climate Change (UNFCCC), Canada is required to regularly develop, update, and publish its national inventory of human-sourced emissions. This is done through the Government of Canada’s National Inventory Report (NIR), which is updated and submitted to the UNFCCC annually before April 15. Due to a data lag associated with GHG accounting and reporting, the most recent NIR (published in April 2021) documents Canada’s annual GHG emissions estimates for the 1990–2019 period.

According to the NIR, total national greenhouse emissions were 730 million tonnes of carbon dioxide equivalent (Mt CO_2 eq) in 2019. Oil and gas and transportation continue to be Canada’s largest sectoral emissions sources, with buildings, heavy industry, and agriculture following closely behind. Canada’s 2019 emissions were approximately 9 Mt lower than in 2005. Since 2005, emissions in the oil and gas and transportation sectors have increased by 20 percent and 16 percent, respectively. Decreases in electricity (48 percent), heavy industry (12 percent) and waste and others (10 percent) have offset these increases.



Long description



Long description

What does cutting emissions mean for Canadians?

- **Good, sustainable jobs:** The Royal Bank of Canada (RBC) analysis suggests that the clean economy could create between 235,000 and 400,000 new jobs in Canada by 2030. By 2025, clean tech's contribution to Canada's GDP is expected to grow to $80 billion from $26 billion in 2016. Trends show Canada has been able to grow its economic output while decreasing emissions from some industries.
- **A strong, resilient economy for everyone** by positioning Canada to succeed in a world moving to clean, net-zero options. There is a major market evolution taking place, and Canada has the choice now to lead or be left behind.
- **Making life more affordable for the middle class:** Programs such as the Climate Action Incentive payments, which put money back in the pockets of families, while ensuring homes and buildings are energy efficient, will help homeowners save money on monthly bills.
- **Clean air:** Everyone deserves clean air to breathe. Each year, poor air quality is costing Canadians their lives, not to mention $120 billion due to

illness and lost productivity. Reducing emissions improves air quality and quality of life.

- **Fighting inequality:** People marginalized through social, economic, cultural, gender, political or other factors are disproportionately impacted by climate change. Taking action to decarbonize the economy and fight climate change provides an opportunity to address these inequities.
- **More opportunities to enjoy nature:** Protecting nature such as through the Nature Smart Climate Solutions Fund not only helps fight climate change, but also means Canadians can enjoy the natural beauty of this country. From spending time with family to the benefits for mental health, this will boost Canadians' quality of life.
- **Climate resilience:** Nature-based solutions, such as the conservation of wetlands, pull carbon out of the air, while also mitigating flood risks, protecting Canadians and communities from climate risk.

How Canada's Emissions Modelling Works

The 2030 Emissions Reduction Plan uses economic modelling to show a pathway to achieving Canada's 2030 target, including the potential for each sector of the economy to reduce emissions by 2030. This modelling approach is widely used by other countries in charting their courses to net zero.

Broken down by sector, Canada's pathway to 2030 is based on today's understanding of the potential for each sector to reduce emissions by 2030. Given the economic interdependencies and interactions among sectors, the focus for further actions may shift in the future as Canada further decarbonizes, costs of abatement technologies change and other opportunities emerge.

The Government of Canada expects that the measures outlined in the 2030 Emissions Reduction Plan, together with complementary climate actions from the provinces and territories, municipalities, the financial community, Indigenous Peoples, innovators, and businesses—as well as with the acceleration of clean technology innovation and deployment—will lead to further emission reductions by 2030. Canada will continue to update its modelling projections, including in Canada's next Biennial Report in December 2022 and first 2030 Emissions Reduction Plan progress report expected in late 2023.

Overview

On climate change, the science is clear – we must take action now to protect our planet and secure our children's future. But the economics are clear too – to build a strong, resilient economy for generations to come, we must harness the power of a cleaner future.

Canada's average temperatures are rising at twice the global average, and three times in the North. Polluting less and taking steps to remove excess carbon from the air will be one of the most important undertakings in Canada's history. Last year, Canada increased its ambition on climate change under the Paris Agreement. The 2030 Emissions Reduction Plan describes the many actions that are already driving significant reductions as well as the new measures that will ensure that we reduce emissions across the entire economy to reach our emissions reduction target of 40 to 45% below 2005 levels by 2030 and put us on a path to achieve net-zero emissions by 2050.

Reaching our climate goals will also help ensure that the conditions are right to seize the growing economic opportunities of a clean future. This Plan includes $9.1 billion in new investments, and reflects economy-wide measures such as carbon pricing and clean fuels, while also targeting actions sector by sector ranging from buildings to vehicles to industry and agriculture. These measures will drive reductions while creating jobs for workers and opportunities for businesses. The Government of Canada is working with Canadians in all parts of the country and all sectors of the economy to achieve Canada's climate goals and seize new economic opportunities.

In developing the 2030 Emissions Reduction Plan, we heard from over 30,000 Canadians – young people, workers, Indigenous Peoples, business owners, and more. Their key message to the Government of Canada is that climate action must go hand in hand with keeping life affordable for Canadians and creating good jobs. This plan reflects that vision.

The 2030 plan is designed to be evergreen—a comprehensive roadmap that reflects levels of ambition to guide emissions reduction efforts in each sector. As governments, businesses, non-profits and communities across the country work together to reach these targets, we will identify and respond to new opportunities.

This is the first Emissions Reduction Plan issued under the *Canadian Net-Zero Emissions Accountability Act*. Progress under the plan will be reviewed in progress reports produced in 2023, 2025, and 2027. Additional targets and plans will be developed for 2035 through to 2050.

Publishing this Plan fulfills a requirement under the Act, and presents Canada's bold next steps forward as we keep our air clean and build a strong economy for everyone.

In the 2030 plan, the Government of Canada is taking action by:

Helping to reduce energy costs for our homes and buildings, while driving down emissions to net-zero by 2050 and boosting climate resiliency through the development of the $150 million Canada Green Buildings Strategy. Working with provinces, territories and other partners the strategy will build off existing initiatives and set out new policy, programs, incentives and standards needed to drive a massive retrofit of the existing building stock, and construction to the highest zero carbon standards. Under the

2030 Emissions Reduction Plan, the Canada Greener Homes Loan program will receive an additional investment of $458.5 million. Together, these measures and others outlined in the 2030 Emissions Reduction Plan, will help Canadians reduce emissions, save money on renovations and heating and cooling costs, and stimulate well-paying jobs in the economy.

Empowering communities to take climate action by expanding the Low Carbon Economy Fund through a $2.2 billion renewal. The funding aims, to leverage further climate actions from provinces and territories, municipalities, universities, colleges, schools, hospitals, businesses, not-for-profit organizations, and Indigenous communities and organizations. The renewed Low Carbon Economy Fund will also support climate action by Indigenous Peoples with a new $180 million Indigenous Leadership Fund. This will support clean energy and energy efficiency projects led by First Nations, Inuit, and Métis communities and organizations. In addition, the Government of Canada will support regional growth opportunities and energy systems transformation through a $25 million investment in Regional Strategic Initiatives that will drive economic prosperity and the creation of sustainable jobs in a net-zero economy.

Making it easier for Canadians to switch to electric vehicles through additional funding of $400 million in additional funding for zero-emission vehicles (ZEVs) charging stations, in support of the Government's objective of adding 50,000 ZEV chargers to Canada's network. In addition, the Canada Infrastructure Bank will also invest $500 million in ZEV charging and refueling infrastructure. The Government of Canada will provide $1.7 billion to extend the Incentives for Zero-Emission Vehicles (iZEV) program will make it more affordable and easier for Canadians to buy and drive new electric light-duty vehicles. The Government will also put in place a sales mandate to ensure at least 20% of new light-duty vehicle sales will be zero-emission vehicles by 2026, at least 60% by 2030 and 100% by 2035. To reduce emissions from medium-and heavy-duty vehicles (MHDVs), the Government of Canada will aim to achieve 35% of total MHDV sales being ZEVs by 2030. In addition, the Government will develop a MHDV ZEV regulation to require 100% MHDV sales to be ZEVs by 2040 for a subset of vehicle types based on feasibility, with interim 2030 regulated sales requirements that would vary for different vehicle categories based on feasibility, and explore interim targets for the mid-2020s.

Driving down carbon pollution from the oil and gas sector. The International Energy Agency's Net-Zero Scenario sees continued oil and gas use globally, but with demand declining significantly in the coming decades. Competing in this future means not only diversifying our energy mix, but also offering lower carbon oil and gas to the world. The Plan presents modelling of the most economically efficient pathway to meeting Canada's 2030 target. Drawing on that modelling, the Plan includes a projected contribution from the oil and gas sector of emission reductions to 31% below 2005 levels in 2030 (or to 42% below 2019 levels). This will guide the Government of Canada's work with industry, provinces, Indigenous partners, and civil society to define and implement the cap on oil and gas sector emissions. Following consultations, the cap will be designed to lower emissions at a pace and scale needed to achieve net-zero by 2050. The government is also working to reduce oil and gas methane by at least 75% by 2030, support clean technologies to further decarbonize the sector, and working to create sustainable jobs.

Powering the economy with renewable electricity. Electrifying more activities – from vehicles to heating and cooling buildings to various industrial processes – will be needed for Canada to transition to

2.5. Oil and Gas

As a major economic contributor to the country and Canada's largest source of greenhouse gas emissions, the oil and gas sector has a critical role to play in meeting Canada's climate objectives.

The sector faces a major transformation as the world moves away from fossil fuels to address climate change and to enhance energy security. The International Energy Agency forecasts that to limit warming to less than 1.5 °C, global oil demand will have to decline from 100 million barrels per day in 2020 to 24 million barrels by 2050. To remain competitive in a tighter future market, Canadian production will have to reduce its carbon intensity while the sector also explores opportunities to transition to non-emitting products and services.

Modelling of the most economically efficient pathway to meeting Canada's 2030 target projects that the oil and gas sector would make a significant contribution (see Chapter 3). Drawing on that analysis, Canada's oil and gas sector emissions would decline by about 31% from 2005 levels to reach 110 Mt in 2030. This projected sectoral contribution represents about a 42% reduction from current levels, because overall emissions from the sector have been rising rather than falling. The projected sectoral contribution will guide the Government of Canada's work with industry, stakeholders, provinces and territories, Indigenous peoples and others to define and develop the cap on oil and gas emissions.

Industry Leadership
Individual oil and gas players are setting ambitious climate goals. For example, Shell Global has set a target to reduce absolute emissions by 50% by 2030, relative to their 2016 baseline.

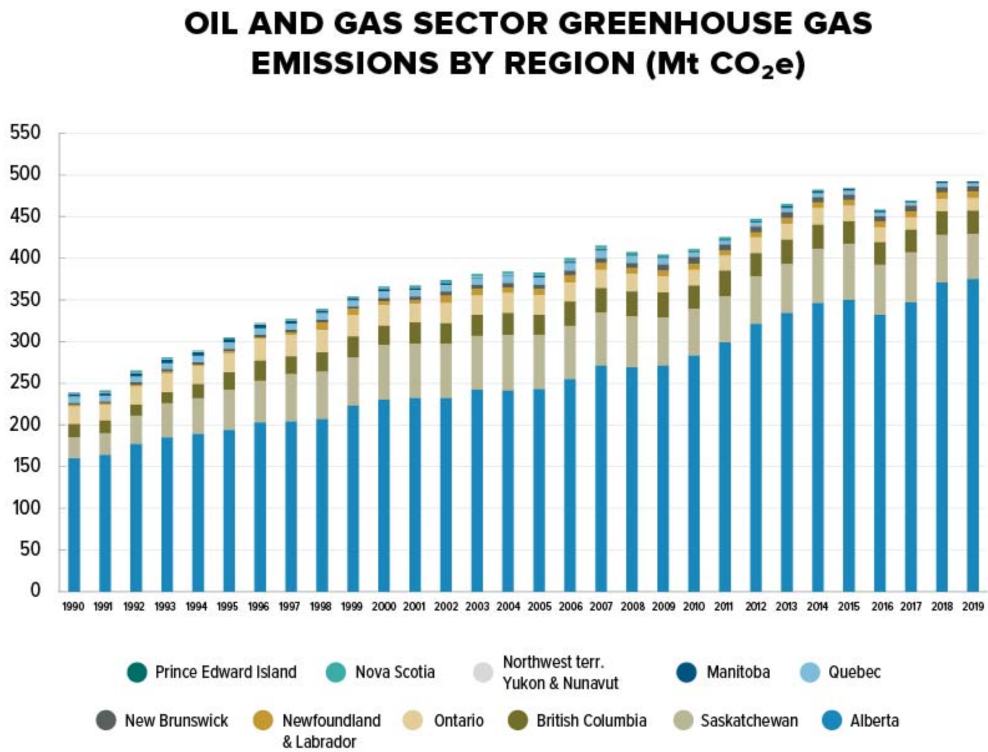
The Oil Sands Pathways Alliance, which represents 95% of Canada's oil sands production, was formed in order to keep the sector competitive in a decarbonizing economy by drastically reducing its carbon footprint to achieve net zero emissions by 2050.

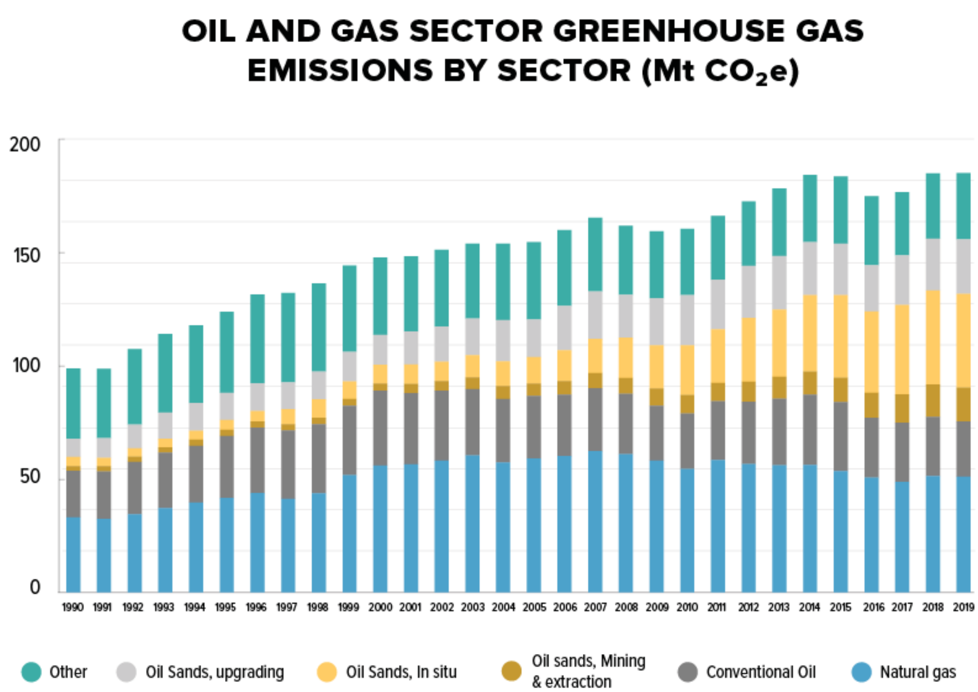
Clean B.C. Roadmap to 2030: Reducing emissions from the oil and gas sector

British Columbia's oil and gas sector is currently responsible for 20% of provincial emissions. As part of its Clean B.C. Roadmap, the Government of British Columbia set a target to reduce emissions from its oil and gas sector by 33-38% below 2007 levels by 2030. This is being implemented through a number of policies and programs, including strengthening British Columbia's methane regulations, modernizing its royalty system, and introducing a new industrial climate program, to be released in 2023.

Current sector emissions

In 2019, the oil and gas sector produced 26% of national emissions. While performance has improved, with a 20% reduction in emissions intensity since 2005, overall emissions have climbed due to significant production growth. The oil sands are the biggest driver of new production and emissions growth, with emissions rising 137% since 2005.





The oil and gas sector in context: key drivers

The oil and gas sector contributes significantly to the Canadian economy

The oil and gas sector is critical to the economy, currently contributing nearly 6% to Canada's GDP. Employing thousands of Canadians throughout the country, the sector is particularly important in Alberta, Saskatchewan, British Columbia, and Newfoundland and Labrador. The sector is diverse, comprising a wide range of activities from exploration, drilling and extraction to processing, transportation, and refining of multiple resources, including light oil, heavy oil, oil sands and natural gas. Most of Canada's oil production is exported to the United States, making the U.S. a key partner.

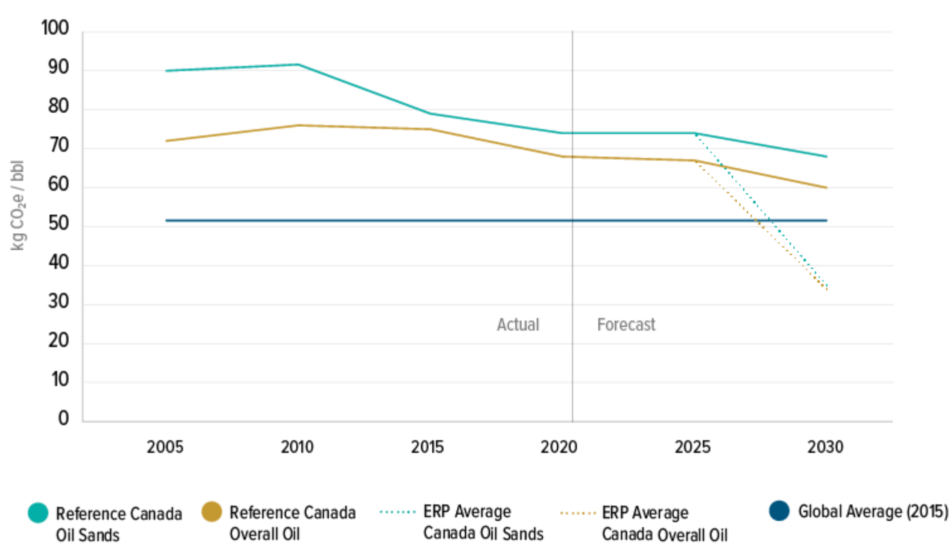
Current economic conditions are creating new opportunities to reduce emissions

With energy demand and prices rebounding to pre-pandemic levels and a tightening global energy market, Canada's oil and gas industry is currently generating record cash flow. If deployed strategically, these funds could enhance carbon competiveness and enable the sector to do its fair share in contributing to the country's climate goals. The extent to which investors and shareholders will direct funds toward decarbonization will depend on many factors, including decisions to pay down debt, reward shareholders and buy back shares, as well as the regulatory environment.

Carbon competitiveness

As the world acts on climate change and the global supply of fossil fuels becomes cleaner, Canada's oil sector will need to continue to drive down emissions and costs to remain competitive. The following graph illustrates how the federal measures outlined in this plan will ensure that Canadian oil and gas production becomes less emissions intensive (i.e. fewer emissions per barrel) over the next decade. While the actual trajectory to 2030 will unlikely be a straight line as portrayed, and the global average is also unlikely to remain static, reducing the carbon intensity of Canadian production below the global average is both possible and likely to be increasingly important in order for the Canadian industry to compete in an increasingly constrained global market.

CANADA OIL CARBON INTENSITY VS GLOBAL AVERAGE



What have we done so far?

Pricing carbon pollution

Since 2019, a price on carbon pollution has been in place across Canada through a mix of federal, provincial and territorial pricing systems. The federal government sets minimum national standards that all systems must meet to ensure they are fair and consistent (“the benchmark”). Putting a price on carbon pollution creates a financial incentive throughout the economy to reduce emissions and invest in clean innovation. Oil and gas activities across Canada are subject to carbon pollution pricing under the federal Output Based Pricing System or equivalent provincial systems.

Methane regulations

Federal regulations require the oil and gas sector to reduce methane emissions by 40-45% below 2012 levels by 2025. In 2021, Canada joined the Global Methane Pledge, which aims to reduce global methane emissions by 30% below 2020 levels by 2030. As part of this Pledge, Canada was the first country to commit to reducing methane emissions in the oil and gas sector by at least 75% below 2012 levels by 2030.

Clean Fuel Regulations

The Clean Fuel Regulations will reduce the carbon intensity of liquid fossil fuels in Canada, including by reducing emissions from oil and gas production.

Emissions Reduction Fund

The $675M Emissions Reduction Fund (ERF) – Onshore Program is helping Canadian onshore oil and gas companies invest in green solutions to continue their progress toward reducing methane emissions in the context of the COVID-19 pandemic. The $42M Offshore Deployment Program will further position the offshore oil and gas sector as a leader in Canada’s transition to a low carbon future. The $33 million Offshore RD&D Program is supporting research, development, and demonstration projects that advance solutions to decarbonize the offshore oil and gas industry.

Clean Growth Program

The Clean Growth Program (CGP) was a $155 million investment in clean technology research, development, and demonstration projects in three Canadian sectors: energy (including oil and gas), mining, and forestry.

Energy Innovation Program

Canadian Emissions Reduction Innovation Network (CERIN): aims to accelerate the development, validation and deployment of technologies that reduce oil and gas sector emissions. CERIN is jointly funded by NRCan, contributing $9 million and Alberta Innovates, contributing $6 million. Carbon Capture, Utilization, and Storage (CCUS) Stream: As part of Budget 2021, the government is investing $319 million into research, development, and demonstrations to advance the commercial viability of CCUS technologies.

CCUS Investment Tax Credit

The Government is developing an investment tax credit for capital invested in CCUS projects to encourage the development and deployment of CCUS technologies.

What was heard from the 2030 ERP engagement process?

- Canadians expressed support for eliminating fossil fuel subsidies, ending expansion of oil and gas projects, supporting a just transition for affected workers, and advancing clean technologies, such as carbon capture, utilization and storage.
- Stakeholders also highlighted the importance of leveraging public and private capital, supports for enabling infrastructure, regulatory cooperation and clarity, as well as Indigenous equity and reconciliation, particularly with respect to upholding First Nations' rights to self-determination, including the minimum standard of free, prior and informed consent.
- Provinces and territories are also prioritizing emissions reductions in the oil and gas sector, including through investments in carbon capture, utilization and storage.
- In response to the Ministers of Environment and Climate Change and Natural Resources request for advice on guiding principles for the development of five-year emissions reductions targets for the oil and gas sector, the Net-Zero Advisory Body noted that targets should: be set using a whole-of-economy lens; include clear parameters for the use of offsets; apply to all parts of the sector and to all firms; be announced early to provide clarity and certainty; align with technical feasibility recognizing that pathway to net-zero emissions is not linear; and should lead to a scale of emissions reductions that would not otherwise have occurred. The Advisory Body also noted principles for success, including data and monitoring of progress and support for workers, families and communities.

What's next?

The challenge of meeting Canada's climate objectives and transforming an industry as complex as oil and gas to net-zero emissions is huge. For its part, the Government of Canada will pair increased stringency in measures to accelerate and deepen emissions reductions from the sector with a range of supporting policies.

Oil and gas companies have proven repeatedly that they can innovate and develop new technologies and more competitive business models. The technical hurdles they have cleared to develop technologies like in situ oil sands extraction demonstrate that the sector can meet the challenge with the appropriate regulations, incentives and supports. Close partnership among all levels of government and industry will be needed. With a clear and collaborative plan, the sector can transform itself into the cleanest global oil and gas producers, while also moving to provide low-carbon and non-emitting energy products and services, such as low-carbon hydrogen, geothermal heat and power, carbon fiber, and asphaltenes.

Investments today in decarbonization and diversification, during a period of record profitability, will also better position the sector over the medium-term, minimizing future climate-related financial risks for companies, workers and Canadians. These investments can also create new jobs and support local and regional economies.

To meet Canada's 2030 target and the lay the groundwork for net-zero emissions by 2050, the Government of Canada commits to:

Capping emissions

The Government of Canada is committed to cap and cut emissions from the oil and gas sector at the pace and scale needed to get to net zero by 2050. The details of how best to design and implement this cap will require close collaboration with industry, provinces, Indigenous partners, and civil society. The government is considering a range of options to achieve these emissions reductions.

The Government will work closely with provinces and the sector to manage competitiveness challenges, remain attuned to evolving energy security and climate risk considerations, maximize opportunities for ongoing investment in the sector, and minimize the risk of carbon leakage. The intent of the cap is not to bring reductions in production that are not driven by declines in global demand. Mechanisms like the CCUS investment tax credit will help support decarbonization. The sector may also need time-limited flexibilities, for example using domestic or international offsets, to achieve a small portion of reductions.

These and other considerations will be explored in a discussion paper that will initiate formal consultations on the cap this spring.

Advancing carbon capture, storage and utilization

Increased use of CCUS features in the mix of every credible path to achieving net zero by 2050, including all 1.5°C pathways developed by the United Nations Intergovernmental Panel on Climate Change and the IEA. The Government of Canada is supporting development of CCUS technology and working to provide policy certainty to facilitate the development and deployment of this technology. This includes the details of a new CCUS investment tax credit, the details of which will be provided soon. The Government will also continue efforts to increase coordination between public and private sectors to eliminate regulatory barriers and facilitate CCUS deployment.

Further reducing methane emissions

Reducing methane emissions from oil and gas operations is not only essential, but also one of the most cost effective climate solutions. The methane review, published in December 2021, concluded that Canada is on track to meet our 2025 target. However, scientific studies indicate methane emissions have been historically underestimated, so while progress has been made, more work is required to improve methane measurements and drive further reductions in this sector. The Government has committed to go beyond the current regulatory requirements (aimed at a 40-45% reduction by 2025) and to develop new measures to reduce oil and gas methane emissions by at least 75% below 2012 levels by 2030. Strengthened regulations to meet this target will be introduced in early 2023. See Chapter 2.1.4 for further information on Canada's holistic approach to addressing methane.

Eliminating subsidies for fossil fuel

The Government has committed to eliminating inefficient fossil fuel subsidies, and developing a plan to phase-out public financing for the fossil fuel sector, including by federal Crown corporations.

Good Jobs Now and in the Future

The Government will always have the backs of Canadian workers. The energy needs of Canada and the world will grow in the decades to come, while global demand for oil and gas will decline. Responding to these changes requires thoughtful, coordinated, and deliberate investment and policy choices to meet Canada's and the world's clean energy needs. Increased green investments will create jobs. Even though the oil and gas sector is seeing record cash flow, the sector employs 6% fewer people than in 2013, the last time the price of oil was over $90 per barrel. The sector has gone from representing 30% of private sector capital spending in Canada to 11%.

Canada has the contractors, roughnecks, construction crews, and labour to build and maintain energy systems of all types. Alberta is home to more professional engineers per capita than any other Canadian province or territory. A hydrogen production facility utilizing carbon capture technology will not look much different from an existing refinery – and the same holds true for a biofuels plant. Building and operating carbon capture and storage is forecast to create tens of thousands of jobs globally by 2030. The International CCS Knowledge Centre, based in Regina, estimates that just three major Canadian projects would create more than 2,300 direct jobs and more than 6,000 jobs in total, including indirect and induced jobs. The Government is working with provinces and businesses to get the transition right – so that we achieve our pollution reduction goals and ensure economic competitiveness, prosperity and good jobs for Canadians. See Chapter 2.12 for further action to support sustainable jobs, skills and communities.

4.3. International Leadership

Canada has a long history of stepping up to tackle global challenges. Through Canada's leadership in the G7, G20, United Nations, and other international fora and bilateral relationships the Government of Canada has been active in pushing for increased global ambition and concrete actions to address the dual crises of climate change and biodiversity loss.

This 2030 ERP is one important way that Canada is meeting its commitments under the world's main agreement to tackle climate change: the Paris Agreement. To ensure the effective implementation of the Paris Agreement, Canada not only takes concrete action at home, but also actively promotes and facilitates global climate change efforts by other countries. Moreover, financing for developing country implementation of climate mitigation and adaptation efforts is an integral part of Canada's support for sustainable international development.

The Paris Agreement

The Paris Agreement is an international agreement adopted by Parties to the UNFCCC. Canada played an active and constructive role in securing international consensus on the Paris Agreement, which entered into force on November 4, 2016. The Agreement's goals are to:

1. Keep the global average temperature to well below 2 degrees Celsius above pre-industrial levels and undertake efforts to limit temperature increase even further to 1.5 degrees Celsius;
2. Enhance climate resilience and the ability to adapt to climate change; and,
3. Make global finance flows consistent with low greenhouse gas emissions and climate-resilient development.

