Energy Tidbits

OPEC+ to Implement Voluntary 1.16 mmb/d Cuts Effective May 1 thru Dec 31

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Table 1. Summary of natural gas supply and disposition in the United States, 2018-2023

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]
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 total	**40,614**	**36,202**	**2,710**	**33,493**	**63**	**-2,734**	**-180**	**-129**	**30,513**
2021									
January	3,517	3,118	235	2,884	6	-279	719	16	3,344
February	2,950	2,609	196	2,412	5	-152	795	40	3,099
March	3,518	3,144	237	2,907	6	-357	64	30	2,649
April	3,438	3,069	231	2,838	5	-356	-180	-42	2,265
May	3,535	3,168	239	2,930	6	-373	-424	-21	2,117
June	3,400	3,056	230	2,826	5	-331	-254	-8	2,238
July	3,514	3,182	240	2,943	6	-338	-175	-23	2,412
August	3,545	3,196	241	2,956	6	-343	-164	-20	2,434
September	3,423	3,087	232	2,854	5	-315	-398	-4	2,142
October	3,600	3,245	244	3,001	6	-317	-368	-60	2,263
November	3,545	3,170	239	2,931	6	-315	137	-66	2,693
December	3,680	3,284	247	3,037	6	-368	330	3	3,007
Total	**41,666**	**37,328**	**2,811**	**34,518**	**66**	**-3,845**	**82**	**-157**	**30,665**
2022									
January	E3,591	E3,199	246	E2,953	7	R-315	994	-47	3,592
February	E3,227	E2,870	223	E2,647	6	R-289	658	38	3,061
March	E3,614	E3,225	267	E2,958	6	R-380	163	R33	2,781
April	E3,520	E3,152	257	E2,895	6	R-343	-214	R23	2,367
May	E3,667	E3,296	266	E3,030	6	R-386	-403	R-4	2,242
June	E3,557	E3,215	259	E2,956	4	R-324	-324	R6	2,318
July	E3,690	E3,330	276	E3,055	6	R-301	-180	R4	2,583
August	E3,699	E3,349	270	E3,079	6	R-321	-206	R1	R2,560
September	E3,638	E3,281	265	E3,016	4	-293	-436	-3	R2,289
October	E3,769	E3,394	275	E3,119	5	-315	-422	-21	2,366
November	RE3,683	RE3,297	269	RE3,029	4	-308	71	R-23	R2,773
December	RE3,723	RE3,322	249	RE3,073	R5	R-305	573	R35	R3,382
Total	**RE43,378**	**RE38,930**	**3,120**	**RE35,810**	**65**	**R-3,877**	**275**	**R40**	**R32,314**
2023									
January	E3,808	E3,409	264	E3,145	6	-328	456	32	3,311

[a] We derive monthly natural gas plant liquid (NGPL) production, gaseous equivalent, 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] We only collect supplemental gaseous fuels data on an annual basis except for the Dakota Gasification Co. coal gasification facility, which provides data each month. We calculate the ratio of annual supplemental fuels (excluding Dakota Gasification Co.) to the sum of dry gas production, net imports, and net withdrawals from storage. We apply this ratio to the monthly sum of these three elements. We add the Dakota Gasification Co. monthly value to the result to produce the monthly supplemental fuels estimate.

[d] Monthly and annual data for 2018 through 2020 include underground storage and liquefied natural gas storage. Data for January 2021 forward include underground storage only. Appendix A, Explanatory Note 5, contains a 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): 212 for 2021; 209 for 2020; -8 for 2019; and -12 for 2018. Appendix A, Explanatory Note 7, contains a full discussion of balancing item calculations.

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

[R] Revised data.

[E] Estimated data.

[RE] Revised estimated data.

Source: 2018-2021: U.S. Energy Information Administration (EIA), *Natural Gas Annual 2021*. January 2022 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*. Table 7 includes detailed source notes for Marketed Production. Appendix A, Notes 3 and 4, includes discussion of computation and estimation procedures and revision policies.

Note: Data for 2018 through 2020 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.

Table 2. Natural gas consumption in the United States, 2018-2023

billion cubic feet, or as indicated

Year and month	Lease and plant fuel[a]	Pipeline and distribution use[b]	Delivered to consumers: Residential	Commercial	Industrial	Electric power	Vehicle fuel	Total	Total consumption	Heating value[c] (Btu per cubic foot)
2018 total	**1,694**	**877**	**4,998**	**3,514**	**8,417**	**10,589**	**50**	**27,568**	**30,139**	**1,036**
2019 total	**1,823**	**1,018**	**5,019**	**3,515**	**8,417**	**11,288**	**53**	**28,291**	**31,132**	**1,038**
2020 total	**1,809**	**1,018**	**4,674**	**3,170**	**8,161**	**11,632**	**49**	**27,686**	**30,513**	**1,037**
2021										
January	159	125	895	497	791	872	5	3,060	3,344	1,038
February	133	116	876	497	686	787	4	2,850	3,099	1,041
March	160	98	574	358	703	752	5	2,392	2,649	1,038
April	156	83	342	248	676	756	4	2,026	2,265	1,036
May	161	77	218	183	658	816	5	1,879	2,117	1,035
June	156	82	130	144	638	1,085	4	2,001	2,238	1,034
July	162	88	113	143	666	1,235	5	2,162	2,412	1,035
August	163	89	106	142	669	1,261	5	2,182	2,434	1,034
September	157	78	118	150	639	995	4	1,907	2,142	1,035
October	165	82	193	197	677	944	5	2,015	2,263	1,035
November	161	99	482	338	726	882	4	2,432	2,693	1,037
December	167	112	669	402	767	886	5	2,729	3,007	1,038
Total	**1,901**	**1,130**	**4,716**	**3,298**	**8,295**	**11,271**	**54**	**27,634**	**30,665**	**1,037**
2022										
January	E163	E132	961	553	817	961	E5	3,296	3,592	1,038
February	E146	E113	796	465	722	815	E4	2,802	3,061	1,038
March	E164	E102	591	387	753	779	E5	2,515	2,781	1,036
April	E161	E87	390	277	700	748	E4	2,120	2,367	1,035
May	E168	E83	201	183	677	925	E5	1,992	2,242	1,034
June	E164	E85	124	147	648	1,146	E4	2,069	2,318	1,033
July	E170	E95	110	145	658	1,400	E5	2,318	2,583	1,033
August	E171	E94	103	141	670	1,375	E5	2,295	R2,560	1,035
September	E167	E84	114	150	646	1,122	E4	2,037	R2,289	1,036
October	E173	E87	242	224	686	950	E5	2,106	2,366	1,036
November	E168	E102	R516	356	723	903	E4	R2,503	R2,773	1,036
December	E169	E125	R840	496	754	993	E5	R3,088	R3,382	1,041
Total	**E1,983**	**E1,190**	**R4,990**	**3,525**	**8,455**	**12,118**	**E53**	**R29,140**	**R32,314**	**1,036**
2023										
January	E174	E122	800	476	767	968	E5	3,016	3,311	1,039

[a] We only collect plant fuel data and lease fuel data annually. We estimate monthly lease and plant fuel use from monthly marketed production by assuming that the preceding annual percentage remains constant for the next 12 months.

[b] We base published pipeline and distribution use data on reports collected on an annual basis. We estimate monthly pipeline and distribution use data from monthly total consumption (excluding pipeline and distribution use) by assuming that the preceding annual percentage remains constant for the next 12 months. Pipeline and distribution use volumes include line loss, defined as known volumes of natural gas that were the result of leaks, damage, accidents, migration, and/or blow downs, as well as fuel used in liquefaction and regasification.

[c] Heating value is the average number of British thermal units per cubic foot of natural gas as reported on EIA-857 and EIA-176. Appendix A, Explanatory Note 11, contains further information.

R Revised data.

E Estimated data.

Source: 2018-2021: U.S. Energy Information Administration (EIA): Form EIA-857, *Monthly Report of Natural Gas Purchases and Deliveries to Consumers*; state and federal agencies; EIA estimates based on historical data; and *Natural Gas Annual 2021*. January 2022 through current month: Form EIA-914, *Monthly Crude Oil and Lease Condensate, and Natural Gas Production Report*; Form EIA-857; Form EIA-923, *Power Plant Operations Report*. Appendix A, Explanatory Note 6, contains an explanation of computation procedures and revision policy.

Note: Data for 2018 through 2020 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. Appendix A, Explanatory Note 6, contains a definition of sectors.

Table 5. U.S. natural gas exports, 2021-2023

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

	2023					2022
	January	Total	December	November	October	September
Exports						
Volume (million cubic feet)						
Pipeline						
Canada	104,399	R959,630	98,718	90,179	72,738	61,926
Mexico	162,085	2,074,340	158,638	160,986	171,766	169,159
Total pipeline exports	**266,483**	**R3,033,970**	**257,355**	**251,165**	**244,505**	**231,086**
LNG						
Exports						
By vessel						
Antigua and Barbuda	4	22	1	2	2	3
Argentina	0	66,939	0	0	0	0
Bahamas	42	489	42	35	40	43
Bangladesh	3,369	12,663	0	0	0	0
Barbados	0	93	0	1	0	0
Belgium	3,640	80,245	3,274	0	7,190	9,165
Brazil	0	71,998	0	0	3,439	0
Chile	3,307	30,131	0	0	0	3,365
China	17,896	R96,659	R6,992	17,308	R22,598	10,275
Colombia	0	5,703	0	0	3,699	0
Croatia	2,913	77,286	6,204	5,122	2,922	9,073
Dominican Republic	3,643	50,824	6,644	0	3,469	3,196
Egypt	0	0	0	0	0	0
Finland	0	329	329	0	0	0
France	34,124	571,399	38,311	50,655	41,959	57,943
Germany	14,314	7,113	7,112	1	0	0
Greece	3,207	69,031	2,869	421	4,424	0
Haiti	8	115	9	0	0	8
India	6,956	122,518	14,139	10,138	7,005	10,528
Indonesia	805	6,579	3,256	505	625	509
Israel	0	0	0	0	0	0
Italy	10,082	116,034	6,992	3,205	0	8,355
Jamaica	107	1,516	147	137	144	240
Japan	17,696	R209,220	R20,535	24,396	10,684	7,005
Jordan	0	0	0	0	0	0
Kuwait	0	57,018	0	0	3,299	7,038
Lithuania	6,713	77,212	3,281	3,708	7,072	3,541
Malaysia	0	0	0	0	0	0
Malta	2,592	5,273	0	2,928	0	0
Mexico	3,219	3,832	539	0	0	0
Netherlands	36,453	378,329	39,893	20,645	39,703	30,924
Nicaragua	0	0	0	0	0	0
Pakistan	0	3,074	0	0	0	0
Panama	2,718	13,759	249	3,833	0	0
Poland	11,538	127,404	13,885	3,453	7,095	16,917
Portugal	6,816	69,583	10,025	3,732	7,005	5,806
Singapore	0	R22,980	0	0	R6,628	0
South Korea	24,507	R292,732	24,700	14,069	R38,844	19,736
Spain	13,987	426,657	33,847	26,445	26,369	21,263
Taiwan	3,471	106,738	9,203	3,592	9,041	9,753
Thailand	3,738	25,988	0	0	0	3,673
Turkiye	36,126	192,067	17,979	31,430	10,333	5,458
United Arab Emirates	0	0	0	0	0	0
United Kingdom	63,032	464,462	69,332	76,693	46,040	51,467
By truck						
Canada	0	76	8	0	19	0
Mexico	133	1,552	160	153	175	94
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	**337,155**	**3,865,643**	**339,960**	**302,608**	**309,823**	**295,379**
CNG						
Canada	*	2	0	*	1	*
Total CNG exports	*	**2**	**0**	*	**1**	*
Total exports	**603,639**	**R6,899,616**	**597,316**	**553,774**	**554,328**	**526,465**

See footnotes at end of table.

Table 5. U.S. natural gas exports, 2021-2023

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

	2022					
	August	July	June	May	April	March
Exports						
Volume (million cubic feet)						
Pipeline						
Canada	R75,220	R69,774	R70,105	R79,214	R80,475	R105,074
Mexico	181,124	188,178	181,700	185,965	176,440	169,885
Total pipeline exports	**R256,344**	**R257,951**	**R251,805**	**R265,179**	**R256,916**	**R274,958**
LNG						
Exports						
By vessel						
Antigua and Barbuda	2	2	3	2	3	2
Argentina	2,202	9,448	25,246	20,111	9,933	0
Bahamas	53	45	47	42	34	43
Bangladesh	0	0	0	3,346	0	3,421
Barbados	0	0	0	0	0	34
Belgium	3,589	0	7,023	3,441	7,341	17,743
Brazil	10,542	5,192	3,857	15,303	3,448	2,236
Chile	0	6,917	0	9,943	3,530	3,214
China	10,272	784	7,329	0	10,217	7,527
Colombia	606	0	912	0	0	0
Croatia	7,824	4,600	7,925	8,543	6,763	3,358
Dominican Republic	3,357	6,532	5,838	4,964	3,645	6,530
Egypt	0	0	0	0	0	0
Finland	0	0	0	0	0	0
France	33,885	53,443	37,564	47,150	56,343	64,415
Germany	0	0	0	0	0	0
Greece	10,763	12,922	9,633	12,650	1,336	4,116
Haiti	11	8	13	9	11	10
India	10,265	13,902	10,653	7,152	14,223	10,438
Indonesia	967	0	0	0	0	0
Israel	0	0	0	0	0	0
Italy	15,462	9,914	7,137	21,696	15,519	7,088
Jamaica	110	121	48	144	135	92
Japan	20,156	18,189	21,561	24,024	13,231	17,697
Jordan	0	0	0	0	0	0
Kuwait	6,415	5,382	8,105	14,204	7,298	0
Lithuania	7,579	7,947	6,729	11,237	13,770	5,700
Malaysia	0	0	0	0	0	0
Malta	0	0	0	0	0	0
Mexico	0	0	3,292	0	0	0
Netherlands	50,020	32,637	34,420	28,902	28,395	24,922
Nicaragua	0	0	0	0	0	0
Pakistan	0	0	0	0	3,074	0
Panama	0	0	623	1,192	1,536	0
Poland	6,885	17,780	14,282	18,224	13,882	3,831
Portugal	3,202	6,412	5,582	3,888	6,632	10,728
Singapore	0	6,275	3,352	0	0	6,725
South Korea	36,033	34,342	25,054	17,538	13,813	19,289
Spain	26,140	34,396	29,639	40,337	40,259	59,224
Taiwan	8,901	9,353	6,892	15,975	9,541	12,161
Thailand	3,607	0	6,920	3,419	0	0
Turkiye	0	0	7,542	7,281	6,637	16,629
United Arab Emirates	0	0	0	0	0	0
United Kingdom	21,263	3,797	3,326	10,608	39,775	56,799
By truck						
Canada	0	0	8	8	15	0
Mexico	103	76	105	115	122	144
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	**300,215**	**300,415**	**300,659**	**351,448**	**330,463**	**364,116**
CNG						
Canada	*	1	*	0	0	*
Total CNG exports	*****	**1**	*****	**0**	**0**	*****
Total exports	**R556,559**	**R558,367**	**R552,464**	**R616,627**	**R587,378**	**R639,074**

See footnotes at end of table.

Table 5. U.S. natural gas exports, 2021-2023

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

	2022		2021			
	February	January	Total	December	November	October
Exports						
Volume (million cubic feet)						
Pipeline						
Canada	R74,630	R81,577	937,124	108,568	85,136	62,464
Mexico	155,032	175,467	2,154,457	166,956	165,449	184,472
Total pipeline exports	**R229,662**	**R257,045**	**3,091,580**	**275,524**	**250,585**	**246,936**
LNG						
Exports						
By vessel						
Antigua and Barbuda	0	2	8	3	2	0
Argentina	0	0	83,449	2,077	0	0
Bahamas	31	34	486	36	34	36
Bangladesh	5,896	0	37,734	0	0	0
Barbados	31	28	297	34	27	25
Belgium	7,691	13,786	5,584	0	0	0
Brazil	10,660	17,322	307,714	24,246	10,715	40,769
Chile	0	3,162	121,881	2,938	2,956	6,364
China	3,357	0	453,304	17,050	50,228	42,202
Colombia	0	486	2,247	0	0	0
Croatia	5,870	9,084	36,133	3,117	9,416	0
Dominican Republic	0	6,647	53,095	5,969	2,780	5,619
Egypt	0	0	0	0	0	0
Finland	0	0	0	0	0	0
France	39,646	50,084	170,780	33,892	10,021	9,333
Germany	0	0	0	0	0	0
Greece	8,094	1,802	39,708	5,305	7,629	1,515
Haiti	16	20	137	4	8	17
India	7,210	6,866	196,218	3,203	14,807	10,548
Indonesia	717	0	3,269	1,218	456	477
Israel	0	0	8,906	0	0	0
Italy	13,629	7,037	34,210	0	0	0
Jamaica	111	86	25,276	113	715	1,858
Japan	10,214	21,527	354,948	24,297	33,947	37,666
Jordan	0	0	0	0	0	0
Kuwait	5,277	0	34,476	0	0	6,193
Lithuania	3,131	3,518	30,919	0	0	0
Malaysia	0	0	0	0	0	0
Malta	2,345	0	5,427	0	0	0
Mexico	0	0	15,200	0	0	1,088
Netherlands	31,591	16,279	174,339	23,354	8,829	17,157
Nicaragua	0	0	1	0	0	0
Pakistan	0	0	45,818	0	2,490	3,138
Panama	3,069	3,255	8,436	0	0	911
Poland	7,475	3,695	56,320	7,159	7,068	3,270
Portugal	3,703	2,868	65,865	9,630	5,380	10,459
Singapore	0	0	20,918	0	3,728	0
South Korea	27,489	21,824	453,483	38,201	30,787	33,836
Spain	39,359	49,379	215,062	32,579	22,821	35,638
Taiwan	6,115	6,211	99,350	12,034	3,404	7,123
Thailand	4,880	3,490	14,548	0	0	0
Turkiye	43,697	45,081	188,849	38,420	47,330	19,385
United Arab Emirates	0	0	0	0	0	0
United Kingdom	25,301	60,060	195,046	60,315	30,648	3,302
By truck						
Canada	4	13	128	20	8	8
Mexico	157	148	1,250	148	160	182
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	**316,766**	**353,791**	**3,560,818**	**345,363**	**306,397**	**298,119**
CNG						
Canada	0	0	211	0	0	0
Total CNG exports	**0**	**0**	**211**	**0**	**0**	**0**
Total exports	**R546,428**	**R610,836**	**6,652,609**	**620,886**	**556,982**	**545,055**

See footnotes at end of table.