Key international commitments

Canada is implementing a number of international commitments[36] that affect its emissions reduction efforts, including:

- **International climate finance:** In 2021, Canada doubled its international climate finance commitment to $5.3 billion over five years. Canada will allocate at least 20% of this commitment to projects that contribute to nature and increase funding for climate adaptation to at least 40% to help developing countries build resistance to climate change impacts.

- **Powering Past Coal Alliance:** Canada co-leads with the United Kingdom the Powering Past Coal Alliance, which is the world's leading initiative to end global emissions from unabated coal power on timelines to meet the Paris Agreement's goals.

- **Phasing out inefficient fossil fuel subsidies:** In 2009, G20 leaders committed to "rationalize and phase out over the medium term inefficient fossil fuel subsidies". At the North American Leaders' Summit on June 29, 2016, Canada agreed to implement this commitment by 2025. Canada recently accelerated this commitment from 2025 to 2023, and is developing a plan to

[36] A Compendium of Canada's Engagement in International Environmental Agreements and Instruments is available here: Participation in international environmental agreements and instruments - Canada.ca.

phase out international public financing of the unabated fossil fuel sector, including by federal Crown corporations.

- **Global Methane Pledge:** At COP26, Canada joined the Global Methane Pledge, which aims to reduce global anthropogenic methane emissions across all sectors by at least 30% by 2030, relative to 2020. Canada was the first country to commit to further reduce methane from oil and gas operations by at least 75% below 2012 levels by 2030, as called for by the International Energy Agency.

- **Climate and Clean Air Coalition:** In 2021, Canada renewed its support for the CCAC on short-lived climate pollutants (SLCPs) and added $10 million to support the CCAC's 2030 strategy.

- **Arctic Council Framework for Action on Enhanced Black Carbon and Methane Emissions Reductions:** Arctic Council States adopted the first pan-Arctic collective and aspirational goal to reduce emissions of black carbon by 25-33% below 2013 levels by 2025.

- **Kigali Amendment to the Montreal Protocol:** Canada has committed to phase down the production and consumption of hydrofluorocarbons (HFCs) under this agreement.

- **Ocean Plastics Charter:** Canada continues to champion the Ocean Plastics Charter, and advocate for the transition to a circular economy for plastics. As a significant source of greenhouse gas emissions, addressing upstream production of plastics through a full lifecycle approach will also help halt and reverse biodiversity loss, and address climate change.

- **Deforestation and sustainable land use commitments:** At COP26, Canada endorsed several commitments aimed at ending deforestation and advancing sustainable land use, including the Glasgow Leaders Declaration on Forests and Land Use, which commits to working collectively to halt and reverse forest loss and land degradation by 2030.

- **Circular economy:** Canada is actively supporting efforts to advance ambition related to the circular economy and hosted the September 2021 World Circular Economy Forum.

- **North American Leaders Summit:** In November 2021, Canada, the U.S. and Mexico held the first NALS meeting since 2016, where all three parties agreed on commitments and approaches to increase climate ambition in the region.

- **Roadmap for a Renewed United States-Canada Partnership and the High Level Ministerial Dialogue on Climate Ambition:** In February 2021, Canada and the United States launched the Dialogue, fulfilling a commitment made under the Roadmap. The Dialogue will coordinate efforts between both countries to increase ambition aligned with the Paris Agreement and net-zero objectives, including bilateral cooperation on regulatory alignment and climate adaptation.

What's next?

In addition to implementing Canada's existing international commitments, Canada will continue to advocate for increasing global ambition and effective climate action from all countries while supporting and enabling Indigenous climate leadership, mainstreaming gender-based analysis, and supporting developing countries with a focus on the most vulnerable and marginalized.

Key Facts

- The oil and gas sector is the largest source of GHG emissions – it represents 26% of Canada's total GHG emissions (191 Mt of CO_2 eq., in 2019).
- GHG emissions from the oil and gas sector have increased by 87 percent over the past thirty years.
- What is clear is that the oil and gas sector has a major role to play if Canada is to achieve its net-zero ambitions by 2050.

CONTEXT

In November 2021, at COP26 in Glasgow, the Prime Minister announced Canada's intention to cut and cap GHG emissions from the oil and gas sector. Leading organizations that represent Canada's oil and gas sector, including the Canadian Association of Petroleum Producers and the Oil Sands Pathways to Net-Zero initiative — an alliance between Canada's six largest oil sands producers — had already signalled their support to attain net-zero emissions by 2050 prior to this announcement.

It is within this context that in fall 2021 the federal Minister of Environment and Climate Change and the Minister of Natural Resources asked the NZAB to develop key guiding principles to inform the development of the Government of Canada's quantitative five-year targets for emissions reductions in the oil and gas sector.

This section of our ERP submission fulfils the ministers' request. As with all the NZAB's work, these key guiding principles build on the ten values and principles from our inaugural publication: *Net-Zero Pathways: Initial Observations*. They are designed to apply to scope 1 and 2 emissions from the oil and gas sector. Applicable scope 3 emissions are addressed through other NZAB lines of inquiry. Consistent with the CNZEAA definition of net-zero, exported emissions are excluded.

In crafting these guiding principles, we were conscious of the tension between the fact that the oil and gas sector has made, and continues to make, significant contributions to the Canadian economy, yet is a large and growing emitter, all while domestic and global demand for most oil and gas products are predicted to dramatically decline. Furthermore, in a net-zero world, the competitiveness of oil and gas companies is expected to be tied to the carbon intensity of their products. Companies with the lowest carbon intensity

Stages of Production

The oil and gas sector can be subdivided into three stages of production (upstream, midstream, and downstream), with significant differences within and between them.

There are 3 scopes of emissions in the sector:

- *Scope 1* emissions originate directly from sources that are owned or controlled by a sector (i.e., combustion, process, and fugitive emissions);
- Scope 2 emissions are those generated indirectly and,
- Scope 3 emissions are indirect emissions resulting from an organization's operations (i.e., emissions from supply chains). These emissions are often combusted in other sectors or other jurisdictions (e.g., exported crude oil; gasoline in internal combustion engine vehicles).

products are expected to hold a larger market share in a declining global market.

Economic Contributions

- The oil and gas industry contributed $118 billion (or 5.7%) to Canada's GDP, employed over 178,500 workers, and exported $86 billion (or 16%) of domestic products in 2020.
- There were nearly 1,200 companies involved in just the extraction of oil and gas in Canada in 2020:
    - 63% had fewer than five employees
    - 35.8% were small and medium-sized companies
    - 1.2% were large employers with more than five hundred employees
- The industry supports an estimated additional 2,711 supply and services companies outside of Alberta.

Demand Forecasts

The Canada Energy Regulator has predicted that demand for Canadian natural gas will decline from around 13 Bcf/d in 2021 to 8.5 Bcf/d in 2050. Even under a scenario in which the world fails to avoid more than a 1.5 °C increase in warming, demand for Canadian natural gas will decline.

While the International Energy Agency (IEA) has forecasted that global demand for oil and gas over the next 5 years will decline, short-term volatility in energy supply and demand is occurring during the economic recovery from the pandemic and in combination with new geopolitical tensions.

In a world where warming does not exceed 1.5 °C, the IEA forecasts that by 2050 global demand for gas will decline by 55% to 1,750 billion cubic metres, and demand for oil will decline by 75% to 24 million barrels per day (mb/d), from around 90 mb/d in 2020.

A common theme across all credible forecasts is that both domestic and global demand for oil and gas will decrease markedly over the next three decades. The trend over time is for demand scenarios to be revised downward, particularly as policy and regulatory signals around the world increase in stringency.

KEY GUIDING PRINCIPLES TO INFORM THE DEVELOPMENT OF QUANTITATIVE FIVE-YEAR TARGETS FOR THE OIL AND GAS SECTOR

PRINCIPLES FOR TARGET DESIGN

28. Do not set targets in isolation

Targets for the oil and gas sector should be set using a whole-of-economy lens

Emissions reduction targets for the oil and gas sector must be set in the context of broader efforts to reduce emissions from the Canadian economy by 40 to 45 percent below 2005 levels by 2030. Should the oil and gas sector not meet these GHG emissions targets by 2030, other sectors would be required to do even more for Canada to achieve its target, or other approaches like carbon removal would need to be invoked. Oil and gas sector emissions reduction targets should be coherent with national targets and should be made legally binding.

29. Set clear boundary conditions for success

Targets for the oil and gas sector should include clear parameters for the acceptable application of offsets, consistent with a credible net-zero plan for Canada

As stated in our inaugural report, *Net-Zero Pathways: Initial Observations*, the most likely net-zero pathways prioritize emissions eliminations and reductions. Removals and offsets should only be used as a last resort. If offset strategies overlap with other sectors' decarbonization plans, Canada may end up with a series of net-zero sectoral plans that do not actually achieve net-zero on an economy-wide basis. We advise strongly against policies that allow one sector to claim emissions reductions in a different established sector for which credible options already exist to eliminate emissions with no offsets required.

30. Recognize that fair may not mean equal

Targets for the oil and gas sector should apply to the entire oil and gas sector while avoiding a "one-size-fits-all" approach

The oil and gas sector is diverse. Targets should be applied across all parts of the sector (e.g., up-, mid-, and down-stream) and to all firms (e.g., large, medium, and small). However, the diversity in sector structure may require a careful sequencing of targets or an approach that establishes different targets that factor in parameters such as company size or position in the value chain. While this implementation flexibility is consistent with the concept of net-zero, it is not intended to provide leniency for continued emissions. Successive reduction targets applied diligently, but flexibly.

31. Set and implement without delay

Targets for the oil and gas sector should be announced and come into force as soon as possible

Acting early and urgently through target setting is a powerful way to stimulate deep reductions and eliminations of GHG emissions while providing greater market certainty with clear policy signals. In order to provide certainty and give industry as much time as possible to comply, the Government of Canada should publicly announce the targets in the 2030 ERP. Communicating early will give the policy and regulatory certainty requested by the oil and gas sector and the investment community.

32. Align the timing of targets with implementation feasibility

Targets for the oil and gas sector should consider that aggressive target setting in some cases will not allow linear progress between now and 2030

Important prospective solutions to reduce GHG emissions at scale in the oil and gas sector, like carbon capture and storage, require large capital projects that take time to plan, approve, and build. While it is unrealistic to expect these solutions will be online by 2025, it is realistic to assume that they could be built and operating by 2030. Other emissions reduction solutions, like those targeting methane fugitive emissions, can be implemented now to potentially contribute to reducing emissions in 2025 but especially for 2030. Taking solution implementation feasibility into account when setting 2025 and 2030 targets is necessary.

33. Prioritize the largest sources of emissions

Targets for the oil and gas sector should focus on the biggest impacts

Targets should be applied aggressively and confidently to the most significant sources of GHG emissions. This generally aligns with the areas of the broader oil and gas sector that are the most equipped to achieve emissions reductions (e.g., larger firms), and with strategic targeting of methane emissions reductions because of its potency and availability of reduction approaches. Stratified application of emissions reduction is an accepted practice in Canada and has already been applied by the Government of Alberta in its TIER system.

When it comes to methane, Canada should explore the feasibility of achieving greater than 75 percent reductions by 2030 to limit added global warming potential, have methane reductions play a greater role in achieving the Canadian 2030 emissions reduction target, and potentially create international business opportunities for Canadian innovation and technology.

34. Drive new and more ambitious actions

Targets for the oil and gas sector should be ambitious and require new actions that go beyond what is already contemplated using existing proven solutions

Regulatory targets drive innovation. Targets should lead to a scale of emissions reductions that would not otherwise have occurred. At the same time, targets must be realistic and credible, while pushing the sector to go further than it would otherwise. Targets should result in visible leadership, innovation in technology and business models, and new investments. It is acceptable to set emissions reduction targets in the future for which there is not currently complete certainty on how to attain the target. The further away the target is (e.g., 2030 versus 2025 or 2026), the more this principle applies.

PRINCIPLES TO SET THE CONDITIONS FOR SUCCESS

35. Prioritize people and communities

Targets for the oil and gas sector should be accompanied by measures to directly address the needs of Canadian citizens

Achieving ambitious targets for the oil and gas sector will have impacts on Canadian workers, families, and communities—especially those who are directly connected to the oil and gas sector. Canadians affected will need to see and benefit from on-the-ground supports through accessible, targeted, supports (e.g., education, retraining, reemployment, retirement). Reducing GHG emissions is a shared responsibility, and so too is supporting those affected. Companies have as big a responsibility to support worker transition as governments do. Companies, governments, and unions all have a role to play. Smart, whole-economy industrial policy integrated with workforce planning could support clearer direction for energy-reliant communities, position Canada to capitalize on the clear economic opportunities associated with the global transition to a net-zero state and provide optimism about the future.

36. Provide certainty while continuously improving data and monitoring

Targets for the oil and gas sector should ensure regulatory certainty while continuing to improve data and monitoring at the same time

There is sufficient data to confidently set meaningful targets and provide predictability to the oil and gas sector. However, the best available science is showing that actual emissions are higher than those reported using current standards and accepted emissions accounting methodology. While continuous improvements to monitoring should be a priority and aligned with international standards, any resulting refinements in data should not result in changes in targets for 2025 or 2026, and 2030. This could undermine market certainty and deter action. Improved data and monitoring should be pursued to inform new policies, programs, and future targets beyond 2030. If new data provides significantly different data, any target adjustment should be done transparently and cautiously.

37. Show accountability through reporting

Targets for the oil and gas sector should be supported by better reporting that is accessible to Canadians

Enhanced and transparent reporting on progress will help Canadians see where and when emissions are reduced, and how industry is performing relative to targets. Innovative reporting methods, such as a public dashboard that collects and reports real-time data, should be implemented. Under all scenarios, reporting should be easy to understand to enable external groups and the public to track progress in a timely manner and hold industry and government to account. Doing so will help to build public trust in emissions reduction efforts.

38. Reinforce and strengthen existing regulations

Targets for the oil and gas sector should be achievable in part through the stronger application of carbon pricing

Carbon pricing[52] is designed to change the Canadian economy. It incents investment in net-zero-compatible services and products. The price on carbon—escalating to $170 per tonne CO_2e by 2030—should make net-zero solutions more economic compared to higher polluting alternatives. Although subject to the realities of a mature democracy where policies can change, the established carbon price schedule can provide investment certainty, increasing private sector investment. If the pricing system were to be applied across the oil and gas sector, with important adjustments to the exemptions that currently exist, it will help facilitate the GHG emissions reductions necessary to meet the targets. Removing loopholes would unlock the potential of carbon pricing. The economic conditions that are created by these regulations will lead to a stronger impetus for the oil and gas industry to direct more resources toward cleaner oil and gas production processes and produce low or zero scope 3 emission products that are fully compatible with a net-zero economy.

[52] The federal *Greenhouse Gas Pollution Pricing Act* establishes two parts different pricing regimes. There is a charge on fuels, and a regulatory trading system for large industrial emitters called the Output-Based Pricing System (OBPS). The extent to which carbon pricing can play a role in reducing emissions from this sector depends on how much of the pan-Canadian price on carbon applies to oil and gas facilities. Facilities' exposure to the pan-Canadian carbon price is determined by the OPBS and parallel provincial trading systems (e.g., TIER in Alberta).

39. Provide only responsible supports to industry

Targets for the oil and gas sector should be accompanied by highly strategic public support for industry

When considering where and how to responsibly allocate its limited resources, the Government of Canada has a role in helping set the conditions for achieving net-zero emissions for the entire economy, not just the oil and gas sector. This means industry support measures will have to be rethought to bring them in line with net-zero goals, including through revision of indicators of success, apportionment, and more. It will be critical to provide targeted support to develop product mixes and business models that will help transform or create sectors across the economy that are critical to, and will permanently thrive in, a net-zero world. This approach should apply across Canada's current economy, including the existing oil and gas sector. To this end, government financial support should be provided only for the purpose of reducing GHG emissions intensity of oil and gas production, where oil and gas will be used in a way that yields no combustion scope 3 emissions.

As for other industrial sectors, there is a legitimate role for significant government financial support for the existing oil and gas sector to create scalable innovations and products required for a net-zero economy. For example, there is a critical need for the production of fuels that are zero-emissions at the point of use, that will eventually eliminate scope 3 emissions across other domestic sectors, and position Canada to capitalize on the emerging global export markets for zero-emission fuel.

40. Ensure approvals processes for projects are working towards, not against, the targets

Targets for the oil and gas sector should be supported by a regulatory regime that allows timely construction or implementation of net-zero projects

To ensure targets are met, it is imperative that regulatory processes, from start to finish, are aligned with the urgency of the climate crisis. New net-zero projects required for emissions reduction and elimination will need to be operational without undue delay in order to meet targets. Existing project review and approval processes may not be compatible with required timelines. The rigour of regulatory processes should not be compromised, but approval processes should not bottleneck progress on GHG emissions reductions and eliminations.

ADVICE FOR 2030: PUTTING THE TRANSPORTATION SECTOR ON THE MOST LIKELY PATHWAYS TO NET-ZERO BY 2050

20. Grow public transportation options
21. Regulate more ZEV vehicle sales as soon as possible
22. Implement and expand measures that support electric vehicle uptake
23. Encourage ZEV adoption
24. Expand the strength and scope of the Clean Fuel Standard
25. Take a supply-chain lens to help the auto sector transition
26. Ensure sufficient investment for zero-emissions heavy freight
27. Drive innovation to reduce emissions in aviation and marine subsectors

KEY GUIDING PRINCIPLES TO INFORM THE DEVELOPMENT OF QUANTITATIVE FIVE-YEAR TARGETS FOR THE OIL AND GAS SECTOR

PRINCIPLES FOR TARGET DESIGN

28. Do not set targets in isolation
29. Set clear boundary conditions for success
30. Recognize that fair may not mean equal
31. Set and implement without delay
32. Align the timing of targets with implementation feasibility
33. Prioritize the largest sources of emissions
34. Drive new and more ambitious actions

PRINCIPLES TO SET THE CONDITIONS FOR SUCCESS

35. Prioritize people and communities
36. Provide certainty while continuously improving data and monitoring
37. Show accountability through reporting
38. Reinforce and strengthen existing regulations
39. Provide only responsible supports to industry
40. Ensure approvals processes for projects are working towards, not against, the targets

Appendix – Key Assumptions

This document provides a detailed list of some of assumptions underlying the modelling of the Emissions Reductions Plan under the Canadian Net-Zero Emissions Accountability Act. This list is not intended to be comprehensive of all of the measures included in the plan.

Table 6.A.1. Key Assumptions

Carbon Pricing	Fuel Charge	The federal government announced that the federal fuel charge rates will reflect an annual increase of \$15/tonne CO_2 eq. after 2022 until the fuel charge rates reflect a carbon price of \$170/t CO_2 eq. in 2030. The federal fuel charge is a backstop policy that applies a regulatory charge on fossil fuels in provinces/territories that do not have a carbon pricing system that meets minimum stringency criteria (the benchmark). As carbon pricing systems are in the process of being adjusted to align with the 2023-2030 minimum national stringency requirements (federal benchmark), for illustrative purposes the modelling assumes the fuel charge applies in all provinces and territories apart from Quebec, which is modeled based on its current cap-and-trade carbon pricing system.
	Federal Output-Based Pricing System	The Output-Based Pricing System (OBPS) is a performance-based emissions trading system for industry that puts a price incentive on all industrial emissions. For every tonne of excess emissions above a specified annual limit (based on emissions intensity output-based standards), facilities have to pay the carbon price or submit eligible credits. Facilities with emissions below the limit receive credits to sell or use for compliance. The federal government announced that the charge for excess emissions under the OBPS will increase annually by \$15/tonne CO2e starting in 2023 until it reaches \$170/tonne CO_2 eq. in 2030. As carbon pricing systems are in the process of being adjusted to align with the 2023-2030 minimum national stringency requirements (federal benchmark), for illustrative purposes

https://www.accuweather.com/en/hurricane/accuweathers-2022-atlantic-hurricane-season-forecast/1164507

AccuWeather's 2022 Atlantic hurricane season forecast

How will this season rank in terms of intensity? How many major hurricanes are forecast to form? And how many direct impacts to U.S. soil will there be? AccuWeather's top experts answer all of those questions and more.

By Kevin Byrne, AccuWeather senior editor
Published Mar. 30, 2022 11:59 AM EDT

The 2021 hurricane season was the third most active on record, and AccuWeather's hurricane experts say the 2022 season could be very similar.

The Atlantic hurricane season is two months away, with the official start arriving on June 1, but AccuWeather forecasters released predictions for the coming season this week**,** noting that there is a high chance for a preseason storm to develop and that another active tropical season is expected. AccuWeather forecasters emphasized that now is the time to prepare, especially since some communities are still recovering from devastating storms over the last couple of years.
The past two hurricane seasons were extraordinarily active, as AccuWeather meteorologists predicted, with the historic 2020 season reaching unprecedented levels and setting a new record for the number of named storms with 30. The 2021 tropical year was almost as prolific with 21 named storms, making it the third most active on record in terms of named systems. It also forced meteorologists to use the entirety of the designated storm name list for the second straight season.

Of course, the seasons prior to 2020 and 2021 certainly weren't underachievers, with the devastating trio of major hurricanes **--** Harvey, Irma and Maria **--** striking over a one-month stretch in 2017, and hurricanes Florence and Michael blasting parts of the Southeast in 2018. In fact, the last season with a below-normal number of named storms was 2015

So what can residents living in hurricane-prone areas of the United States expect in 2022? More of the same, unfortunately.


ATLANTIC HURRICANE SEASON
OUTLOOK 2022

	Named Storms	Hurricanes	Major Hurricanes	Direct U.S. Impact
2021	21	7	4	8
2022 Forecast	16-20	6-8	3-5	4-6
Normal	14	7	3	3.5

AccuWeather’s team of tropical weather forecasters, led by veteran meteorologist and hurricane expert Dan Kottlowski, is once again predicting an above-normal season in terms of tropical activity in the Atlantic, as well as a higher-than-normal chance that a major hurricane could make landfall in the mainland United States, Puerto Rico and the U.S Virgin Islands.

Specifically, Kottlowski’s team is forecasting 16-20 named storms and six to eight hurricanes. Of those hurricanes, about three to five are forecast to reach major hurricane status, which occurs when a storm reaches Category 3 strength with winds exceeding 111 mph or higher.

AccuWeather’s forecast of 16-20 named storms is higher than the 30-year average of 14 per year, while the projection of six to eight hurricanes is about in line with the normal of seven. It’s also nearly identical to how 2021 played out. Last year, the 21 named storms included seven hurricanes and four major hurricanes. Eight of those storms made a direct impact on the U.S. About four to six direct impacts are predicted for 2022.

In order to make such a long-range prediction, Kottlowski’s team studied a number of current weather trends, past hurricane seasons and climatological models to help piece together this meteorological puzzle. Here’s a deeper look at how several influential factors will shape the 2022 season.

La Niña once again expected to play a key role

The climatological phenomenon known as La Niña can help shape weather patterns worldwide, and in particular, play a major factor in how active a hurricane season can become.
La Niña is part of a three-pronged climatological pattern known as the El Niño Southern Oscillation [ENSO], which is a short-term climate fluctuation that is determined by the warming or cooling of the waters in the equatorial Pacific Ocean.

When sea-surface temperatures are anomalously warm in this part of the Pacific and stay that way over a period of 12-18 months, climate experts say an El Niño phase is underway. When the reverse is true, and water temperatures are lower than average, a La Niña phase is declared. The third phase, ENSO-neutral, is when water temperatures are around average.

When a La Niña phase is present, as was the case in the past two extremely active years, the amount of vertical wind shear in the atmosphere can be limited as westerly winds typically stay farther to the north and away from the tropical Atlantic. An abundance of vertical wind shear, which typically occurs over the Atlantic during El Niño patterns, can often stymie burgeoning tropical cyclones or limit their development altogether.

As of March 30, Kottlowski, who has been with AccuWeather for more than four decades, says a weak La Niña is in place and it is expected to persist through the beginning of the tropical season. With less wind shear in the atmosphere, there will be one fewer tropical hindrance in play. Kottlowski noted that a shift to a neutral phase could occur during the summer but if La Niña remains in place, or even intensifies, then it's possible that there could be more than 20 storms, he said.

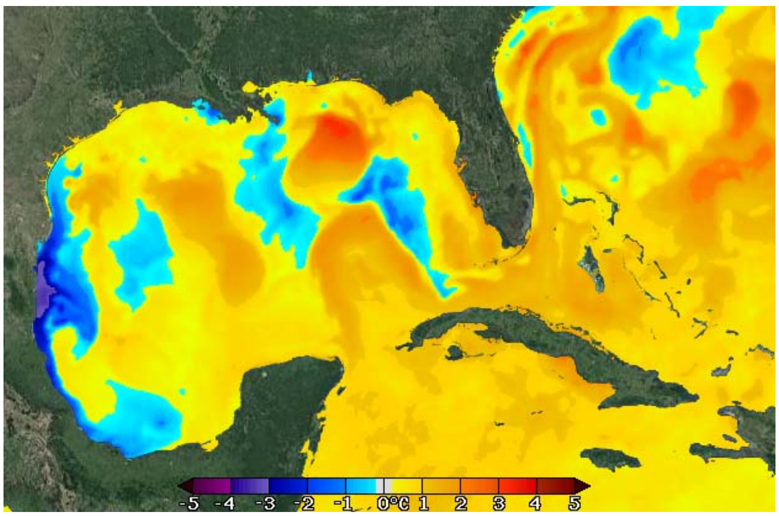
If more than 21 storms end up taking shape, that means forecasters will have exhausted the designated storm list for the third consecutive year and will have to use a supplemental list for any additional storms that develop. The first three storms that form in the Atlantic this year will be named Alex, Bonnie and Colin.

The status of La Niña throughout the summer will be closely monitored by meteorologists. If the La Niña phase ends up fading away over the summer or early in the fall, the tropical activity could wind down well before the official end of the season on Nov. 30.

Warm waters to fuel early-season development

Tropical depressions or storms have gotten a jump start on the official June 1 start date in the Atlantic for seven consecutive seasons, something that has caused the National Hurricane Center (NHC) to consider moving the season's start date to May 15. Kottlowski said that in addition to the presence of La Niña, above-normal sea-surface temperatures in key tropical development regions will result in a higher-than-normal chance of preseason development for the eighth year in a row. Temperatures were already above normal in many areas that meteorologists closely scrutinize for tropical systems during late March.

"Sea-surface temperatures are above normal over much of the Gulf of Mexico and the Caribbean and even off the East Coast of the United States, especially the southeast coast of the United States, and these are critical areas for early season development," Kottlowski said. This includes much of the central Atlantic, the chunk of the ocean forecasters refer to as the main development region, he added.



This image shows warm waters throughout much of the Gulf of Mexico, parts of the Atlantic coast of the U.S., and parts of the Caribbean as of March 28, 2021. (NOAA)

Sea-surface temperatures near Key West, Florida, were about 76-78 degrees as of March 28, which is about 1.6 to 3.8 degrees Fahrenheit above normal.

Warmer-than-normal waters in March often indicate areas in the basin will be sufficiently warm for tropical development by the start of the hurricane season, according to Kottlowski.

Waters are currently cooler in the eastern Atlantic and toward the coast of Africa, but meteorologists expect that the waters will be sufficiently warm enough in that part of the basin by the peak of the season in middle to late August.

Speaking of Africa, the weather on the northwestern part of the continent will also help shape the 2022 season.

Forecasters expect strong winds over Africa to produce frequent tropical waves later in the season. These tropical waves rumble across the Sahara Desert in northern Africa and into the open Atlantic where they can become better organized into tropical depressions or tropical storms.

Kottlowski has previously said that about 85% of all tropical storm development can be linked back to tropical waves, which are areas of low pressure in the atmosphere that are typically situated north to south and move westward from Africa into the Atlantic.

How will this season rank in terms of intensity?

Forecasters determine the overall intensity of a hurricane season by a metric known as Accumulated Cyclone Energy, or ACE**,** which accounts for the strength of a tropical system over its entire lifetime. In the past, a large volume of tropical storms in a season has not always generated a higher ACE value.