Table 5. U.S. natural gas exports, 2021-2023

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

						2021
	September	**August**	**July**	**June**	**May**	**April**
Exports						
Volume (million cubic feet)						
Pipeline						
Canada	72,023	71,586	68,264	69,528	70,561	74,567
Mexico	178,746	193,710	197,623	198,242	192,549	182,918
Total pipeline exports	**250,769**	**265,296**	**265,887**	**267,770**	**263,110**	**257,485**
LNG						
Exports						
By vessel						
Antigua and Barbuda	3	0	0	0	0	0
Argentina	1,950	14,363	22,798	19,312	16,226	4,485
Bahamas	43	56	46	48	45	46
Bangladesh	3,276	7,085	0	3,493	6,948	10,219
Barbados	33	27	31	22	19	30
Belgium	0	0	0	0	2,100	0
Brazil	38,282	34,204	39,637	32,293	19,726	11,615
Chile	7,929	16,262	19,913	0	17,598	10,293
China	48,584	51,662	42,222	42,319	37,731	50,474
Colombia	436	919	0	0	0	892
Croatia	0	2,980	3,299	2,923	3,364	3,666
Dominican Republic	0	5,901	1,806	4,670	5,283	2,905
Egypt	0	0	0	0	0	0
Finland	0	0	0	0	0	0
France	6,578	7,111	0	3,683	11,926	36,120
Germany	0	0	0	0	0	0
Greece	799	3,607	6,651	0	6,796	0
Haiti	10	24	8	18	12	3
India	23,941	20,592	13,090	16,503	28,259	13,752
Indonesia	1,118	0	0	0	0	0
Israel	2,855	0	0	0	0	3,225
Italy	0	3,401	6,826	3,425	2,923	6,896
Jamaica	2,931	2,907	0	2,927	2,925	2,370
Japan	10,290	19,979	24,895	39,783	25,058	28,756
Jordan	0	0	0	0	0	0
Kuwait	10,333	3,298	0	7,126	0	3,705
Lithuania	3,282	1,677	6,469	3,285	3,049	3,078
Malaysia	0	0	0	0	0	0
Malta	2,498	0	0	0	0	2,928
Mexico	0	0	758	0	0	0
Netherlands	10,424	7,347	10,597	3,030	26,611	17,060
Nicaragua	0	0	1	0	0	0
Pakistan	9,642	3,319	13,428	3,376	0	3,323
Panama	0	1,390	0	0	2,341	0
Poland	0	0	6,619	10,635	3,581	7,382
Portugal	3,696	6,382	3,296	5,538	10,765	7,358
Singapore	0	0	3,449	0	3,089	3,660
South Korea	31,375	50,101	39,314	55,918	46,033	21,683
Spain	31,274	23,068	8,630	7,833	5,234	22,974
Taiwan	5,789	6,728	20,653	3,097	10,157	6,594
Thailand	0	3,707	0	0	3,453	7,388
Turkiye	24,176	0	5,591	0	3,017	0
United Arab Emirates	0	0	0	0	0	0
United Kingdom	3,099	0	0	0	10,586	13,877
By truck						
Canada	19	18	16	7	18	15
Mexico	150	147	97	105	48	48
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	**284,813**	**298,262**	**300,143**	**271,368**	**314,922**	**306,818**
CNG						
Canada	0	14	16	27	25	29
Total CNG exports	**0**	**14**	**16**	**27**	**25**	**29**
Total exports	**535,583**	**563,572**	**566,046**	**539,165**	**578,056**	**564,333**

See footnotes at end of table.

Table 5. U.S. natural gas exports, 2021-2023

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

	2021		
	March	February	January
Exports			
Volume (million cubic feet)			
Pipeline			
Canada	91,301	78,198	84,927
Mexico	183,051	137,381	173,360
Total pipeline exports	**274,352**	**215,579**	**258,287**
LNG			
Exports			
By vessel			
Antigua and Barbuda	0	0	0
Argentina	2,238	0	0
Bahamas	39	29	28
Bangladesh	3,566	0	3,148
Barbados	14	19	17
Belgium	3,484	0	0
Brazil	21,977	13,118	21,132
Chile	21,320	6,524	9,784
China	28,476	3,415	38,940
Colombia	0	0	0
Croatia	7,367	0	0
Dominican Republic	5,577	5,689	6,895
Egypt	0	0	0
Finland	0	0	0
France	33,678	14,851	3,587
Germany	0	0	0
Greece	6,805	0	600
Haiti	10	11	12
India	17,381	13,776	20,367
Indonesia	0	0	0
Israel	2,826	0	0
Italy	10,739	0	0
Jamaica	2,458	2,365	3,708
Japan	27,673	18,271	64,331
Jordan	0	0	0
Kuwait	3,821	0	0
Lithuania	3,228	6,851	0
Malaysia	0	0	0
Malta	0	0	0
Mexico	0	13,354	0
Netherlands	24,204	22,777	2,949
Nicaragua	0	0	0
Pakistan	3,421	0	3,682
Panama	3,279	0	516
Poland	3,507	7,099	0
Portugal	0	3,360	0
Singapore	3,303	0	3,688
South Korea	32,203	18,094	55,936
Spain	13,900	3,733	7,377
Taiwan	13,450	0	10,319
Thailand	0	0	0
Turkiye	3,619	20,652	26,659
United Arab Emirates	0	0	0
United Kingdom	17,440	34,343	21,436
By truck			
Canada	0	0	0
Mexico	19	63	83
Re-exports			
By vessel			
Argentina	0	0	0
Brazil	0	0	0
Japan	0	0	0
South Korea	0	0	0
United Kingdom	0	0	0
Total LNG exports	**321,023**	**208,394**	**305,196**
CNG			
Canada	36	32	32
Total CNG exports	**36**	**32**	**32**
Total exports	**595,411**	**424,004**	**563,515**

See footnotes at end of table.

Table 7. Marketed production of natural gas in selected states and the Federal Gulf of Mexico, 2018-2023

million cubic feet

Year and month	Alaska	Arkansas	California	Colorado	Kansas	Louisiana	Montana	New Mexico	North Dakota	Ohio
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 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	31,667	39,285	11,467	160,766	12,900	276,873	3,292	173,929	83,193	193,911
February	28,365	30,183	10,846	143,192	10,142	223,268	2,859	144,804	70,129	175,146
March	31,483	42,466	12,136	157,254	13,251	282,668	3,299	180,669	83,243	193,911
April	29,514	37,756	11,791	156,092	12,842	273,643	3,078	178,912	82,917	185,964
May	29,005	38,563	12,342	162,416	13,063	283,576	3,328	187,994	85,384	192,163
June	27,715	36,918	11,885	154,617	12,716	276,142	2,975	184,732	82,520	185,964
July	26,280	38,045	12,141	160,287	13,215	299,939	3,321	195,904	80,072	189,515
August	27,864	37,753	12,076	158,586	13,224	292,784	3,343	199,365	84,297	189,515
September	28,534	36,508	11,617	153,270	12,769	290,606	3,283	194,290	85,041	183,401
October	30,458	37,626	11,655	160,291	13,213	307,744	3,460	200,567	87,446	199,379
November	30,735	36,079	11,279	155,653	12,722	310,363	3,291	195,365	87,089	192,947
December	33,039	37,006	11,371	157,031	12,928	313,823	3,163	201,176	87,692	199,379
Total	**354,660**	**448,187**	**140,604**	**1,879,457**	**152,986**	**3,431,429**	**38,693**	**2,237,706**	**999,025**	**2,281,193**
2022										
January	32,865	[E]37,302	[E]11,186	[E]151,815	[E]12,255	[E]311,786	[E]3,092	[E]196,780	[E]81,699	[E]196,005
February	30,014	[E]33,465	[E]9,336	[E]138,369	[E]10,930	[E]284,177	[E]2,801	[E]183,345	[E]74,429	[E]172,829
March	32,473	[E]37,518	[E]11,388	[E]155,246	[E]12,194	[E]313,229	[E]3,214	[E]219,028	[E]86,190	[E]187,872
April	30,910	[E]36,247	[E]11,212	[E]151,319	[E]12,037	[E]313,229	[E]3,042	[E]215,953	[E]68,484	[E]179,444
May	31,677	[E]37,042	[E]11,489	[E]155,982	[E]12,469	[E]340,363	[E]3,152	[E]223,843	[E]80,563	[E]189,214
June	28,644	[E]35,573	[E]11,057	[E]150,046	[E]12,037	[E]335,290	[E]3,464	[E]214,602	[E]86,013	[E]190,021
July	29,654	[E]36,446	[E]11,651	[E]153,067	[E]12,457	[E]345,647	[E]3,465	[E]227,099	[E]89,572	[E]193,519
August	29,380	[E]36,659	[E]11,970	[E]154,806	[E]12,526	[E]355,454	[E]3,634	[E]230,690	[E]88,700	[E]196,604
September	29,288	[E]34,405	[E]11,100	[E]151,415	[E]11,565	[E]346,479	[E]3,572	[E]233,548	[E]88,797	[E]189,795
October	31,122	[E]35,354	[E]11,358	[E]155,354	[E]12,749	[E]363,490	[E]3,540	[E]247,855	[E]90,617	[E]195,926
November	30,934	[RE]33,777	[RE]10,905	[RE]151,562	[RE]12,036	[RE]354,732	[RE]3,342	[RE]237,280	[RE]84,563	[RE]195,571
December	36,181	[RE]33,188	[RE]11,175	[RE]150,457	[RE]11,644	[RE]355,564	[RE]3,292	[RE]249,403	[RE]76,058	[RE]186,257
Total	[R]**373,141**	[RE]**426,976**	[RE]**133,826**	[RE]**1,819,437**	[RE]**144,899**	[RE]**4,019,440**	[RE]**39,610**	[RE]**2,679,427**	[RE]**995,684**	[RE]**2,273,057**
2023										
January	33,391	[E]34,782	[E]11,061	[E]151,851	[E]11,881	[E]362,301	[E]3,525	[E]250,294	[E]81,999	[E]198,149

See footnotes at end of table.

Table 7. Marketed production of natural gas in selected states and the Federal Gulf of Mexico, 2018-2023

million cubic feet – continued

Year and month	Oklahoma	Pennsylvania	Texas	Utah	West Virginia	Wyoming	Other states	Federal Gulf of Mexico	U.S. total
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 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	221,544	652,640	798,426	19,392	234,432	97,657	35,223	71,772	3,118,370
February	163,094	585,371	609,757	18,126	208,571	89,337	31,366	64,024	2,608,580
March	220,130	645,407	826,381	20,404	227,218	95,164	34,671	74,200	3,143,955
April	214,334	615,899	820,570	19,783	229,075	92,340	34,427	69,762	3,068,700
May	223,372	635,584	844,723	20,313	234,118	94,341	35,868	72,053	3,168,206
June	213,314	616,270	815,947	19,502	227,987	90,259	29,234	67,429	3,056,126
July	221,002	638,200	858,526	20,601	229,376	93,644	30,467	71,744	3,182,278
August	222,329	646,169	863,509	20,347	241,373	89,749	32,659	61,377	3,196,320
September	216,455	622,275	855,425	19,928	216,452	91,662	30,611	34,559	3,086,687
October	223,093	645,126	873,479	20,457	240,446	93,162	37,663	60,037	3,245,301
November	214,361	646,233	836,104	20,014	229,812	90,176	32,023	65,610	3,169,856
December	218,805	677,331	872,543	20,538	241,569	91,741	36,962	67,903	3,283,998
Total	**2,571,834**	**7,626,504**	**9,875,390**	**239,405**	**2,760,429**	**1,109,232**	**401,172**	**780,471**	**37,328,378**
2022									
January	[E]213,419	[E]660,345	[E]853,214	[E]20,789	[E]234,795	[E]85,192	[E]31,292	[E]65,454	[E]3,199,287
February	[E]192,596	[E]581,432	[E]766,441	[E]18,966	[E]209,707	[E]76,605	[E]28,839	[E]55,884	[E]2,870,165
March	[E]219,732	[E]635,076	[E]871,961	[E]21,315	[E]239,344	[E]84,319	[E]31,519	[E]63,547	[E]3,225,163
April	[E]223,078	[E]616,181	[E]856,759	[E]21,254	[E]235,580	[E]81,405	[E]29,705	[E]65,810	[E]3,151,649
May	[E]237,032	[E]640,189	[E]887,465	[E]22,840	[E]247,179	[E]82,036	[E]31,011	[E]62,326	[E]3,295,871
June	[E]230,337	[E]616,632	[E]862,817	[E]22,278	[E]240,568	[E]80,395	[E]31,237	[E]63,627	[E]3,214,637
July	[E]239,295	[E]641,726	[E]887,919	[E]23,066	[E]251,625	[E]85,506	[E]32,355	[E]66,393	[E]3,330,463
August	[E]238,265	[E]632,014	[E]897,401	[E]23,500	[E]255,603	[E]81,633	[E]32,294	[E]68,280	[E]3,349,415
September	[E]236,726	[E]613,657	[E]882,979	[E]22,110	[E]245,734	[E]81,528	[E]31,485	[E]66,585	[E]3,280,768
October	[E]241,688	[E]629,461	[E]915,309	[E]22,164	[E]251,647	[E]87,030	[E]31,961	[E]67,352	[E]3,393,976
November	[RE]235,873	[RE]605,505	[RE]885,128	[RE]21,326	[RE]255,298	[RE]84,565	[E]30,838	[RE]63,917	[RE]3,297,153
December	[RE]236,647	[RE]611,036	[RE]908,479	[RE]22,711	[RE]253,515	[RE]81,639	[RE]30,737	[RE]63,852	[RE]3,321,835
Total	[RE]**2,744,688**	[RE]**7,483,256**	[RE]**10,475,87**	[RE]**262,320**	[RE]**2,920,595**	[RE]**991,853**	[RE]**373,272**	[RE]**773,028**	[RE]**38,930,383**
2023									
January	[E]241,373	[E]629,580	[E]918,708	[E]22,391	[E]275,925	[E]80,832	[E]31,623	[E]68,983	[E]3,408,649

[R] Revised data.

[E] Estimated data.

[RE] Revised estimated data.

Source: 2018-2021: U.S. Energy Information Administration (EIA), *Natural Gas Annual 2021*, Bureau of Safety and Environmental Enforcement (BSEE), IHS Markit, and Enverus. January 2022 through current month: Form EIA-914, *Monthly Crude Oil and Lease Condensate, and Natural Gas Production Report*; and EIA computations.

Note: For 2022 forward, we estimate state monthly marketed production from gross withdrawals using historical relationships between the two. We collect 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 individually 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 2022, Federal Offshore Pacific is included in California. We obtain all data for Alaska 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 because of independent rounding.

Summary

Overview of Activity for January 2023

- **Top five countries of destination, representing 58.6% of total U.S. LNG exports in January 2023**
  - United Kingdom (63.0 Bcf), Turkiye (39.3 Bcf), Netherlands (36.5 Bcf), France (34.1 Bcf), and South Korea (24.5 Bcf)
- **336.9 Bcf of exports in January 2023**
  - 0.8% decrease from December 2022
  - 4.7% less than January 2022
- **102 cargos shipped in January 2023**
  - Sabine Pass (41), Cameron (33), Corpus Christi (19), Cove Point (6), Elba (3), and Freeport (0)
  - 112 cargos in December 2022
  - 108 cargos in January 2022

1a. Table of Exports of Domestically-Produced LNG Delivered by Region (Cumulative from February 2016 through January 2023)

Region	Number of Countries Receiving Per Region	Volume Exported (Bcf)	Percentage Receipts of Total Volume Exported (%)	Number of Cargos*
East Asia and Pacific	8	4,542.2	32.6%	1343
Europe and Central Asia	15	6,035.6	43.3%	1890
Latin America and the Caribbean**	13	2,148.9	15.4%	767
Middle East and North Africa	5	376.6	2.7%	110
South Asia	3	833.8	6.0%	248
Sub-Saharan Africa	0	0.0	0.0%	0
Total LNG Exports	**44**	**13,937.1**	**100.0%**	**4,358**

*Split cargos counted as both individual cargos and countries

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

1b. Shipments of Domestically-Produced LNG Delivered – by Country (Cumulative from February 2016 through January 2023)

	Country of Destination	Region	Number of Cargos	Volume (Bcf of Natural Gas)	Percentage of Total U.S LNG Exports (%)
1.	South Korea*	East Asia and Pacific	502	1,746.3	12.5%
2.	Japan*	East Asia and Pacific	369	1,260.3	9.0%
3.	Spain*	Europe and Central Asia	339	1,064.9	7.6%
4.	United Kingdom*	Europe and Central Asia	317	1,052.3	7.6%
5.	France*	Europe and Central Asia	308	1,005.9	7.2%
6.	China*	East Asia and Pacific	293	1,000.2	7.2%
7.	Netherlands*	Europe and Central Asia	231	771.3	5.5%
8.	India*	South Asia	188	637.0	4.6%
9.	Turkiye*	Europe and Central Asia	197	631.6	4.5%
10.	Brazil*	Latin America and the Caribbean	217	608.3	4.4%
11.	Mexico*	Latin America and the Caribbean	165	550.1	3.9%
12.	Chile*	Latin America and the Caribbean	133	422.6	3.0%
13.	Taiwan*	East Asia and Pacific	104	327.1	2.3%
14.	Italy*	Europe and Central Asia	101	321.5	2.3%
15.	Poland*	Europe and Central Asia	85	280.3	2.0%
16.	Portugal*	Europe and Central Asia	84	268.3	1.9%
17.	Argentina*	Latin America and the Caribbean	110	265.2	1.9%
18.	Greece*	Europe and Central Asia	75	178.7	1.3%
19.	Dominican Republic*	Latin America and the Caribbean	67	161.4	1.2%
20.	Kuwait	Middle East and North Africa	45	156.4	1.1%
21.	Lithuania	Europe and Central Asia	50	154.0	1.1%
22.	Belgium*	Europe and Central Asia	45	145.3	1.0%
23.	Pakistan*	South Asia	40	128.9	0.9%
24.	Jordan*	Middle East and North Africa	36	124.2	0.9%
25.	Croatia	Europe and Central Asia	40	119.6	0.9%
26.	Singapore*	East Asia and Pacific	33	107.4	0.8%
27.	Thailand*	East Asia and Pacific	25	86.6	0.6%
28.	Bangladesh*	South Asia	20	67.8	0.5%
29.	Jamaica*	Latin America and the Caribbean	26	57.4	0.4%
30.	Panama*	Latin America and the Caribbean	31	54.7	0.4%
31.	United Arab Emirates	Middle East and North Africa	15	51.1	0.4%
32.	Israel*	Middle East and North Africa	9	28.0	0.2%
33.	Colombia*	Latin America and the Caribbean	18	24.2	0.2%
34.	Germany	Europe and Central Asia	6	21.4	0.2%
35.	Malta*	Europe and Central Asia	11	20.1	0.1%
36.	Egypt*	Middle East and North Africa	5	16.9	0.1%
37.	Indonesia*	East Asia and Pacific	16	10.7	0.1%
38.	Malaysia	East Asia and Pacific	1	3.7	0.0%
39.	Finland	Europe and Central Asia	1	0.3	0.0%
	Total Exports by Vessel		**4,358**	**13,932.1**	
	Germany	Europe and Central Asia	1	0.0	0.0%
40.	Antigua and Barbuda	Latin America and the Caribbean	34	0.0	0.0%
41.	Nicaragua	Latin America and the Caribbean	1	0.0	0.0%
42.	Haiti	Latin America and the Caribbean	129	0.4	0.0%
43.	Barbados	Latin America and the Caribbean	305	1.3	0.0%
	Jamaica	Latin America and the Caribbean	142	1.6	0.0%
44.	Bahamas	Latin America and the Caribbean	661	1.7	0.0%
	Total Exports by ISO		**1273**	**5.0**	
	Total Exports by Vessel and ISO		**5,631**	**13,937.1**	

Note:

Volume and Number of Cargos are the cumulative totals of each individual Country of Destination by Region starting from February 2016.

Jamaica has received U.S. LNG exports by both vessel and ISO container. The volumes are totaled separately

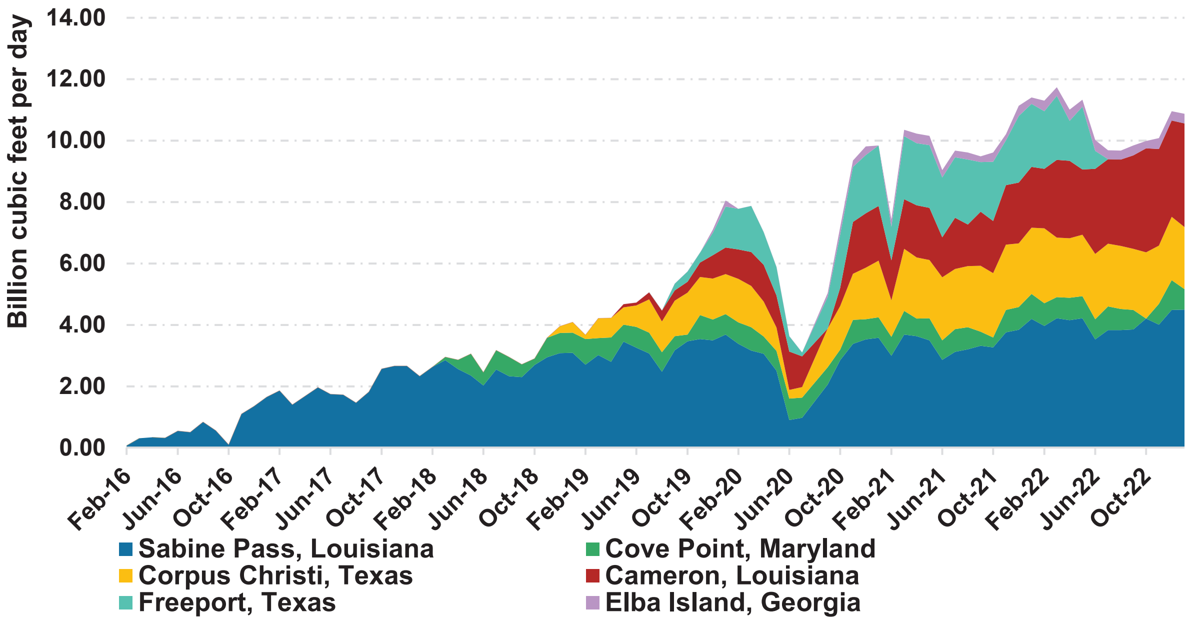
* Split cargos counted as both individual cargos and countries.

Vessel = LNG Exports by Vessel and ISO container = LNG Exports by Vessel in ISO Containers.

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

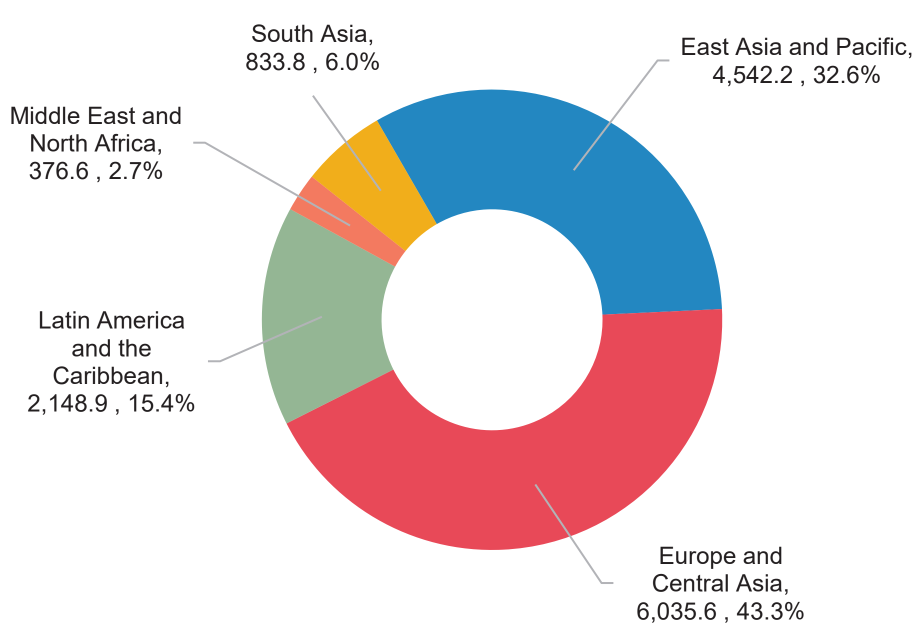
Totals may not equal sum of components because of independent rounding.

1c. Domestically-Produced LNG Exported by Point of Exit
(February 2016 through January 2023)



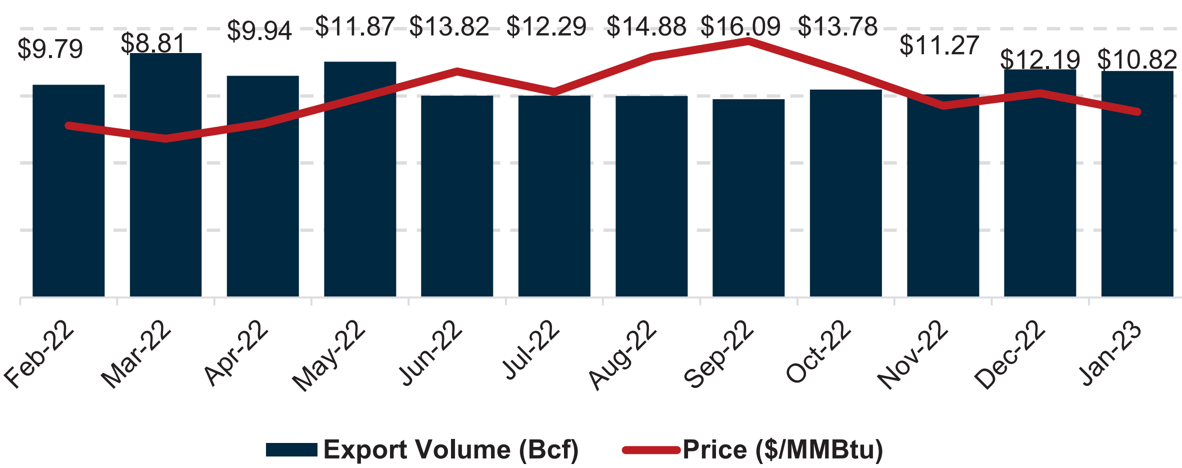
The Cameron, LA point of exit includes exports from Cameron LNG and Venture Global Calcasieu Pass.

1d. Domestically-Produced LNG Exported by Region
(Cumulative from February 2016 through January 2023)
(Bcf, %)



1f. Domestically-Produced LNG Exported – Volume (Bcf) and Weighted Average price ($/MMBtu) by Point of Exit per month

	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	Jan-23	Total
Sabine Pass, LA	110.9	130.5	124.6	130.7	105.7	118.5	118.7	115.6	130.4	120.1	139.2	139.2	**1,484.1**
	$9.81	$7.92	$8.80	$10.93	$12.90	$10.50	$12.71	$13.71	$10.85	$9.26	$10.43	$8.67	**$10.47**
Cove Point, MD	20.9	21.4	21.8	22.2	19.7	24.2	21.4	18.8	0	20.4	29.8	20.8	**241.5**
	$9.74	$8.57	$9.32	$10.85	$12.33	$11.28	$12.36	$13. 61	0	$10.10	$10.98	$8.67	**$10.69**
Corpus Christi, TX	68.2	60.1	58.3	62.0	63.7	63.1	63.4	59.8	66.8	57.0	64.1	62.6	**749.1**
	$10.66	$9.81	$10.48	$11.95	$13. 57	$12.17	$14.70	$15.99	$12.42	$10.36	$10.60	$10.74	**$11.96**
Cameron, LA	54.4	78.6	75.4	65.8	83.3	85.2	87.2	91.1	104.9	94.1	97.1	104.8	**1021.9**
	$8.72	$9.76	$12.33	$14.85	$16.05	$15.15	$18.92	$19.89	$18.38	$14.82	$16.34	$14.33	**$15.31**
Freeport, TX	52.5	64.5	39.3	63.5	17.3	0	0	0	0	0	0	0	**237.1**
	$9.60	$8.42	$9.07	$11.23	$12.83	0	0	0	0	0	0	0	**$9.86**
Elba Island, GA	9.6	8.7	10.8	6.9	10.7	9.1	9.2	9.7	7.4	10.6	9.4	9.4	**111.6**
	$10.40	$10.12	$7.93	$9.66	$11.40	$12.20	$11.58	$14.31	$12.53	$9.62	$10.14	$8.81	**$10.68**
Total	**316.4**	**363.8**	**330.1**	**351.1**	**300.4**	**300.2**	**299.9**	**295.1**	**309.4**	**302.3**	**339.6**	**336.9**	**3,845.3**
	$9.79	**$8.81**	**$9.94**	**$11.87**	**$13.82**	**$12.29**	**$14.88**	**$16.09**	**$13.78**	**$11.27**	**$12.19**	**$10.82**	**$12.03**



Notes:

Prices are free on board (FOB) and are inclusive of all costs of the LNG up to the point of export, including commodity costs and liquefaction fees.

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

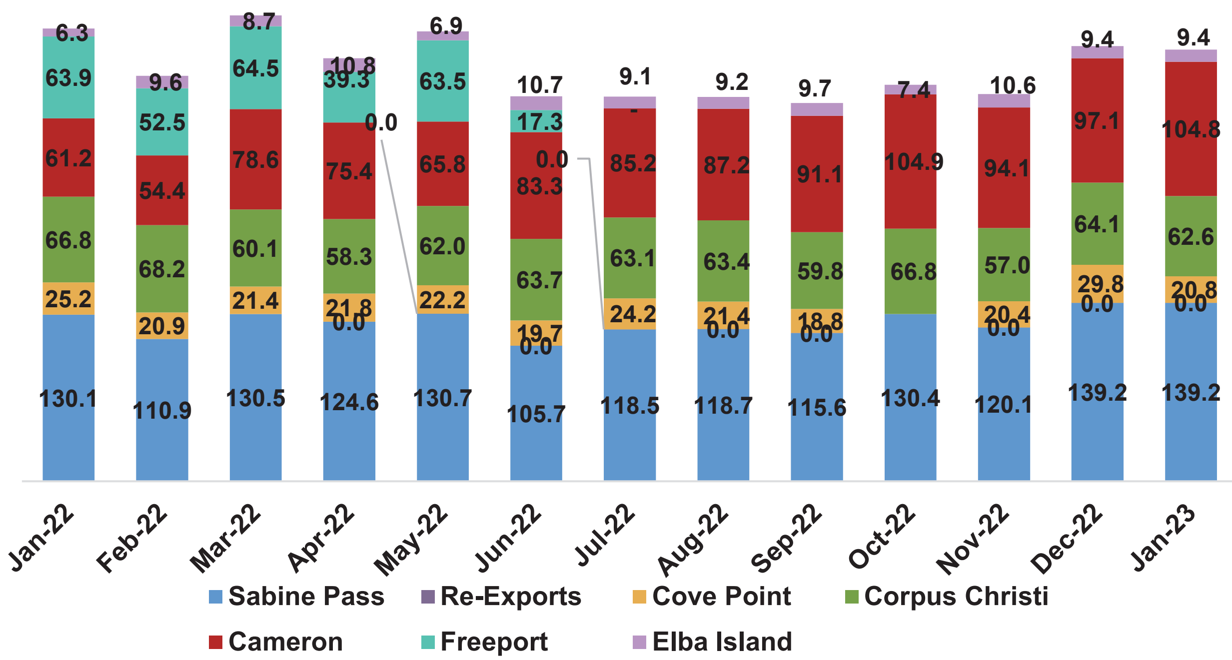
Totals may not equal sum of components because of independent rounding.

The Cameron, LA point of exit includes exports from Cameron LNG and Venture Global Calcasieu Pass.

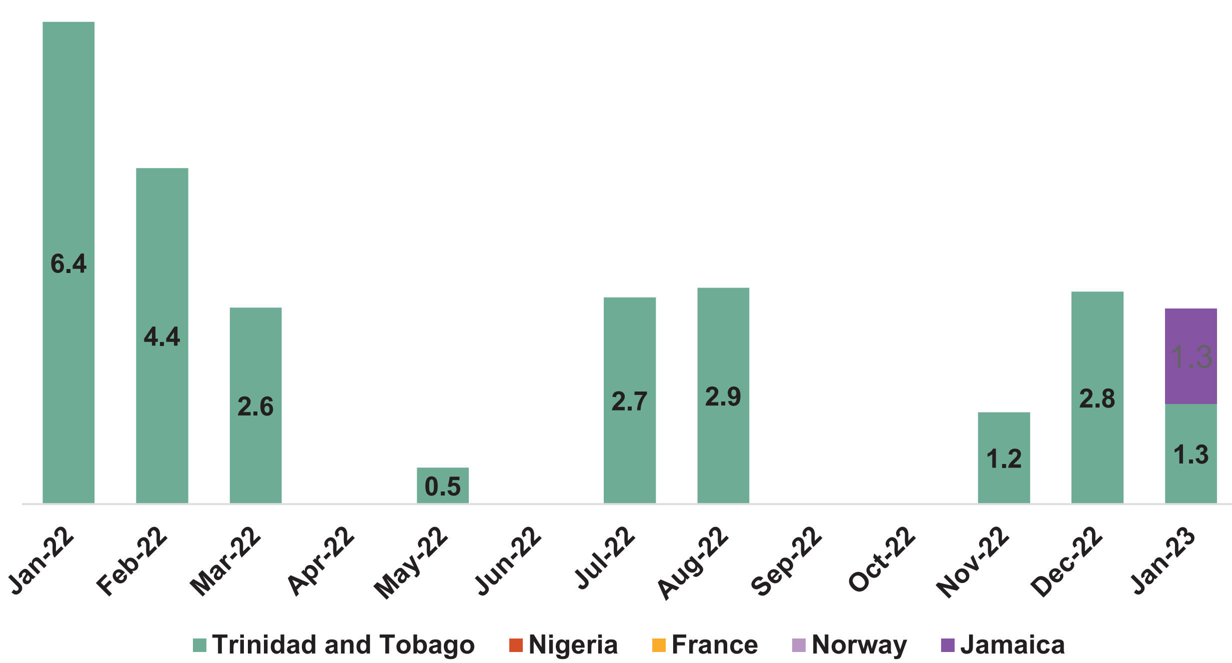
W - Withheld to avoid disclosure of individual company data.

DOE has a confidentiality policy for certain data elements collected on Form FE-746R that allows DOE to publish a monthly volume-weighted average price for each point of LNG import or export, but not a price for each individual imported or exported LNG cargo. For additional information, please see the Federal Register Notice concerning this Information Collection Extension at https://www.federalregister.gov/documents/2018/08/30/2018-18829/information-collection-extension.

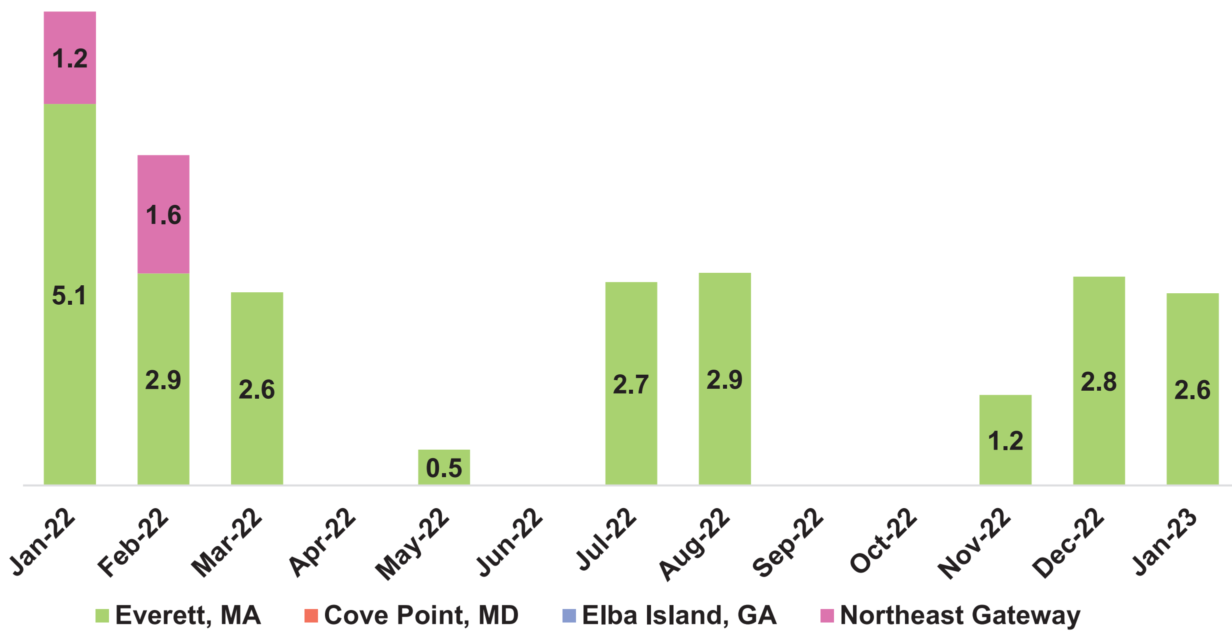
U.S. LNG by Vessel – Export and Re-Export Volumes
(Bcf)



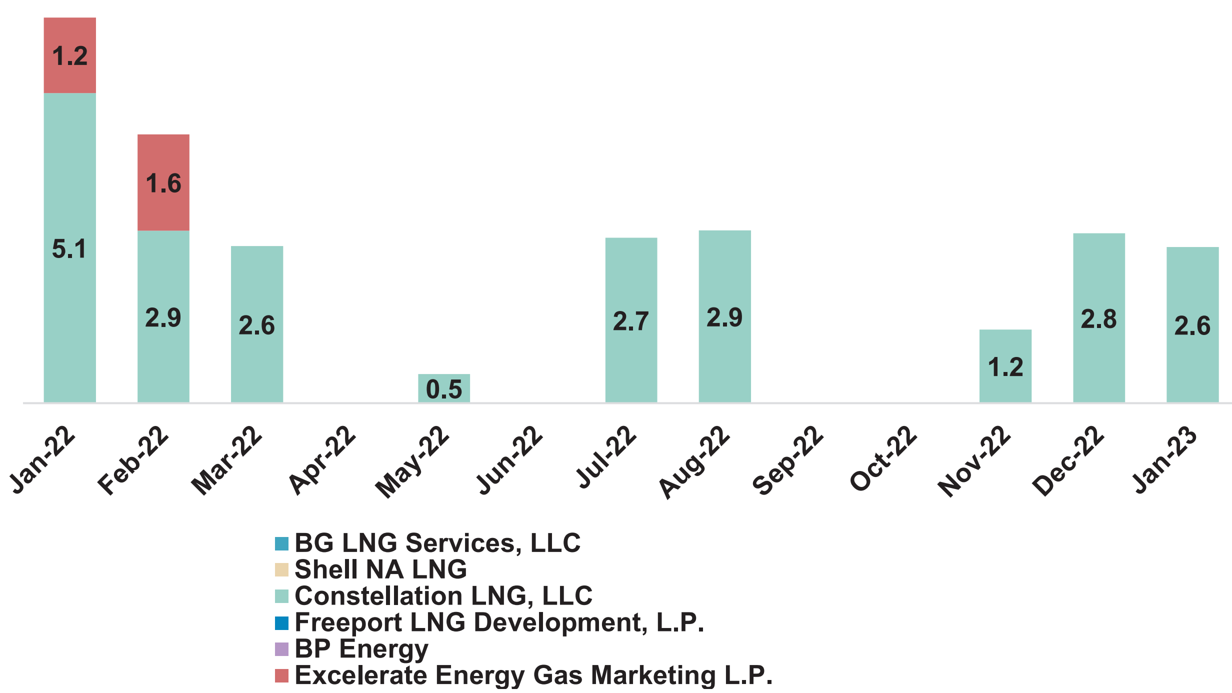
U.S. LNG Import Volume by Source Country
(Bcf)



U.S. LNG Import Volume by Terminal
(Bcf)



U.S. LNG Import Volume by Company
(Bcf)



NATURAL GAS NEWS

SHELL INKS SECOND LNG SPA WITH MEXICO PACIFIC

Mar 27, 2023 3:23:pm

SUMMARY

Shell has now signed up for 3.7mn mt/yr of offtake from Saguaro Eneria facility. [Image credit: MPL]

BY: DALE LUNAN

Shell Eastern Trading and Mexico Pacific Limited (MPL) said March 27 they had signed a second sales and purchase agreement (SPA) coverin an additional 1.1mn metric tons/year of offtake from MPL's Saguaro Energia LNG export facility, planned for Puerto Libertad, Sonora.

Under the SPA, Shell will purchase LNG on a free-on-board basis for 20 years from the third train of the three train, 14.1mn mt/yr first phase of Saguaro Energia. In July 2022, Shell signed its first SPA with MPL, covering 2.6mn mt/yr from the first two trains.

"We are delighted Shell has chosen to grow with us, building upon their initial 2.6mn mt/yr commitment from train 1 and train 2, to also underpin more than 20% of train 3 capacity," MPL CEO Ivan Van der Walt said. "Our project will provide Asia with low-cost Permian gas, avoiding the Panama Canal to ensure a shorter shipping distance to Asia, to achieve lower transportation emissions and landed pricing versus the US Gulf Coast."

He said MPL is working toward delivering a final investment decision on the first two trains at Saguaro Energia while closing out contracting across the "significant commercial momentum" already in place for the third train.

"LNG is an increasingly important pillar of global energy security," said Steve Hill, Shell's executive vice president of energy marketing. "Investment in liquefaction projects is needed to avoid a supply-demand gap that is expected to emerge in the late 2020s."