The 2021 season finished with an Accumulated Cyclone Energy value of 145 and 2020 had a total of 182. Both of those were extraordinarily active seasons that were above normal when measured by intensity. However, they still fall short of past seasons such as 2017 (225) and 2005 (245), according to Colorado State University figures.

AccuWeather meteorologists are projecting a total ACE in the range of 120-150 for the 2022 season. A value of 123 is considered to be normal.

Who is at greatest risk?

Homes are flooded in the aftermath of Hurricane Ida, Monday, Aug. 30, 2021, in Jean Lafitte, La. (AP Photo/David J. Phillip)
(AP Photo/David J. Phillip)

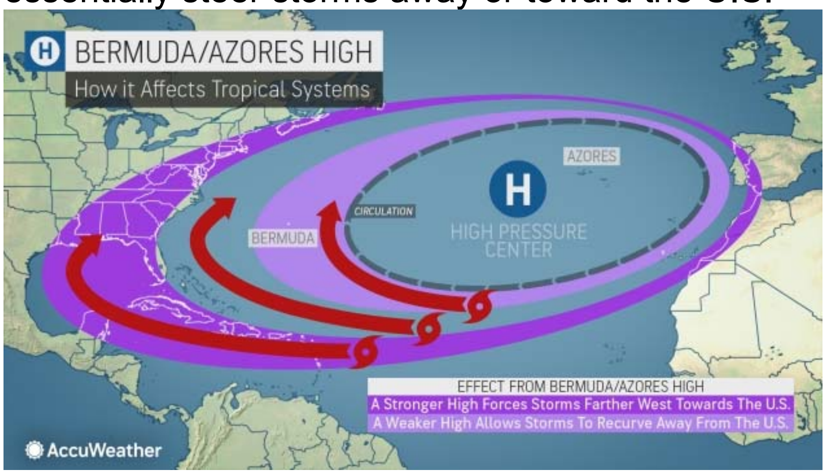
Forecasters will often refer to analog years when putting together a hurricane season forecast. These data points are past seasons that featured weather patterns similar to the current and projected trends of ENSO.

Eight years bear striking similarities to this year, according to Kottlowski's research. Several of those most recent seasons include 2021, 2012 and 2001.

Kottlowski cautioned that just because a storm hit a certain part of the United States in a previous analog year, such as Hurricane Ida in Louisiana in 2021, Superstorm Sandy in New Jersey in 2012, or Hurricane Hugo in South Carolina in 1989, there is no implication that the same areas will be struck again this year. Conversely, areas that weren't impacted by landfalling storms in a given analog year, are not less likely to be impacted in 2022.

Based on those past landfall locations, the areas with the greatest potential for direct impacts along the mainland U.S. are the southeast Texas coast eastward through Florida, particularly the panhandle area, and the coast of the Carolinas.

One major player that is watched closely by meteorologists for determining how close to U.S. shores storms will approach -- and the timing for close encounters and direct impacts -- is an area of high pressure known as the Bermuda Azores high, or, simply, the Bermuda high. Forecasters say the Bermuda high's strength, orientation and central position can essentially steer storms away or toward the U.S.



During the first part of the season, the center of the Bermuda high will likely be well west of the Azores, an island chain in the northern Atlantic. Due to this positioning, early-season storms are likely to be guided into or close to the U.S.

During the latter stages of the season, the center of this high pressure area will move northeast and over the Azores. Kottlowski's team said this suggests more, but not necessarily all, storms could curve north and then northeastward, taking a track that moves them away from the U.S.

With the official start of the season still months away, Kottlowski is urging people to begin hurricane preparations now, particularly given the ongoing global supply chain issues along with the heightened possibility of an early storm.

"Don't wait until June to prepare," he said. "We've had preseason development over the last seven years and certainly you need to prepare now. So now's the time to get your hurricane plan in place."

https://www.accuweather.com/en/severe-weather/accuweather-2022-us-severe-weather-tornado-forecast/1151718

2022 predicted to spawn more tornadoes than recent years

Spring is almost here, but severe weather season is already ramping up -- and AccuWeather forecasters say that tornado activity will shift into high gear in one particular month across the central and eastern U.S.

By Brian Lada, AccuWeather meteorologist and staff writer
Published Mar. 9, 2022 9:33 AM MDT | Updated Mar. 11, 2022 8:50 AM MDT

Paul Pastelok and Tony Laubach talk about the severe weather season forecast for the coming months.

The arrival of meteorological spring on March 1 also marked the opening chapter of severe weather season across the central United States, a season that AccuWeather predicts could spin up a higher number of twisters and life-threatening storms than what has unfolded in recent years.

Last year was turbulent in terms of severe weather. The 2021 severe weather season was strong right out of the gate with multiple outbreaks across the South in March. This was followed up by an unusually quiet April and then another active period once the calendar turned to May. The year was capped off with a "ridiculously active" December with a tornado outbreak on Dec. 10-11, which caused more than 90 fatalities, and then a rare and destructive derecho on Dec. 15.

Severe thunderstorms and tornadoes can happen at any time of the year, but the ingredients for powerful storms and large twisters come together most frequently in the central U.S. during March, April and May. This is why meteorologists consider these months to be severe weather season.

AccuWeather National Reporter Tony Laubach and his wife dropped everything they were doing to capture an evolving tornado on June 7, 2021. (AccuWeather / Tony Laubach)

There have already been previews of the brewing severe weather season with thunderstorms and isolated tornadoes in the central and eastern U.S. on Feb. 17, Feb. 22-

23 and March 5-6. The outbreak on the first weekend of March turned deadly after an EF4 tornado tore through the Des Moines, Iowa, area destroying dozens of homes and leaving at least seven people dead.
One of the key characteristics of the 2022 severe weather season is that the worst of the storms may hit areas located outside of the traditional Tornado Alley.

A large shelf cloud, which is often associated with strong winds flowing out from a thunderstorm or line of thunderstorms, is visible over farmland.

Tornado Alley, a term coined in 1952 by Maj. Ernest J. Fawbush and Capt. Robert C. Miller of the U.S. Air Force, for decades, was used to refer to an area where there was a high potential for tornado development. The ingredients for tornadoes came together frequently in this region as Arctic air from the north clashed with warm, moist air from the Gulf of Mexico.
Hearing the term Tornado Alley may conjure up thoughts of storm chasers racing toward a towering thunderstorm in Oklahoma or Kansas, but trends in twisters in recent years have sparked debate among meteorologists as to whether the zone for most frequent tornadoes is shifting eastward.
The area historically referred to as Tornado Alley encompasses a swath of the southern Plains to the northern Plains that includes central Texas, much of Oklahoma, Kansas, Nebraska and South Dakota. On its western flank, this traditional Tornado Alley includes slivers of eastern Colorado and eastern New Mexico and, on its opposite side, a narrow slice of Iowa. But in recent years, the area with the most frequent tornadic activity has seemed to shift farther east toward the Mississippi and Tennessee valleys.
AccuWeather Senior Meteorologist Paul Pastelok and his team of long-range forecasters believe that there will still be twisters across the traditional Tornado Alley in 2022, but the worst of the storms and tornadoes may follow the recent trend and focus on areas farther to the east.

AccuWeather meteorologists approached the severe weather forecast in the same manner that they did when forging the annual spring forecast.
"Looking at severe weather this season, we do our research," Pastelok explained. This research entails analyzing the current weather patterns around the globe and comparing the current conditions to past years when there were similar weather patterns. This method can help meteorologists predict what is going to unfold in the future by studying the past.

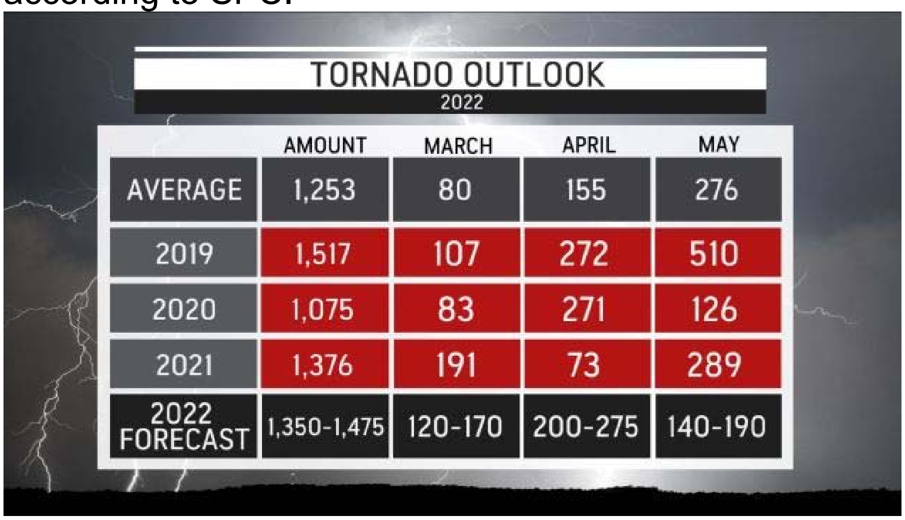
Pastelok said when releasing the U.S. spring forecast that severe weather in March would ramp up fast, a forecast that has already come to fruition following the deadly tornado in Iowa on Saturday, March 5.
AccuWeather is forecasting between 120 and 170 tornadoes will touch down across the U.S. in March, which could be double the month's long-term average of 80 tornadoes, according to NOAA's Storm Prediction Center (SPC).

"There can be a few big events in March concentrated over the south-central Plains," Pastelok said, adding that there could also be severe weather events over the Gulf Coast states during the second half of the month.

Unlike last season when there was a lull in the middle of the season, AccuWeather predicts that severe weather will be even more intense heading into April.

"April looks like a very active month," Pastelok warned. "That could be the most active as far as the number of tornadoes."

Between 200 and 275 tornadoes are forecast to spin up in April, significantly more than what unfolded last April, when 73 tornadoes were recorded, and well above the average of 155. The long-term averages are based on tornado data from 1991 through 2010, according to SPC.


TORNADO OUTLOOK
2022

	AMOUNT	MARCH	APRIL	MAY
AVERAGE	1,253	80	155	276
2019	1,517	107	272	510
2020	1,075	83	271	126
2021	1,376	191	73	289
2022 FORECAST	1,350-1,475	120-170	200-275	140-190

The average numbers shown above are from data gathered between 1991 and 2010.

The most active month for tornadoes will also coincide with when storms begin to shift eastward.

This shift will be related to two big factors: the expanding drought conditions across the Four Corners and the High Plains and a change in the jet stream that will influence where severe thunderstorms can develop.
As of March 3, most of the traditional Tornado Alley was experiencing severe drought conditions with pockets of extreme to exceptional drought in the Texas Panhandle and western Oklahoma. Drought conditions can hinder the development of storms, creating a cycle that can cause the drought to become even worse.

This translates to a lower risk of storms in April, May and into the summer for places such as Lubbock and Amarillo in northwestern Texas. The reduced tornado risk will extend to Dodge City in southwestern Kansas and about 150 miles to the west for places like Lamar, which is in eastern Colorado, and, essentially, right through the heart of traditional Tornado Alley to North Platte, Nebraska**,** which is about 270 miles to the north of Dodge City. However, the drought will not completely eliminate the chances of occasional storms.

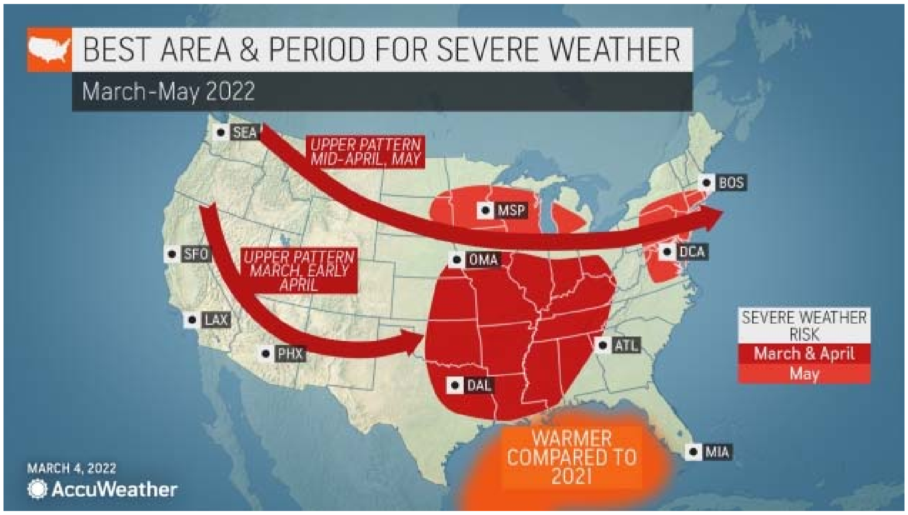
During this period, the higher risk of severe weather is predicted to occur across the Midwest, Mississippi Valley, Tennessee Valley and Ohio Valley, especially in April and May, instead of being focused on the traditional Tornado Alley.

The frequency of storms may throttle back heading into May with AccuWeather projecting between 140 and 190 tornadoes across the country. Typically, May features around 276 twisters as warm, humid air expands northward.

While the overall risk of intense storms and tornadoes will decrease somewhat heading into May, the threat area will expand to include more areas of the country.

"There may be fewer tornadoes in May, but severe weather can be more concentrated in the Midwest," Pastelok warned, adding that there could even be "an event or two in the mid-Atlantic and Northeast."

"A couple of severe events are possible in the Northeast in May, with the greatest threat of straight-line wind damage rather than tornadoes," Pastelok said. "Also, there can be some storms in the Midwest diving southeast, but overall May's tornado count may be down compared to April."



Stepping back to look at the bigger picture, AccuWeather is predicting a total of 1,350 to 1,475 tornadoes across the U.S. in 2022, above the annual average of 1,253, which is based on SPC data from 1991-2010. This could also potentially be the highest tornado count since 2019 when 1,517 twisters touched down.

While AccuWeather forecasters are predicting the number of tornadoes, they are not predicting the intensity of the tornadoes. Tornadoes are rated on the Enhanced Fujita (EF) scale, an updated version of the Fujita (F) scale which was named after the late meteorologist Dr. Ted Fujita, who developed the scale.
The U.S. is currently experiencing its longest stretch without an EF5 tornado, the highest and most extreme rating possible for a twister since reliable tornado records began in the 1950s.
The most recent EF5 tornado to touch down on U.S. soil took place nearly nine years ago on May 20, 2013, when a catastrophic, mile-wide tornado hit Moore, Oklahoma. The previous record for the longest period without an EF5 tornado was eight years between May 3, 1999, and May 4, 2007.

To be considered an EF5 tornado, damage survey teams from the National Weather Service must find evidence of winds of at least 200 mph.

The historic streak almost came to an end on Dec. 10, 2021, when a deadly tornado tracked across western Kentucky. Survey teams assessed the damage and determined the storm was a high-end EF4 tornado with peak winds of 190 mph, just 10 mph shy of making it into the record books as one of the most destructive forces of nature in U.S. history.

Independent Statistics & Analysis
U.S. Energy Information Administration

Country Analysis Executive Summary: Colombia

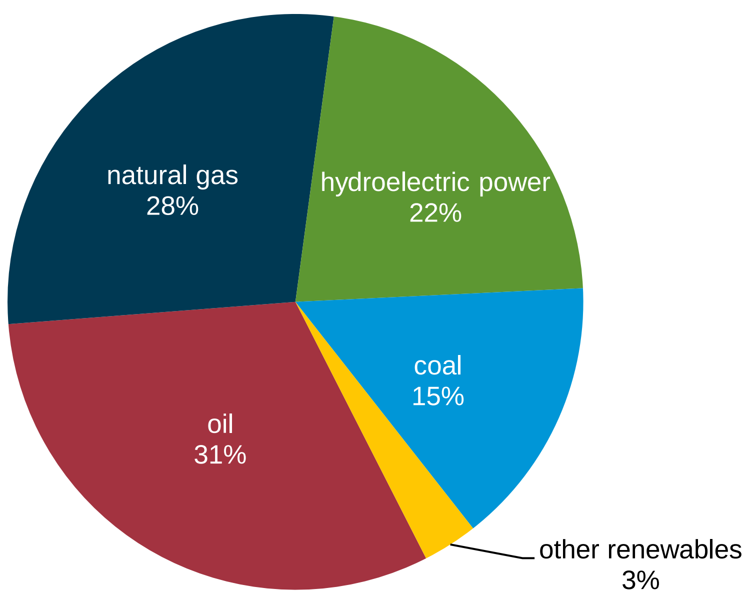
Last Updated: March 31, 2022

Overview

- In 2021, Colombia was South America's largest coal producer and second-largest petroleum and other liquids producer after Brazil. The country is also a significant oil exporter; in 2021, it was the fifth-largest crude oil exporter to the United States.

- Energy consumption in Colombia totaled 1.7 quadrillion British thermal units (quad) in 2020. At 31%, oil accounted for the largest share of Colombia's total energy consumed (Figure 1).[1]

Figure 1. Primary energy consumption in Colombia by fuel type, 2020



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

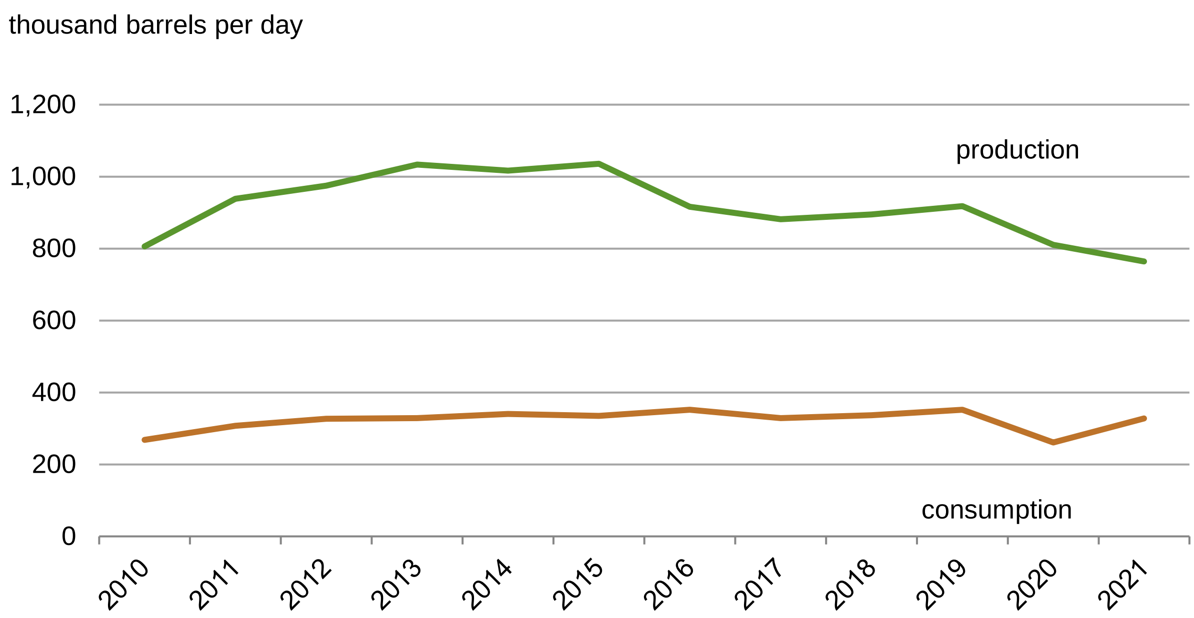
- Columbia uses hydropower for most of its electricity needs. Despite being a major coal producer, Colombia uses very little coal domestically, instead exporting most of its coal production.

Petroleum and Other Liquids

Exploration and production

- According to the *Oil & Gas Journal*, Colombia had 1.8 billion barrels of proved crude oil reserves as of January 2022.[2]
- Colombia's total petroleum and other liquids production fell from 808,000 barrels per day (b/d) in 2020 to an average of 760,000 b/d in 2021, continuing a production decline trend from recent years (Figure 2). Production declines in both years were the result of shut-ins driven by COVID-19-related lockdowns and delayed exploration in addition to social protests and attacks by guerilla groups on key midstream oil infrastructure.[3]
- All of Colombia’s crude oil production occurs onshore (a mature resource base), and EIA expects that crude oil production will continue to decline. Ecopetrol, Colombia’s national oil company, is focusing on increasing output from the maturing Rubiales, Castilla, La Cira, and Chichimene fields through infill drilling, rather than undertaking new exploration.[4] The Llanos Orientales (Eastern Llanos) Basin east of the capital, Bogota, is the main source of production. Its heavy, sour crude oil make up Colombia's key export grades, Castilla Blend and Vasconia.

Figure 2. Total petroleum and other liquids production and consumption



Source: Chart by the U.S. Energy Information Administration, *International Energy Statistics* and *Short-Term Energy Outlook, March 2022*

- The country's sub-soil and non-renewable natural resources belong to the state as codified in its constitution. However, any qualified local or foreign company is permitted to explore and produce hydrocarbons without having to partner with the national oil company, Ecopetrol. Although private foreign investment in the oil sector exists, Ecopetrol operates over two-thirds of the country's total oil and natural gas production.[5] Colombia’s government has attempted to create an attractive investment environment for foreign companies, including implementing a more attractive fiscal and tax regime.[6] In November 2015, the Ministry of Mining and Energy (Minminas) lowered tax rates for oil companies drilling in certain offshore blocks off the Caribbean coast in an effort to increase exploration. Rates were discounted 25%, and contracts were exempt from the value added tax (VAT) and customs charges. This policy was enacted to revive offshore exploration activity and has had mixed success in attracting large foreign companies. [7] Currently foreign companies are allowed to own 100% stakes in ventures and no local content requirements are required. In 2018, the Duque administration proposed changing its bidding process, including adjusting contracts to match international crude oil price fluctuations, in an effort to increase investment and find new reserves. These changes have since stalled. [8]

- Colombia has no offshore oil production, but its plans include contracting with companies to explore and develop its offshore region in an effort to increase oil reserves. Industry reports indicate that offshore oil production could increase reserves, but production would likely not begin until the late 2020s.[9]

- The shale formations in Colombia are the Cesar-Rancheria Basin, the Middle Magdalena Valley Basin, the Llanos Basin, and the Maracaibo/Catatumbo Basin (on the border of Venezuela and Colombia). Since 2019, unconventional drilling has been under a moratorium. The Agency of National Hydrocarbon (ANH), Colombia's hydrocarbon regulator, planned to start pilot fracking projects in 2020. However, these projects were delayed as a result of the COVID-19 pandemic.

- The Colombian government has approved four companies to participate in pilot projects: Ecopetrol, ExxonMobil, Drumond Energy, and Tecpetrol Colombia.[10] Ecopetrol and Repsol are scheduled to start drilling in Colombia's offshore Caribbean block this year,[11] while additional pilots were also approved in Colombia's Middle Magdalena Valley Basin. In 2013, an EIA report indicated that the quality of the La Luna formation (part of the Middle Magdalena Valley Basin) is similar to North America's shale plays.[12] The La Luna formation is a deep marine shale mixed with marl and limestone, much like the Eagle Ford and Niobrara Shale plays in the United States.[13,14]

Consumption

- Refined products demand declined by 20% to 282,000 b/d in 2020. The COVID-19 pandemic national quarantine measures that restricted travel also decreased refined fuel consumption (Figure 2). Gasoline and fuel oil demand typically account for over 70% of all refined petroleum products consumption in Colombia. Consumption of refined products rebounded to 328,000 b/d in 2021 as travel restrictions and quarantine measures were lifted.

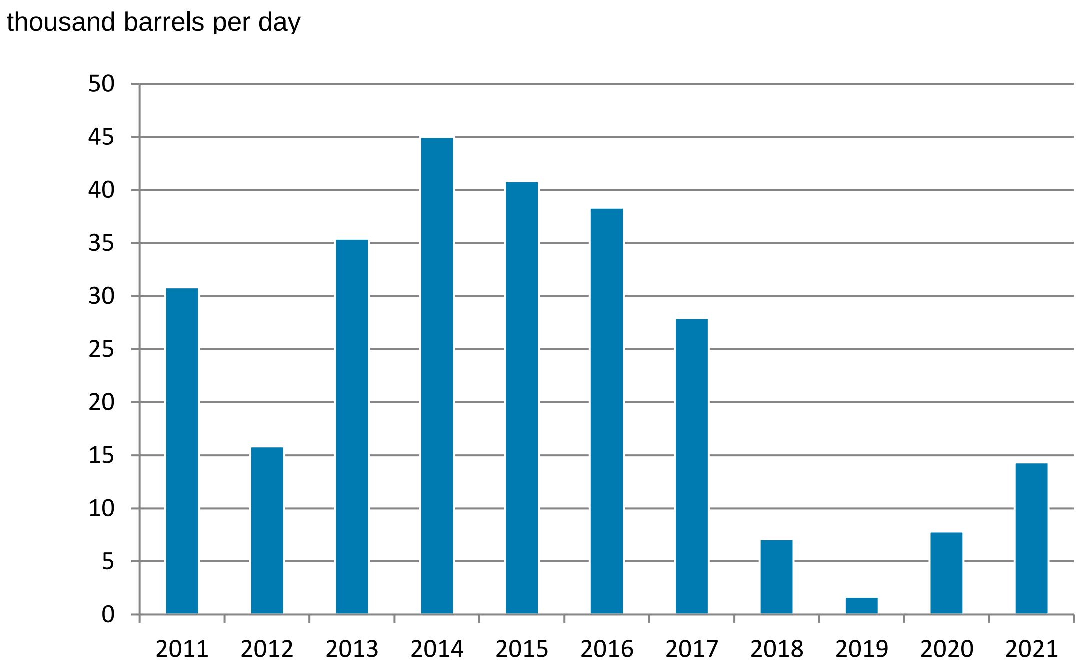
- Diesel consumption has been increasing over recent years as a result of expanding cargo and passenger transportation. Legislation was enacted in 2019 to limit sulfur content in diesel fuel from 500 parts per million (ppm) to 50 ppm. As a result, there is not enough domestic refining capacity to produce the higher quality diesel fuel. Although Colombia is a net exporter of refined products, it imports diesel because domestic demand for diesel is higher than domestic supply.

Supply disruptions

- Despite a 2016 peace agreement between the Revolutionary Armed Forces of Colombia (FARC) guerillas and the government, Colombia's oil industry continues to be the target of pipeline attacks. The National Liberation Army (ELN) and the Colombian government had been in peace negotiations, but those were suspended after attacks by ELN in early 2018.

- Attacks by the ELN targeting oil pipelines and other infrastructure in Colombia are frequent—over 30 such incidents were recorded in 2021. In 2020, Ecopetrol recorded 51 oil infrastructure attacks and EIA estimates that 8,000 b/d were disrupted during that year and 14,000 b/d in 2021 (Figure 3).[15]

Figure 3. Liquid fuels supply disruptions in Colombia, 2011–2021



Source: Chart by the U.S. Energy Information Administration, *Short-Term Energy Outlook, March 2022*

- Attacks on key midstream infrastructure, especially the Caño Limon-Covenas pipeline, have disrupted the supply of crude oil for export. During 2020, 29 pipeline attacks occurred. [16] In 2019, 71 attacks occurred against Colombian pipelines, and 42 of these attacks targeted the Caño Limon-Coveñas line. The number of attacks in 2019 was less than in 2018, when the total number of attacks reached 107. The pipeline runs from the Caño Limón oil field to the port of Coveñas, where most of Colombia's crude oil exports leave the country. Most recently, Caño Limón-Coveñas was attacked in January 2022. The Bicentenario crude oil pipeline was reversed in 2018 to transport crude oil displaced by the attacks, but this alternative route is more costly.

- In addition to attacks, production was also shut in in 2020 because of social protests and lockdowns during the COVID-19 pandemic. Protests in April 2020 began in opposition to a tax proposal, and these protests blocked access to oil fields in the Arauca, Meta, and Putumayo provinces until June 2020. A number of companies announced cuts in production or suspension of exploration activities amid the protests.[17] EIA estimates that an average of 31,000 b/d was offline between April and June 2020. Including these shut-ins, Colombia's petroleum and other liquids production in 2020 fell approximately 100,000 b/d year-over-year and 48,000 b/d in 2021.