In February, MPL signed two SPAs with US major ExxonMobil covering 2mn mt/yr of offtake from the first two trains, with an option to purchase an additional 1mn mt/yr from the third train.

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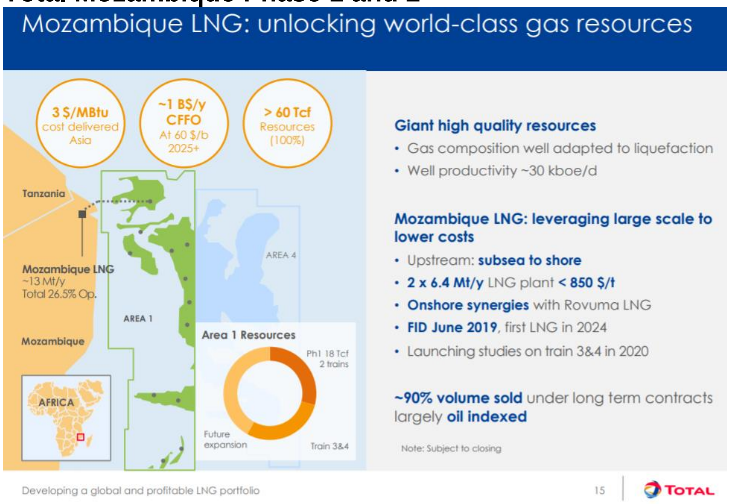
Multiple Brownfield LNG FIDs Now Needed To Fill New LNG Supply Gap From Mozambique Chaos? How About LNG Canada Phase 2?

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

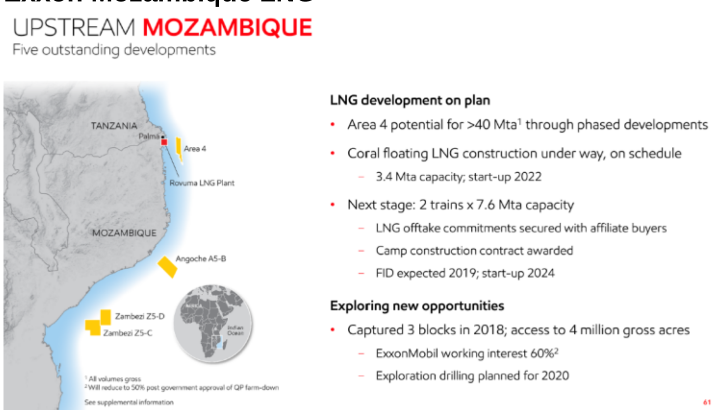
<u>Total's Mozambique force majeure is no surprise, especially the need to the restoration of security and stability "in a sustained manner"</u>. Yesterday, Total announced [LINK] "*Considering the evolution of the security".* No one should be surprised by the force majeure or the sustained manner caveat.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

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

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

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

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

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

Source: IEA

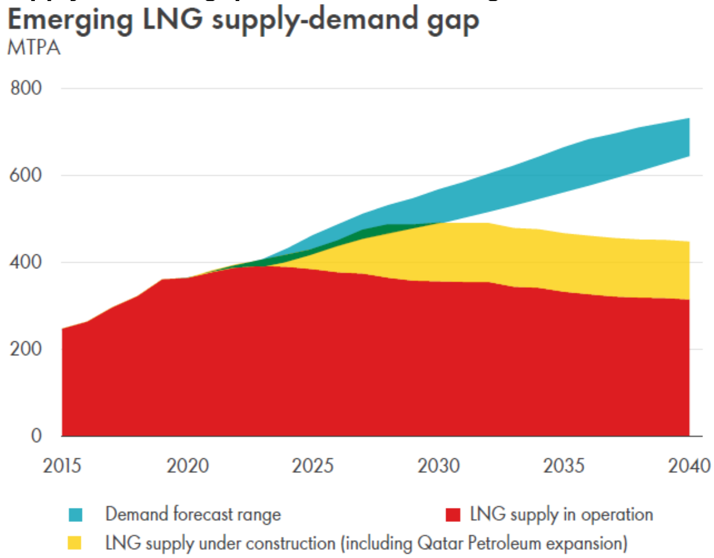
On Track More Efforts Needed Not on Track

Source: IEA Tracking Clean Energy Progress, June 2020

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

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

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



Source: Shell LNG Outlook 2021, Feb 25, 2021

<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."*

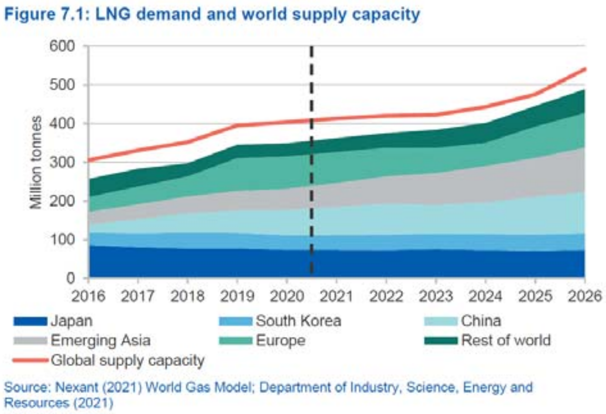
<u>Cheniere stopped the game playing the game on June 30</u>. Our July 4, 2021 Energy Tidbits memo noted that it looks like Cheniere has stopped playing stupid with respect to the strengthening LNG market in 2021. We can't believe they thought they were fooling anyone, especially their competitors. Bu 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

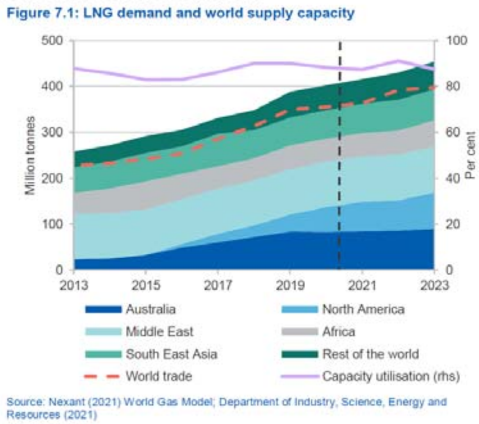
demand that we highlight later in the blog. They didn't say anything else specific on Mozambique but, surely they have to also be delaying the follow on Total Phase 2 of 1.3 bcf/d and Exxon Rozuma Phase 1 of 2.0 bcf/d.

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

March 2021 LNG Outlook



June 2021 LNG Outlook

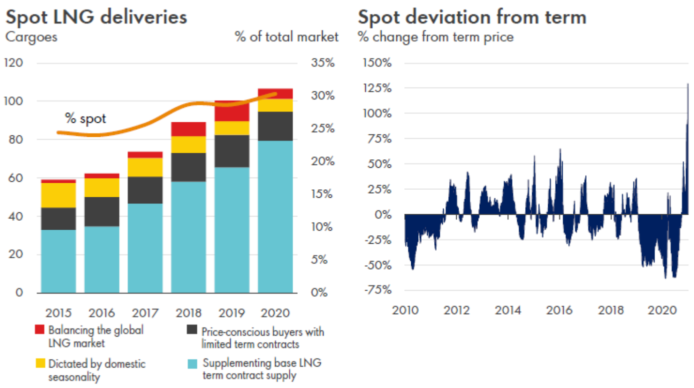


Source: Australia Resources and Energy Quarterly

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

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

Spot LNG deliveries and Spot deviation from term price



Source: Shell LNG Outlook 2021 on Feb 25, 2021

<u>Asian LNG buyers moving to long term LNG deals provide financing capacity for brownfield LNG FIDs</u>. 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.

<u>Four Asian buyer long term LNG deals in the last week.</u> 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.

> <u>Petronas/CNOOC is 10 yr supply deal for 0.3 bcf/d.</u> 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.*"
>
> <u>Qatar Petroleum/CPC (Taiwan) is 15 yr supply deal for 0.16 bcf/d.</u> 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.

<u>BP/Guangzhou Gas, a 12-yr supply deal for 0.13 bcf/d</u>. 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.

<u>Qatar/Korea Gas is a 20-yr deal to supply 0.25 bcf/d.</u> 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.

<u>More Asian buyer long term LNG deals (ie. India) will be coming.</u> 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.

<u>Supermajors are aggressively competing to commit 30+ year capital to Qatar's LNG expansion despite stated goal to reduce fossil fuels production</u>. 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.

<u>Remember Qatar's has a massive expansion but India alone needs 3x the Qatar expansion LNG capacity</u>. 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/17384353

March 28, 01:28,
updated 28 March, 03:04

Novak: Russia needs a resource base and technologies to achieve the goal of producing 100 million tons of LNG

According to the Deputy Prime Minister, Russia plans several new projects to liquefy gas

MOSCOW, March 28. /TASS/. Russia needs a resource base and technologies to implement the goal of producing 100 million tons of LNG per year, Deputy Prime Minister Alexander Novak said at the board of the Ministry of Energy of the Russian Federation.

"Expansion of production and export of LNG. I believe that this is a key task in the current conditions, when the infrastructure to Europe has suffered and we have lost quite large volumes of pipeline gas exports. Yes, we will develop supplies to the eastern countries, however, the LNG market is actively developing," Novak said.

He recalled that the Russian Federation plans several new projects for gas liquefaction. "In my opinion, we should set a more ambitious task - to reach at least 2030 million tons of LNG by 100. To do this, we need, on the one hand, to provide such projects with a resource base, on the other hand, we must ensure independence in terms of technology, equipment production, which we are working on today," Novak said.

According to him, the first meeting of the headquarters of the relevant coordination council has already been held.

In early March, Novak said that Russia needs to find a resource base for LNG projects for another 34 million tons per year in order to increase the production of liquefied gas to 100 million tons. According to the implemented projects, LNG production in the Russian Federation is about 33 million tons, taking into account the projects under construction, the plants in Ust-Luga and Arctic LNG-2, Russia will reach the production of 66 million tons of LNG per year.

Tags:

Novak, Alexander ValentinovichRussia

https://tass.com/economy/1549513

12 DEC, 08:37

Launch of first line of Arctic LNG 2 set for December 2023

According to Russian Ambassador to Tokyo Mikhail Galuzin, around 2 mln tonnes of LNG will be added to gas supplies to Japan "with the full-scale launch of Arctic LNG-2"

SABETTA, December 12. /TASS/. The launch of Novatek's first line of the Arctic LNG 2 plant is still scheduled for December 2023, and the second and third lines - for 2024 and 2026, respectively, Deputy General Director for capital construction of Arctic LNG 2 Timofey Sazonov told reporters.

"The goal is to launch … in December 2023. [Second and third stages] - in 2024 and 2026. We are not reconsidering [deadlines]," he said.

It was reported back in November that Russia may start deliveries of liquefied natural gas (LNG) to Japan from the Arctic LNG-2 project in 2023, which can reach 2 mln tonnes per year in the future.

"This project [Arctic LNG-2] is developing successfully. We hope that next year Japan will receive additional volumes of Russian LNG, in addition to what is already supplied from Sakhalin-2," Russian Ambassador to Tokyo Mikhail Galuzin said, drawing attention to the fact that Russia and Japan have areas "for mutually beneficial cooperation", among which he mentioned energy.

According to Galuzin, around 2 mln tonnes of LNG will be added to gas supplies to Japan "with the full-scale launch of Arctic LNG-2." He noted that now the volume of Japanese imports of Russian LNG reaches roughly 5-6 mln tonnes, which means that, taking into account fuel from the Arctic LNG-2 project, the share of Russian gas in the structure of Japanese imports may increase.

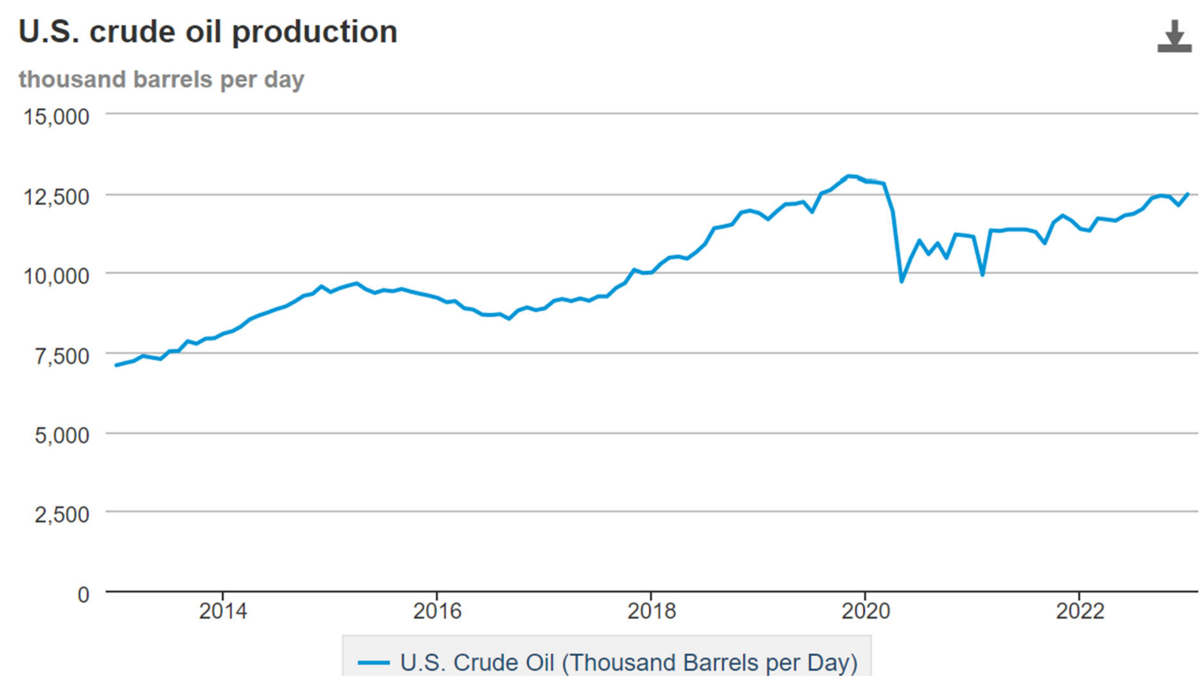
Arctic LNG-2 is Novatek's second LNG project. It includes the construction of three lines for the production of liquefied natural gas with a capacity of 6.6 mln metric tons per year each and stable gas condensate up to 1.6 mln metric tons per year. The launch of the first line is planned for December 2023, the launch of the second and third lines is expected in 2024 and 2026, respectively.

Excerpt EIA Form 914 – "actuals" for Jan US oil production [LINK]

Monthly Crude Oil and Natural Gas Production

Release date: March 31, 2023 | **Next release date:** April 28, 2023

Crude oil *Natural gas*



March 2023

Table 2. Production of crude oil and lease condensate in the United States with monthly and annual changes
thousand barrels per day

Report month	U.S. Total			Lower 48 States			Alabama		
	Production	% change from last month	% change from last year	Production	% change from last month	% change from last year	Production	% change from last month	% change from last year
Jan-22	11,369	-2.3%	2.2%	10,920	-2.4%	2.4%	11	-4.7%	-11.2%
Feb-22	11,316	-0.5%	14.0%	10,866	-0.5%	14.8%	12	8.3%	-2.0%
Mar-22	11,701	3.4%	3.3%	11,261	3.6%	3.6%	10	-13.5%	-16.1%
Apr-22	11,668	-0.3%	3.2%	11,227	-0.3%	3.4%	10	-3.1%	-17.1%
May-22	11,629	-0.3%	2.4%	11,182	-0.4%	2.5%	10	4.8%	-11.6%
Jun-22	11,797	1.4%	3.9%	11,379	1.8%	4.2%	10	-1.9%	-7.4%
Jul-22	11,844	0.4%	4.4%	11,412	0.3%	4.1%	10	0.3%	-13.2%
Aug-22	12,002	1.3%	6.4%	11,589	1.6%	6.6%	10	2.2%	-8.8%
Sep-22	12,337	2.8%	13.0%	11,907	2.7%	13.5%	10	-0.1%	-10.1%
Oct-22	12,417	0.6%	7.3%	11,982	0.6%	7.6%	11	0.4%	-10.5%
Nov-22	12,379	-0.3%	5.0%	11,935	-0.4%	5.2%	10	-0.6%	-7.5%
Dec-22	12,115	-2.1%	4.1%	11,668	-2.2%	4.3%	10	-6.5%	-15.0%
Jan-23	12,462	2.9%	9.6%	12,013	3.0%	10.0%	10	6.4%	-5.1%

Report month	Nebraska Production	Nebraska % change from last month	Nebraska % change from last year	Nevada Production	Nevada % change from last month	Nevada % change from last year	New Mexico Production	New Mexico % change from last month	New Mexico % change from last year
Jan-22	4	-9.9%	-4.2%	1	-4.9%	-2.4%	1,343	-1.6%	23.4%
Feb-22	4	5.0%	16.7%	1	12.3%	6.1%	1,401	4.4%	43.6%
Mar-22	5	2.3%	-1.8%	1	5.7%	4.1%	1,468	4.8%	27.4%
Apr-22	5	2.0%	-2.4%	1	-17.6%	-5.0%	1,514	3.2%	29.9%
May-22	4	-16.6%	-20.4%	1	9.1%	-2.2%	1,519	0.3%	25.1%
Jun-22	5	21.6%	-2.7%	1	26.8%	25.0%	1,529	0.7%	22.8%
Jul-22	4	-5.9%	-7.5%	1	-8.7%	7.8%	1,573	2.9%	23.7%
Aug-22	5	8.8%	1.3%	1	-2.1%	2.6%	1,609	2.3%	16.8%
Sep-22	4	-7.9%	-6.0%	1	-8.5%	21.3%	1,686	4.8%	24.6%
Oct-22	4	-4.7%	-12.0%	1	-9.7%	-7.2%	1,730	2.6%	25.4%
Nov-22	4	5.0%	-10.9%	1	29.5%	14.5%	1,725	-0.3%	21.5%
Dec-22	4	-6.8%	-12.2%	1	-19.5%	-0.9%	1,773	2.8%	29.9%
Jan-23	4	-10.3%	-12.6%	1	-4.8%	-0.9%	1,792	1.1%	33.4%

Report month	Tennessee Production	Tennessee % change from last month	Tennessee % change from last year	Texas Production	Texas % change from last month	Texas % change from last year	Utah Production	Utah % change from last month	Utah % change from last year
Jan-22	0	-14.9%	17.9%	4,853	-2.8%	4.8%	111	-1.2%	24.5%
Feb-22	1	36.1%	49.0%	4,821	-0.7%	27.7%	114	2.8%	29.2%
Mar-22	1	-5.7%	5.4%	4,976	3.2%	4.2%	114	0.2%	27.8%
Apr-22	0	-19.2%	32.5%	5,016	0.8%	4.9%	115	0.9%	29.1%
May-22	0	-6.2%	-2.8%	4,966	-1.0%	4.4%	122	5.6%	38.7%
Jun-22	0	7.9%	-3.5%	4,975	0.2%	4.0%	125	2.3%	34.5%
Jul-22	0	-16.8%	-25.6%	4,979	0.1%	3.5%	127	1.9%	31.9%
Aug-22	0	-8.3%	-34.2%	5,092	2.3%	4.7%	138	8.6%	37.2%
Sep-22	0	32.0%	-16.2%	5,211	2.4%	4.6%	134	-3.1%	34.0%
Oct-22	0	-13.3%	-23.4%	5,233	0.4%	5.4%	145	8.6%	34.3%
Nov-22	0	17.6%	-13.1%	5,220	-0.2%	4.5%	141	-3.1%	25.4%
Dec-22	0	-18.9%	-25.5%	5,161	-1.1%	3.4%	140	-0.9%	24.2%
Jan-23	0	4.7%	-8.5%	5,237	1.5%	7.9%	128	-7.9%	15.8%

Report month	California Production	California % change from last month	California % change from last year	Colorado Production	Colorado % change from last month	Colorado % change from last year	Federal Offshore Gulf of Mexico Production	Federal Offshore Gulf of Mexico % change from last month	Federal Offshore Gulf of Mexico % change from last year
Jan-22	342	-0.2%	-8.8%	408	-9.8%	4.1%	1,708	0.9%	-5.6%
Feb-22	342	0.2%	-9.6%	430	5.2%	10.8%	1,615	-5.5%	-10.0%
Mar-22	344	0.6%	-8.1%	439	2.2%	14.2%	1,691	4.7%	-10.0%
Apr-22	343	-0.4%	-8.9%	440	0.1%	5.6%	1,765	4.4%	-1.7%
May-22	339	-1.2%	-9.2%	438	-0.5%	3.4%	1,589	-10.0%	-12.5%
Jun-22	332	-2.1%	-12.0%	435	-0.7%	6.5%	1,751	10.3%	-1.8%
Jul-22	334	0.6%	-11.2%	431	-0.9%	4.9%	1,764	0.7%	-4.6%
Aug-22	333	-0.2%	-10.9%	433	0.6%	3.7%	1,783	1.1%	15.1%
Sep-22	331	-0.7%	-11.9%	434	0.3%	0.1%	1,844	3.4%	73.9%
Oct-22	332	0.3%	-5.8%	437	0.7%	-5.0%	1,821	-1.2%	8.5%
Nov-22	328	-1.4%	-6.6%	445	1.7%	-2.2%	1,794	-1.5%	1.2%
Dec-22	325	-0.9%	-5.1%	408	-8.3%	-9.8%	1,789	-0.3%	5.7%
Jan-23	312	-3.8%	-8.6%	406	-0.4%	-0.6%	1,914	7.0%	12.0%

https://rbnenergy.com/slow-it-down-us-eandps-temper-2023-capex-increases-after-aggressive-late-22-investment-spurt

Slow It Down - U.S. E&Ps Temper 2023 Capex Increases After Aggressive Late-'22 Investment Spurt
Thursday, 03/23/2023
Published by: Tom Biracree

In marking the third anniversary of COVID's onset, the Washington Post detailed a study that showed most of us are already shedding the virus-impacted memories of that tedious and often traumatic time to concentrate on looking ahead — a trait scientists label "future-oriented positivity bias." That transition was clearly evident in the 2022 investment decisions of U.S. E&Ps as the capex budgets of the 42 companies we monitor, pared to the bone during the pandemic, expanded through last year from initial guidance of a 24% increase over 2021 to a final 54% reported increase for the full year. They increased production by 9% year-over-year, but producers haven't forgotten fiscal discipline or a focus on cash flow generation. In today's RBN blog, we analyze 2023 capital budgets that generally sustain the pace of Q4 2022 spending and eschew additional increases in a lower commodity price environment.