Refining

- According to the *Oil & Gas Journal*, as of January 2021, Colombia had 378,600 b/d of crude oil refining capacity. Colombia's main oil blend is the Castilla Blend, which has an API gravity of 18.8 degrees and is a heavy and sour (high sulfur-1.97%) crude oil. In addition to output from the Castilla field, the blend includes crude oil from other heavy oil fields such as the Rubiales and Quifa fields.[18] Ecopetrol's refineries were originally built to process light, sweet crude oil from fields such as Cusiana and Cupaigua, and Colombia's increasingly heavy crude oil production has presented challenges to the refining and midstream sectors.[19]

- Colombia has two large refineries, the Barrancabermeja refinery and Cartagena (Reficar) refinery, both operated by Ecopetrol (Table 1). In addition, Ecopetrol's subsidiaries and independent refiners operate smaller units.

Table 1. Major refining capacity in Colombia

Refinery	Location (department)	Current capacity (barrels per day)	Ownership
Barrancabermeja	Santander	218,600	Ecopetrol
Cartagena	Bolivar	155,000	Ecopetrol
Apiay	Meta	2,500	Ecopetrol
Orito	Putumayor	2,500	Ecopetrol
		Total: 378,600	

Source: Table by the U.S. Energy Information Administration, based on data from the Oil & Gas Journal, *2021 Worldwide Refining Survey*

- In 2016, the Reficar refinery was modernized to allow the facility to run heavy and sour crude oil feedstock, which is more dominant domestically. In 2021, Ecopetrol announced plans to upgrade and expand Reficar further, investing $180 million. According to Ecopetrol, capacity is expected to grow from 165,000b/d to 200,000 b/d.[20] A completion date has yet to be set. With this investment, Ecopetrol aims to position itself as a producer of low-sulfur fuel to meet new standards (IMO 2020) enacted in 2020 that require a maximum sulfur content of 0.5% in international marine fuels.[21]

Trade

- Crude oil production far exceeds domestic demand, making Colombia a net crude oil exporter. According to Global Trade Tracker, in 2020, Colombia exported 552,000 b/d of crude oil, a decline from 618,000 b/d in 2019. This decline occurred during the start of the COVID-19 pandemic as global demand waned and domestic lockdown restrictions caused supply disruptions.

- The United States was the primary destination for Colombia's crude oil exports in 2021, receiving 180,000 b/d. Other main destinations included China, Panama, and India.

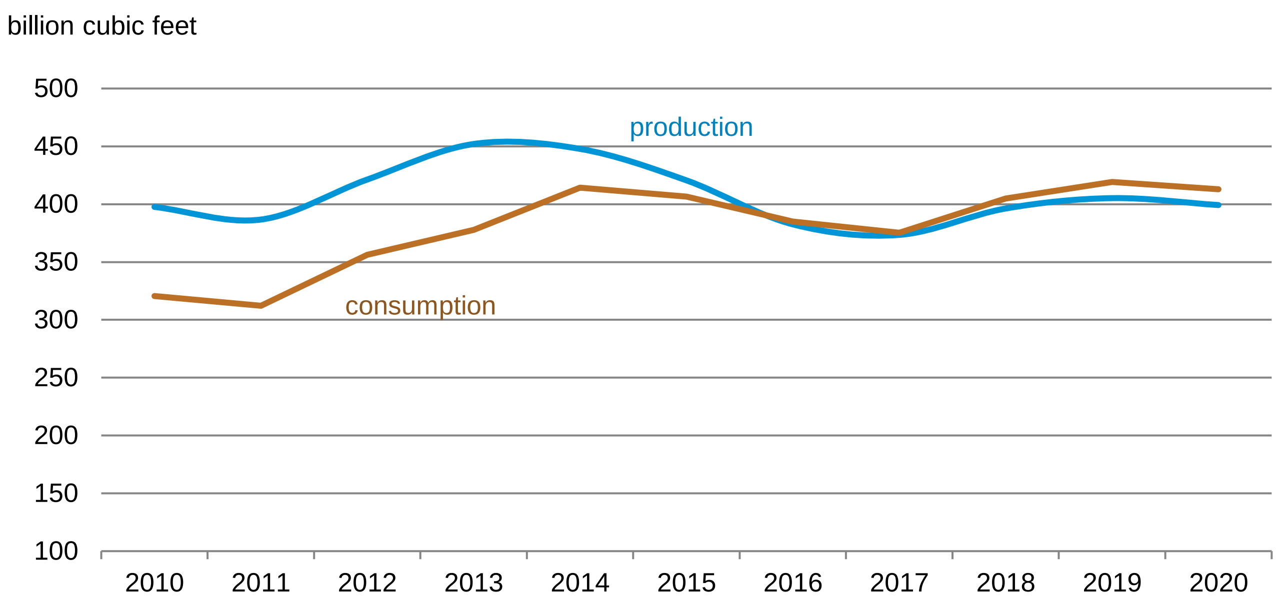
Natural Gas

Exploration and production

- According to the *Oil & Gas Journal*, Colombia had proved natural gas reserves of nearly 3 trillion cubic feet (Tcf) as of January 2022.[22]

- In 2020, Colombia produced 399 billion cubic feet (Bcf) of dry natural gas, and it consumed about 413 Bcf (Figure 4). Colombia predominantly produces associated natural gas (meaning natural gas from oil deposits). Natural gas production in Colombia comes from two main sources: associated gas from inland fields (Cusiana, Cupiagua, and Pauto Sur) and unassociated gas from offshore fields (Chuchupa field). Colombia's national oil company, Ecopetrol, is the primary producer, but foreign firms, including Repsol, Anadarko, and other North American independents, also operate in Colombia. Among the largest fields, only one–Chuchupa–is located offshore and was operated by Chevron until the sale to Hocol in November 2019.[23]

Figure 4. Colombia's dry natural gas production and consumption



Source: Chart by the U.S. Energy Information Administration, *International Energy Statistics*

- Colombia's oil production requires the majority of the country's produced natural gas (nearly 50%) to be re-injected to bolster recovery efforts, which will become increasingly widespread as producers seek to enhance oil recovery amid declining exploration. [24] In addition, the Barrancabermeja and Reficar refineries use natural gas-fired plants to power their daily operations.[25]

- Colombia has a large shale gas potential; however, only pilot projects are currently allowed. In 2019, the national oil company Ecopetrol entered into a joint venture with Occidental to develop natural gas in the United States' Permian Basin to gain relevant knowledge in shale projects that is likely to be used in Colombia once the ban on fracking is lifted.[26]

- In November 2020, Ecopetrol announced a climate strategy to reach its sustainability goals, including a 20% emissions reduction by 2030 or zero routine flaring by 2030.[27] To achieve this goal, Ecopetrol committed to stop routine flaring at its operations, joining the Global Gas Flaring Reduction Program led by the World Bank.[28]

Liquefied natural gas (LNG)

- Colombia imports a small amount to fill the gap between domestic production and demand. Concerns about supply reliability prompted the Colombian government to approve the country's first LNG import terminal in November 2014. The facility came online in November 2016. A second LNG import facility, the Pacific Regasification LNG terminal, was proposed in June 2015. The facility will be located near the Pacific coast port city of Buenaventura and could gasify up to 400 million cubic feet a day. According to media reports, the plant is expected to come online in 2026.[29]

- Like in other South American countries, a significant drought in 2020 led to a fall in hydropower output and an increase in LNG imports to fuel natural gas-fired thermal power plants in Colombia. According to media reports, Colombia's LNG cargos increased over the first half of 2020 compared with the same period in the previous year. The Sociedad Portuaria El Cayao regasification facility received nine LNG shipments between January and May 2020, compared with six shipments in all of 2019. [30,31]

Coal

- Colombia had 5 trillion short tons of proved coal reserves (mostly bituminous coal) in 2020, the second-largest amount in South America behind Brazil.[32]

Exploration and production

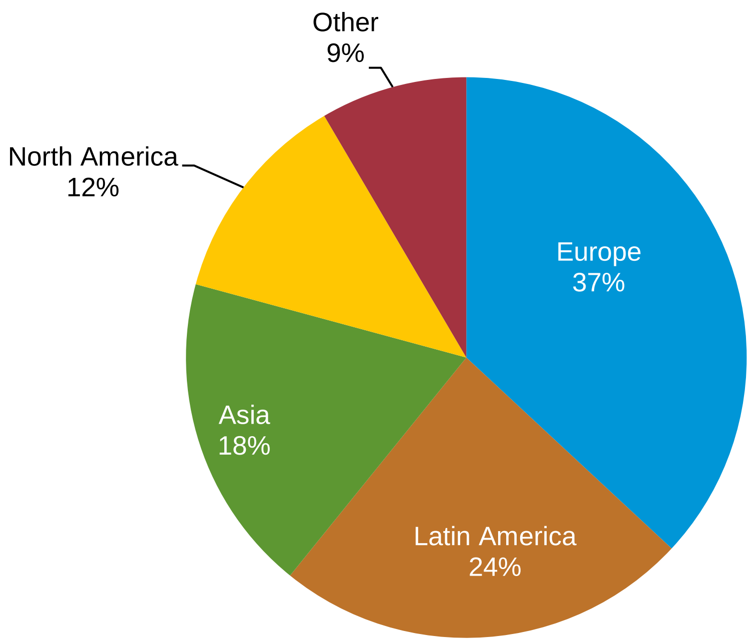
- Colombia produced 54 million short tons (MMst) of coal in 2020, and 9 MMst was consumed domestically. In 2020, coal production fell 42% amid the COVID-19 pandemic and a 91-day strike at a major mine in the north of the country.[33]

Trade

- Most of the coal produced in Colombia is exported, making it the fourth-largest coal exporter in the world in 2020 after Australia, Indonesia, and Russia.[34]

- Coal is the country's second-largest export commodity by value after oil and petroleum products. Colombia exported 75 MMst of coal in 2020, mainly to Europe and Latin America (Figure 5).[35]

Figure 5. Colombia's coal exports by destination, 2020



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

- In 2020, Colombia was the largest source of U.S. coal imports, accounting for 71% of total U.S. coal imports, or about 6.1 MMst.

Electricity

- In 2020, Colombia had 17 gigawatts (GW) of installed electricity generation capacity.[36]
- Colombia generated 69 billion kilowatthours (kWh) and consumed 70 kWh in 2020. Generation mainly came from renewable resources, which accounted for 73% of total generation, nearly all of which was hydropower.[37]
- Because Colombia predominately uses hydropower as its main source of power generation, droughts can significantly affect the generation mix. Droughts have led to significant demand increases for fossil fuels in periods of low rain. In 2020, thermal generation increased to account for the lower levels of hydroelectricity resulting from low water inputs during the year.[38]
- The delayed Ituango hydroelectric dam project, known locally as Hidroituango, is expected by Empresas Públicas de Medellín E.S.P. (EPM) to have the first power-generating unit in service in 2022.[39] Once the number one unit of Hidroituango begins operation, it will generate the first 300 megawatts of energy for the national interconnected system. The entire project will have a

generation capacity of 2.4 GW in 2025, when it is operating with all eight units. The project will be the largest hydropower plant in Colombia.

- Colombia's non-hydropower renewables sector is not as extensive as its hydropower sector, but Colombia's Mining and Energy Planning Unit (UPME) expects non-hydropower renewables to grow through 2030 because of significant opportunities in solar and wind power.[40] Colombia has committed to reach 4 GW of renewable electricity generation capacity and to derive 74% of total electricity consumption from renewables by 2030.[41]

- Colombia currently does not have enough transmission infrastructure to develop non-hydropower renewables in rural areas where renewable power potential is highest. La Guajira holds the largest wind and solar power potential in the country, estimated at 3.5 GW of wind and 2.5 GW of solar. However, the area is isolated from the country's main power grid.[42] According to the UPME, transmission and distribution infrastructure is a priority under the government's 2031 expansion plan, namely, increasing power supply and improving the ability to develop new clean power capacity in regions that have not been connected to the national grid.

Trade

- Colombia imports electricity from Ecuador to help meet demand. In 2020, Colombia imported 1.3 gigawatthours of electricity.[43] Colombia's and Ecuador's electrical grids are linked by dual 230-kilovolt power lines spanning 132 miles.

- Colombia maintains international electricity interconnections with neighboring countries Ecuador and Venezuela. Exports to Ecuador were 250 MWh in 2020.[44]

Notes

- Data presented in the text are the most recent available as of March 31, 2022
- Data are EIA estimates unless otherwise noted.

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![eia logo] Independent Statistics & Analysis
U.S. Energy Information Administration

Background Reference: Colombia

Last Updated: January 7, 2019

Overview

Colombia is South America's largest coal producer and an important regional supplier of crude oil; however, persistent attacks on domestic crude oil pipelines since the 1980s have restrained production levels.

Figure 1. Map of Colombia

Source: Central Intelligence Agency, *World Factbook*

Petroleum and other liquids

***Much of Colombia's crude oil production occurs in the Andes foothills and in the eastern Amazonian jungles*.**[1]

Colombia's crude oil and product infrastructure is primarily located in the northwest and center of the country, close to major crude producing and refined product-consuming regions. Meta Department, in central Colombia, is an important production area, producing predominately heavy crude oil. The area's Llanos Basin contains the Rubiales oilfield, the largest producing oil field in the country.

Sector organization

A series of regulatory reforms enacted in 2003 made the oil and natural gas sector more attractive to foreign investors and led to an increase in Colombian oil and natural gas production.

Ecopetrol, the national oil company of Colombia, controlled the development of all hydrocarbon resources until 2003, when then President Álvaro Uribe enacted energy sector reforms. President Uribe moved administrative and regulatory responsibility for the country's hydrocarbon resources from Ecopetrol to a new regulatory agency, Agencia Nacional de Hidrocarburos (ANH).[2] In 2012, additional restructuring consolidated responsibility for upstream and downstream planning and oversight in the Ministry of Mines and Energy.[3]

Colombia's government has taken measures to make the investment climate more attractive to foreign oil companies. Upstream sector initiatives give foreign oil companies the right to own 100% of shares in oil ventures and to compete with Ecopetrol.[4] In addition, the government has sold shares of Ecopetrol to private investors, reducing its ownership to about 90%.

Ecopetrol, via its wholly-owned subsidiary, Cenit, controls most of Colombia's pipeline infrastructure. Cenit also owns nearly all refined product pipeline capacity in Colombia.

Exploration and production

Colombia has fewer proved oil reserves than Argentina or Ecuador, even though it produces more oil than either country.

Colombia's oil production rose steadily until peaking in 1999. The principal causes of the fall in oil production after 1999 were natural declines at existing oil fields and a lack of new discoveries.

However, changes to the regulatory framework led to more investment from international oil companies. As a result of these investments, Colombia experienced rapid growth in petroleum and other liquids production between 2008 and 2013, peaking again more recently again at 1.03 million barrels per day (b/d) in 2015. The country once again faces declining production in the Chichimene, Castilla, and Rubiales fields as a result of continued pipeline attacks, falling oil prices, and a lack of returns made on investments resulting from the new regulatory framework.

The largest producing oil field in Colombia is the Rubiales heavy oil field, located in Meta Department.[5] Low levels of production began at Rubiales in the late 1980s, but increasing investment and the completion of a new pipeline allowed production rates to rise. Since 2013, however, production at Rubiales has fallen. In August 2015, Ecopetrol elected not to extend its production agreement with Pacific Rubiales, opting instead to maintain the field alone.

Supply disruptions

Frequent attacks by guerilla forces on oil infrastructure during the past three decades have severely affected Colombia's already declining oil production.

Colombia has a long history of attacks on oil infrastructure, roads, and personnel by its guerilla groups, and the number of attacks significantly increased between 2010 and 2013. The U.S. Energy Information Administration (EIA) began tracking disruptions in 2011. In 2014, Colombian disruptions reached a peak with a recorded annual outage of 45,000 b/d which later fell after peace agreements between the government and the guerilla groups.

Despite a 2016 peace agreement between the Revolutionary Armed Forces of Colombia (FARC) guerillas and the government, Colombia's oil industry continues to be the target of pipeline attacks.[6] The National Liberation Army (ELN) and the Colombian government had been in peace negotiations, but those were suspended after attacks by ELN in early 2018.

The 480-mile Caño Limón–Coveñas oil pipeline, which has a capacity of up to 220,000 b/d, is the guerilla groups' most frequent target. It has been bombed more than an estimated 1,400 times during its 32-year history. Since 1986, the attacks have kept it offline for the equivalent of 11 years, approximately one-third of its life. According to Ecopetrol, 66 million gallons of crude oil have been spilled since 2000.[7]

Ecopetrol can use the bi-directional Bicentenario pipeline as a contingency to run oil through to the Covenas port on Colombia's Caribbean coastline when the Caño–Limón pipeline is damaged from bombing. However, this alternative route costs more for producers.[8]

Refining

Colombia's main oil blend is the Castilla Blend, with an API gravity of 18.8, a heavier and sourer (high sulfur-1.97%) crude oil. In addition to output from this field, the blend includes crude oil from other heavy oil fields such as the Rubiales and Quifa fields.[9] Ecopetrol's refineries were originally built to process light, sweet crude oil from fields such as Cusiana and Cupaigua, and Colombia's increasingly heavy crude oil production has presented challenges to the refining and midstream sectors.[10]

Colombia's Barrancabermeja refinery and the Cartagena (aka Reficar) refinery together account for effectively all domestic fuel production. In 2016, the Cartagena refinery came back fully online from an expansion and modernization project. The project increased capacity by 85,000 b/d.[11] Despite the Cartagena expansion, Colombia is still a net importer of refined products.

New projects, including a major modernization project at the Barrancabermeja refinery, have stalled. Two new refineries, Meta and Sebastopol, have been proposed.[12] The 40,000 b/d Meta refinery had reached an agreement with Ecopetrol for crude oil supply beginning at the end of 2015, but it was delayed by legal and corruption issues. The 100,000 b/d Sebastopol has been put on hold because of a lack of financial support. There are no planned expansions to Colombia's refining system before 2021, and any growth will come mainly from improved refinery utilization (Table 1).

Table 1. Refining capacity

Refinery	Location (department)	Current capacity (b/d)	Ownership
Barrancabermeja	Santander	250,000	Ecopetrol
Cartagena	Bolivar	165,000	Ecopetrol
Apiay	Meta	2,500	Ecopetrol
Orito	Putumayor	2,500	Ecopetrol
		Total: 420,000	

Source: Oil & Gas Journal, *2018 Worldwide Refining Survey*

Pipelines

Colombia has a relatively extensive crude oil distribution infrastructure which is primarily located in the northwest and center of the country close to major crude oil-producing and refined product-consuming regions. Colombia has seven major oil pipelines, five of which connect production fields to the Caribbean export terminal at Coveñas (Table 2). The country's largest storage terminals are also located along the coast.

Ecopetrol owns more than 80% of crude oil pipeline capacity, and all product pipeline capacity in Colombia runs through its Cenit subsidiary.[13] The combined length of crude oil and refined product pipeline is more than 6,300 miles long. [14]

Table 2. Major oil pipelines

Pipeline	Length	Origin	Destination	Capacity	Owner or operator
Ocensa	520 miles	Cusiana-Cupiagua	Caribbean port of Coveñas	590,000 b/d	Ecopetrol/Cenit
Llanos	146 miles	Rubiales, Pirirí and Quifa fields	Ocensa pipeline	340,000 b/d	Cenit/Pacific Midstream Ltd.
Caño-Limón	485 miles	Caño-Limón field	Caribbean port of Coveñas	220,000 b/d	Ecopetrol/Occidental Petroleum Corp
Bicentenario	143 miles	Casanare/ Llanos basin	Caribbean port of Coveñas	120,000 b/d	Pacific Rubiales Energy/ Hocol S.A/Cenit
Transandino	190 miles	Orito field (Ecuador)	Pacific port of Tumaco	85,000 b/d	Cenit
Colombia	298 miles	Vasconia station	Caribbean port of Coveñas	15,000 b/d	Ecopetrol
Alto Magdalena	248 miles	Upper Magdalena Valley	Vasconia	9,200 b/d	Ecopetrol/Hocol/Shell

Source: Ecopetrol, BNAmericas

Key projects such as the second and third phases of the Bicentenario pipeline and the Pacífico oil pipeline (OAP), designed to connect the Llanos Basin with the Colombian Pacific port of Buenaventura and facilitate crude oil exports to Asia, have been halted or canceled because of attacks on various parts of the pipeline system.

Trade

Colombia has one transnational pipeline, the Oleoducto Transandino pipeline (OTA). The 85,000 b/d OTA crude oil pipeline connects Colombia's southern port of Tumaco with Ecuador's oil fields. The OTA has been a frequent target for guerrilla attacks.[15]

Natural gas

Most of Colombia's natural gas reserves are in the Llanos Basin, although the Guajira Basin accounts for most of the current production.

Sector organization

Transport and distribution activities are competitive and subject to open access. In 2003, further liberalization measures were taken with the enactment of Presidential Decree 1760, including the creating of the ANH and allowing companies other than state-controlled Ecopetrol to perform upstream activities under ANH supervision

Three companies—Ecopetrol, Equion Energia (a partnership between Ecopetrol and Talisman Energy), and Chevron—account for most of Colombia's natural gas production.[16] Ecopetrol operates the Cupiagua and Cupiagua Sur fields in the large Llanos Basin in eastern Colombia. Equion Energia, formed after Ecopetrol and Talisman Energy acquired BP's Colombian assets in 2010, operates the Cusiana, Cusiana Norte, and Cupiagua Liria fields, also in the Llanos Basin.[17] Chevron, in partnership with Ecopetrol, operates the Caribbean Chuchupa offshore field in the Guajira Basin, the largest nonassociated natural gas field in the country.[18] The company also operates the nearby onshore Ballena and Riohacha fields. [19]

The Colombian government published a decree in March 2011 outlining a plan to increase domestic natural gas production, including production from shale or coalbed methane gas fields. Policies aimed at increasing domestic natural gas consumption and exports, combined with increased demand from the power sector as a result of weather-related hydroelectric shortages, have made expanding natural gas production a priority for the government.

Exploration and production

Natural gas production, like oil production, has risen substantially in the past few years because of increasing international investment in exploration and development.

Natural gas production in Colombia comes from two main sources: associated gas from inland fields (Cusiana, Cupiagua, and Pauto Sur) and unassociated gas from offshore fields (Chuchupa field). Colombia's national oil company, Ecopetrol, is the primary producer, given its role in associated gas production, with an assortment of foreign firms, including Repsol, Anadarko, and other North American independents, also operating.

Of the country's total gross natural gas production, about half was reinjected to aid in enhanced oil recovery. In 2007, natural gas production began to exceed consumption, supporting exports.

Production is divided between two main regions: the Atlantic Coast, where large non-associated gas fields are located, and inland regions, where production is mostly associated with oil.

Colombian gross natural gas production has been steadily decreasing because fields from the Guajira Basin are mature and declining. However, over the past decade, reinjection has decreased from historical levels of over 80% to about 50% as a way to increase natural gas availability in the Colombian market.

Natural gas supplies are highly concentrated in the Cusiana-Cupiagua and Chuchupa fields and in three companies: Ecopetrol, BP, and Chevron. Although gross supplies have been decreasing, net supplies have been increasing as a result of decreasing reinjection levels at the Cusiana-Cupiagua fields.

Ecopetrol and its partner Anadarko made the biggest discovery in nearly three decades with the offshore Gorgon-1 discovery in May 2017. Gorgon-1 is estimated to hold reserves of between 4.6 Tcf – 7 Tcf.

Pipelines

Colombia has about 3,100 miles of natural gas pipelines[20] (Table 3).

Transportadora de Gas Internacional (TGI), a subsidiary of Grupo Energia de Bogota, is the largest operator of natural gas pipelines in Colombia, with a network of approximately 2,300 miles.[21] TGI was formed after Grupo Energia de Bogota acquired the state-owned Empresa Colombiana de Gas (Ecogás) at auction in 2006.[22]

Table 3. Major natural gas pipelines

Pipeline	Origin	Destination	Capacity (MMcf/d)	Owner or operator
Ballena-Barrancabermeja	Ballena field	Barrancabermeja	260	TGI S.A ESP
Barrancabermeja-Nevia-Bogota	Bogota	Nevia	436	TGI S.A ESP
Mariquita-Cali	Mariquita	Cali	168	Transgas de Occidente S.A.

Source: Transportadora de Gas Internacional[23]

Liquefied natural gas

Designed to meet growing fuel demand and reduce reliance on hydropower, Colombia's first liquefied natural gas (LNG) floating storage and regasification unit (FSRU), located at the Atlantic port of Cartagena and owned by Sociedad Portuaria El Cayao (SPEC), started operation in late 2016 when it received its first import cargo. It received a second cargo in mid-2017. SPEC has signed a contract with Norwegian Höegh LNG to operate the 400 million cubic feet per day (MMcf/d) facility.[24]

Colombia's national mining and energy planning body, Planning Unit of the Mines and Energy (UPME), has proposed a second terminal for the country's Pacific coast, Buenaventura LNG. It would have a capacity of around 400 MMcf/d, to begin operations in 2021.

Trade

The Trans-Caribbean Gas Pipeline, also known as the Antonio Ricaurte Pipeline, came online in 2007, linking fields in northeastern Colombia's Guajira Department with western Venezuela. [25] Venezuela's Petróleos de Venezuela S.A. (PdVSA) financed the $335 million pipeline. In November 2011, an agreement was signed to extend the Ricaute Pipeline across Colombia to Panama and Ecuador. Although initial contracted volumes for export from Colombia ranged from 80 to 150 million cubic feet per day (MMcf/d), actual exports to Venezuela have often exceeded these levels because of rising Venezuelan demand for natural gas for power generation and to support enhanced oil recovery. Natural gas exports through the pipeline, which had reached 250 MMcf/d, were stopped in May 2014 amid fears that Colombia's power supply, derived primarily from hydroelectric facilities, would be affected by drought.[26] Since then, Colombia has resumed exports, but at a lower level.[27]

Plans to reverse the pipeline so that Venezuela can export natural gas to Colombia were discussed but have not yet taken place.

In 2017, Colombian natural gas distributor Promigas and its local partner Gases de la Guajira proposed to use the Antonio Ricaurte Pipeline cross-border pipeline to import Venezuelan natural gas as an alternative to sending domestic natural gas to the Colombian border city Maicao.[28]

Coal

Sector organization

Colombia is by far the largest producer of coal in South America, and has the second largest coal reserves in the region. The government owns all hydrocarbon reserves, and Colombian coal production is exclusively managed by private companies.

The largest coal producer in Colombia is the Carbones del Cerrejon (Cerrejon) consortium, composed of Anglo-American, BHP Billiton, and Glencore Xstrata, which operate in the region of La Guajira.[29] The consortium operates the Cerrejon Zona Norte (CZN) project, the largest coal mine in Latin America and one of the largest open-pit coal mines in the world.[30] CZN is an integrated system connecting the mine, railroad, and a Caribbean coast export terminal.

U.S.-based Drummond Company, the second-largest coal producer in Colombia, operates two mines near La Loma, in the Cesar Basin.[31] In June 2011, Drummond entered into an 80%-20% partnership with Japan's Itochu Corporation, known as Drummond International, which now owns and operates its Colombia interests.[32] Itochu's initial investment of $1.5 billion enabled expansion construction of a new export facility, increasing Drummond's export capacity to 60 million metric short tons (MMst) per year. The partnership aims to increase coal exports to Japan and other Asian countries.[33]

Exploration and production

Colombia's coal reserves are concentrated in the Guajira peninsula bordering the Caribbean and in the Andean foothills. Most of Colombia's coal production and export infrastructure is located on the Caribbean coast. Colombia is considered to be a low-cost producer, and its coal is highly sought after because it is considered relatively clean-burning and has a sulfur content of less than 1%.[34]

The largest exporting coal fields are located in the Guajira and Cesar Departments at the northeast, close to the Venezuelan border. Production at these two departments accounts for approximately 90% of the country's total.

The remainder of Colombia's domestic output is mostly produced in the interior departments of Boyacá, Cundinamarca, Norte de Santander, and Santander.

Coalbed methane

Coalbed methane (CBM) is a gaseous hydrocarbon that occurs alongside coal resources. This source of natural gas is transported and used in the same way as natural gas found in shale or other deposits. CBM has the potential to significantly increase Colombia's proved natural gas reserves and eventually its production, which would provide additional natural gas to export to neighboring countries. Estimates of Colombia's total potential coalbed methane resources range from 11 trillion cubic feet (Tcf) to 35 Tcf; however, only some of those reserves may be economically recoverable. [35]

Electricity

Sector organization

The Colombian Commission for the Regulation of Energy and Gas (CREG) was established to regulate the activities of public utilities in 1994 through Laws 142 and 143.[36]

The competitive market model for the provision of public utilities in Colombia was introduced in 1994. Law 143 of 1994 established the scheme that governs generation, transmission, distribution, and commercialization of electricity as well as the key elements and guidelines creating the Wholesale Electricity Market (Mercado de Energía Mayorista, or MEM), which came into operation in July 1995.[37]

The planning, supervision, and control of the integrated operation of resources for generation, interconnection, and transmission of the National Interconnected System (Sistema Interconectado Nacional, or SIN) are undertaken by the subsidiaries of XM, a public utility corporation regulated by the CREG [38] (Table 4).

Table 4. Institutional structure of the Mercado de Energía Mayorista (MEM)

Policies	Ministry of Mines and Energy
Planning	Planning Unit of the Mines and Energy
Regulation	Commission for the Regulation of Energy and Gas
Control and surveillance	Superintendency of Public Utility Services
System operation	National Dispatch Center (Centro Nacional de Despacho, "CND")
Market administration	Commercial Interchange System (Administrador del Sistema de Intercambios Comerciales, "ASIC")

Source: Colombian Commission for the Regulation of Energy and Gas (CREG)

Key projects

The Ituango Hydroelectric Project is located on the Cauca River, approximately 105 miles from the city of Medellin.[39] The project was approved in 2009 and was expected to cover between 17%-20% of Colombia's energy demand once in full operation. Since the start of construction, environmental activists have opposed the dam for its impact on the environment and its disruption in fishing and farming communities.[40] Extreme heavy rainfall has caused concerns that the dam may burst and Empresas Publicas de Medellin (EPM) has suspended certain activities, which has delayed completion until 2021.[41]

Trade

Colombia is a net exporter of electricity. According to the Planning Unit of the Mines and Energy (UPME), Colombia is looking to increase its electricity imports to neighboring Panama by 2021.[42]

Note

- 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 December 12, 2018.
- Data are EIA estimates unless otherwise noted.

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MARCH 25, 2022

TEXAS UPSTREAM EMPLOYMENT INCREASES IN FEBRUARY

Subscribe to this blog post

Print

Austin, Texas - Citing the latest Current Employment Statistics (CES) report from the U.S. Bureau of Labor Statistics (BLS), the Texas Independent Producers and Royalty Owners Association (TIPRO) today highlighted new employment figures showing another month of positive job growth for the Texas upstream sector in 2022. According to TIPRO's analysis, Texas upstream employment for February 2022 totaled 181,900, an increase of 5,100 jobs from revised January numbers. Texas upstream employment in February 2022 represented an increase of 20,700 positions compared to February 2021, including an increase of 1,900 positions in oil and natural gas extraction and 18,800 jobs in the services sector.

TIPRO also once again noted strong job posting data for upstream, midstream and downstream sectors for the month of February in line with rising employment, showing a strong demand for talent in the Texas oil and natural gas industry. According to the association, there were 9,985 active unique job postings for the Texas oil and natural gas industry in February of 2022, a 20 percent increase compared to January.

Among the 14 specific industry sectors TIPRO uses to define the Texas oil and natural gas industry, Support Activities for Oil and Gas Operations ranked the highest in February for unique job listings with 2,712 postings, followed by Crude Petroleum Extraction (1,239) and Petroleum Refineries (905). The leading three cities by total unique oil and natural gas job postings were Houston (3,319), Midland (1,048) and Odessa (541), said TIPRO. The top three companies ranked by unique job postings in February were Baker Hughes, National Oilwell Varco, Inc. and Halliburton. Top posted occupations for February included heavy tractor-trailer truck drivers (413), maintenance and repair workers (284) and software developers and software quality assurance analysts and testers (262).

"Rising global energy demand and strains on oil and natural gas supply exacerbated by geopolitical conflicts necessitate the urgent need for increased domestic production," said Ed Longanecker, president of TIPRO. "Though the U.S. energy sector is not immune to supply chain challenges and workforce shortages presented by both COVID-19 and the unfolding conflict in Eastern Europe, Texas oil and natural gas operators stand ready to support growing energy demand here and around the world. To successfully meet this demand both today and tomorrow, we must encourage long-term investments in domestic production. This includes taking immediate action on all U.S. LNG export facility and gas pipeline applications, ending the moratorium on new leases on federal lands and putting a stop to the political rhetoric against our industry, including the inaccurate and irresponsible notion that the oil and natural gas sector is taking advantage of the global energy crisis to increase profits. It's time to work together and develop real strategies to address the energy challenges facing American citizens and our allies abroad," added Longanecker.

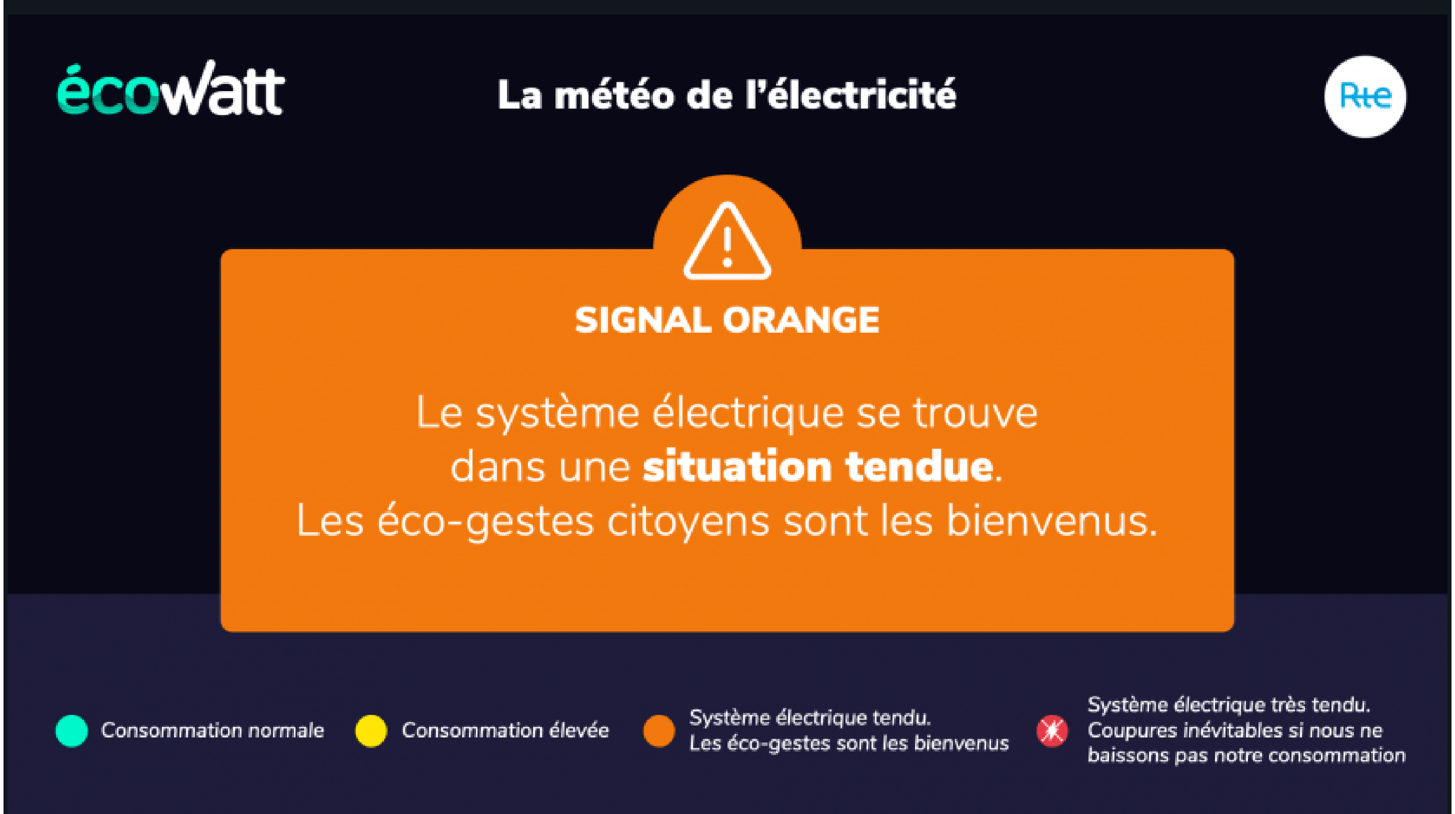
https://www.rte-france.com/actualites/baisse-temperatures-rte-active-signal-orange-national-ecowatt-lundi-4-avril-2022

Lower temperatures: RTE activates the Orange national Ecowatt signal for Monday April 4, 2022

02.04.2022

CONSUMPTION

RTE warns that the situation on Monday morning could be tense with regard to the balance between electricity consumption and production. RTE reminds that everyone (households, businesses or local authorities) can help reduce their electricity consumption by adopting the right actions during the peak consumption scheduled for this Monday, April 4, between 06:00 and 12:00.



Due to the drop in temperatures, electricity consumption will be high this Monday, April 4, 2022 and could reach 73,000 MW around 09:00. Electricity production should be 65,000 MW, but France should be able to import up to 11,000 MW.
However, RTE does not envisage a power outage on Monday morning, unless unforeseen events occur this weekend. RTE will update its analyzes on Sunday based on the most recent weather forecasts on the one hand and the level of electricity production on the other.
RTE asks **companies and communities to moderate their consumption on Monday morning** (in particular between 07:00 and 10:00 a.m.) and asks French people who can to**shift their electricity consumption to this weekend rather than Monday with regard to the use of household appliances** (such as dishwashers or washing machines).
At work or at home, everyone can act by performing simple actions presented on the monecowatt.fr website, for example by lowering the temperature of their home in the event of absence during the day, or by completely switching off their devices on standby, even by limiting the number of lights on in a room, etc.
These gestures can have a real impact. For example, if all French people turn off a light bulb, this leads to a saving in electricity consumption of 600 MW, or approximately the consumption of a city like Toulouse.

Moreover, in the current energy context, any reduction in electricity consumption makes it possible to limit the use of means of producing electricity from gas. Indeed, the reductions in consumption lead to limiting the use of gas-fired power plants and contribute to saving gas stocks for next winter.

Visit **MonEcowatt.fr**

About RTE
RTE, manager of the French electricity transmission network, carries out a public service mission: to guarantee the supply of electricity at all times and with the same quality of service on the national territory thanks to the mobilization of its 9,500 employees. RTE manages electricity flows and the balance between production and consumption in real time. RTE maintains and develops the high and very high voltage network (from 63,000 to 400,000 volts) which has more than 100,000 kilometers of overhead lines, more than 6,000 kilometers of underground lines, 2,800 electrical substations in operation or co-operation and 51 cross-border lines. The French network, which is the most extensive in Europe, is interconnected with 33 countries. As a neutral and independent industrial energy transition operator, RTE optimizes and transforms its network to connect electricity production facilities regardless of future energy choices. RTE, through its expertise and its reports, sheds light on the choices made by public authorities.

About Ecowatt
RTE – manager of the French electricity transmission network, in partnership with ADEME has developed Ecowatt, a citizen device for managing the electricity system. Real electricity forecast,

Ecowatt describes in real time the level of consumption of the French, region by region. At all times, clear signals guide the consumer to adopt the right gestures and know when to reduce their consumption to avoid cuts: for example during cold spells in winter.

French Nuclear Availability Drops to 50% as Unit Halts (Table)
By Jesper Starn
(Bloomberg) --
France's nuclear reactors were operating at 50% of full capacity on Thursday, down from 52% on Monday, according to Bloomberg calculations using data from grid operator RTE.
Electricite de France SA halted its Chinon-1 reactor on Wednesday until 6 p.m. on Thursday while the start of Dampierre-1 was delayed until Saturday.
The world's biggest nuclear-plant operator had 29 reactors available with a combined output of 29,620 megawatts as of 8:15 a.m. in Paris. Its 56 units generate more than two-thirds of the country's electricity.
The table below lists EDF reactors that are out of service, their capacity in megawatts, when they halted, the expected return date if known, and details of the latest changes:

Unit name	Megawatts	Outage date	Return date	Comment
Chinon-1	905	March 30	March 31	To start at 6 p.m.
Dampierre-1*	890	March 26	April 2	Extended 3 days
Cattenom-3	1,300	March 26	April 30	
Paluel-4	1,330	March 25	June 29	
Flamanville-1	1,330	March 22	April 28	
Gravelines-3	910	March 19	Sept. 29	
St Laurent-2	915	March 12	May 1	
Blayais-2	910	March 12	April 21	
Belleville-1	1,310	March 12	April 24	
Tricastin-3	915	March 12	Aug. 30	
Nogent-2*	1,310	March 10	April 3	
Dampierre-2*	890	March 10	April 10	
Golfech-1	1,310	Feb. 26	Aug. 16	
Bugey-2	910	Feb. 19	April 18	
Chinon-3	905	Feb. 19	July 09	
Cattenom-4	1,300	Feb. 18	May 31	
Flamanville-2	1,330	Feb. 12	July 29	
Chooz-1	1,500	Feb. 11	Dec. 31	
Chinon-4	905	Feb. 5	May 1	
Cruas-4	915	Feb. 05	May 7	
Chooz-2	1,500	Dec. 16, 2021	Dec. 31	
Civaux-2	1,495	Nov. 20, 2021	Dec. 31	
Penly-1	1,330	Oct. 2, 2021	Oct. 31	
Gravelines-6	910	Sept. 25, 2021	April 1	
Civaux-1	1,495	Aug. 21, 2021	Aug. 31	
Gravelines-1	910	Aug. 14, 2021	April 8	
Bugey-5	880	July 31, 2021	April 8	

*=unplanned, Source: RTE, EDF

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SAF Group created transcript of CNBC's Hadley Gamble with Eni CEO Claudio Descalzi on March 28, 2022

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

Descalzi "*I think that's also, the minister said clearly that in the last years, in the past, we create a conflict between energy transition and gas or oil and decarbonization. It became an ideology so just renewables. We are producing also renewables. We know we cannot do everything with just renewables. There are a lot of different technologies. But gas, until two months ago, in Europe, the taxonomy, gas was out. In November, October, I don't want to say that you are a criminal if you produce gas and oil, but not far to be a criminal okay if you are producing gas or oil. And now, so that is a big mistake to be radical and say I want just that, renewables. And the rest have to disappear. We know very well that in the last 200 years, all the different energy vectors have been added – so coal, plus oil, plus gas and plus renewables. We never found a source or energy source that replaced everything. it's crazy to think that there is something that can replace everything. for that reason, the transition, we have to accept that we have some infrastructure for what we spent billion and billion that are hard to abate so we have to capture. And we need to use all the different technologies if we think that we are to choice some technology by in an ideologic approach, its crazy. Technology is neutral, there is no religion, it is not a god a technology. You have to use to phase the transition. so I think that when we talk about energy, first of all, we have to know what you are talking about – competencies. Everybody talks about energy, everybody talk about Covid. And make a big confusion. They create a big mistake and now we see what happened. It's not just Russia, the gas price is not just Russia. Because for seven years, we underinvested, we invested just 45% of what we invested in the previous seven years until 2014. Then we have Russia, then we have Covid, so I think that the worldwide leadership was not wise and without any equilibrium in evaluating the energy situation*."

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

SAF Group created transcript of CNBC's Hadley Gamble with Saudi Energy Minister Prince Abdulaziz on March 29, 2022
https://www.cnbc.com/2022/03/29/saudi-energy-minister-says-opec-will-leave-politics-out-of-oil-decisions.html

Source: CNBC
Items in "*italics*" are SAF Group created transcript

Abdulaziz referring to his speech at COP26 in November at Glasgow "… *the last paragraph of that speech, I enumerated three things. And it was in Glasgow when everyone was talking about sustainability, climate change, climate change, climate change. I said and I will repeat and I would differ with Dan Yergin because I was the one who first mentioned security of supply at that meeting. I said the [xxx] of what we should do is energy security. Second, economic sustainability and growth and prosperity. Third and I am not ranking, but actually I call them the three pillars, climate change attendance. But truly, you cannot attend to climate change without getting energy security. And certainly, if you don't have energy security, you would not have economic prosperity, you will not have economic growth. if you don't' have the two, you would lose the means of attending to climate change And, that day, I can see it in faces, oh yeah yeah yeah, he's the representative of Saudi Arabia bragging about these things. Well, here comes Johnny, look at what is happening today. Who's talking about climate change now? Who is talking about attending to energy security first and foremost? Look at the countries that juggled their own energy mix. Look at how much people are advancing their idea of thoughts we should focus on energy, on oil and gas, and we are pro producing oil and gas. And pro, and pro, Hallelujah, pro using coal*"

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

https://www.regjeringen.no/en/aktuelt/strengthening-climate-risk-efforts-in-the-government-pension-fund-global/id2906678/

Strengthening climate risk efforts in the Government Pension Fund Global

Press release | Date: 01/04/2022
| No: 15/2022

The Government will strengthen the efforts on climate risk in the Government Pension Fund Global (GPFG). The changes proposed in the white paper The Government Pension Fund 2022 are largely in line with the recommendations in the expert report Climate Risk and the Government Pension Fund Global.

The Government's proposals:

- The responsible investment efforts are to be based on a long-term goal that the companies the Fund is invested in align their activities in a way consistent with global net zero emissions in accordance with the Paris Agreement
- Norges Bank shall stipulate principles for the management and measurement of climate risk
- Stress testing of the portfolio, including a scenario in accordance with global warming limited to 1.5 degrees
- Reporting in accordance with recognised standards and leading frameworks
- The responsible investment efforts to be reviewed on a regular basis

"The Government wants to make the GPFG world leading in responsible investment and the management of climate and nature risks. There is, at the same time, a broad political consensus that the Fund has a financial objective and is not a climate policy tool", says Minister of Finance Trygve Slagsvold Vedum (Centre Party).

Climate change gives rise to financial risk and investment opportunities

Climate change affects the global economy and financial markets. Company earnings will be influenced by climate policy, technological development, changing stakeholder preferences and physical implications of climate change. Uncertainty with regard to how companies and the global economy will be affected gives rise to financial risk, which needs to be managed by investors.

A comprehensive and systematic approach

Climate risk assessments have for a number of years formed an integral part of risk management, investment decisions and active ownership for the GPFG. Climate risk is nonetheless only one of many risk factors to which the Fund is exposed. Climate risk should therefore continue to be addressed in the context of overall risk management within the general objective of the Fund; to attain the highest possible return given an acceptable level of risk.

The investment strategy should remain unchanged

There is no reason to change the composition of the benchmark index in response to climate risk. This is highlighted both by the expert group and by Norges Bank. A broad, global market index is a suitable basis for managing climate risk and ensuring that the Fund will be exposed to the investment opportunities that arise.

Basing the responsible investment efforts on a long-term goal

As a long-term global investor, the Fund has a financial interest in companies decarbonising and the climate transition taking place in an orderly manner. Responsible investment and active ownership will be of key importance in climate risk management.

The responsible investment efforts shall be based on a long-term goal that the companies the Fund is invested in align their activities in a way consistent with global net zero emissions in accordance with the Paris Agreement. Such a goal was also the recommendation of the expert group, and was supported by Norges Bank. This does not mean that the Fund shall be managed with a view to realising any other objective than the highest possible return, given an acceptable level of risk. The key to reducing climate risk is an effective and predictable climate policy. This falls outside the responsibilities of the GPFG as a financial investor.

Comprehensive climate reporting in line with leading frameworks
Norges Bank must report on climate risk in conformity with recognised principles and standards. Such reporting shall be in accordance with leading frameworks in this field and be further developed to reflect new knowledge and practises over time.

Since a more ambitious climate risk management and reporting arrangement is now being established for the Fund *as a whole*, the Ministry of Finance is proposing to remove the management mandate requirement for Norges Bank to establish specific environmental investment mandates. It is the *requirement* that it proposed removed. This does not mean that the Fund's investments in climate- and environmentally-related activities *must* be reduced. The GPFG may still be invested in unlisted renewable energy infrastructure, within the current cap of 2 percent of the market value of the Fund. This implies, in somewhat simplified terms, that the cap on such investments is increased from NOK 120 billion to about NOK 240 billion, based on the market value of the Fund at the beginning of this year.
Read more:

https://www.norges-bank.no/aktuelt/nyheter-og-hendelser/Foredrag-og-taler/2021/2021-12-21-borsum/

Ownership and climate risk in the GPFG - on the instruments for managing climate risk in the GPFG

Speech by Deputy Governor Øystein Børsum, 21 December 2021.

Actual performance may differ from published text

Introduction

Climate challenges are an engaging theme.

Figure: Emissions must be reduced

The world economy, as it operates today, is not sustainable. It must be, and then emissions must go down. It concerns us all - and not least our common fund. With a broadly diversified, global portfolio and a long horizon, we are in many ways burdened with the world economy.

Norges Bank is a financial investor. We will secure and create financial value for future generations. It is our task as manager of the fund. But how the assignment is carried out can also have an impact beyond the purely financial. Among other things, in the transition to a low-emission society. What our role should be - what our work should consist of - is what I want to talk about today.

This summer, an expert group submitted a report to the Ministry of Finance with recommendations on how climate risk should be managed in the fund. During the autumn, we at Norges Bank worked to assess the proposals and look at how they can be implemented.

A couple of days ago, the Executive Board sent its response to the Ministry of Finance. In the bank's management of climate risk, a lot is already being done, and we are outlining even more ambitious plans for the future. As a long-term and global investor with ownership interests in several thousand companies, we have a financial interest in the companies adapting to the risk and opportunities that climate change entails in a good way.

We propose that Norges Bank be a driving force for the companies we are invested in to adjust to net zero emissions over time - that the companies we invest in reflect the restructuring that the world has to go through.

The fund as an investor

Our characteristics as an investor

The climate risk in the fund is related to who we are as an investor and our overall investment strategy. In short: The fund is large, broadly diversified, long-term and close to the index.

Chart: Large, broadly diversified, long-term and index-linked

Of the fund's more than 12,000 billion, 70 per cent is invested in shares. With that, we are one of the world's largest shareholders. We are owners of 9000 companies in 70 countries.

And we are long-term. By using only the real return, the fund can in principle be perpetual.

The strategy is based somewhat simply on the following: If we are to achieve the best balance between expected return and risk, we must spread the investments widely and own a little of everything in the market. There is a solid professional basis for this approach.

How climate risk is relevant to the fund

What does this way of managing the fund have to say for the fund's climate risk? By spreading the investments widely, we are protected against incidents that only affect individual companies or special sectors. But we can not protect ourselves from events or developments that affect everyone.

The fund is exposed to two types of climate risk - physical risk and transition risk.

Transition risk is about whether the *companies* we own will manage the transition to a low-emission economy. Here the challenge is very different across sectors and companies.

Chart: Transition risk and the fund

The fund's equity investments can be categorized according to transition risk as assessed by the research company MSCI today. The blue bars in the figure show shares of the fund's portfolio. The white bars show the emissions in the companies. The companies that have ended up in the category «restructuring» have high emissions and must therefore restructure significantly. They make up 14 percent of the equity portfolio. The rest are companies that are either considered to be neutrally positioned or are considered to make a positive contribution to a green transition. The latter are thus part of the solution. [1]

Physical risk is more directly linked to climate change. The easiest to think about are acute events such as extreme weather, but also more gradual changes such as warmer climates, droughts and increased sea levels can affect individual investments in both negative and positive directions.

In a scenario where the world does not succeed in the transition to a low-emission economy, the risk increases, also for the fund, because the consequences of major climate change will be felt everywhere. As owners of shares, bonds and real assets, we are invested in everything from real estate and infrastructure, forestry and the food industry to all kinds of production capital. All of these are investments that can be affected by changes in the environment, including heat waves, floods and fires. We own a little of everything.

For a large, long-term, global fund, there will be nowhere to hide.

Climate risk is a long-term and important risk that the fund must deal with.

What does a long-term goal of net zero emissions mean for the fund?

A key recommendation from the expert group is that Norges Bank's responsible management be given a long-term goal of working towards net zero emissions from the companies in which the fund is invested. Norges Bank supports this recommendation.

Some may interpret this as a plan to sell shares in companies with large emissions.

But that is not our approach, nor is it the expert group's proposal. Instead of selling ourselves out, we will through active ownership be a *driving force* for the companies to adapt. In order to influence, we must actually be owners.

And we believe that ownership work works.

It works because we are big. Norges Bank is among the ten largest owners in about half of the companies we are invested in, and we have experienced that the companies listen when we talk.

Responsible management - a chain of instruments

Figure: Responsible management - a chain of instruments

Responsible management is our foremost tool in the work with climate risk and climate-related investment opportunities. I will now consider some important parts of this work. We are already doing a lot, and now we want to do even more.

The work can be grouped into three: The work we do towards the markets, towards the companies and with the portfolio. Together, this constitutes a coherent chain of instruments. I can not take a full review of the work here, but will highlight some points.

Default setting

The first point, standard setting, is about standards for reporting and measuring companies' climate risk.

Good common standards are important. This enables us as managers to assess the companies' prospects, prioritize ownership work and make good investment decisions.

But not just us. Better reporting will make the financial markets more well-functioning and better able to allocate capital. International standards provide equal conditions across markets and set the list for all companies. We, and other major investors, have an important role to play in contributing to the development of these standards.

Among the particularly important initiatives we have supported are climate reporting from the Task Force on Climate-Related Financial Disclosures (TCFD). Such reporting has been voluntary, but we believe that it must now become a requirement. Another issue we are working on is a comprehensive standard for sustainability reporting in line with the recently launched International Sustainability Standards Board (ISSB).

We will also work for good standards for reporting on companies' indirect emissions in the value chain, so-called "framework 3". In many sectors, this is crucial for understanding the companies' climate risk. We will also work with other climate-related issues where international standards may be appropriate. The use of various forms of climate quotas can be an example of this.

Our work with the companies starts with setting clear expectations.

We have formulated our expectations in our own expectations documents. In the climate area, we already expect companies to have a climate strategy, set emission targets, report on developments and stress test their business models against different climate scenarios. Going forward, it is natural for us to emphasize the horizon towards zero emissions. This will provide a clearer direction for the exercise of ownership.

Exercise of ownership

The exercise of ownership will be central to the work to manage the fund's climate risk. Not least, the dialogue with the companies is important.

Figure: Climate is more often a theme in the dialogue

The dialogue with the companies follows our expectations. Last year we had about 3,000 meetings with the companies, and as you can see from this figure, sustainability is increasingly on the agenda.

Going forward, we will increase ownership activity on climate, both in scope and depth.

We will give particular priority to ownership activity towards the companies that have the largest emissions, towards those that have not published their own climate plans or have inadequate climate reporting. We will also strengthen the ownership activity aimed at the financial sector, which is indirectly exposed to climate risk through lending and investments.

The dialogue is adapted to the sector and situation. Steel and cement are an example. These companies currently have large emissions, but are also manufacturers of products we also need in a low-emission society. Therefore, the dialogue is precisely about transition plans, much about the technological measures and investments needed for change. We also address the need for industry standards and lobbying, which is a significant challenge.

Figure: Companies report better on climate

We see signs that the work is working. For example, when we analyze the reporting from 1,500 companies, we see that the companies we have been actively involved in have made greater progress in reporting on climate strategy than the other companies. Of course, we should not take all the credit for these advances. But there is progress.

In the future, we will report more about the dialogue with the companies, what they are about and changes we see. That it is visible is a tool in itself.

Reporting and voting

The dialogue with the companies will not succeed in all cases. We can then hold the boards responsible for their decisions through our voting. This year, we have, among other things, in six cases voted against renewed confidence in board members due to inadequate management of climate risk. This sounds small, but in the future we will work to use this tool to a greater extent than today.

We have started by announcing our voting five days before the actual voting. What we do is noticed.

Another alternative is to promote shareholder proposals, alone or together with others. In the past year, we have supported 19 shareholder proposals on climate. One of those who gained a majority led to a large international company initiating work on reporting on emissions in the value chain ("Box 3"). Going forward, we will also consider promoting our own shareholder proposals.