The commodity price plunge at the onset of the pandemic in March 2020 sent shock waves through the oil and gas industry. The 42 producers in our universe, which includes every publicly held U.S. E&P with a market capitalization over $500 million (but not integrated energy companies like ExxonMobil and Chevron), slashed investment by 50% in 2020 to $37 billion from $74 billion in 2019, as shown by the stacked bars (and left axis) in Figure 1. Despite a substantial recovery in realizations, investment inched up just 6% to $39.7 billion in 2021. Estimated oilfield service inflation of 10%-20% and the need to rebuild the inventory of drilled but uncompleted wells (DUCs) after a steep pandemic drawdown drove a 24% increase in initial 2022 investment guidance to $49.3 billion. However, sustained high commodity prices resulted in surging cash flows, allowing producers to dramatically increase shareholder returns and increase drilling to more than offset steep short-term shale decline rates. As we pointed out in It's Growing, our blog on Q3 2022 investment, capital budgets increased 3%-4% in each of the first three quarterly reporting periods to $54.9 billion — a 38% gain over the previous year. Full-year results revealed a dramatic and unprecedented 12% investment growth in Q4 compared with Q4 2021, raising total expenditures 54% to $61.6 billion, the largest year-on-year growth in more than a decade.

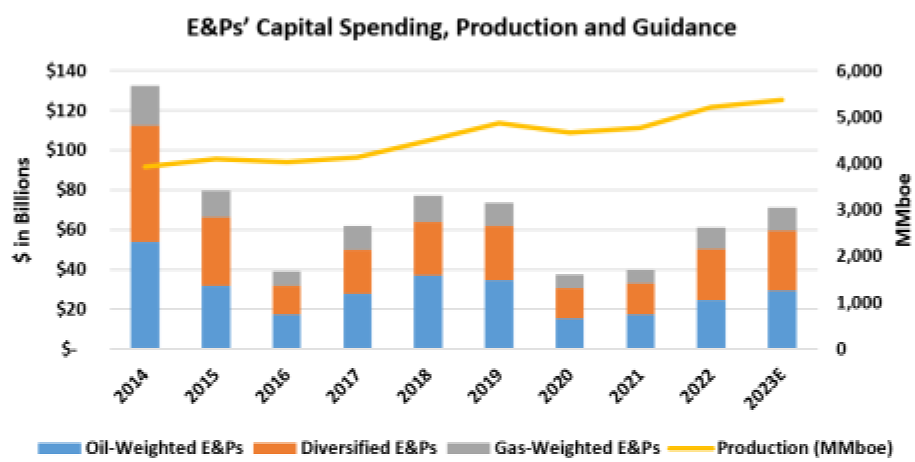


Figure 1. E&Ps' Capital Spending, Production and Guidance. Source: Oil & Gas Financial Analytics, LLC

Gas-Weighted producers boosted 2022 capital investment by 64%, including a 13% increase in Q4, as they sought to take advantage of a significant rise in commodity prices after years of low realizations. The investment generated an 11% increase in production to 1.7 billion barrels of oil equivalent (boe; includes crude oil, natural gas, and NGLs), which is 19% higher than 2019, in part because gas output rose during the pandemic despite sharply reduced drilling-and-completion activity. Higher oil and gas prices spurred a 60% rise in Diversified E&P peer group capital spending last year, including a 15% spurt in Q4. Production by the peer group jumped 13%, surpassing pre-pandemic output in 2019. Oil-Weighted producers grew capital investment by a more modest 40% in 2022, including a 9% boost in Q4. Given the longer lead time for oil-focused projects, output rose just 4% as producers struggled to reverse a slight decline in output from 2020 to 2021.

The 2023 capital expenditure guidance released by these U.S. E&Ps shows that the companies are putting the brakes on those hefty quarter-over-quarter investment increases. The companies we track are guiding toward total investment of $71.3 billion this year — 17% higher than 2022 but 3% below pre-pandemic investment of $73.7 billion in 2019. These budgets broadly sustain the level of E&P expenditures in Q4 2022. The steady-as-she-goes spending reflects the retreat of oil prices from mid-2022 highs to the $70-$80/bbl range and a much sharper decline in domestic natural gas prices exacerbated by a mild winter and LNG facility shut-ins. (Oil and gas prices have, of course, fallen even more in early 2023.) E&Ps also expect a more moderate 10% cost inflation going forward, down from the 15%-20% estimates in 2022. The updated estimates are driven by (1) an easing of supply chain issues that last year resulted in soaring capital costs for casing and other materials and (2) the impact of lower diesel costs and slightly reduced rig counts on operating costs. As a result of the tempered spending, the 42 E&Ps are guiding toward a 3% production increase to 5.4 billion boe.

The Oil-Weighted Peer Group

As shown by the blue bar to the far right in Figure 2 (and the left axis), the 16 Oil-Weighted producers, which reported the lowest capital spending increase in 2022, are guiding toward the largest increase in 2023 capex on optimism about a recovery in crude oil prices. Pioneer Natural Resources CEO Scott Sheffield said during the company's February 23 earnings call that he believed "we'll move back into that $90-to-$100 range sometime early this summer." That viewpoint is supported by bullish oil demand outlooks issued by OPEC and the International Energy Agency (IEA) tied to China's exit from its zero-COVID policy and OPEC's decision to stick to production cuts until year's end. However, it's worth noting that those expectations could be upended by a recession. The 16 oil-focused producers we track have set total 2023 investment budgets of $29.6 billion, 21% higher than the previous year. That is expected to generate 8% production growth to 1.9 billion boe (right end of orange line and right axis in Figure 2), surpassing the 1.8 billion boe produced in 2019.

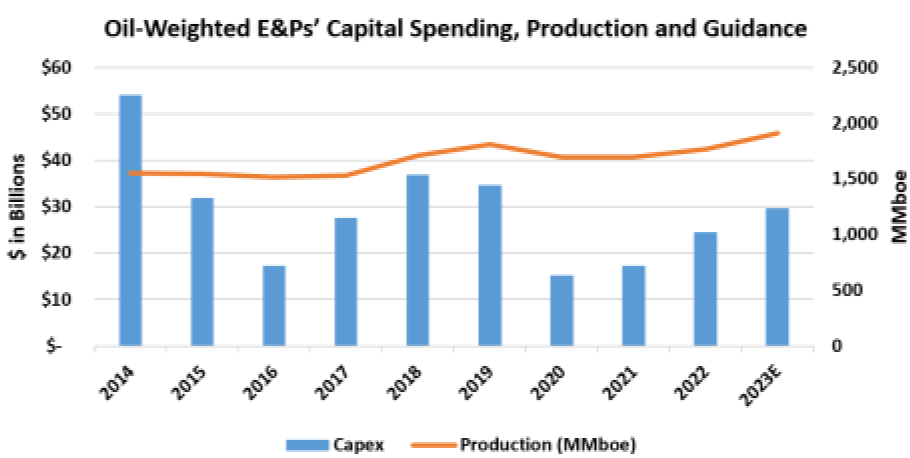


Figure 2. Oil-Weighted E&Ps' Capital Spending, Production and Guidance.
Source: Oil & Gas Financial Analytics, LLC

EOG Resources is boosting its peer-group-leading investment program by 30% from $4.6 billion last year to $6.0 billion in 2023. The company has conducted the most aggressive exploration program in the industry, which has led to the announcement of three new major unconventional resource plays over the last two years in the Powder River Basin in the Rockies, the Dorado gas play in South Texas, and [the Utica Combo play] in Appalachia. EOG now operates in 16 plays across nine basins and is targeting 3% oil and 9% total production growth in 2023. Occidental Petroleum, the largest producer in the peer group, is raising its drilling-and-completion budget by 14%, year-over-year from $3.9 billion to $4.5 billion. Oxy focused on reducing debt after the acquisition of Anadarko Petroleum in 2019, but after retiring $10.5 billion in liabilities in 2022, the company is increasing funding to reverse declines in its Permian, Gulf of Mexico and Denver-Julesburg (DJ) Basin focus areas and is targeting 2% production growth.

Devon Energy, in turn, is guiding to a 34% increase in capital spending after closing major acquisitions in the Williston Basin and Eagle Ford Shale, which is expected to grow production by 7%. Marathon Oil is raising investment by 37% after the December 2022 closing of its $3 billion purchase of Ensign Natural Resources, while acquisitions/mergers are resulting in a doubling and 70% increase in capital spending by smaller producers Permian Resources and Earthstone Energy, respectively. The only two companies in the peer group that have announced significant declines in investment are California heavy oil producers California Resources and Berry Petroleum, which have been most heavily impacted by lower commodity prices.

For tables showing the Oil-Weighted companies' capex and production plans, click here.

The Diversified Peer Group

As shown in Figure 3 (blue bar to far right, left axis), the 15 companies in the Diversified E&Ps peer group are targeting a 16% increase in finding and development capital expenditures to $29.8 billion in 2023 after investment surged 64% in 2022. Natural gas represented 34% of total output for the Diversified companies during Q4 2022, and the steep decline in U.S. gas realizations more heavily impacted investment decisions than for the Oil-Weighted group. The E&Ps in this group that have significant international assets are highlighting investment in major long-term oil and gas projects while maintaining or tempering short-term investment in U.S. unconventional resource plays. Production by the Diversified E&Ps surged 13% last year, partially driven by major acquisitions such as ConocoPhillips's $9.5 billion purchase of Shell's Permian assets. In 2023, these producers are targeting more modest 2% output growth (right end of orange line, right axis).

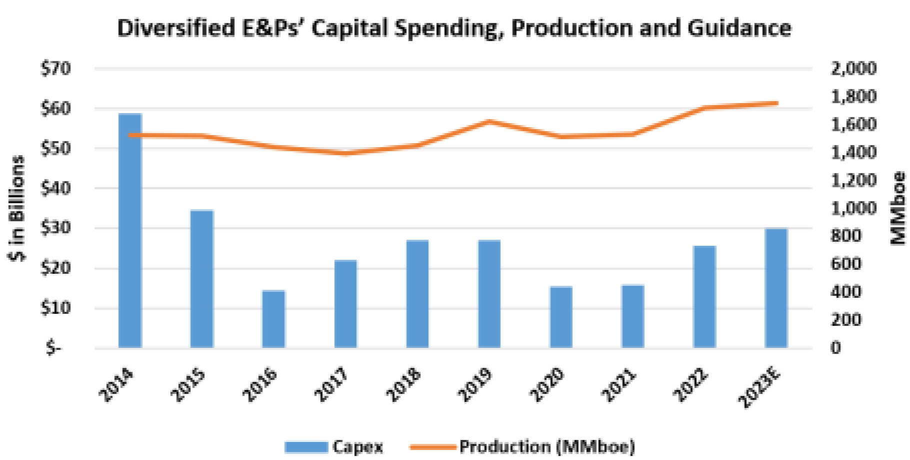


Figure 3. Diversified E&Ps' Capital Spending, Production and Guidance.
Source: Oil & Gas Financial Analytics, LLC

ConocoPhillips, by far the largest E&P we track, exemplifies this trend. The company's investment surged nearly 70% in 2022 to $9.4 billion (from $5.5 billion in 2021) after the $9.7 billion acquisition of Concho Resources and the $9.5 billion purchase of Shell's Permian assets. In 2023, the company is guiding to a 12% — or $1.1 billion — increase, to $10.5 billion. After allocating $500 million to $600 million to cover inflation, Conoco is adding incremental investment in LNG projects, including the North Field East and South projects in Qatar and the Willow oil development in northern Alaska, which was just approved by the Biden administration. As a result, the company is guiding to a 3% production increase in 2023.
Hess Corp. announced a 26% increase in 2023 investment to $3.7 billion, the lion's share of which is directed toward its massive ExxonMobil-operated oil discoveries offshore Guyana. APA Corp. is raising

investment by 8% while shifting spending to its oil-weighted properties, particularly in Egypt, where it is running 17 rigs compared with five in the Permian. APA is anticipating 10% oil and 4%-5% total boe production growth. Then there's Ovintiv, which is raising spending by 17% to $2.25 billion to reflect the impact of inflation as well as a rebuilding of its DUC inventory. The company is guiding to flat output as it shifts investment away from its gas-weighted Anadarko Basin assets to its oil-weighted Uinta Basin and Bakken assets. The two major DJ Basin producers we follow, Civitas Resources and PDC Energy, are charting very different paths. Concerns about the steep decline in gas prices and persistent inflation are leading Civitas to cut 2023 investment by 15% to $850 million while keeping production flat. In contrast, PDC is raising capital spending by 27% to $1.4 billion as it steps up development of its growing inventory of approved permits in the Wattenburg Field to support 3%-5% oil and total production growth.

For tables showing the Diversified companies' capex and production plans, click here.

The Gas-Weighted Peer Group

The steep plunge in natural gas prices to the sub-$3.00/MMBtu range in early 2023 has led the gas-focused producers we monitor to sharply curtail the pace of capital spending in 2023, as shown in Figure 4 (blue bar to far right, left axis), after a 64% increase in investment in 2022. The magnitude of the decline is vividly demonstrated by Comstock Resources, which reported an unhedged average gas realization of $5.57/MMBtu in Q4 2022, double the expected realization for Q1 2023. Total capital expenditures for the 11 Gas-Weighted E&Ps are estimated at $12 billion, a 9% increase over 2022, a pace that falls slightly short of the 10%-15% expected inflation that their companies referenced in their year-end conference calls. While gas producers were confident about the long-term recovery of natural gas prices due to growing export and domestic demand, they also indicated their preliminary 2023 budgets were subject to further reductions if realizations continued to drift lower. The impact of lower drilling-and-completion activity is reflected in the guidance to a slight decline in production to 1.72 billion boe after nine consecutive years of output growth (right end of orange line, right axis). We should note here that this does not mean gas production will fall generally because it will be held up by associated gas from Oil-Weighted and Diversified producers.

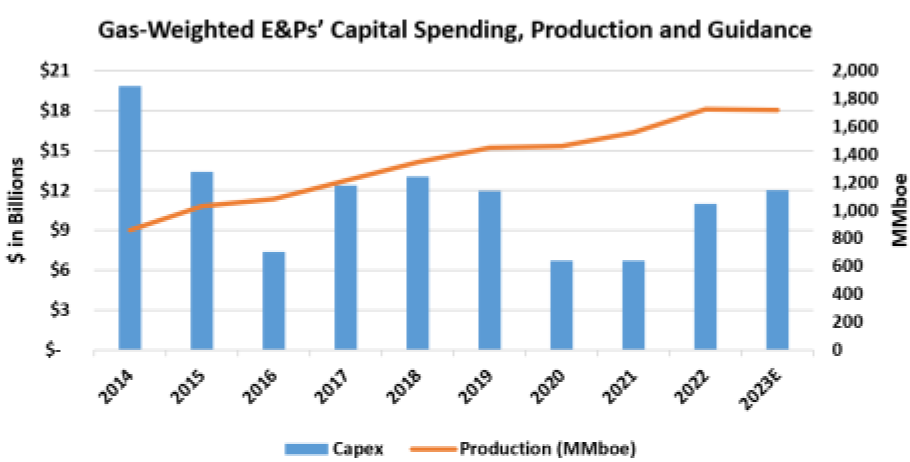


Figure 4. Gas-Weighted E&Ps' Capital Spending, Production and Guidance.
Source: Oil & Gas Financial Analytics, LLC

The modest increase in investment by the gas-focused group was largely driven by significant increases from EQT Corp. and Coterra Energy. EQT, the largest U.S. gas producer, is raising its planned investment by 39%, from $1.3 to $1.8 billion, which largely reflects delays in the start-up of 30 wells from 2022 to 2023 due to third-party constraints. The company said the "catch-up capital" associated with this is non-recurring and that investment will decline in 2024. Coterra, formed by the merger of gas producer Cabot Oil & Gas with Permian and Anadarko basin E&P Cimarex Energy, is increasing capital spending by 17%, or $300 million, to target 2% oil growth while reining in gas investment. Excluding these two companies, capital spending for the remaining nine Gas-Weighted producers is essentially flat. Southwestern Energy, which doubled capex from $1 billion to $2 billion in 2022 after major Haynesville acquisitions, is reducing its rig count by two and targeting a 2%-3% production decline from investment that is rising just 4%. Major Haynesville producer Comstock Resources is guiding toward flat spending while paring its rig count from nine to seven in 2023, and Chesapeake Energy, which emerged from bankruptcy as an Appalachia- and Haynesville-focused producer, is cutting capital investment by 11%.

For tables showing the Gas-Weighted companies' capex and production plans, click here.

In addition to issuing full 2023 capital expenditure guidance, the U.S. E&Ps we follow disclosed significant information on their planned drilling-and-completion activities in the major domestic unconventional resource plays. We will review these basin-by-basin development plans in an upcoming blog.

https://www.reuters.com/article/usa-oilreserve-granholm-idAFL1N3602TY

COMMODITIES NEWS

MARCH 28, 20235:02 PMUPDATED 11 HOURS AGO

US could buy back oil for strategic reserve late this year

By Reuters Staff

3 MIN READ

OROCOVIS, Puerto Rico, March 28 (Reuters) - The U.S. could start buying back crude oil for the Strategic Petroleum Reserve late this year after President Joe Biden last year directed the largest ever sale from the stockpile, Energy Secretary Jennifer Granholm said.

The administration intended to repurchase crude oil for the SPR when prices were at or below about $67-$72 a barrel, after last year's 180 million barrel sale drove the level of the stockpile to its lowest since 1983, the White House said in October. Biden conducted the sale to relieve oil prices that shot up after Russia invaded Ukraine.

U.S. oil prices this month touched that range but no sales were announced. Last week, Energy Secretary Jennifer Granholm told lawmakers in a House hearing it would be tough to take advantage of this year's relatively low prices to fill the reserve back up, raising concerns about energy security.

But Granholm told Reuters during a visit to Puerto Rico that purchases could begin late in 2023.

"We will begin that process this year but to refill the full amount is impossible to do in one year," Granholm said.