Risk-based divestments

A last resort, when the exercise of ownership does not succeed, is the sale. It will not be the case that we automatically sell out if the ownership work does not succeed. But in some cases it can be the result.

Norges Bank can sell out of a company on a financial basis. This is what we call risk-based divestments. These are companies that we believe handle climate risk in a very deficient way - and thus provide an increased financial risk. This is about avoiding companies that we believe do not have sustainable business models.

Figure: More than half of the sales are related to climate

Risk-based divestments are active decisions made by Norges Bank, which draw on the fund's framework for deviations from the benchmark index. In the period 2012-2020, we have made more than 300 such sales, and more than half have been linked to climate change.

We are ready to do more of this in the future.

As a continuation of risk-based divestments, we have also begun to systematically assess companies' sustainability risk before entering the fund's benchmark index.

The fund is managed close to the index. Risk-based divestments will therefore mainly be relevant for smaller companies. For larger companies, we have more limited room for maneuver, as such sales will to a greater extent draw on the framework for deviations from the benchmark index.

The behavioral criterion

Figure - Responsible management - a chain of instruments

This takes me over to the second form of divestiture, namely exclusion on ethical grounds. The fund's ethical guidelines contain both a product-based coal criterion and a behavior-based climate criterion.

The latter includes companies that are linked to serious environmental damage or to an unacceptable degree lead to greenhouse gas emissions.

The Council on Ethics advises observing or excluding a company based on this criterion. Based on their recommendations, the Executive Board of Norges Bank makes the final decision based on these recommendations. A decision on exclusion means that the company is excluded from both the portfolio and the benchmark index. It therefore does not draw on our framework for deviations.

It is our experience that the practice of this criterion is complex and that it requires broad insight and detailed information about companies' activities and plans.

Norges Bank expects that we will - in light of the work I have talked about today - gather further detailed information about the companies' climate risk and climate plans. We will share this information with the Council on Ethics.

Downsizing or exclusion is the last link in the chain of instruments, but far from the most important. We plan for Norges Bank to be a driving force for the companies in the portfolio to adjust to net zero emissions over time. Active ownership is the key tool.

End

Before I conclude, I would like to mention that we invest in companies that can contribute to solutions to the climate challenges, both through the environmental mandates and in the rest of equity management. We are now also in the process of building up a portfolio of high-quality wind and solar power plants.

The first environmental mandates were established in December 2009, and have had positive learning effects for several parts of the organization. As we write in the letter to the ministry, we will in future draw more on the competence of the managers of the environmental mandates in other parts of the administration.

Overall: Our ambition is for us to be a leader in responsible management. In collaboration with other large investors, we will contribute to the development of standards and methods for reporting. We will strengthen our dialogue with companies about climate both in scope and depth, and utilize the entire toolbox we have as an investor. We will influence companies to take the restructuring seriously. We expect concrete plans, not empty words or greenwashing! And not least - we must have a clear voice in our ownership work.

Footnote

[1] The calculations are based on the analysis company MSCI's classification of companies' transition risk. 80 per cent of the market value of the fund's equity portfolio ends up in the group of companies that are neutrally exposed to transition risk.

PUBLISHED December 21, 2021 9:00 AM

https://www.cppinvestments.com/public-media/headlines/2021/cpp-investments-highlights-importance-of-decarbonizing-hard-to-abate-sectors-in-addressing-climate-change

CPP Investments highlights importance of decarbonizing hard-to-abate sectors in addressing climate change

• CPP Investments releases position outlining investors' role in enabling an economy-wide evolution to a low-carbon future
• Introduces new investment approach that will identify, fund and support companies in their effort to decarbonize

Toronto, CANADA (December 15, 2021) – Helping essential, high-emitting businesses decarbonize is critical to addressing climate change, according to a recent perspective published by Canada Pension Plan Investment Board (CPP Investments). The perspective, "Investing to enable an economy-wide evolution to a low-carbon future," highlights the opportunity decarbonization presents for long-term investors, noting the need to address a particularly serious obstacle to decarbonization: strategic sectors that are essential, high-emitting and hard-to-abate.

The perspective also outlines CPP Investments' new investment approach which aims to identify, fund and support companies that are committed to creating value by lowering their emissions over time, consistent with CPP Investments' time horizon advantage.

"High-emitting companies that successfully navigate the economy-wide evolution to a low-carbon future will preserve and deliver embedded value for patient long-term investors like CPP Investments," said Deb Orida, Global Head of Real Assets & Chief Sustainability Officer. "This new investment approach complements the Fund's ongoing commitment to investing in companies that have the potential to develop innovative climate technologies around the world and furthers our existing capabilities in technologies that enable the energy evolution."

Strategic sectors that are essential, high emitting and hard-to-abate within this investment approach include agriculture, chemicals, cement, conventional power, oil and gas, steel and heavy transportation. The successful decarbonization of these sectors is not only essential to meet wider net-zero ambitions, but also to sustain economic growth, stability and a responsible transition. CPP Investments plans to work in partnership with like-minded companies, industry leaders, investors, and other interested parties to build out a dedicated investment approach to support current and future portfolio companies in their evolution.

CPP Investments also released a related perspective today focusing on an additional key element of sustainable investing, "Financing a greener future," highlighting green bonds as part of the Fund's approach to deploying capital for projects with environmental benefits. The paper outlines how for green bonds to go from a fast-growing niche to a mainstream offering, standards will have to grow out of a mix of evolving draft rules into something closer to the bond market's extant framework for governing how debt is rated, issued and evaluated for performance. The imperative is to improve green bond standards and practices quickly. Doing so can help the financial sector realize its enormous potential for guiding capital toward investments that support the transition to a low-carbon economy while also boosting returns. In 2018, CPP Investments was the world's first pension fund to issue green bonds and has floated six more issuances since.

For more information, the "*Investing to enable an economy-wide evolution to a low-carbon future*" perspective can be found on the CPP Investments website here. The "*Financing a greener future*" paper can be found here.

About CPP Investments

Canada Pension Plan Investment Board (CPP Investments™) is a professional investment management organization that manages the Fund in the best interest of the more than 20 million contributors and beneficiaries of the Canada Pension Plan. In order to build diversified portfolios of assets, investments are made around the world in public equities, private equities, real estate, infrastructure and fixed income.

Headquartered in Toronto, with offices in Hong Kong, London, Luxembourg, Mumbai, New York City, San Francisco, São Paulo and Sydney, CPP Investments is governed and managed independently of the Canada Pension Plan and at arm's length from governments. At September 30, 2021, the Fund totalled $541.5 billion. For more information, please visit www.cppinvestments.com or follow us on LinkedIn, Facebook or Twitter.

https://www.ft.com/content/1ac7d696-0fee-40a0-baa0-db27d1dc481f

Daimler trucks chief warns cost of electric will ‘forever be higher’

World’s largest truckmaker more than tripled the sales of zero-emission trucks and buses last year

Martin Daum, chief executive officer of Daimler Truck. © Alex Kraus/Bloomberg

Joe Miller in Frankfurt 8 HOURS AGO

The cost of building a battery-powered truck will “forever be higher” than a combustion engine equivalent, the boss of the world’s largest truckmaker has warned, as the war in Ukraine accelerates an already rapid rise in the price of crucial commodities.

“If you take the entirety of engine, transmission, axle, tank system, cooling . . . ” the chief executive officer of Daimler Truck, Martin Daum, told the Financial Times, “we have a maximum of about €25,000 [of material in a combustion engine truck].”

“How much battery do you get for €25,000? Even if [battery costs fall to] €60 per kilowatt hour, and I need 400 kilowatt hours, then I need €24,000 alone for the battery cells [in a single truck]”.

He added that it would be up to governments to make up the difference, using whichever mechanism they chose. “Without any subsidies . . . the price of an [electric] truck will always, forever be higher than a [combustion engine] truck.”

Daum’s comments come after Daimler Truck, which was an early entrant into the electric market and has been manufacturing batter-powered vehicles since 2017, reported that it had more than tripled the sales of zero-emission trucks and buses last year, to a total of 712.

However, that accounts for a fraction of the 455,000 trucks and buses the company delivered in total in 2021.

Its long-haul eActros model, which went into series production last year, still costs three times the price of its combustion engine equivalent, and that gap is unlikely to narrow significantly in the near future.

The cost of the key raw materials used in modern batteries has risen sharply over the past year, with cobalt and lithium more than doubling in price, and nickel climbing by almost 40 per cent, according to IHS Markit.

As a result, battery pack prices, which fell to an average of $132 per kilowatt hour in 2021, according to a survey conducted by BloombergNEF, are predicted to remain above the $100 level until at least 2024.

Daum, who like other bosses in the industry has called for a tax on carbon to narrow the cost disparity between combustion engine trucks and battery-powered models, said he nonetheless supported efforts by the German government to help businesses deal with soaring diesel costs.

“We have to raise the price over time,” the executive said, “we can live with two or three euros per litre, but we can’t live if that comes overnight.”

Daimler Truck, whose longstanding strategy has been to pursue both battery-powered and hydrogen trucks, could focus more on the latter if battery costs continued to soar, and commodities remained scarce, Daum added.

“In the fuel cell, we have far less rare raw material,” he said, “and we don’t compete with millions of passenger cars for the same material.”

Daum praised German economics minister Robert Habeck for signing an agreement with Qatar last week for the delivery of hydrogen, as well as for the supply of liquid natural gas.

But he criticised antitrust authorities in Brussels for dragging their feet when it comes to approving a joint venture between Daimler and its key competitors Volvo and Traton, which will spend €500mn on developing a network of 1700 truck charging points in Europe.

“We are ready to invest the money,” he said, “we have someone ready to take over the chief executive role and she can’t do it because we don’t have the approval.

“It should have been done three months ago. We should have been up and running operationally.”

2022 Deloitte Global Automotive Consumer Study

From September through October 2021, Deloitte surveyed more than 26,000 consumers in 25 countries to explore opinions regarding a variety of critical issues impacting the automotive sector, including the development of advanced technologies. The overall goal of this annual study is to answer important questions that can help companies prioritize and better position their business strategies and investments.

Willingness to pay for advanced tech remains limited

A majority of consumers are unwilling to pay more for advanced technologies in most global markets as they have been trained to expect new vehicle features as a cost of doing business for brands looking to differentiate themselves from their competitors.

Interest in EVs driven by lower running costs and better experience

Consumer interest in electrified vehicles (EVs) centers on the perception of lower fuel costs, environmental consciousness, and a better driving experience. However, driving range and lack of available charging infrastructure remain barriers to adoption.

In-person purchase experience still preferred by many

Most consumers would still prefer to purchase a vehicle at an authorized dealership. However, a perception of increased convenience and ease of use will likely support continued growth of virtual purchase processes.

Personal vehicles continue as the preferred mode of transportation

Shared mobility services like ride-hailing and car sharing have been slow to return to their prepandemic pace of growth as people prefer using personal vehicles to satisfy their transportation requirements.

Advanced technologies and vehicle connectivity

Consumer willingness to pay for advanced technologies, including alternative powertrains and vehicle connectivity, is limited in most global markets.

Percentage of consumers that are unwilling to pay more than ~US$500[1] for a vehicle with advanced technologies (including people that would not pay any more)

Advanced technology category	US	Germany	Japan	Rep. of Korea	China	India	Southeast Asia†
Safety	56%	70%	66%	58%	31%	48%	59%
Connectivity	65%	77%	83%	72%	39%	48%	65%
Infotainment	69%	82%	86%	78%	39%	57%	72%
Autonomy	61%	69%	56%	42%	31%	37%	48%
Alternative engine solutions	53%	56%	57%	41%	31%	35%	46%
Unwilling to pay more than...	$500	€400	¥50,000	₩500,000	¥2,500	₹25,000	Local currencies‡

Note: Did not consider "don't know" responses.

† Southeast Asia region comprises Indonesia, Malaysia, Philippines, Singapore, Thailand, and Vietnam markets.

‡ IDR 5 million/MYR 2,000/25,000 Php/SGD 500/15,000 Thai baht/10 million VND.

1 Calculated for each country in local market currency (roughly equivalent to $US500).

Q3. How much more would you be willing to pay for a vehicle that had each of the technologies listed below?

Sample size: China=1,016; Germany=1,401; India=989; Japan=880; Republic of Korea=961; Southeast Asia=5,070; US=960

Depending on the market, consumers will share personal data in exchange for less congested and safer routes, and vehicle health reporting/lower maintenance costs.

Interest (somewhat/very interested) in a connected vehicle if it provides benefits related to...

	US	Germany	Japan	Rep. of Korea	China	India	Southeast Asia
Updates regarding traffic congestion and suggested alternate routes	58%	55%	70%	79%	81%	83%	78%
Suggestions regarding safer routes (i.e., avoid unpaved roads)	58%	41%	69%	69%	80%	82%	76%
Updates to improve road safety and prevent potential collisions	56%	51%	72%	76%	81%	83%	81%
Customized/optimized vehicle insurance plan	48%	38%	51%	59%	75%	82%	72%
Maintenance updates and vehicle health reporting	59%	54%	63%	69%	79%	84%	80%
Maintenance cost forecasts based on your driving habits	51%	44%	54%	61%	79%	81%	74%
Customized suggestions regarding ways to minimize service expenses	51%	45%	63%	76%	81%	82%	75%
Over-the-air vehicle software updates	50%	53%	51%	66%	73%	77%	65%
Access to nearby parking (i.e., availability, booking, and payment)	47%	46%	56%	64%	79%	80%	72%
Special offers regarding non-automotive products and services related to your journey or destination	40%	29%	43%	55%	77%	75%	62%
Receiving a discount for access to a Wi-Fi connection in your vehicle	46%	35%	55%	62%	75%	77%	69%

Top three interests

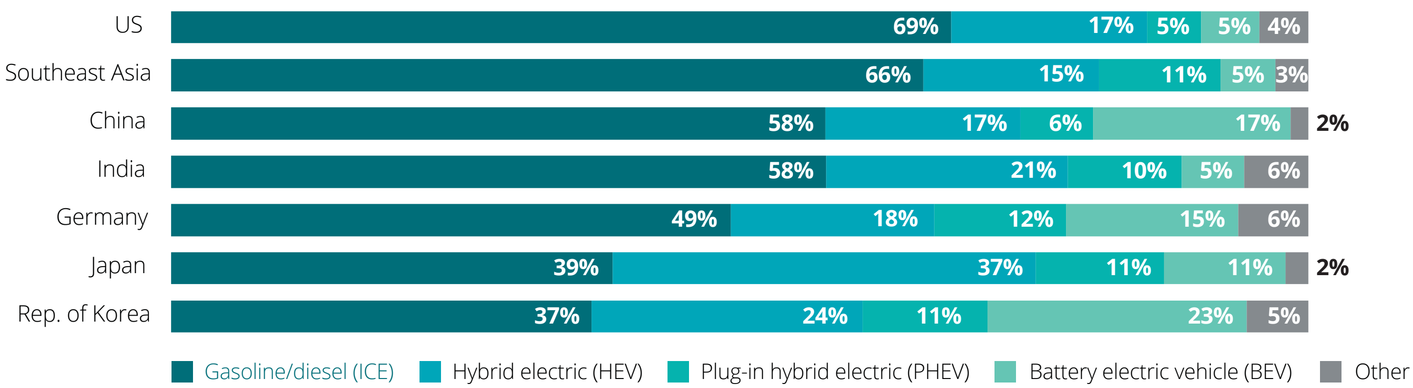
Q34. How interested are you in the following benefits of a connected vehicle if it meant sharing your own personal data and vehicle/operational data with the manufacturer or a third party?

Sample size: China=888; Germany=1,303; India=910; Japan=695; Republic of Korea=899; Southeast Asia=5,249; US=974

Vehicle electrification

Consumer interest in BEVs is highest in South Korea, China, and Germany while Japanese consumers prefer HEVs. ICE still dominates future intentions in the US.

Consumer powertrain preferences for their next vehicle



Note: "Other" includes engine types such as compressed natural gas, ethanol, and hydrogen fuel cells; did not consider "don't know" responses.
Q25. What type of engine would you prefer in your next vehicle?
Sample size: China=881; Germany=1,150; India=895; Japan=608; Republic of Korea=843; Southeast Asia=5,070; US=918

For the most part, people are drawn to an EV because of an expectation of lower fuel costs, or they are concerned about climate change and want to reduce emissions.

Factors that impact the decision to acquire an electrified vehicle

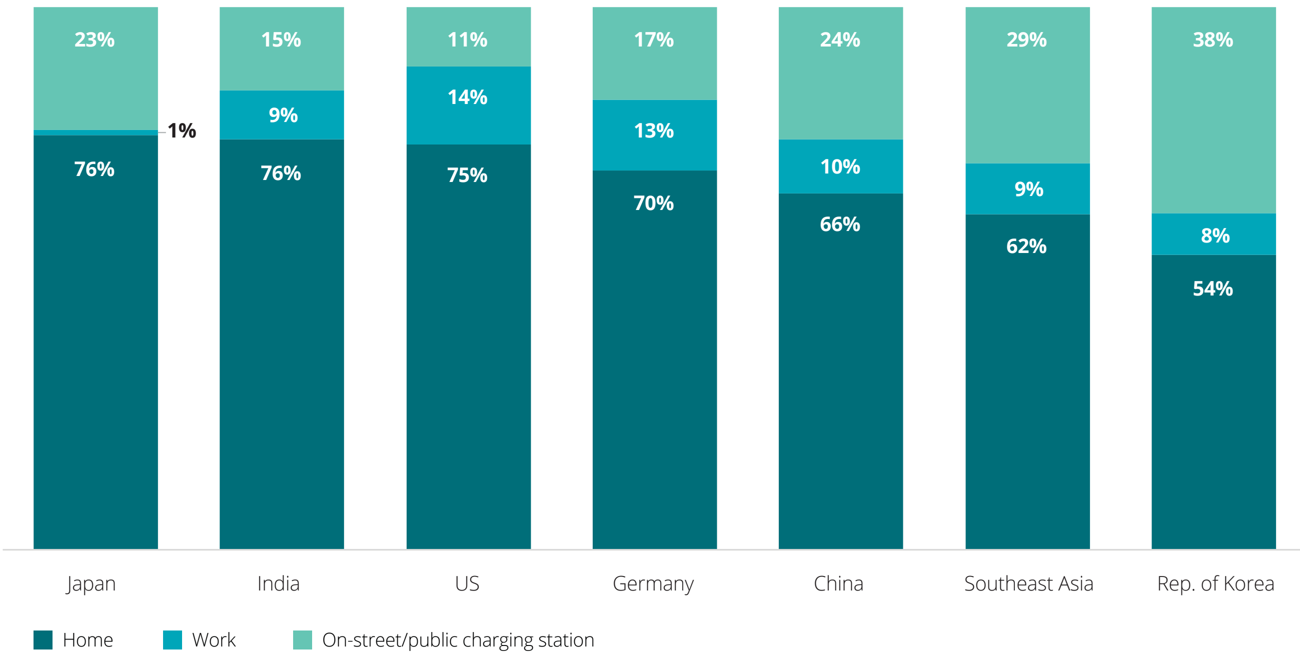
Factors	US	Germany	Japan	Rep. of Korea	China	India	Southeast Asia
Concern about climate change/ reduced emissions	2	1	2	2	1	1	2
Concern about personal health	6	4	5	7	3	4	5
Lower fuel costs	1	2	1	1	4	2	1
Less maintenance	4	7	7	3	6	5	4
Better driving experience	3	5	3	4	2	3	3
Government incentives/ stimulus programs	5	3	4	5	7	6	6
Potential for extra taxes/ levies applied to internal combustion vehicles	7	6	6	6	5	7	7

Top concern

Q26. Please rank the following factors in terms of their impact on your decision to acquire an electrified vehicle (highest to lowest).
Sample size: China=360; India=331; Germany=513; Japan=361; Republic of Korea=482; Southeast Asia=1,568; US=250

Most people in Japan, India, and the US plan to charge their PHEV/BEVs at home, while demand for public charging is high in South Korea and the SEA region.

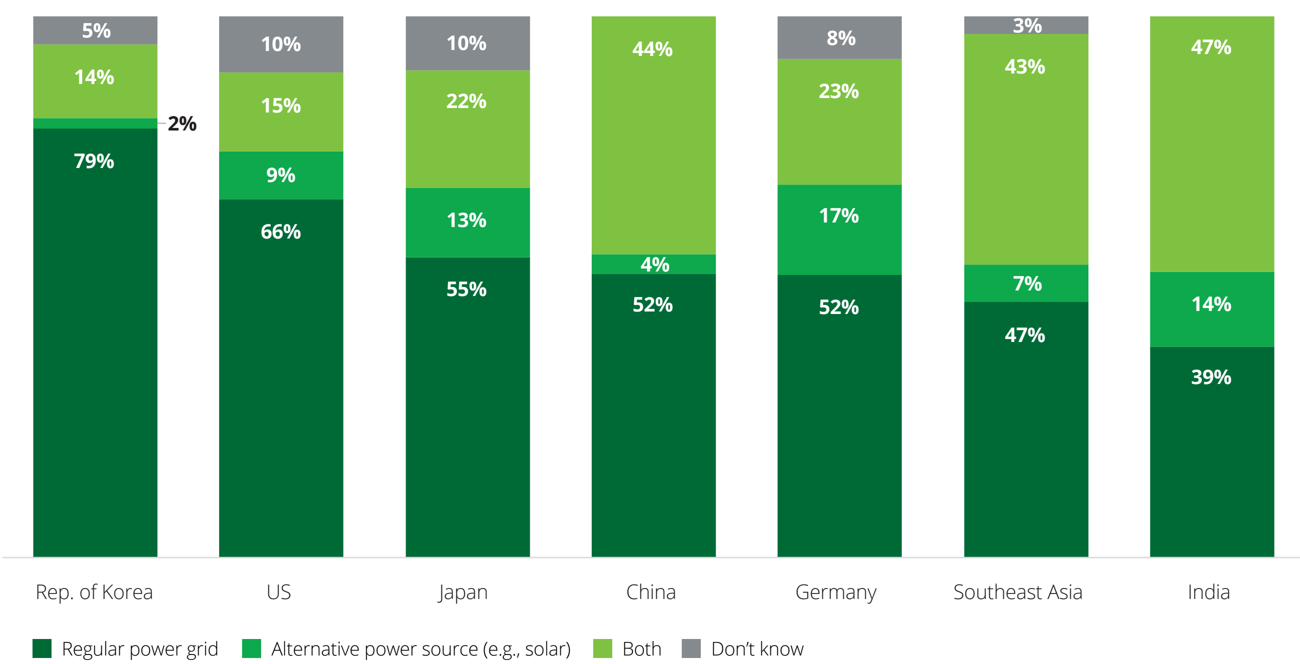
Location people expect to charge their electrified vehicle most often



Q27. Where do you expect to charge your electrified vehicle most often?
Sample size: China=209; Germany=307; India=143; Japan=133; Republic of Korea=284; Southeast Asia=784; US=91

Among those who plan to charge their PHEV/BEV at home, consumers in India, China, and the SEA region plan to use both regular grid and renewable power.

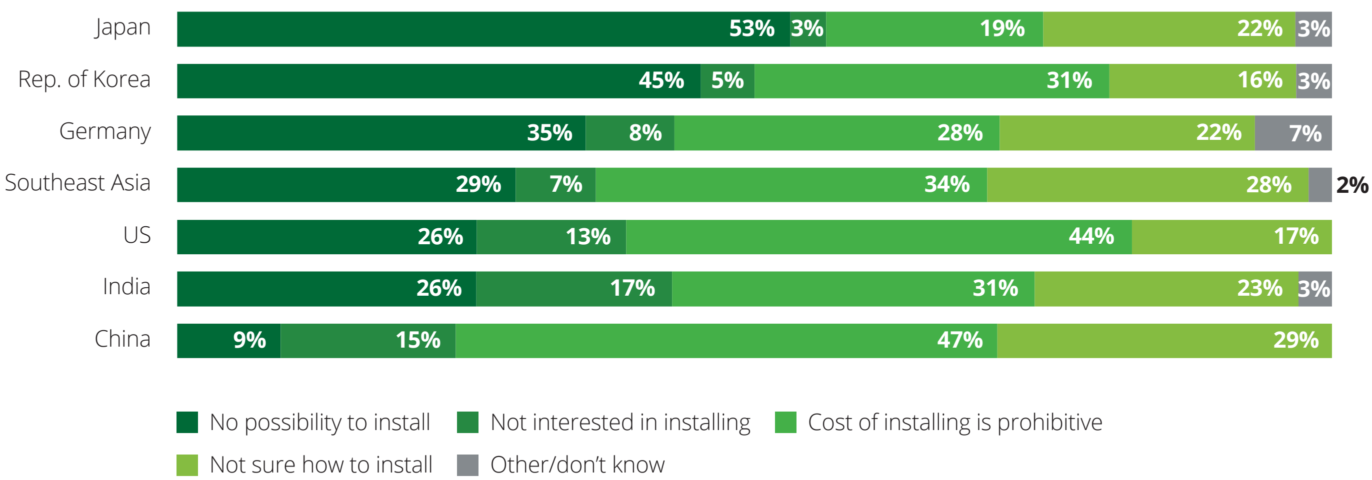
Source of power consumers intend to use to charge electric vehicles



Q28. How do you intend to charge your electrified vehicle at home?
Sample size: China=137; Germany=216; India=108; Japan=101; Republic of Korea=154; Southeast Asia=482; US=68

Consumers not planning to charge a PHEV/BEV at home say they either can't install a charger or the cost of installing a charger is prohibitive.

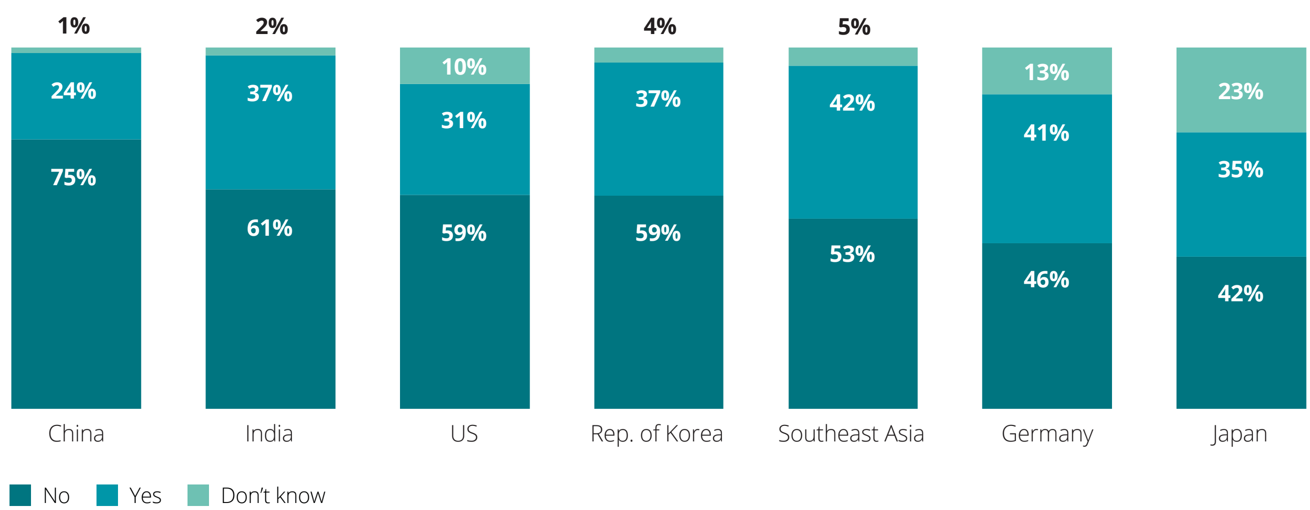
Reasons for not charging the electrified vehicle at home



Q29. What is the main reason you do not intend to charge your electrified vehicle at home?
Sample size: China=72; Germany=91; India=35; Japan=32; Republic of Korea=130; Southeast Asia=302; US=23

Potential increases in the price of electricity may sway a significant number of consumers away from a PHEV/BEV purchase in most global markets.

How many consumers would alter their decision to purchase an electrified vehicle if the electricity used for mobility was priced similar to current fossil fuels?



Q30. Would your decision to purchase an electrified vehicle change if the electricity used for mobility was priced similar to current fossil fuels?
Sample size: China=209; Germany=307; India=143; Japan=133; Republic of Korea=284; Southeast Asia=784; US=91

Consumers who said they are not considering an EV as their next vehicle cited range anxiety and a lack of public charging infrastructure as their biggest concerns.

Greatest concern regarding all battery-powered electric vehicles

Concern	US	Germany	Japan	Rep. of Korea	China	India	Southeast Asia
Driving range	20%	24%	15%	10%	22%	10%	13%
Cost/price premium	13%	12%	16%	9%	6%	12%	11%
Uncertain resale value	2%	2%	2%	1%	4%	4%	3%
Potential for extra taxes/levies associated with BEVs	4%	2%	1%	2%	6%	5%	4%
Time required to charge	10%	9%	8%	15%	11%	11%	11%
Lack of public electric vehicle charging infrastructure	14%	14%	19%	26%	12%	23%	28%
Lack of charger at home	8%	10%	19%	7%	5%	4%	6%
Lack of alternate power source (e.g., solar) at home	5%	4%	4%	3%	4%	6%	5%
Safety concerns with battery technology	9%	8%	6%	19%	16%	14%	11%
Lack of sustainability (i.e., battery manufacturing/recycling)	6%	10%	4%	4%	12%	8%	6%
Lack of choice	3%	3%	1%	1%	3%	3%	2%

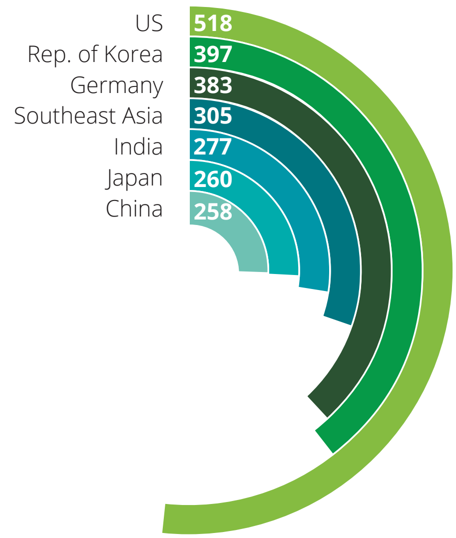
Greatest concern

Note: Sum of "concerns" for a market may not add up to 100% as "Other" and "Don't know" percentages are not shown.
Q31. What is your greatest concern regarding all battery-powered electric vehicles?
Sample size: China=888; Germany=1,303; India=910; Japan=695; Republic of Korea=899; Southeast Asia=5,249; US=974

US consumers expect fully charged BEV driving range to be north of 500 miles, while those in China, Japan, and India are content with a range of around 250 miles.

Consumer expectation of driving range from a fully charged all-battery electric vehicle

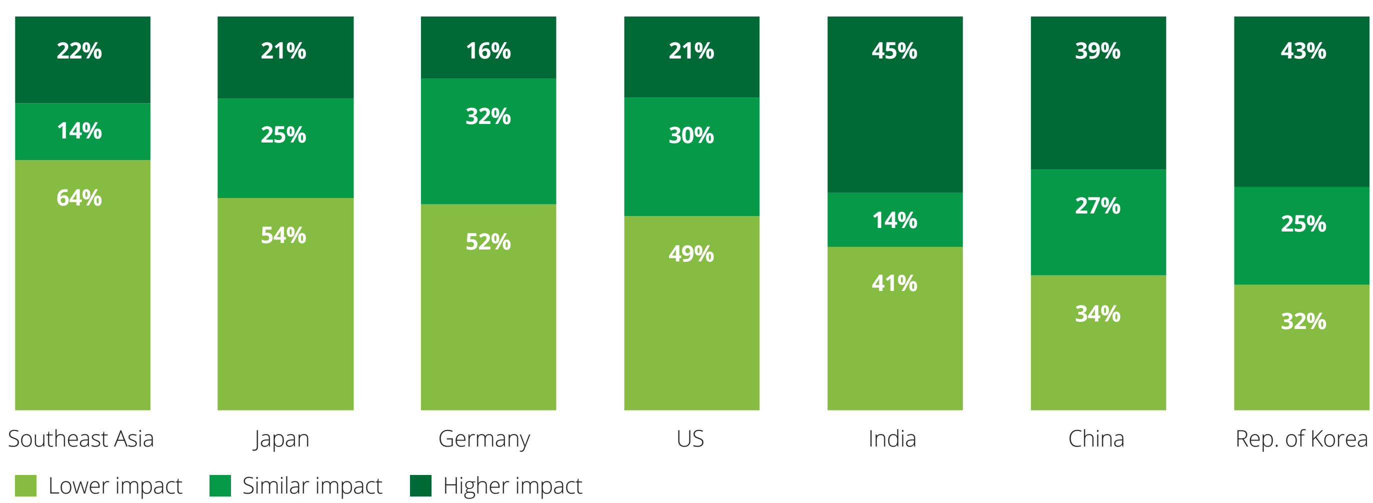
Driving range (in miles)



Q32. How much driving range would a fully charged all-battery electric vehicle need to have in order for you to consider acquiring one?
Sample size: China=735; Germany=1,129; India=861; Japan=630; Republic of Korea=709; Southeast Asia=5,004; US=927

Twice as many consumers in the SEA region see BEVs as having a lower environmental impact than ICE vehicles as compared to South Korea.

Comparison of all-battery electric vehicles with internal combustion vehicles from an environmental impact point of view



Note: Did not consider "Don't know" responses.
Q33. In your opinion, how do all-battery electric vehicles compare to internal combustion vehicles from an environmental impact point of view?
Sample size: China=878; Germany=1,194; India=894; Japan=605; Republic of Korea=838; Southeast Asia=4,952; US=831

Excerpt Hedges & Company “New Car Buyer Demographics 2022 (Updated)” [LINK]

New car & truck buyer demographics by income

Two household income groups account for most new vehicle purchases: Under $50,000 per year (mostly single-person households) and $100,000 per year and up (mostly families).

New SUV Buyers by Household Income

Under $50,000	31%
$50,000 to $74,999	19%
$75,000 to $99,000	10%
$100,000 and up	40%

New Sedan Buyers by Household Income

Under $50,000	39%
$50,000 to $74,999	18%
$75,000 to $99,000	9%
$100,000 and up	34%

New Truck Buyers by Household Income

Under $50,000	37%
$50,000 to $74,999	20%
$75,000 to $99,000	10%
$100,000 and up	33%

New Plug-In Hybrid Buyers by Household Income

Under $50,000	21%
$50,000 to $74,999	12%
$75,000 to $99,000	10%
$100,000 and up	57%

New Battery Electric (BEV) Buyers by Household Income

Under $50,000	20%
$50,000 to $74,999	16%
$75,000 to $99,000	4%
$100,000 and up	60%

The average buyer of a new car, according to the National Automobile Dealers Association (NADA) in 2015, earned about $80,000 per year.

A study by the University of California-Davis showed that in California, people with income over $150,000 per year purchase a third of electric vehicles (EVs) and plug-in hybrid electric vehicles (PHEVs). People with household income of $100,000 to $149,000 account for about 20% and people with household income of $50,000 to $99,999 per year account for about 27%

BlackRock president warns ’entitled generation’ to ‘put their seatbelts on’ over speeding inflation
2022-03-30 12:39:08.170 GMT

BlackRock president warns ’entitled generation’ to ‘put their seatbelts on’ over speeding inflation

By Sophie Mellor

(FORTUNE)

BlackRock President Rob Kapito warned that a "very entitled" generation of people would soon have to face shortages for the first time in their lives as some goods grow scarce because of rising inflation.

“For the first time, this generation is going to go into a store and not be able to get what they want,” Kapito said Tuesday at the Texas Independent Producers and Royalty Owners Association conference—an annual oil and gas industry convention.

“We have a very entitled generation that has never had to sacrifice,” Kapito added, Bloomberg reported.

Without stating exactly which generation he was referring to, Kapito said that many people who had always had everything available to them at the supermarket would soon face “scarcity inflation”—the consequence of shortages in anything from workers to oil, housing or silicon chips.

“I would put on your seat belts because this is something that we haven’t seen,” said Kapito, who co-founded Blackrock, the world’s largest asset manager, along with CEO Larry Fink and retired vice president Susan Wagner.

Inflation is already at a 40-year high in the United States and it is accelerating across the globe as Russia’s war on Ukraine pushes oil prices to record highs, and COVID-19 supply chain issues exacerbate price pressures further.

Global inflation shock

Price inflation in the U.S. hasn’t been this high since the 1980s. A Gallup poll published Tuesday reported that concerns over rising costs are the most pressing worry of just under one-in-five Americans—double the number in January.

The annual inflation rate in the U.S. stands at 7.9%, the highest 12-month change since June 1982. The highest inflation ever reached was in March and April 1980, when the price of West Texas Intermediate crude oil peaked at $138.37 a barrel and inflation hit a record 14.6%.

In Europe, which is more exposed to oil price shocks due to its dependence on energy imports and its proximity to Russia and its war on Ukraine, things are equally dire. As the cost-of-living rises across the continent, Spain on Wednesday announced a 9.8% year-on-year rise in consumer prices, an almost 40-year high that shocked many analysts.

The inflation spike "is due to generalized increases in most of [the price basket's] components," the country's statistics office said in a statement. "These included increases in electricity prices, in fuels and oil prices, and in food and non-alcoholic beverages."

Germany is releasing its inflation data later on Wednesday. It is likely above 7% for March, according to Reuters, as already released regional data from five states has surpassed analyst predictions.

Eurozone inflation data for March is scheduled to be released Friday, and polling indicate it is expected to be above 6%. A Reuters poll of analysts pointed to an overall annual CPI rate of 6.3% for March and the EU-harmonized inflation figure, or the overall price increase across all EU states, is projected to come in at 6.7%—far above the European Central Bank's 2% target.

As inflation trickles into supply chains and production, it threatens to undermine the continent's fragile economic recovery. France, Germany and Italy are seeing drops in consumer confidence as a result of the price shock—something that is leading analysts to downgrade their economy growth targets. A slow-growth economy with inflation pushing up the cost of production will almost inevitably lead to shortages at the supermarket.

In an effort to quell fears over rising food and energy prices, European Central Bank President Christine Lagarde insisted inflation will soon stop rising. "We know you will see higher inflation this year, there is no question about that," she said Wednesday. "But we are also seeing some of those factors that fuel inflation today, energy and food, that will stay high. But we don't forecast them...to continue to move higher and higher."

This story was originally featured on Fortune.com

]]> -0- Mar/30/2022 12:39 GMT

Dan Tsubouchi @Energy_Tidbits · 3h ···

Bit of a surprise, @rte_france warns France to conserve electricity during shoulder season? Recall recent EDF nuclear issues have led to low #Nuclear generation. Bloomberg's @JesperStarn reports "french nuclear availability drops to 50% as Units halt" #OOTT

French Nuclear Availability Drops to 50% as Unit Halts (Table)
By Jesper Starn
(Bloomberg) --
France's nuclear reactors were operating at 50% of full capacity on Thursday, down from 52% on Monday, according to Bloomberg calculations using data from grid operator RTE.
Electricite de France SA halted its Chinon-1 reactor on Wednesday until 6 p.m. on Thursday while the start of Dampierre-1 was delayed until Saturday.
The world's biggest nuclear-plant operator had 29 reactors available with a combined output of 29,620 megawatts as of 8:15 a.m. in Paris. Its 56 units generate more than two-thirds of the country's electricity.
The table below lists EDF reactors that are out of service, their capacity in megawatts, when they halted, the expected return date if known, and details of the latest changes:

Unit name	Megawatts	Outage date	Return date	Comment
Chinon-1	905	March 30	March 31	To start at 6 p.m.
Dampierre-1*	890	March 26	April 2	Extended 3 days
Cattenom-3	1,300	March 26	April 30	
Paluel-4	1,330	March 25	June 29	
Flamanville-1	1,330	March 22	April 28	
Gravelines-3	910	March 19	Sept. 29	
St Laurent-2	915	March 12	May 1	
Blayais-2	910	March 12	April 21	
Belleville-1	1,310	March 12	April 24	
Tricastin-3	915	March 12	Aug. 30	
Nogent-2*	1,310	March 10	April 3	
Dampierre-2*	890	March 10	April 10	
Golfech-1	1,310	Feb. 26	Aug. 16	
Bugey-2	910	Feb. 19	April 18	
Chinon-3	905	Feb. 19	July 09	
Cattenom-4	1,300	Feb. 18	May 31	
Flamanville-2	1,330	Feb. 12	July 29	
Chooz-1	1,500	Feb. 11	Dec. 31	
Chinon-4	905	Feb. 5	May 1	
Cruas-4	915	Feb. 05	May 7	
Chooz-2	1,500	Dec. 16, 2021	Dec. 31	
Civaux-2	1,495	Nov. 20, 2021	Dec. 31	
Penly-1	1,330	Oct. 2, 2021	Oct. 31	
Gravelines-6	910	Sept. 25, 2021	April 1	
Civaux-1	1,495	Aug. 21, 2021	Aug. 31	
Gravelines-1	910	Aug. 14, 2021	April 8	
Bugey-5	880	July 31, 2021	April 8	

*=unplanned, Source: RTE, EDF

To contact the reporter on this story:
Jesper Starn in Stockholm at jstarn@bloomberg.net

RTE @rte_france · Apr 2

Baisse des températures : RTE active le signal Orange national Ecowatt pour le lundi 4 avril 2022
rte-france.com/actualites/bai...

2

Dan Tsubouchi @Energy_Tidbits · 4h

Plus Poltava Governor Dmytro Lunin reportedly saying Ukraine's only operating refinery, Kremenchuk, is out of commission post missile attacks Sat. #OOTT

Richard Gaisford @richardgaisford · 10h

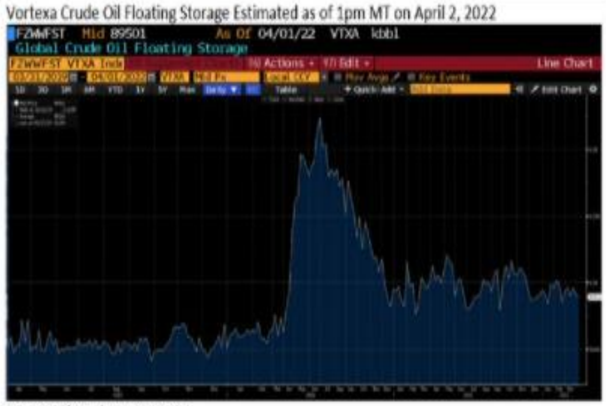
Fuel storage terminals in Odessa are on fire, after multiple missile strikes early this morning hit the port area of the southern Ukrainian city. We counted at least five separate impact points, having been woken by large explosions that were felt across Odessa. @GMB @itvnews

1 1

Dan Tsubouchi @Energy_Tidbits · 20h

#Vortexa crude #Oil floating storage for 04/01 est 89.50 mmb, -0.69 mmb WoW vs revised down 90.19 mmb at 03/25. Floating storage has been fairly steady in the ~90-100 mmb range for past few months. Thx @Vortexa @TheTerminal #OOTT

Vortexa Crude Oil Floating Storage Estimated as of 1pm MT on April 2, 2022



Source: Bloomberg, Vortexa

Est as of Apr 2, 1pm MT

FZWWFST VTXA Indx — 03/31/2019 - 04/01/2022

Date	FZWWFST V... Mid Px
Fr 04/01/2022	89501
Fr 03/25/2022	90194
Fr 03/18/2022	96062
Fr 03/11/2022	90367
Fr 03/04/2022	96009
Fr 02/25/2022	94149
Fr 02/18/2022	85687
Fr 02/11/2022	99352
Fr 02/04/2022	100.9k
Fr 01/28/2022	95887
Fr 01/21/2022	98802

Est as of Mar 26, 1pm MT

FZWWFST VTXA Indx — 03/24/2020 - 03/25/2022

Date	FZWWFST V... Mid Px
Fr 03/25/2022	91443
Fr 03/18/2022	95618
Fr 03/11/2022	89990
Fr 03/04/2022	96966
Fr 02/25/2022	93293
Fr 02/18/2022	85019
Fr 02/11/2022	97292
Fr 02/04/2022	98869
Fr 01/28/2022	94032
Fr 01/21/2022	98387
Fr 01/14/2022	84689

Est as of Mar 19, 1pm MT

FZWWFST VTXA Indx — 03/17/... - 03/18/2022

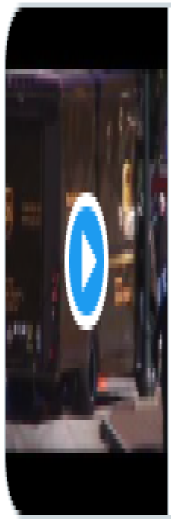
Date	FZWWFST V... Mid Px
Fr 03/18/2022	87894
Fr 03/11/2022	92535
Fr 03/04/2022	98407
Fr 02/25/2022	94289
Fr 02/18/2022	84645
Fr 02/11/2022	98207
Fr 02/04/2022	101.946k
Fr 01/28/2022	95109
Fr 01/21/2022	101.164k
Fr 01/14/2022	86550
Fr 01/07/2022	92922

Source: Bloomberg, Vortexa

2 14

Dan Tsubouchi @Energy_Tidbits · 23h

If municipal politicians want to cut #Gasoline consumption, wonder if they would risk voter ire by banning left turns? Here is an old UPS clip on banning left turns in cities saves time waiting for gaps (also safer) & therefore saves gasoline? #OOTT



youtube.com

Why UPS trucks never turn left

Senior VP Bob Stoffel explains how a policy of only making right turns saves the company both time a...

1 1

Dan Tsubouchi @Energy_Tidbits · Apr 1

Cdn E&P should report record Q1/22 cash flows. Ed par in Q1 of US$93.66/b, +72.9% YoY, +26.8% QoQ. WCS in Q1 of US$82.51/b, +80.0% YoY, +35.3% QoQ. AECO in Q1 $4.51, +43.9% YoY, +0.6% QoQ. Plus Q2/22 cash should also be great cash flows, possibly even up be up QoQ. #OOTT #NatGas

Oil and Natural Gas Prices

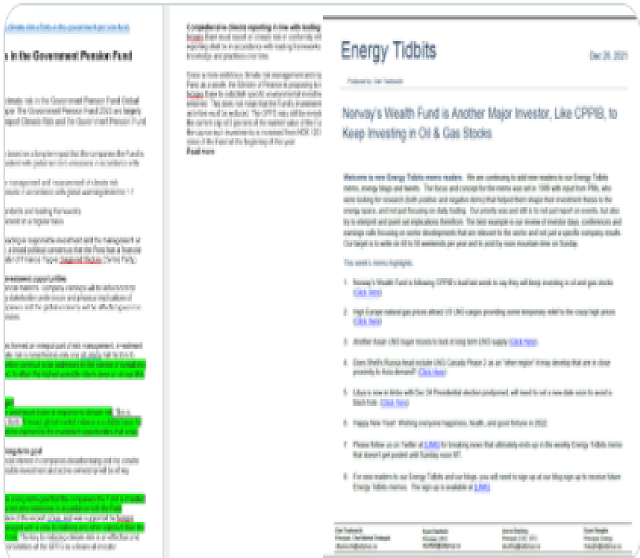
Quarter	Brent US$	WTI US$	EdPar US$	WCS US$	HH US$	AECO C$
Q1/18	$67.00	$62.86	$57.19	$37.11	$3.09	$2.06
Q2/18	$74.41	$67.83	$60.78	$49.88	$2.84	$1.23
Q3/18	$75.27	$69.69	$59.81	$42.32	$2.92	$1.25
Q4/18	$68.18	$59.41	$36.53	$25.63	$3.78	$1.62
Q1/19	$62.91	$54.49	$50.28	$43.79	$2.92	$2.55
Q2/19	$68.58	$59.96	$54.41	$47.46	$2.55	$1.13
Q3/19	$61.95	$56.48	$52.43	$43.91	$2.37	$1.00
Q4/19	$62.51	$56.83	$50.61	$37.98	$2.36	$2.46
Q1/20	$51.28	$46.73	$39.75	$28.55	$1.91	$2.04
Q2/20	$31.14	$27.67	$21.84	$18.02	$1.70	$2.00
Q3/20	$42.70	$40.87	$36.83	$31.13	$1.98	$2.26
Q4/20	$44.47	$42.67	$37.92	$31.34	$2.47	$2.65
Q1/21	$60.51	$57.75	$54.17	$45.83	$3.39	$3.13
Q2/21	$68.44	$65.90	$61.94	$53.11	$2.89	$2.95
Q3/21	$72.95	$70.57	$66.90	$57.65	$4.28	$3.41
Q4/21	$79.43	$77.31	$73.84	$60.96	$4.74	$4.49
Q1/22	$99.08	$94.79	$93.66	$82.51	$4.61	$4.51
Source: Bloomberg						

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

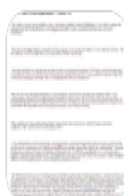
2 · 10

Dan Tsubouchi @Energy_Tidbits · Apr 1

Norway's "strengthening climate risk efforts in the GPFG" sounds it should be tougher on #Oil #NatGas but it isn't. "investment strategy should remain unchanged [see 12/21 below], "no reason to change the composition of the benchmark index in response to climate risk". #OOTT



Dan Tsubouchi @Energy_Tidbits · Dec 21, 2021



Multiple expansion for #Oil #NatGas stocks? Norway wealth fund has #MacronMoment & follows @cppib to slow play #EnergyTransition, won't sell, rather be a driving force for their equity investments to "adjust to #NetZero emissions over time". Less sellers is always ...

1 2

Dan Tsubouchi @Energy_Tidbits · Apr 1

SAF GROUP

No surprise, Guangzho/#MexicoPacificLNG 0.26 bcfd 20yr deal is another Asian LNG buyer secures long term #LNG supply. #EU is playing catch up to Asians, see SAF 07/14/21 blog "Asian LNG Buyers Abruptly Change and Lock in Long Term Supply". Thx @SStapczynski #NatGas #OOTT

SAF GROUP

Blog Summary

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

Posted Wednesday, July 14, 2021 at 10:00 MT

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.

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

Stephen Stapczynski @SStapczynski · Mar 31

China signs deal to purchase LNG from Mexico's west coast
🇨🇳🤝🇲🇽

🚢 Guangzhou Development agreed to buy 2 million ...

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1 · 6 · 3

Dan Tsubouchi @Energy_Tidbits · Apr 1

#OOTT

Dan Tsubouchi @Energy_Tidbits · Mar 31

China Caixin PMI for Mar 48.1 vs Est 49.9 & Feb 50.4. COVID-19 in China weighed heavily on manufacturing performance in March. Companies registered the quickest falls in output and new business since the
initial onset of the pandemic in February 2020" Thx @IHSMarkitPMI #OOTT


Caixin China General Manufacturing PMI™

Manufacturing performance dampened by latest COVID-19 wave in March

SAF

Dan Tsubouchi @Energy_Tidbits · Mar 31

#JCPOA status. "There are a small number of outstanding issues. The onus is now on Tehran to make those decisions" says @StateDeptSpox. #OOTT

Excerpt https://www.state.gov/briefings/department-press-briefing-march-31-2022/

Department Press Briefing – March 31, 2022

NED PRICE, DEPARTMENT SPOKESPERSON WASHINGTON, D.C. MARCH 31, 2022

MR PRICE: Thank you, Matt. Rather than Iran's proxies be subdued, we have actually seen them emboldened. And you can quantify that in a number of ways, but here's one important way: From 2012 to 2018, there were no significant attacks, there were no attacks against U.S. service members, diplomatic facilities in Iraq. That changed in 2018. And between 2019 and 2020, the number of attacks from Iran-backed groups went up 400 percent. This was in the aftermath of the decision to abandon the JCPOA. It was in the aftermath of the decision to apply the FTO designation to the Iranian Revolutionary Guard Corps. It was in the aftermath of the killing of Soleimani, the IRGC chief.

So clearly the effort to put Iran's nuclear program back in a box, the effort to subdue Iran's proxies, has not worked under the strategy that we inherited. We want to see to it that we have a strategy that does work, that is effective. When it comes to Iran's nuclear program, we continue to believe that a mutual return to compliance with the JCPOA is that appropriate recourse. And we know that, again, because we have done this before. This is not conjecture on our part. From January of 2016 until May of 2018, it was in full effect. Iran was complying with it, and Iran's nuclear program was verifiably and permanently constrained. And what that means is that Iran was permanently barred from obtaining a nuclear weapon. That is the reality, the reality we've experienced before, that we seek to get back to.

Now, in terms of where we are, we've spoken before of the progress that had been achieved in recent weeks. There are a small number of outstanding issues. The onus is now on Tehran to make those decisions. We continue to believe that, at least for the time being, a mutual return to compliance would bring with it non-proliferation benefits that would be in our interest, in the interests of our allies and partners – our allies in Europe, the E3 that's part of the P5+1, our allies and partners around the world who are not part of the P5+1.

1 2 4

SAF

Dan Tsubouchi @Energy_Tidbits · Mar 31

ICYMI, the unnamed CEO being shaded by #Biden Admin "One CEO even acknowledged that, even if the price goes to $200 a barrel, they're not going to step up production" is @PXDtweets CEO Sheffield. See below for his 02/18 comments to @kaileyleinz. #OOTT

t from Bloomberg's Kailey Leinz and Guy Johnson interview with Pioneer Natural Resources
eos/2022-02-17/oil-prices-won-t-impact-pioneer-s-growth-plans-ceo-says-video

transcript.

ıssian action against Ukraine, *"should there actually be armed conflict, should that result in a di*
ction to help make up any potential shortfall?"
plan. We announced a capex plan. As I said, regardless of whether its $150 , $200 oil, or $100 oil,
E, they have a pact with OPEC+. They probably are about the only two countries than can change
anctioned or if Russia decides to stop exporting , then its going to be up to the Saudis and UAE to
delines."

p.ca/news-insights/

2 6 7

Dan Tsubouchi @Energy_Tidbits · Mar 31

Pretty simple why #IN is buying more RUS crude. "When #Oil prices go up, I think it's natural for countries to go out into the market and look for what are good deals for their people" says India's FM @DrSJaishankar. Thx @latikambourke. #OOTT

smh.com.au

'It's natural': India's Foreign Minister defends inking cheap Russian oil...

India's Foreign Minister says it is natural for a country to seek cheap oil, as criticism grows over India's purchase of discounted Russian oil.

1

Dan Tsubouchi @Energy_Tidbits · Mar 31

Quick meeting and no surprises. #OPEC+ sticks to plan for +432,000 b/d in May and revised reference (baseline) effective May 1 that were agreed on July 18, 2021. both tables below. #OOTT

Eq.Guinea	122
Gabon	179
Iraq	4461
Kuwait	2694
Nigeria	1753
Saudi Arabia	10549
UAE	3040
Azerbaijan	688
Bahrain	197
Brunei	98
Kazakhstan	1638
Malaysia	571
Mexico	1753
Oman	846
Russia	10549

	Reference Production up to end of April 2022	Reference Production effective May 2022
Algeria	1057	1057
Angola	1528	1528
Congo	325	325
Eq.Guinea	127	127
Gabon	187	187
Iraq	4653	4803
Kuwait	2809	2959
Nigeria	1829	1829
Saudi Arabia	11000	11500
UAE	3168	3500
Azerbaijan	718	718
Bahrain	205	205
Brunei	102	102
Kazakhstan	1709	1709
Malaysia	595	595
Mexico*	1753	1753
Oman	883	883
Russia	11000	11500
Sudan	75	75
South Sudan	130	130
OPEC 10	26683	27815
Non-OPEC	17170	17670

1 2 8

Dan Tsubouchi @Energy_Tidbits · Mar 31

thank you says #OPEC+ to #Biden admin for these leeks ahead of our meeting right now. #OOTT

> Dan Tsubouchi @Energy_Tidbits · Mar 30
>
> Breaking: WTI down $4 on report #Biden weighing a plan to release ~1 mmb/d for several months. Thx @JenniferJJacobs @AlbertoNardelli @SalehaMohsin #OOTT twitter.com/JenniferJJacob...