The department is conducting a 26 million barrel SPR sale mandated by Congress and two of the four SPR sites in Texas and Louisiana are down for maintenance, both of which have delayed buy-backs.

Granholm said the SPR sites undergoing life extension work at Bryan Mound in Texas and Bayou Choctaw in Louisiana would be "down into the fall."

"We can start the process of buying back depending on some of these exchanges in the fourth quarter," Granholm said, referring to returns of more than 25 million barrels of oil from previous exchanges with oil companies. She said any buy-backs would also depend on where the price was.

The SPR currently holds about 372 million barrels, the lowest since 1983, in hollowed-out salt caverns along the Gulf Coast.

Granholm was visiting Puerto Rico to seek ways to make the island's power grid more robust. (Reporting by Timothy Gardner; Editing by Stephen Coates) https://www.newswire.ca/news-releases/aramco-to-expand-presence-in-china-by-acquiring-10-stake-in-rongsheng-petrochemical-824083340.html

Aramco to expand presence in China by acquiring 10% stake in Rongsheng Petrochemical

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NEWS PROVIDED BY
Aramco

Mar 27, 2023, 10:43 ET

- Deal involves placement of 480,000 barrels per day of crude to the largest integrated refining and chemicals complex in China

DHAHRAN, Saudi Arabia, March 27, 2023 /CNW/ -- Aramco, one of the world's leading integrated energy and chemicals companies, has signed definitive agreements to acquire a 10% interest in Shenzhen-listed Rongsheng Petrochemical Co. Ltd. ("Rongsheng") for RMB 24.6 billion ($3.6 billion at current exchange rates), in a deal that would significantly expand its downstream presence in China.

Amin H. Nasser, Aramco President & CEO (center), attends the signing ceremony for Aramco's acquisition of a 10% interest in Rongsheng Petrochemical Co. Ltd. Mohammed Y. Al Qahtani, Aramco Executive Vice President of Downstream (sitting right), and Li Shuirong, Rongsheng Chairman (sitting left), signed the documents in the presence of Anwar Al Hejazi, Aramco Asia President (standing left) and Xiang Jiongjiong, Rongsheng CEO (standing right) (PRNewsfoto/Aramco)

Through the strategic arrangement, Aramco would supply 480,000 barrels per day (bpd) of Arabian crude oil to Rongsheng affiliate Zhejiang Petroleum and Chemical Co. Ltd (ZPC), under a long-term sales agreement. Aramco Overseas Company ("AOC"), a wholly-owned subsidiary of Aramco, will acquire the interest in Rongsheng.

Among other assets, Rongsheng owns a 51% equity interest in ZPC, which in turn owns and operates the largest integrated refining and chemicals complex in China with a capacity to process 800,000 bpd of crude oil and to produce 4.2 million metric tons of ethylene per year.

Mohammed Y. Al Qahtani, Aramco Executive Vice President of Downstream, said: "This announcement demonstrates Aramco's long-term commitment to China and belief in the fundamentals of the Chinese petrochemicals sector. It is an important acquisition for Aramco in a key market, supporting our growth ambitions and advancing our liquids to chemicals strategy. It also promises to secure a reliable supply of essential crude to one of China's most important refiners."

Li Shuirong, Rongsheng Chairman, said: "This strategic co-operation will take our long-term friendship and mutual trust to a new level, and paves the way for a bright future for the high-quality development of the world's petrochemicals industry. I believe that Aramco's involvement will greatly help Rongsheng implement its petrochemical growth strategy."

The investment would anchor an important association between Aramco, Rongsheng and ZPC, which operates one of the world's most state-of-the-art chemical conversion assets.

The transaction involves an off-market secondary sale of Rongsheng shares by majority shareholder Zhejiang Rongsheng Holding Group, with potential for future collaboration between the parties in trading, refining, chemicals production and technology licensing. The transaction is expected to close by the end of 2023, and is subject to regulatory approvals.

It follows the announcement on March 26 that the Aramco joint venture, Huajin Aramco Petrochemical Company (HAPCO), planned to start construction of a major integrated refinery and petrochemical complex in northeast China in the second quarter of 2023. Aramco, which has a 30% stake in HAPCO, will supply up to 210,000 bpd of crude oil feedstock to the complex.

Combined, the partnership with Rongsheng and the HAPCO joint venture would see Aramco supply a total of 690,000 bpd of crude to high chemical conversion assets.

About Aramco

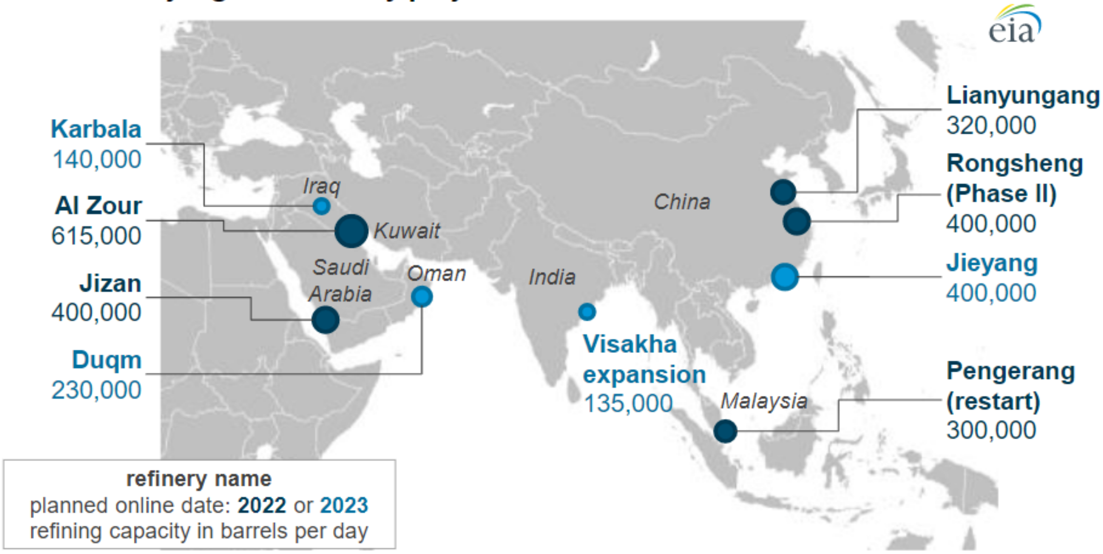
Aramco is a global integrated energy and chemicals company. We are driven by our core belief that energy is opportunity. From producing approximately one in every eight barrels of the world's oil supply to developing new energy technologies, our global team is dedicated to creating impact in all that we do. We focus on making our resources more dependable, more sustainable and more useful. This helps promote stability and long-term growth around the world. www.aramco.com.

https://www.eia.gov/todayinenergy/detail.php?id=53279

AUGUST 2, 2022

Several refining projects are scheduled in Asia and the Middle East

Selected major global refinery projects scheduled for 2022 and 2023



Data source: U.S. Energy Information Administration

In Asia and the Middle East, at least nine refinery projects are beginning operations or are scheduled to come online before the end of 2023. At their current planned capacities, they will add 2.9 million barrels per day (b/d) of global refinery capacity once fully operational. In the International Energy Agency's (IEA) June 2022 *Oil Market Report*, the IEA expects net global refining capacity to expand by 1.0 million b/d in 2022 and by an additional 1.6 million b/d in 2023. Net capacity additions reflect total new capacity minus capacity that has closed.

The scheduled expansions follow a period of reduced global refining capacity. Net global capacity declined in 2021 for the first time in 30 years, according to the IEA. The new refinery projects would increase production of refined products, such as gasoline and diesel, and in turn, they might reduce the current high prices for these products.

China's refinery capacity is scheduled to increase significantly this year. The Shenghong Petrochemical facility in Lianyungang has an estimated capacity of 320,000 b/d, and they report that trial crude oil-processing operations began in May 2022. In addition, PetroChina's 400,000 b/d Jieyang refinery is expected to come online in the third quarter of 2022. A planned 400,000 b/d Phase II capacity expansion also began operations earlier this year at Zhejiang Petrochemical Corporation's (ZPC) Rongsheng facility. More information on these expansions is available in our *Country Analysis Executive Summary: China*.

Outside of China, the 300,000 b/d Malaysian Pengerang refinery (also known as the RAPID refinery) restarted in May 2022 after a fire forced the refinery to shut down in March 2020. In India, the Visakha Refinery is undergoing a major expansion, scheduled to add 135,000 b/d by 2023.

New projects in the Middle East are also likely to be an important source of new refining capacity. The 400,000 b/d Jizan refinery in Saudi Arabia reportedly came online in late 2021 and began exporting petroleum products earlier this year. More recently, the 615,000 b/d Al Zour refinery in Kuwait—the largest in the country when it becomes fully operational—began initial operations earlier this year. A new 140,000 b/d refinery is scheduled to come online in Karbala, Iraq, this September, targeting fully operational status by 2023. A new 230,000 b/d refinery is set to come online in Duqm, Oman, likely in early 2023.

These estimates do not necessarily include all ongoing refinery capacity expansions. Moreover, many of these projects have already been subject to major delays, and the possibility of partial starts or continued delays related to logistics, construction, labor, finances, political complications, or other factors may cause these projects to come online later than estimated. Although the potential for project complications and cancellations is always a significant risk, these projects could otherwise account for an increase of nearly 3.0 million b/d of new refining capacity by the end of 2023.

https://china.aramco.com/en/creating-value/products/refining-and-chemicals/zhejiang-project

Zhejiang Project

Saudi Aramco signed a Memorandum of Understanding (MOU) to acquire a 9% stake in Zhejiang Petrochemical, which is developing a 800,000 barrels per day integrated refinery and petrochemical complex, with an integrated retail network, located in the city of Zhoushan, Zhejiang province.

For more detailed information, please click Press Release.

https://china.aramco.com/en/news-media/china-news/2018/saudi-aramco-expands-presence-in-china-refining-market-with-sign

Saudi Aramco expands presence in China refining market with signing of MoU with Zhejiang Petrochemical

Zhoushan, China, October 19, 2018

Saudi Aramco recently signed a Memorandum of Understanding with the Chinese Zhejiang provincial government to acquire a share of Zhejiang Petrochemical's new refinery project. The signing ceremony was held during the 2nd International Petroleum and Natural Gas Enterprises Conference (IPEC).

"We are exploring opportunities for new refining and petrochemicals facilities, making further investments in China. Saudi Aramco has recently signed a crude oil supply agreement with Zhejiang Petrochemical (Rongsheng)," said Abdulaziz M. Al-Judaimi, Saudi Aramco senior vice president of Downstream. "This increase in customer base is due to our continuous focus and attention to the Chinese market.

"We are also a major joint venture partner in a growing portfolio of refining and petrochemical assets in China," he added.

A key part of China's energy security

Saudi Aramco plays an important part in China's energy security. Since our first crude oil delivery to China, we have steadily increased our supply to Chinese oil companies in line with their requirements. Since 2006, no one has delivered more oil to China than Saudi Aramco. Helping China meet its critical energy needs shows Saudi Aramco's commitment to key global markets.

Saudi Aramco is working to achieve a better balance between its world-class upstream and its growing downstream operations.

The company's downstream strategy seeks to enhance the value of the hydrocarbon resource base by targeting increased horizontal and vertical integration across the hydrocarbon value chain. The successful execution of the downstream strategy would deliver a world leading, strategically integrated downstream network and a robust portfolio that is more resilient to market turbulence.

Major refining, marketing, and petrochemicals joint ventures are being created in leading consuming nations such as China, India, and Malaysia, in addition to our existing assets in the U.S., South Korea, and Japan.

https://saudigazette.com.sa/article/631072/SAUDI-ARABIA/REGA-chief-Foreigners-will-be-allowed-to-own-property-in-Saudi-Arabia

REGA chief: Foreigners will be allowed to own property in Saudi Arabia

Demand — supply gap causes hike in real estate prices

March 26, 2023

Abdullah Alhammad

Okaz/Saudi Gazette

RIYADH — Abdullah Alhammad, CEO of the Real Estate General Authority (REGA), acknowledged that real estate prices are high owing to a gap between demand and supply in Saudi Arabia. Attending Al-Liwan program on Rotana Khalejia Television channel, the authority chief stated that foreigners will be allowed to own real estate soon.

The authority is not satisfied with the high real estate prices, and this rise is negative for the real estate sector as a whole Alhammad said while noting that the real estate market is an open market and it is subject to supply and demand. “The rise in real estate prices is negative for all parties, as the economy is in continuous rotation, and the state is working to enable demand in a way that achieves economic balance for the real estate sector.”

He stated that the largest percentage of those who seek real estate today do not have purchasing power, and the price of the property today is higher than the purchasing power, and therefore it is not easy to obtain a suitable property. “The investors were also affected by the high prices of the real estate, due to the high prices of the land, and the landowners became unable to make easier transactions, and when the landowner wanted to sell, he reduces prices in order to be able to sell it,” he pointed out.

Alhammad stressed that the new law for ownership of a real estate by foreigners is in its final stages, and will be made public in a short period. The new law will be broader and more comprehensive than the current law for real estate ownership, he pointed out.

The authority chief stated that foreigners will be allowed to own real estate of all kinds including commercial, residential, and agricultural in accordance with the regulations. “The initial reading of the law shows that it allows foreigners to own property everywhere in the Kingdom, including Makkah and Madinah. The negative effects of foreign ownership of the property were monitored in advance so as to avoid them, and solutions were developed for all problems and unacceptable practices,” he said.

Regarding the move to impose fees on white lands, Alhammad said that the fees started imposing in 2017, while noting that the Ministry of Municipal and Rural Affairs began working on proposals to increase or raise the efficiency of fees by a further hike of SR10 percent.

https://www.reuters.com/business/energy/baghdad-krg-close-deal-resume-iraqs-northern-oil-exports-2023-04-01/
3 minute readApril 1, 202311:03 AM MDTLast Updated 7 hours ago

Baghdad and KRG close to deal to resume Iraq’s northern oil exports

By Rowena Edwards , Ahmed Rasheed and Orhan Coskun

LONDON/BAGHDAD, April 1 (Reuters) - Iraq's federal government and the Kurdistan Regional Government (KRG) are close to striking a deal aimed at resuming northern oil exports, four sources familiar with the discussions told Reuters on Saturday.

Turkey stopped pipeline flows from the Kirkuk fields in northern Iraq's semi-autonomous Kurdistan region to its port of Ceyhan on March 25, after it lost an arbitration case brought by Baghdad.

In the case, Iraq accused Turkey of violating their 1973 pipeline agreement by allowing the Kurdish government to export oil without Baghdad's consent between 2014 and 2018.

The halted flows of around 450,000 barrels per day (bpd) only accounted for about 0.5% of global oil supply, but the stoppage, which forced oil firms operating in the region to halt output or move production into rapidly-filling storage tanks, still helped boost oil prices last week back to near $80/bbl.

An initial agreement between the two sides states that Iraq's northern oil exports will be jointly exported by Iraq's state-owned marketing company SOMO and the KRG's ministry of natural resources (MNR), according to two of the sources – a senior Iraqi oil official and a KRG official.

Revenues will be deposited in an account managed by the MNR and supervised by Baghdad, the KRG official said.

The preliminary agreement has been sent to Iraq's prime minister for final approval, according to two of the sources. The KRG source expects the deal to be confirmed by Monday.

The KRG declined to comment. Iraq's oil ministry spokesman could not immediately be reached outside regular business hours.

Baghdad and the KRG have agreed to continue meetings following the resumption of oil exports to find solutions to other lingering problems.

"[These include] the contracts of the foreign companies operating in Kurdistan and the Kurdish debts," the senior Iraqi oil official said.

With its oil exports at a standstill, Kurdistan had halted repayments to energy traders including Vitol and Petraco on crude cargo deals worth $6 billion, trading sources said.

Another sticking point in discussions so far has come from the Turkish side.
A second arbitration case relating to the 1973 pipeline agreement for the period from 2018 onwards remains open, and one source said this could take around two years to settle.

Turkey wants that case resolved before reopening the pipeline, three sources told Reuters.

A Turkish senior official said Turkey has yet to be informed about the initial agreement by the KRG or federal Iraqi officials and that discussions are ongoing.

Reporting by Rowena Edwards in London, Ahmed Rasheed in Baghdad, Orhan Coskun in Ankara and Maha el Dahan in Dubai; Additional reporting by Can Sezer in Istanbul and Ron Bousso in London; Editing by David Holmes https://www.dno.no/en/investors/announcements/dno-starts-shutdown-of-kurdistan-oilfields-as-pipeline-closure-continues-2023-03-29/

DNO Starts Shutdown of Kurdistan Oilfields as Pipeline Closure Continues

Oslo, 29 March 2023 – DNO ASA, the Norwegian oil and gas operator, today announced that it has started an orderly shutdown of its operated oil fields in the Kurdistan region of Iraq four days after it was instructed to temporarily cease deliveries to the Iraq-Turkey Pipeline destined for the Mediterranean port of Ceyhan following an arbitration ruling in favor of Iraq against Turkey for exporting Kurdish oil without Baghdad's approval.

DNO had diverted oil production to storage tanks, but capacity is limited, as previously announced.

The Company's prolific Tawke and Peshkabir fields averaged combined production of 107,000 barrels of oil per day in 2022, representing a quarter of Kurdistan's total exports. Peshkabir production was halted last night and plans drawn up to conduct deferred maintenance. Tawke production shutdown has started but will take an additional day or so given the much larger numbers of wells spread across some 10 kilometers.

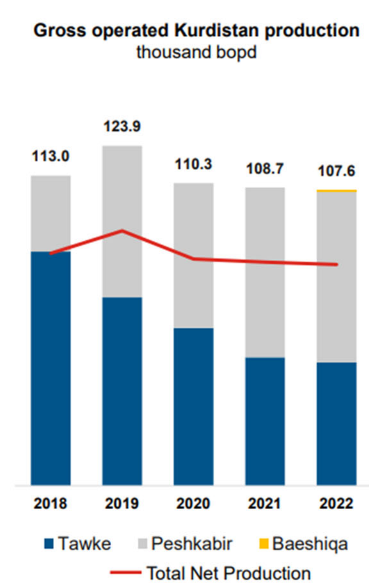
"It is unfortunate it has come to this given the likely impact of a continuing supply disruption on oil prices and at a fragile time in global financial markets," said DNO's Executive Chairman Bijan Mossavar-Rahmani.

Prior to the shutdown, the Iraq-Turkey Pipeline carried some 400,000 barrels a day of Kurdish oil and another 70,000 barrels a day of Iraqi oil for export to Mediterranean and other refineries.

Excerpt DNO 2022 Interim Results Presentation

Kurdistan operations

- Tawke license gross operated production averaged 107,100 bopd in 2022 (106,500 bopd in Q4 2022), of which Peshkabir field 62,000 bopd and Tawke field 45,100 bopd
- Ramped up activity in both fields with stepped up drilling campaign to manage natural decline; first quarterly Tawke field production increases since 2015
- Completed USD 25 million expansion of Peshkabir-to-Tawke gas project, Kurdistan's only gas capture and enhanced recovery injection project
- Since 2020, the project has captured 1.2 million tonnes of CO_2e through avoided flaring, simultaneously improving Tawke field performance through gas injection
- Fast-track development of Baeshiqa license with test production commencing from first discovery wells in June 2022, averaging 1,000 bopd and ~12 MMscf/d



DNO

https://www.libyaherald.com/2023/02/libya-will-produce-more-than-1-5-million-barrels-of-oil-per-day-in-2023-agoco-chairman/

Libya will produce more than 1.5 million barrels of oil per day in 2023: AGOCO chairman

Provision of budget, continued and fast development, stability in Libya and oil sector - all contributing factors

by **Ibrahim Senusi** February 14, 2023

AGOCO chairman Gatrani said Libya can increase production to 1.5 million bpd this year (Photo: AGOCO).

The continuation of the Arabian Gulf Oil Company's (AGOCO) development operations at this pace will inevitably lead to Libya reaching a production rate of more than 1.5 million barrels of oil per day in 2023, AGOCO chairman Salah Gatrani said in an exclusive statement to *Libya Herald*.
He said this was because of the stability witnessed by the country in general, and by the oil sector in particular. Therefore, he continued, the Gulf Company has developed its own plan within the efforts of the National Oil Corporation (NOC). Libya has been unable to maintain production beyond 1.2 million bpd.