3

Dan Tsubouchi @Energy_Tidbits · Mar 30

Breaking: WTI down $4 on report #Biden weighing a plan to release ~1 mmb/d for several months. Thx @JenniferJJacobs @AlbertoNardelli @SalehaMohsin #OOTT

> Jennifer Jacobs @JenniferJJacobs · Mar 30
>
> Scoop: Biden admin is weighing a plan to release roughly A MILLION BARRELS OF OIL A DAY from U.S. reserves, for several months, to combat rising gasoline prices and supply shortages following Russia's invasion of Ukraine, sources tell @AlbertoNardelli @SalehaMohsin and me.
>
> Show this thread

2 4

SAF

Dan Tsubouchi @Energy_Tidbits · Mar 30

Is #Trudeau #EmissionsReductionPlan setting up #Oil #NatGas #OilSands for failure and be the fall guy? See pg 197, how can they hit targets if Liberals plan says will need new actions/inventions beyond existing proven solutions to meet targets including 2025/26 targets? #OOTT

Dan Tsubouchi @Energy_Tidbits · Mar 29

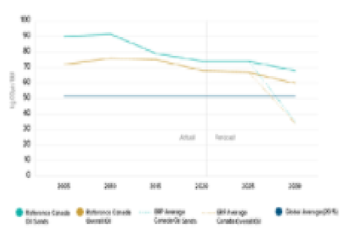
Hmmm! One of the tidbits in 271-pg Liberals 2030 Emissions Reduction Plan. pg 197, #Oil #NatGas sector will need to develop new actions beyond existing proven solutions to meet still to be defined targets, even to meet 2025 & 2026 reduction targets. #OOTT canada.ca/content/dam/ec...

Excerpts 2030 Emissions Reduction Plan https://www.canada.ca/content/dam/eccc/documents/pdf/climate-change/erp/Canada-2030-Emissions-Reduction-Plan-eng.pdf

Items in [*italics*] are from the ERP

No change to the big picture target of oil and gas reductions, but still haven't defined the specific 2025 target or interim years prior to 2030. Pg 8 "*The Plan presents modelling of the most economically efficient pathway to meeting Canada's 2030 target. Drawing on that modelling, the Plan includes a projected contribution from the oil and gas sector of emission reductions to 31% below 2005 levels in 2030 (or to 42% below 2019 levels). This will guide the Government of Canada's work with industry, provinces, Indigenous partners, and civil society to define and implement the cap on oil and gas sector emissions. Following consultations, the cap will be designed to lower emissions at a pace and scale needed to achieve net-zero by 2050.*" Note their Pg 50 graph, the dotted line on the targets for any year are subject to what is defined, so the slope of emissions reduction are not yet known but the end point in 2030 is the target.

CANADA OIL CARBON INTENSITY VS GLOBAL AVERAGE



The oil and gas sector is being put on notice (warned) that they will need to develop new actions beyond existing proven solutions to meet the still to be defined oil and gas emissions reductions targets, even for 2025 and 2026. Pg 197 "*Drive new and more ambitious actions. Targets for the oil and gas sector should be ambitious and require new actions that go beyond what is already contemplated using existing proven solutions. Regulatory targets drive innovation. Targets should lead to a scale of emissions reductions that would not otherwise have occurred. At the same time, targets must be realistic and credible, while pushing the sector to go further than it would otherwise. Targets should result in visible leadership, innovation in technology and business models, and new investments. It is acceptable to set emissions reduction targets in the future for which there is not currently complete certainty on how to attain the target. The further away the target is (e.g., 2030 versus 2025 or 2026), the more this principle applies.*"

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

5 7

Dan Tsubouchi @Energy_Tidbits · Mar 30

If not asking UAE for more #Oil, who in #OPEC is #Biden asking? @SecBlinken says its critical to have abundant energy supplies on market now "but as it happens, we didn't focus on that issue specifically" in his meet with UAE @MohamedBinZayed. Thx @PeterMartin_PCM #OOTT

BN 03/30 16:08 *BLINKEN: DIDN'T FOCUS ON ENERGY ISSUES WITH UAE CROWN PRINCE
BN 03/30 16:08 *U.S. SECRETARY OF STATE BLINKEN SPEAKS IN ALGIERS

Blinken: Didn't Focus on Energy With Abu Dhabi Crown Prince
2022-03-30 16:15:32.979 GMT

By Peter Martin
(Bloomberg) -- "We believe it's critical that there be abundant supplies of energy on markets now and that there should also be a steady supply, but as it happens, we didn't focus on that issue specifically," Blinken tells reporters in Algiers about his meeting this week with Abu Dhabi Crown Prince Mohammed bin Zayed.

To contact the reporter on this story:
Peter Martin in Algiers at pmartin138@bloomberg.net
To contact the editor responsible for this story:
Bill Faries at wfaries@bloomberg.net

To view this story in Bloomberg click here:
https://blinks.bloomberg.com/news/stories/R9KFN8DWX2PS

Dan Tsubouchi @Energy_Tidbits · Mar 28

Busted, wasn't US asking #OPEC for oil? #UAEEnergyMinister "I haven't received any call or any request for a call from the Secretary of Energy [Granholm]" Gamble "nothing?" Al Marzouei "No, she didn't call me, she didn't approach me" Another grea...

2 4

Dan Tsubouchi @Energy_Tidbits · Mar 30

Return to #JCPOA doesn't sound this week. "I think it will take a few more days or possibly weeks until everything falls into place" "we did everything right and now the word is up to our partners" says RUS Deputy FM Ryabkov. #OOTT

Ryabkov: Participants in the nuclear deal on Iran will be able to find a solution in the coming days or weeks

The Deputy Foreign Minister of the Russian Federation resolutely denied accusations that Russia allegedly "tried to complicate the course of negotiations until the very end, putting forward new demands"

Read TASS at

Yandex.NewsYandex.Zen

MOSCOW, March 30. /TASS/. The search for a mutually acceptable compromise on the further implementation of the Joint Comprehensive Plan of Action (JCPOA) on the Iranian nuclear program may take several more days or weeks. This was stated on Wednesday by Deputy Foreign Minister of Russia Sergei Ryabkov on the air of the RT TV channel.

"I think it will take a few more days or possibly weeks until everything falls into place," he said.

The Deputy Foreign Minister of the Russian Federation resolutely denied accusations that Russia allegedly "tried until the very end to complicate the course of negotiations by putting forward more and more new demands." "It didn't happen," he stressed. "We only made it clear that our only interest is that, depending on how the JCPOA is implemented in the event of its renewal, to ensure that our legitimate and multifaceted interaction with Iranian partners is protected from American and European sanctions. No more, no less."

"We did everything right, and now the word is up to our partners," Ryabkov concluded. "Russia will do everything in its power to ensure a positive outcome of these very frank and devoid of a hidden agenda negotiations that require full commitment from all participants, including Iran, the United States and European coordinators. This is our firm and balanced position. I hold my fists at random in the hope that we will be able to succeed."

1 2

Dan Tsubouchi @Energy_Tidbits · Mar 30

For those not near their laptop. @EIAgov weekly #Oil #Gasoline #Distillates inventory data as of March 25 just out. Prior to release, WTI was $108.23. #OOTT

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

Inventory March 25: EIA, Bloomberg Survey Expectations

s)	EIA	Expectations
	-3.45	-2.00
	0.79	-1.60
	1.40	-1.50
	-1.26	-5.10

mmercial so builds in impact of 3.0 mmb draw from SPR for Ma

d in the oil data, Cushing had a draw of 1.01 mmb for Mar 25 w

loomberg

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

1 3

Dan Tsubouchi @Energy_Tidbits · Mar 30

SAF

Russia not ready yet to force payment in rubles for #NatGas as of Mar 31 as "the process is technologically more time-consuming". But intent is still to do so "there is an instruction from the president, it must be executed" says #Peskov. #OOTT #NatGas tass.ru/ekonomika/1422...

Peskov said that data on the mechanism of gas supplies in rubles will be available

The press secretary of the President of the Russian Federation stressed that payment in rubles will not be accepted immediately, as the process needs to be worked out technologically.

MOSCOW, March 30. /TASS/. Data on the mechanism of gas supplies in rubles will be available, the President's order must be executed. This was stated to journalists by the press secretary of the President of the Russian Federation Dmitry Peskov.

"I don't have this information yet," he answered the question in what form and when this mechanism will be presented to the president. "But in any case, data on all this will be available. Let's wait until March 31 (the deadline for fulfilling the instruction of the head of state to develop this procedure - note TASS), there is an instruction from the president, it must be executed."

Peskov stressed at the same time that the payment itself in rubles will not be accepted immediately from March 31.

"Payment and deliveries are a time-consuming process. This does not mean that everything that will be delivered tomorrow must be paid for tomorrow evening (in rubles). No, the process is technologically more time-consuming," he added.

Follow our news on Telegram, VKontakte and Odnoklassniki.

Stay informed

This Tweet links to a Russia state-affiliated media website.

Find out more

3 2

Dan Tsubouchi @Energy_Tidbits · Mar 29

"then #LNG off the West Coast and i think there is a lot more demand beyond the first 2 trains, which is 2 bcf in demand" says $KEY in Q&A today. Will #Shell FID #LNGCanada Phase 2? still think yes. #NatGas #OOTT

Company Name: Keyera Corp
Company Ticker: KEY CN Equity
Date: 2022-03-29

INITIAL DRAFT

natural gas and ultimately get natural gas liquids and the demand not only in North American so but worldwide it's certainly a differentiator in our minds.

The fundamentals around natural gas and NGLs to be a little bit repetitive really do speak to an expectation that we're going to start to or continue to see increased utilization within our gathering and processing assets. So I think over the coming months. We expect to see some continued growth in that segment of our business.

A - James Urquhart (BIO 1850345 <GO>)

Robert and maybe just add we want to emphasize that we see a lot of growth in our basin over the next 5 years. And again, I think people forget about just how much market access that either been built or is getting built now and specifically with natural gas. Again you look at the coal to gas switching in Alberta more export capacity into the US and then LNG off the West Coast and I think there is a lot more demand beyond the first 2 trains, which is 2 bcf in demand.

But when you add it all up, it translates to growth and a lot of that's going to happen in the Deep Basin and also the Montney, we're well situated. We are volume-based business, so as the volume. So as we see more growth in our basin. We expect to see increase volumes through our gas plants. And again the discussions that we're having with our customers sort of line with that view. And in some of our plants as utilization increases.

It also probably creates an opportunity to increase our per unit margins as well. So I think those are 2 reasons why we feel more optimistic over the next several years of our G&P business.

Keyera Investor Day 2022

Dan Tsubouchi @Energy_Tidbits · Mar 25

#Biden #LNG deal with #EC says LNG supply growth be consistent with shared #NetZero goals. Who has lowest carbon intensity of any #LNG project in the world? #LNGCanada said Shell on 02/21. Will #Shell FID LNG Canada Phase 2? Still think yes. #NatGas ...

3 3

Dan Tsubouchi @Energy_Tidbits · Mar 29

Another still to be disclosed from Liberals Emissions Reduction Plan - what is on the list of "inefficient fossil fuel subsidies" being eliminated in 2023, not 2025. Will it be like Biden's all inclusive list? #OOTT canada.ca/content/dam/ec...


an https://www.canada.ca/conten
Reduction-Plan-eng.pdf

es are being eliminated in 2023 ie.
lling costs ie. CDE. Pg 53 "*Eliminati*
ating inefficient fossil fuel subsidies
or, including by federal Crown corp
25 to 2023".

up.ca/news-insights/

1 1 4

Dan Tsubouchi @Energy_Tidbits · Mar 29

Hmmm! One of the tidbits in 271-pg Liberals 2030 Emissions Reduction Plan. pg 197, #Oil #NatGas sector will need to develop new actions beyond existing proven solutions to meet still to be defined targets, even to meet 2025 & 2026 reduction targets. #OOTT canada.ca/content/dam/ec...

Excerpts 2030 Emissions Reduction Plan https://www.canada.ca/content/dam/eccc/documents/pdf/climate-change/erp/Canada-2030-Emissions-Reduction-Plan-eng.pdf

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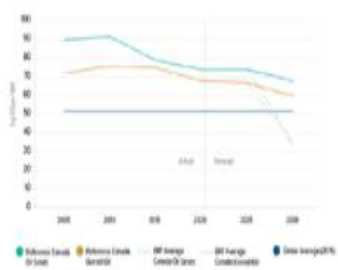
CANADA OIL CARBON INTENSITY VS GLOBAL AVERAGE



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

4 5 7

Dan Tsubouchi @Energy_Tidbits · Mar 29

Forgot to include Brent #Oil price dive down $7 post the constructive Russia/Ukraine reports from TASS. #OOTT

Dan Tsubouchi @Energy_Tidbits · Mar 29

ICYMI. constructive reports from @TASS post RUS/Ukraine meeting - negotiations are "moving into practice" "decision was made to radically, at times, reduce military action in the Kieve and Chernihiv directions" said RUS defense ministry.

SAF

Dan Tsubouchi @Energy_Tidbits · Mar 29

ICYMI. constructive reports from @TASS post RUS/Ukraine meeting - negotiations are "moving into practice" "decision was made to radically, at times, reduce military action in the Kieve and Chernihiv directions" said RUS defense ministry.

sian Defense Ministry decided to significantly reduce military activity in the Kiev and Chernihiv direc

y noted that negotiations on the preparation of the Treaty on the Neutrality and Nuclear-Free Status of Ukraine, as well as on t
f security guarantees to Ukraine, are moving into practice.

29 March. /TASS/. The Russian Defense Ministry decided to drastically reduce military activity in the Kiev and Chernigov directions. This is
nt of the department following the results of the Russian-Ukrainian talks in Istanbul, which was read out by the Deputy Minister of Defens
eration, Colonel-General Alexander Fomin.

fact that negotiations on the preparation of the Treaty on the Neutrality and Non-Nuclear Status of Ukraine, as well as on the provision of
to Ukraine, are moving into practice, taking into account the principles discussed during today's meeting, by the Ministry of Defense of the
n order to increase mutual trust and create the necessary conditions for further negotiations and achievement of the ultimate goal - the a
of the above agreement - a decision was made to radically, at times, reduce military activity in the Kiev and Chernihiv directions," he said

news on Telegram, VKontakte and Odnoklassniki.

2

SAF

Dan Tsubouchi @Energy_Tidbits · Mar 29

"Here comes Johnny, look at what is happening today. Who's talking about climate change now? Who is talking about attending to energy security first and foremost" people are pro producing #Oil #NatGas, pro, Halleluha, pro using coal. classic #Abdulaziz to @_HadleyGamble #OOTT

SAF Group created transcript of CNBC's Hadley Gamble with Saudi Energy Minister Prince Abdulaziz on March 29, 2022
https://www.cnbc.com/2022/03/29/saudi-energy-minister-says-opec-will-leave-politics-out-of-oil-decisions.html

Source: CNBC
Items in "italics" are SAF Group created transcript

Abdulaziz referring to his speech at COP26 in November at Glasgow "*... the last paragraph of that speech, I enumerated three things. And it was in Glasgow when everyone was talking about sustainability, climate change, climate change, climate change. I said and I will repeat and I would differ with Dan Yergin because I was the one who first mentioned security of supply at that meeting. I said the [xxx] of what we should do is energy security. Second, economic sustainability and growth and prosperity. Third and I am not ranking, but actually I call them the three pillars, climate change attendance. But truly, you cannot attend to climate change without getting energy security. And certainly, if you don't have energy security, you would not have economic prosperity, you will not have economic growth. If you don't' have the two, you would lose the means of attending to climate change And, that day, I can see it in faces, oh yeah yeah yeah, he's the representative of Saudi Arabia bragging about these things. Well, here comes Johnny, look at what is happening today. Who's talking about climate change now? Who is talking about attending to energy security first and foremost? Look at the countries that juggled their own energy mix. Look at how much people are advancing their idea of thoughts we should focus on energy, on oil and gas, and we are pro producing oil and gas. And pro, and pro, Hallelujah, pro using coal*"

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

5 7

Dan Tsubouchi @Energy_Tidbits · Mar 29

it's like a picture is worth a thousand words, but in this case, a non-answer says it all. #Abdulaziz is The Man. #OOTT

CNBC Middle East @CNBCMiddleEast · Mar 29

Saudi Energy Minister rebuffs @_HadleyGamble question on U.S. commitment to Saudi Arabia, says his 39 years in Government allows him to "ditch the question"

2

Dan Tsubouchi @Energy_Tidbits · Mar 28

At least #Biden's reasons are clear - raising taxes on high income because need the revenue. "Reforms to the taxation of capital gains and qualified dividends will reduce economic disparities among Americans and raise needed revenue". raising needed revenue shows up other spots.

REFORM THE TAXATION OF CAPITAL INCOME

Current Law

Most realized long-term capital gains and qualified dividends are taxed at graduated rates based on the taxpayer's taxable income, with 20 percent generally being the highest rate (23.8 percent including the net investment income tax, if applicable based on the taxpayer's modified adjusted gross income). Moreover, capital gains are taxable only upon the sale or other disposition of an appreciated asset. When a donor gives an appreciated asset to a donee during the donor's life, the donee's basis in the asset is the basis of the donor; the basis is "carried over" from the donor to the donee. There is no realization of capital gain by the donor at the time of the gift, and there is no recognition of capital gain by the donee until the donee later disposes of that asset. When an appreciated asset is held by a decedent at death, the basis of the asset for the decedent's heir is adjusted (usually "stepped up") to the fair market value of the asset at the date of the decedent's death. As a result, the appreciation accruing during the decedent's life on assets that are still held by the decedent at death avoids Federal income tax.

Reasons for Change

Preferential tax rates on long-term capital gains and qualified dividends disproportionately benefit high-income taxpayers and provide many high-income taxpayers with a lower tax rate than many low- and middle-income taxpayers. The rate disparity between taxes on capital gains and qualified dividends on the one hand, and taxes on labor income on the other, also encourages economically wasteful efforts to convert labor income into capital income as a tax avoidance strategy.

Under current law, because a person who inherits an appreciated asset receives a basis in that asset equal to the asset's fair market value at the time of the decedent's death, appreciation that had accrued during the decedent's life is never subjected to income tax. In contrast, less-wealthy individuals who must spend down their assets during retirement pay income tax on their realized capital gains. This dynamic increases the inequity of the tax treatment of capital gains. In addition, the preferential treatment for assets held until death produces an incentive for taxpayers to inefficiently lock in portfolios of assets and hold them primarily for the purpose of avoiding capital gains tax on the appreciation, rather than reinvesting the capital in more economically productive investments.

Moreover, the distribution of wealth among Americans has grown increasingly unequal, concentrating economic resources in a steadily shrinking percentage of individuals. Coinciding with this period of growing inequality, the long-term fiscal shortfall of the United States has significantly increased. Reforms to the taxation of capital gains and qualified dividends will reduce economic disparities among Americans and raise needed revenue.

1

SAF

Dan Tsubouchi @Energy_Tidbits · Mar 28

Buckle up! #Biden FY23 "proposals would also elminate all fossil fuel subsidies". Take a flip thru pgs 22-26. nice timing given #Biden #Granholm trying to get US to produce more oil & gas. good thing $100 #Oil and $5 #NatGas. #OOTT

home.treasury.gov/system/files/1...

Proposal

The proposal would repeal: (a) the enhanced oil recovery credit for eligible costs attributable to a qualified enhanced oil recovery project; (b) the credit for oil and gas produced from marginal wells; (c) the expensing of intangible drilling costs; (d) the deduction for costs paid or incurred for any qualified tertiary injectant used as part of a tertiary recovery method; (e) the exception to passive loss limitations provided to working interests in oil and natural gas properties; (f) the use of percentage depletion with respect to oil and gas wells; (g) two year amortization of geological and geophysical expenditures by independent producers, instead allowing amortization over the seven-year period used by major integrated oil companies; (h) expensing of exploration and development costs; (i) percentage depletion for hard mineral fossil fuels; (j) capital gains treatment for royalties; (k) the exemption from the corporate income tax for publicly traded partnerships with qualifying income and gains from activities relating to fossil fuels; (l) the

25

General Explanations of the Administration's Fiscal Year 2023 Revenue Proposals

OSTLF excise tax exemption for crude oil derived from bitumen and kerogen-rich rock; and (m) accelerated amortization for air pollution control facilities.

Unless otherwise specified, the proposal provisions would be effective for taxable years beginning after December 31, 2022. In the case of royalties, the proposal provision would be effective for amounts realized after taxable years beginning after December 31, 2022. The repeal of the exemption from the corporate income tax for publicly traded partnerships with qualifying income and gains from activities relating to fossil fuels would be effective for taxable years beginning after December 31, 2027.

6 24 35

Dan Tsubouchi @Energy_Tidbits · Mar 28

SAF

Busted, wasn't US asking #OPEC for oil? #UAEEnergyMinister "I haven't received any call or any request for a call from the Secretary of Energy [Granholm]" Gamble "nothing?" Al Marzouei "No, she didn't call me, she didn't approach me" Another great @_HadleyGamble interview. #OOTT

SAF Group created transcript of CNBC's Hadley Gamble with UAE Energy Minister Suhail Mohamed Al Marzouei on March 28, 2022 https://twitter.com/themmagraham/status/1508473389580705799

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

Al Marzouei "*...because what we want to do is be friend with everyone. we're friends with the US. we're friends with the*". Gamble "*but you're not taking a call from President Biden.*" Al Marzouei "*No, I think*". Gamble "*that's what you told me the last time we spoke*". Al Marzouei "*no, President Biden doesn't call me.*" Gamble "*but if the United States were to call you, you'd take the call?*" Al Marzouei "*I had a meeting today with some envoys from the United States, the United States*". Gamble "*but it doesn't' necessarily sway your opinion one way or another.*" Al Marzouei "*I don't think we should take it that way. the United States is a very important partner to us. And we have significant investments. We have much more in common with the United States, but that doesn't mean that we would have to agree on everything. I mean we would agree on the things that we think we can agree. And there are things that we could disagree. And we're not going to be told what to do. We know what is sensible for us. and in the field of energy, I haven't received any call or any request for a call from the Secretary of Energy*" Gamble "*nothing?*" Al Marzouei "*No, she didn't call me, she didn't approach me.*" Gamble "*Huh*". Al Marzouei "*And if she wanted to call, she is always going to be welcome. I will not say no to, I speak with everyone. So, I think taking it that way is not the right approach. but if taking a call means that we have to listen to something that is, that we cannot do, then that is not how it should be interpreted. US is important, it is an important friend, we are investing there, they are investing here, we have lots of collaboration with them. And cooperation. So, it's the largest economy in the world*".

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

Emma Graham @themmagraham · Mar 28

BREAKING: UAE's Energy Minister tells CNBC's @_HadleyGamble he hasn't yet received a call from the U.S. Energy Secretary

4 12

Dan Tsubouchi @Energy_Tidbits · Mar 28
#Oil #NatGas #LNG will be stronger thru 2030. #OOTT

> Dan Tsubouchi @Energy_Tidbits · Dec 9, 2021
> Time for #2022Predictions. My #1 is more #EnergyTransition #NetZero leaders come out of closet, have a #MacronMoment ie. have "transition" not self inflicted shortage so 2021 energy crisis isn't every year. A return to #EnergySecurity = #Oil #NatGas #LNG strong thru 2030. #OOTT twitter.com/Energy_Tidbits...

1 3 5

Dan Tsubouchi @Energy_Tidbits · Mar 28
Oops, self inflicted #EnergyCrisis. "they create a big mistake & now see what happened. it's not just RUS, the gas price is not just RUS" "the worldwide leadership was not wise & without equilibrium in evaluating the energy situation" @c_descalzi to @_HadleyGamble #OOTT #NatGas

> SAF Group created transcript of CNBC's Hadley Gamble with Eni CEO Claudio Descalzi on March 28, 2022
>
> Items in "italics" are SAF Group created transcript
>
> Descalzi *"I think that's also, the minister said clearly that in the last years, in the past, we create a conflict between energy transition and gas or oil and decarbonization. It become an ideology so just renewables. We are producing also renewables. We know we cannot do everything with just renewables. There are a lot of different technologies. But gas, until two months ago, in Europe, the taxonomy, gas was out. In November, October, I don't want to say that you are a criminal if you produce gas and oil, but not far to be a criminal okay if you are producing gas or oil. And now, so that is a big mistake to be radical and say I want just that, renewables. And the rest have to disappear. We know very well that in the last 200 years, all the different energy vectors have been added – so coal, plus oil, plus gas and plus renewables. We never found a source or energy source that replaced everything. It's crazy to think that there is something that can replace everything. for that reason, the transition, we have to accept that we have some infrastructure for what we spent billion and billion that are hard to abate so we have to capture. And we need to use all the different technologies if we think that we are to choice some technology by in an ideologic approach, its crazy. Technology is neutral, there is no religion, it is not a god a technology. You have to use to phase the transition. so I think that when we talk about energy, first of all, we have to know what you are talking about – competencies. Everybody talks about energy, everybody talk about Covid. And make a big confusion. They create a big mistake and now we see what happened. It's not just Russia, the gas price is not just Russia. Because for seven years, we underinvested, we invested just 45% of what we invested in the previous seven years until 2014. Then we have Russia, then we have Covid, so I think that the worldwide leadership was not wise and without any equilibrium in evaluating the energy situation."*
>
> Prepared by SAF Group https://safgroup.ca/news-insights/

> Emma Graham @themmagraham · Mar 28
>
> 
>
>
> Only two months ago it was "criminal" to produce oil and gas in Europe, Eni CEO Claudio Descalzi tells CNBC's @_HadleyGamble at @AtlanticCouncil

5 15

Dan Tsubouchi @Energy_Tidbits · Mar 27

""Without any subsidies… the price of an [electric] truck will always, forever be higher than a [combustion engine] truck"says @DaimlerTruck CEO. Can #EVs meet growth fcasts if they don't get broad buying below high income? Thx @JoeMillerJr #OOTT ft.com/content/1ac7d6...

> **Dan Tsubouchi** @Energy_Tidbits · Jan 13
>
> 53% of US won't pay >$500 for alternative engine solutions (#EVs), 69% prefer ICE vs 5% EVs for next vehicle. It's why EVs are still mostly for higher income & need even bigger subsidies. Much more in @Deloitte 2022 Global Automative Consumer Study. Thx @KarenBowman #OOTT
>
> 

6 12

Dan Tsubouchi @Energy_Tidbits · Mar 27

SAF GROUP

Our weekly SAF Mar 27, 2022 Energy Tidbits memo is posted on our SAF Group website. This 56-pg energy research memo expands upon & covers more items than tweeted this week. See news/insights section of SAF website #Oil #OOTT #LNG #NatGas #EnergyTransition safgroup.ca/news-insights/

SAF GROUP

Energy Tidbits

March 27, 2022

Produced by: Dan Tsubouchi

Liberals to Unveil the Hard Emissions Reduction Targets For 2025 (Only 3 Years Away) For Oil & Gas Sector

Welcome to new Energy Tidbits memo readers. We are continuing to add new readers to our Energy Tidbits memo, energy blogs and tweets. The focus and concept for the memo was set in 1999 with input from PMs, who were looking for research (both positive and negative items) that helped them shape their investment thesis to the energy space, and not just focusing on daily trading. Our priority was and still is to not just report on events, but also try to interpret and point out implications therefrom. The best example is our review of investor days, conferences and earnings calls focusing on sector developments that are relevant to the sector and not just a specific company results. Our target is to write on 48 to 50 weekends per year and to post by noon mountain time on Sunday.

This week's memo highlights:

1. The Liberals are announcing their hard emissions reduction targets for 2025 for the oil and gas sector this week and we remind 2025 is only 3 years away (Click Here)
2. Will Biden's "*For God's sake, this man cannot remain in power*" cause Russia to put JCPOA in limbo? (Click Here)
3. LNG supply gap will be sooner and larger with uncertain length delays to Novatek under construction Arctic LNG-2 project. (Click Here)
4. More Asian LNG buyers lock up long term LNG supply (Click Here)
5. Will Biden's reported 1st version wealth tax open the flood gates to future wealth taxes in states and Canada? (Click Here)
6. Please follow us on Twitter at [LINK] for breaking news that ultimately ends up in the weekly Energy Tidbits memo that doesn't get posted until Sunday noon MT.
7. For new readers to our Energy Tidbits and our blogs, you will need to sign up at our blog sign up to receive future Energy Tidbits memos. The sign up is available at [LINK].

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