Gatrani was commenting to *Libya Herald* following Sunday's AGOCO's meeting on developing reserves and increasing oil production in the sector companies, attended by relevant AGOCO and NOC management.
The AGOCO chairman said that his company has already begun to implement the plan prepared by the NOC to raise production and increase reserves.

Training, localising and developing new techniques
He said AGOCO had actually delayed several projects to raise the efficiency of the employees in the company, including a cooperation project with KAMCO Oil Services Company to raise the efficiency

of employees, localize and develop technology in the company, and keep pace with global updates in the fields of drilling oil wells and extracting crude oil.

Gatrani referred to the conclusion of a training course for workers in the Nafoura field in the field of production engineering on the use of new techniques of electrical narratives and their applications to evaluate rock layers in oil-producing wells as well as water injection wells.

NOC is providing finance after securing it from government

He commended the NOC for supporting its oil companies financially, especially after allocating a good budget to the sector from the Abd Alhamid Aldabaiba government, which positively affected the entire oil sector, as several oil wells have returned to production and the completion of preparations in several new wells.

At the meeting Gatrani referred to the speech by NOC chairman Farhat Bengdara at a previous expanded meeting on the NOC's strategic plan to raise production and develop reserves. He pointed to the importance of this plan, which he said requires concerted efforts to achieve it and provide the necessary capabilities that would ensure access to the target smoothly. The most important of these capabilities, he said, is the steady cash flow as well as overcoming and developing all the problems that hinder the productive process.

AGOCO expected to increase most production

Speaking at the meeting, Khalifa Abdul Sadig, NOC board member, said that this meeting is very important and strategic to increase production and develop reserves in AGOCO, which, he said, constitutes the largest percentage of this plan. He said the NOC is counting on AGOCO to Increase production, develop reserves, and counting on it for the success of the NOC's increased production plan. He admitted that the challenges are great, but with a strong will and wise management, Libya will be able to achieve the goals and results.

Tags: AGOCO Arabian Gulf Oil Company https://www.globaltimes.cn/page/202302/1285849.shtml

Foreign airlines ramp up international flights to China amid rising demand

By Global Times Published: Feb 20, 2023 10:08 PM

Beijing airport Photo: VCG

A number of foreign airlines that have benefited from the rapid growth of China's outbound travel are working hard to restart flights serving the country as China has lifted the travel ban, bringing a fast recovery of demand.

KLM Royal Dutch Airlines, a subsidiary of the Air France-KLM Group, said it will increase the frequency of flights connecting with China starting from March 26. It also plans to have three flights from Amsterdam to Hong Kong and to start six direct flights per week to Beijing and Shanghai on the same day, and increase service to a daily flight from May.

Air France plans to increase the frequency of flights between Paris and Beijing, Shanghai and Hong Kong to one daily from July.

As a leading European airline group in China, Lufthansa Group has a long history. The first Lufthansa flight arrived in Beijing from Berlin in 1926.

After the reopening of the Chinese mainland, Lufthansa Group further increased its flight frequency. Starting from March, Lufthansa will double its flights to the Chinese mainland from five weekly flights to nine.

China is always a very important intercontinental market of Lufthansa, the company told the Global Times on Monday.

Airlines in Southeast Asia, which are favored by Chinese tourists, are expanding more rapidly. AirAsia restarted the Guangzhou-Kuala Lumpur route on February 11, and it plans to increase service to eight flights per week from March 2.

Emirates will increase flights between Dubai and Shanghai to daily from March, and will restart the Dubai-Beijing route on March 15. Qatar Airways announced that it will resume daily flight services from Doha to Beijing Daxing International Airport from March 26, while increasing services between Doha and Guangzhou to daily flights.

China-UK direct flights, which were interrupted during the COVID-19 epidemic, are set to resume soon.

According to British Airways, the route between London Heathrow Airport and Shanghai Pudong International Airport will be resumed operations on April 23, with seven flights per week, and British Airways will resume London Heathrow to Beijing Daxing International Airport on June 3.

China has maintained a fast recovery of international flights, as resumed weekly fixed passenger flights have increased by more than 60 percent over the week before downgrading management of COVID-19 on January 8.

The number of fixed international passenger flights stood at 795 across 98 carriers from home and abroad from February 6 to 12, covering 58 countries and regions, the Civil Aviation Administration of China said on Thursday.

The number of flights was up 65 percent over the week from January 2 to 8, the week before China prioritized its COVID-19 management.

Although the return of international routes is accelerating overall, market analysts said it is difficult for domestic airports to see a sharp increase in a short time.

By looking at routes longer than 3,000 miles, the number of flights departing from East Asian airports in the first quarter of this year was 41 percent lower than in the first quarter of 2019. The figure was partly influenced by the Chinese region, a report released by industry consultancy Cirium sent to the Global Times on Monday showed.

Due to the reopening of China, there may be significant changes to flight schedules in the region. The China flight schedule for the first quarter of 2023 shows that while inbound and outbound capacity is roughly 82 percent below pre-pandemic levels, it is more than double that of the first quarter of 2022, Cirium said.

Global Times

https://www.vortexa.com/insights/crude/time-to-get-bullish-again-on-crude/

Time to get bullish again on crude?

Numerous structural and seasonal factors are pointing to higher crude prices in the coming months, and onshore crude inventories are already drawing right now.

30 MARCH, 2023

David Wech, Chief Economist

Most investors and oil traders started the year 2023 with a bullish outlook on crude prices, primarily driven by strong oil demand growth expectations of around 2mbd. That was particularly palpable at the IE Week in London in late February. Fast forward to mid March, crude oil was trading around $10/b lower, with ICE Brent zooming in to just $70/b. So, were most people wrong?

Probably not. The mini collapse was largely driven by the banking crisis, with some poor economic readings coming in as well for Q1, feeding GDP growth fears. However, not much is pointing towards a fully-fledged recession. And it may anyway be better to look at direct crude/oil market fundamentals than macro indicators. What are we seeing there?

Demand is surely not doing particularly well right now. Apart from the slow economic growth and wider inflation pressure, we are just coming out of a winter period that from an oil (and gas) seller's point of view was nothing else than horrendously disappointing. Weather, and the anticipation and actions of consumers and fuel suppliers worked together to allow markets coming out of the season with reasonably ample fuel stocks. And Q2 is the seasonal low point in oil demand. So it may still take 4-8 weeks for dynamics on the product-side to catch up. But crude procurement has to be ahead of the curve and buying should already and increasingly reflect expectations for the summer travel and construction season in the Northern Hemisphere, including China. US refiners are already upping runs post maintenance and that will very soon eat into US crude exports.

This leads us to the supply side, where US production expectations are revised down on a regular and consistent basis. The recent fall of WTI and related prices into the $60ies is surely not helping any of the many trends curtailing US shale production. Pretty much everybody around the globe is producing flat out, including most OPEC countries and at least until very recently Russia. Product exports from the latter have been running at ridiculously high levels in March, but also Russian crude exports are close to the upper end of the Covid-era range. As projected in our analysis pieces earlier this year, the country is not really struggling to place its exports, and the preference for clean product exports will prevail due the higher sales value amid Russia's dire budget situation. So there appears to be only one direction for Russian crude exports out of many reasons (incl. announced cuts and seasonality), which is southwards. Otherwise, production outages have been rare recently, with the Kirkuk blockade serving as reminder that new hiccups will show up down the line.

With ample supply and limited demand, crude balances shouldn't be supportive to prices at this point of the year, with the picture widely expected to tighten substantially, but only in H2 2023. However, Vortexa real-time global onshore inventory data is showing substantial, widespread and persistent draws over the last two months. Seven of the last nine weeks saw draws, averaging a strong 1.6mbd.

World onshore crude inventory change by region (4-week average, mbd)

China has kicked off the trend of draws early in the year, but has turned around to builds in more recent weeks. This may be reflective of two things: currently lacklustre refining economics and strong crude procurement from all around the world, including Russia, Iran and parts of the Atlantic Basin. Barrels arriving currently and over the coming months have been bought at low outright prices, and more is expected to come as seasonal demand and rising prices may stimulate more purchases amid concerns of even high prices in the future.

Dirty tanker rates are already lofty, especially for the bigger vessel classes, giving support to the notion of strong Chinese buying and even more upside is expected for the remainder of the year. That is if the supply is actually there to meet crude oil demand! But either way, crude prices are set to rise.

David Wech

Chief Economist

Vortexa

David Wech is contributing his extensive experience in research operations across strategy execution, product development, supply and demand modelling, competitive market positioning, commodity analysis and price forecasting. Before joining Vortexa, he spent 18 years at JBC Energy, including 8 years as Managing Director and 7 years as the Head of Research.

Dallas Fed **Energy** Survey

First Quarter | March 29, 2023

Oil and gas expansion stalls amid surging costs and worsening outlooks

What's New This Quarter

Special questions this quarter include an annual update on breakeven prices by basin, anticipated employee head count changes in 2023, the main factor influencing company profitability and the top cause of worker shortages in the oilfield.

Growth in the oil and gas sector stalled out in first quarter 2023, according to oil and gas executives responding to the Dallas Fed Energy Survey. The business activity index—the survey's broadest measure of conditions facing Eleventh District energy firms—was 2.1 in the first quarter, down sharply from 30.3 in fourth quarter 2022. The near-zero reading indicates activity was largely unchanged from the prior quarter, a break from the more than two-year stretch of rising activity.

Oil and natural gas production increased at a slower pace compared with the prior quarter, according to executives at exploration and production (E&P) firms. The oil production index remained positive but declined to 10.5 in the first quarter from 25.8 in the fourth. Similarly, the natural gas production index fell to 7.4 from 29.4.

Firms reported rising costs for a ninth consecutive quarter as all series remained significantly above their averages. Among oilfield services firms, the input cost index was roughly unchanged at an elevated 61.6. Among E&P firms, the finding and development costs index slipped to 46.8 from 52.5. Additionally, the lease operating expenses index declined 11 points to 37.6.

The supplier delivery time index for all firms moved into negative territory, declining to -14.0 in the first quarter from 14.4 in the fourth. This is the first negative reading since fourth quarter 2020 and signals that it takes less time to receive materials and equipment relative to the prior quarter. Among oilfield services firms, the measure of lag time in delivery of services declined to zero from 20.0, suggesting delivery times for these firms are no longer increasing.

For oilfield services firms, the equipment utilization index slid 29 points to 3.9 in the first quarter. The operating margin index declined to 1.9 from 25.9. The index of prices received for services remained positive but declined to 25.0 from 43.6.

Indexes related to employment and hours worked eased in the first quarter. The aggregate employment index posted a ninth consecutive positive reading but dipped to 14.3 from 25.7. The aggregate employee hours index declined to 12.3 from 27.7 in the prior quarter. Meanwhile, the aggregate wages and benefits index edged higher, to 43.6 from 40.2.

The company outlook index turned negative in the first quarter, falling 27 points to -14.1. The overall outlook uncertainty index increased 23 points to 62.6, pointing to firms' continued heightened uncertainty regarding their outlooks. Sixty-eight percent of firms reported greater uncertainty.

On average, respondents expect a West Texas Intermediate (WTI) oil price of $80 per barrel by year-end 2023; responses ranged from $50 to $160 per barrel. Survey participants expect Henry Hub natural gas prices of $3.43 per million British thermal units (MMBtu) at year-end. For reference, WTI spot prices averaged $68.51 per barrel during the survey collection period, and Henry Hub spot prices averaged $2.23 per MMBtu.

Next release: June 22, 2023

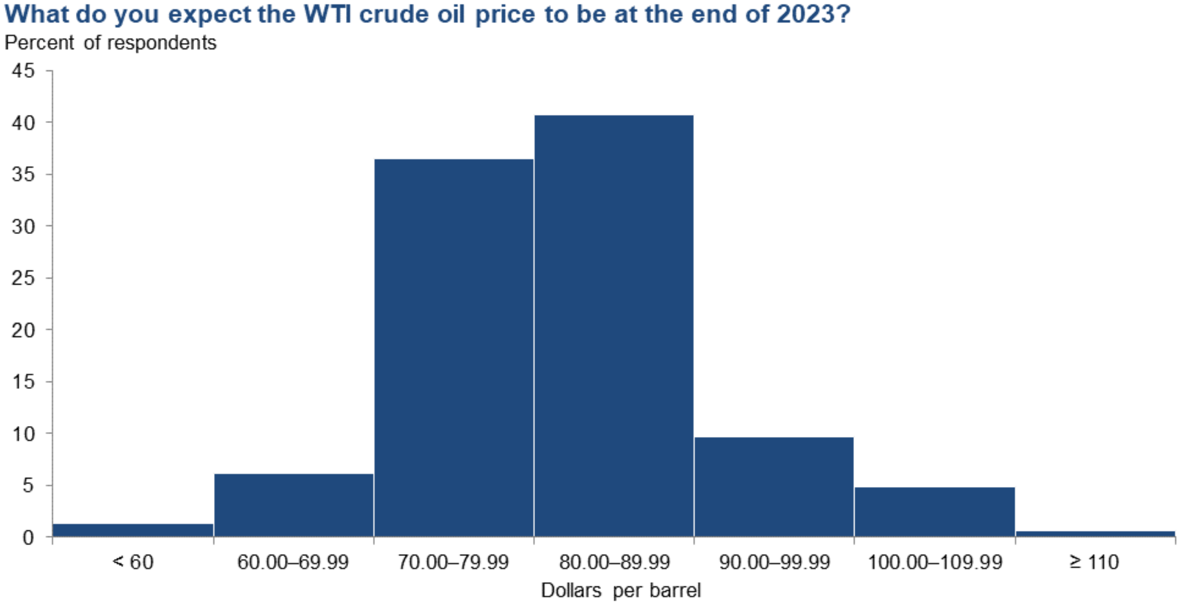
Data were collected March 15–23, and 147 energy firms responded. Of the respondents, 95 were exploration and production firms and 52 were oilfield services firms.

The Dallas Fed conducts the Dallas Fed Energy Survey quarterly to obtain a timely assessment of energy activity among oil and gas firms located or headquartered in the Eleventh District. Firms are asked whether business activity, employment, capital expenditures and other indicators increased, decreased or remained unchanged compared with the prior quarter and with the same quarter a year ago. Survey responses are used to calculate an index for each indicator. Each index is calculated by subtracting the percentage of respondents reporting a decrease from the percentage reporting an increase. When the share of firms reporting an increase exceeds the share reporting a decrease, the index will be greater than zero, suggesting the indicator has increased over the previous quarter. If the share of firms reporting a decrease exceeds the share reporting an increase, the index will be below zero, suggesting the indicator has decreased over the previous quarter.

First Quarter | March 29, 2023

Price Forecasts

West Texas Intermediate Crude



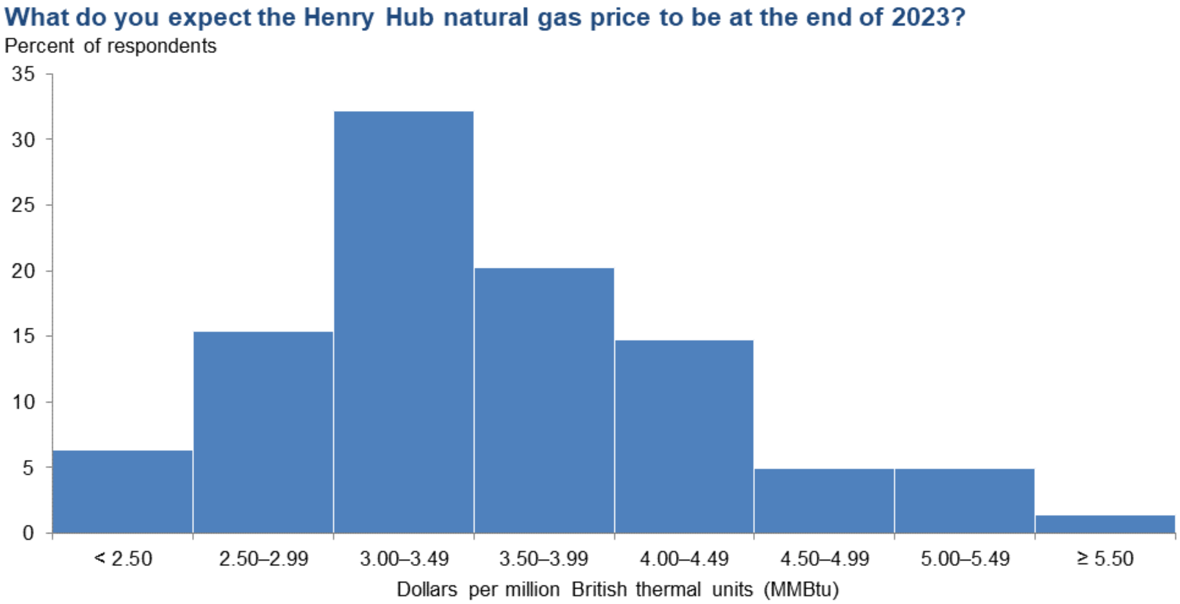
NOTES: Executives from 145 oil and gas firms answered this question during the survey collection period, March 15–23, 2023. The average response was $80 per barrel. For reference, WTI (West Texas Intermediate) spot prices averaged $68.51 per barrel during the period.
SOURCES: Federal Reserve Bank of Dallas; Energy Information Administration (reference price).

West Texas Intermediate crude oil price (dollars per barrel), year-end 2023

Indicator	Survey Average	Low Forecast	High Forecast	Price During Survey
Current quarter	$79.64	$50.00	$160.00	$68.51
Prior quarter	$83.63	$65.00	$160.00	$73.67

NOTE: Price during survey is an average of daily spot prices during the survey collection period.
SOURCES: Energy Information Administration; Federal Reserve Bank of Dallas.

Henry Hub Natural Gas



NOTES: Executives from 143 oil and gas firms answered this question during the survey collection period, March 15–23, 2023. The average response was $3.43 per MMBtu. For reference, Henry Hub spot prices averaged $2.23 per MMBtu during the period.
SOURCES: Federal Reserve Bank of Dallas; Energy Information Administration (reference price).

Henry Hub natural gas price (dollars per MMBtu), year-end 2023

Indicator	Survey Average	Low Forecast	High Forecast	Price During Survey
Current quarter	$3.43	$1.75	$12.50	$2.23
Prior quarter	$5.64	$2.50	$9.00	$5.93

NOTE: Price during survey is an average of daily spot prices during the survey collection period.
SOURCES: Federal Reserve Bank of Dallas; Energy Information Administration.

First Quarter | March 29, 2023

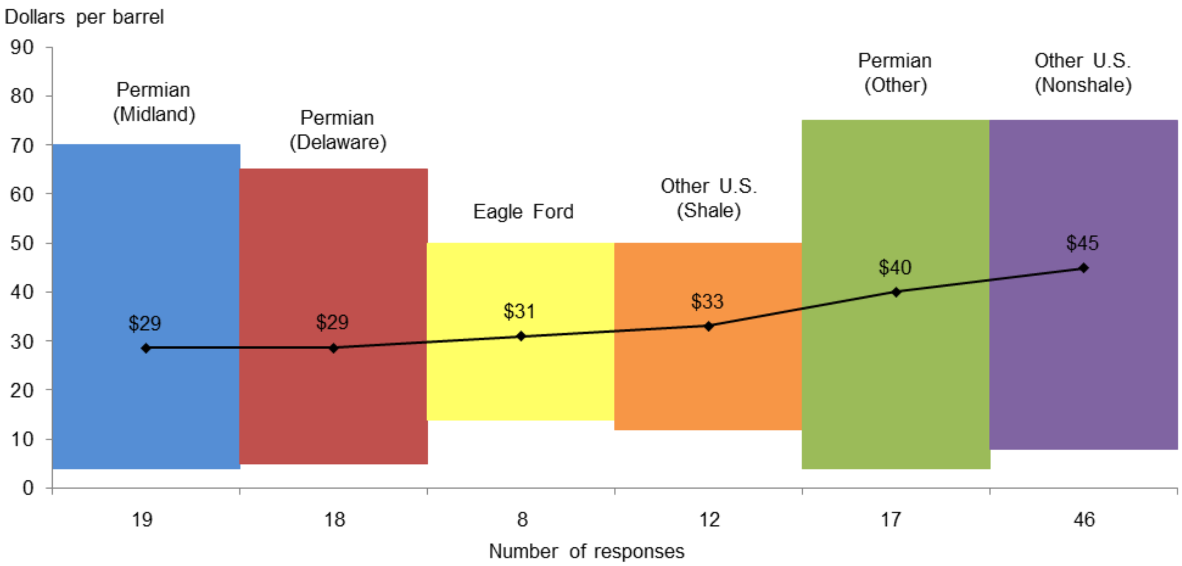
Special Questions

Data were collected March 15–23; 140 oil and gas firms responded to the special questions survey.

Exploration and Production (E&P) Firms

In the top two areas in which your firm is active: What West Texas Intermediate (WTI) oil price does your firm need to cover operating expenses for existing wells?

The average price across the entire sample is approximately $37 per barrel, up from $34 last year. Across regions, the average price necessary to cover operating expenses ranges from $29 to $45 per barrel. Almost all respondents can cover operating expenses for existing wells at current prices.

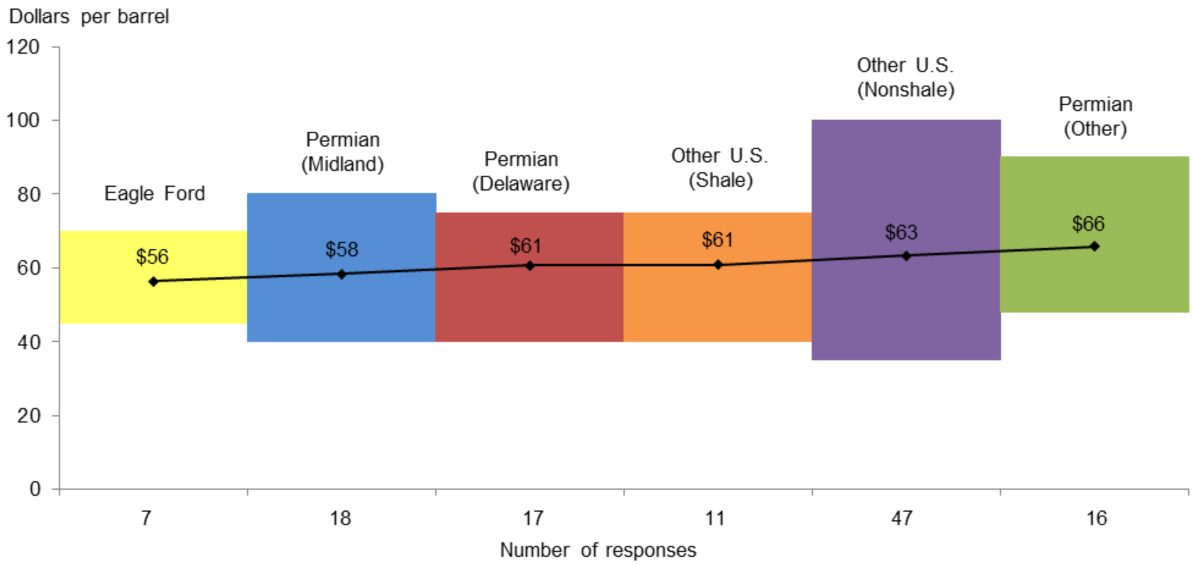


NOTES: Lines show the mean, and bars show the range of responses. The average response was $37 per barrel. Executives from 83 exploration and production firms answered this question during the survey collection period, March 15–23, 2023.
SOURCE: Federal Reserve Bank of Dallas.

In the top two areas in which your firm is active: What WTI oil price does your firm need to profitably drill a new well?

For the entire sample, firms need $62 per barrel on average to profitably drill, higher than the $56-per-barrel price when this question was asked last year. Across regions, average breakeven prices to profitably drill range from $56 to $66 per barrel. Breakeven prices in the Permian Basin average $61 per barrel, $9 higher than last year. Despite recent oil price declines, most firms in the survey can profitably drill a new well at current prices.

Large firms (with crude oil production of 10,000 barrels per day or more as of fourth quarter 2022) require prices of $55 per barrel to profitably drill, based on the average of company responses. That compares with $64 for small firms (fewer than 10,000 barrels per day).



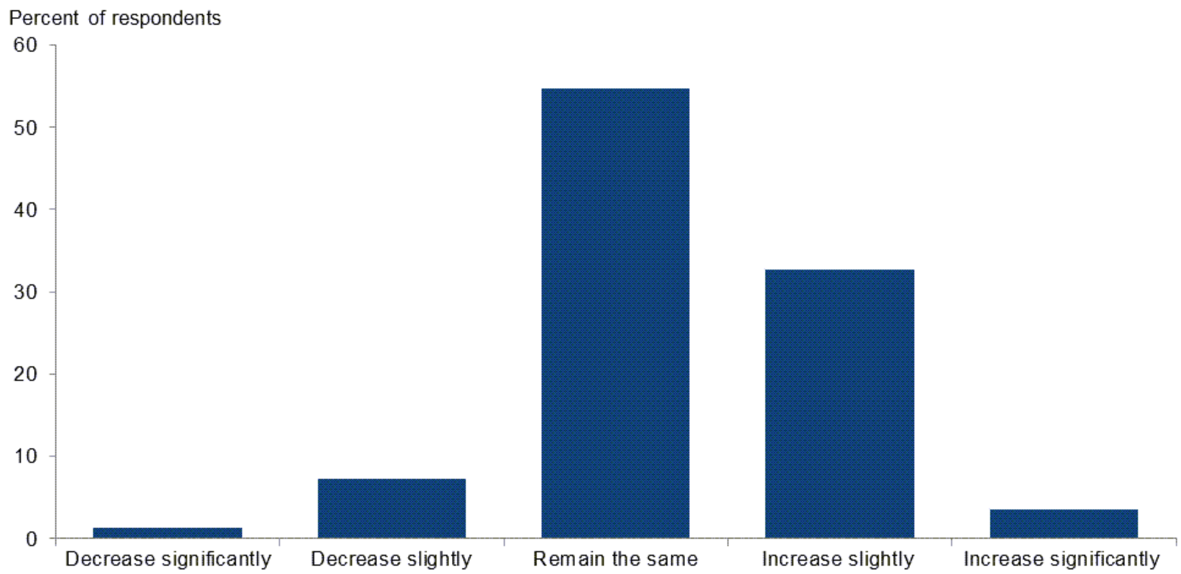
NOTES: Lines show the mean, and bars show the range of responses. The average response was $62 per barrel. Executives from 80 exploration and production firms answered this question during the survey collection period, March 15–23, 2023.
SOURCE: Federal Reserve Bank of Dallas.

All Firms

How do you expect the number of employees at your company to change from December 2022 to December 2023?

More than half of the executives—55 percent—expect their head count to remain unchanged from December 2022 to December 2023. Thirty-seven percent of executives expect the number of employees to increase, of which 4 percent expect a significant increase and 33 percent anticipate a slight increase. Only 8 percent foresee the number of employees decreasing over the period.

Whereas the most-selected response among E&P firms was for employment to "remain the same" in 2023, the most-selected response of support service firms was for employment to "increase slightly" in 2023. (See table for more detail.)



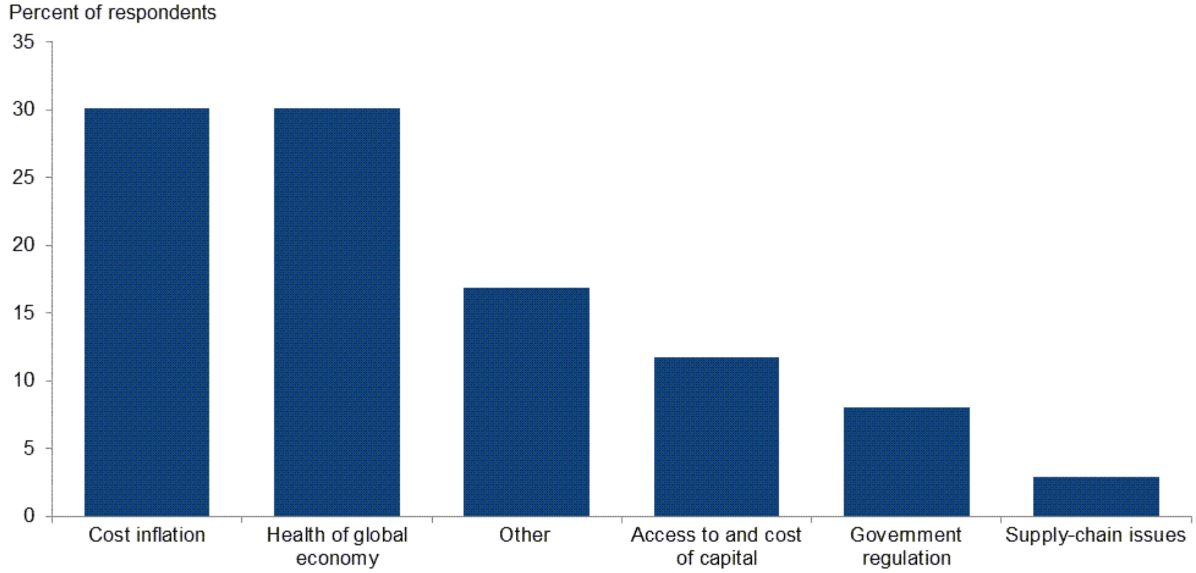
NOTE: Executives from 137 oil and gas firms answered this question during the survey collection period, March 15–23, 2023.
SOURCE: Federal Reserve Bank of Dallas.

Response	Percent of respondents (among each group)		
	All firms	E&P	Services
Increase significantly	4	2	6
Increase slightly	33	25	46
Remain the same	55	66	36
Decrease slightly	7	6	10
Decrease significantly	1	1	2

NOTES: Executives from 87 exploration and production firms and 50 oil and gas support services firms answered this question during the survey collection period, March 15–23, 2023. The "All" column reports the percentage out of the total 137 responses. Percentages may not sum to 100 due to rounding.
SOURCE: Federal Reserve Bank of Dallas.

Which of the following do you believe will have the most influence on the profitability of your firm this year?

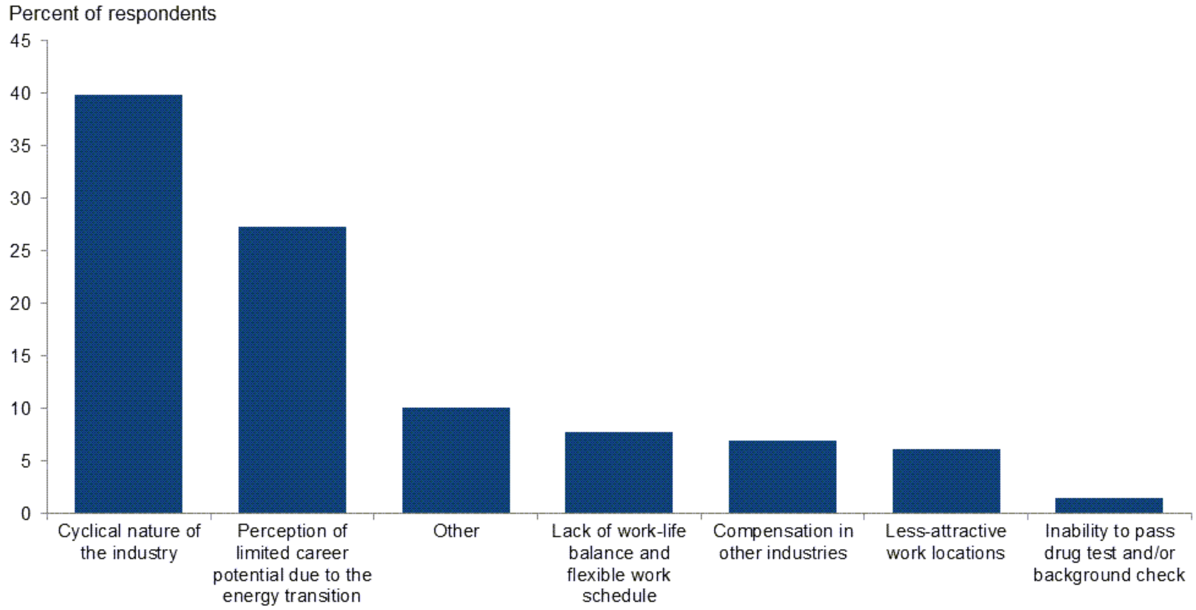
"Cost inflation" and "health of global economy" were each selected by 30 percent of executives as having the greatest influence on the profitability of their firm in 2023.



NOTE: Executives from 136 oil and gas firms answered this question during the survey collection period, March 15–23, 2023.
SOURCE: Federal Reserve Bank of Dallas.

Which of the following is the primary factor causing worker shortages in the oilfield?

Forty percent of executives cited the cyclical nature of the industry as the primary factor causing oilfield worker shortages. A total of 27 percent selected “perception of limited career potential due to the energy transition,” and 10 percent indicated “other.”



NOTE: Executives from 128 oil and gas firms answered this question during the survey collection period, March 15–23, 2023.
SOURCE: Federal Reserve Bank of Dallas.

Special Questions Comments

Exploration and Production (E&P) Firms

- Government roadblocks are a major issue for our firm. "Majors" have the world to play in. They are at an advantage compared with independents who are currently entangled in red tape and buffeted by public pronouncements in the U.S. about this perceived evil industry. Capital providers have been politicized by design by the current political operatives, hurting the entire industry, especially small businesses. The industry, and independents in particular, have an important role to play for the next 50 years at least. I believe a large part of service cost inflation is due to service companies restricting rig count and active frac crews in an effort to boost their margins, not due to labor shortages.
- Seems like oil prices have gone down to where the federal government said it would buy barrels to replace the Strategic Petroleum Reserve. With all these jobs in the South tied to energy, I'm sure the administration follows through with its promises, right? Or will it choose the easy path and continue harmful and confusing rhetoric against energy producers while cheering on lower gasoline prices? Also, the Energy Information Administration put out its Annual Energy Outlook this week, and it forecasts that oil production from the U.S. will be flat for the next 30 years. We should probably inform them of the collapse in shale production we are going to see in under five years.
- Service costs and authorization for expenditures keep climbing. The latest commodity price action feels like the sword of Damocles is back; where is oil going to bottom this time?
- The sudden drop in natural gas prices from year-end 2022 into 2023 significantly shifted the priorities for 2023 from growth to maintaining margins.
- The administration's policies against domestic oil production will have catastrophic effects on our ability to protect our economic way of life. Our way of life is degrading.
- We hear some rigs' and fracs' availability is leading to lower quoted rates. Natural gas and fuel price reduction coupled with steel reduction is leading to cost relief on several oilfield items. Supply-chain pressures have now eased significantly and are back to prepandemic levels. Labor productivity is impaired as market tightness has led to a less-experienced pool.

Oil and Gas Support Services Firms

- Uncertainty rules the day. It is extremely difficult to plan for the future with so much of the base data we are used to using being all over the board. Seems like business patterns go against trends proven over the last 30–40 years in the oil and gas industry as a whole and the oil and gas service business specifically. However, overall the adage "go hard now, bank as much as you can, and hope it is enough to get you through the lean times we know are coming" is still true today.
- The factors that impact availability of labor seem different for every demographic. Many left the oilfield in 2020 and are not coming back, either due to age or the booms and busts. Wages are not high enough to bring them back compared with other sectors. Gen Z's and work/life balance desires are the same with blue-collar and white-collar employees, with many entering the workforce willing to accept lower earnings for predictability and scheduling not available in the oilfield. Perceived energy transition concerns seem less impactful than the overall perception of oilfield work. Drug charges/tests and multiple driving under the influence charges also eliminate many otherwise willing applicants.
- Currently, finding skilled labor is our biggest challenge. Rates of pay have risen to the point that they're diminishing our gross margins, and competitors are overpaying, sometimes to the point of offering raises based on being able to "steal" the work from our customers. In some cases, [this is] close to a 30 percent bump in wages. Bottom line is most will fail.
- Inflation, supply-chain issues, rising interest rates and governmental regulation are all major issues that will influence profitability. For the question regarding the primary factor causing worker shortages, all elements listed are major issues relating to personnel.

- The cyclical nature of the industry and the perception of it as a dying industry both make it hard for landmen to stay in this business and for new ones to enter. Pay has not risen in years for field landmen, while other industries have had significant hikes. I would not recommend the industry to any young people.

First Quarter | March 29, 2023

Business Indicators: Quarter/Quarter

Business Indicators: All Firms
Current Quarter (versus previous quarter)

Indicator	Current Index	Previous Index	% Reporting Increase	% Reporting No Change	% Reporting Decrease
Level of Business Activity	2.1	30.3	29.3	43.5	27.2
Capital Expenditures	17.1	40.1	41.1	34.9	24.0
Supplier Delivery Time	–14.0	14.4	9.8	66.4	23.8
Employment	14.3	25.7	23.1	68.0	8.8
Employee Hours	12.3	27.7	21.1	70.1	8.8
Wages and Benefits	43.6	40.2	45.6	52.4	2.0

Indicator	Current Index	Previous Index	% Reporting Improved	% Reporting No Change	% Reporting Worsened
Company Outlook	–14.1	13.1	19.7	46.5	33.8

Indicator	Current Index	Previous Index	% Reporting Increase	% Reporting No Change	% Reporting Decrease
Uncertainty	62.6	40.1	68.0	26.5	5.4

Business Indicators: E&P Firms
Current Quarter (versus previous quarter)

Indicator	Current Index	Previous Index	% Reporting Increase	% Reporting No Change	% Reporting Decrease
Level of Business Activity	–2.1	29.9	25.3	47.4	27.4
Oil Production	10.5	25.8	31.6	47.4	21.1
Natural Gas Wellhead Production	7.4	29.4	28.7	50.0	21.3
Capital Expenditures	11.7	38.2	38.3	35.1	26.6
Expected Level of Capital Expenditures Next Year	6.4	35.0	31.9	42.6	25.5
Supplier Delivery Time	–16.5	18.6	7.7	68.1	24.2
Employment	8.4	14.4	14.7	78.9	6.3
Employee Hours	10.5	16.4	13.7	83.2	3.2
Wages and Benefits	37.8	36.0	38.9	60.0	1.1
Finding and Development Costs	46.8	52.5	47.9	51.1	1.1
Lease Operating Expenses	37.6	48.4	44.1	49.5	6.5

Indicator	Current Index	Previous Index	% Reporting Improved	% Reporting No Change	% Reporting Worsened
Company Outlook	–18.9	6.5	16.7	47.8	35.6

Indicator	Current Index	Previous Index	% Reporting Increase	% Reporting No Change	% Reporting Decrease
Uncertainty	64.2	45.4	69.5	25.3	5.3

Business Indicators: O&G Support Services Firms
Current Quarter (versus previous quarter)

Indicator	Current Index	Previous Index	% Reporting Increase	% Reporting No Change	% Reporting Decrease
Level of Business Activity	9.6	30.9	36.5	36.5	26.9
Utilization of Equipment	3.9	32.8	30.8	42.3	26.9
Capital Expenditures	27.0	43.6	46.2	34.6	19.2
Supplier Delivery Time	–9.6	7.3	13.5	63.5	23.1
Lag Time in Delivery of Firm's Services	0.0	20.0	7.7	84.6	7.7
Employment	25.0	45.5	38.5	48.1	13.5
Employment Hours	15.4	47.2	34.6	46.2	19.2
Wages and Benefits	53.9	47.3	57.7	38.5	3.8
Input Costs	61.6	61.8	63.5	34.6	1.9
Prices Received for Services	25.0	43.6	34.6	55.8	9.6
Operating Margin	1.9	25.9	28.8	44.2	26.9

Indicator	Current Index	Previous Index	% Reporting Improved	% Reporting No Change	% Reporting Worsened
Company Outlook	–5.8	24.5	25.0	44.2	30.8

Indicator	Current Index	Previous Index	% Reporting Increase	% Reporting No Change	% Reporting Decrease
Uncertainty	59.6	30.9	65.4	28.8	5.8

Business Indicators: Year/Year

Business Indicators: All Firms

Current Quarter (versus same quarter a year ago)

Indicator	Current Index	Previous Index	% Reporting Increase	% Reporting No Change	% Reporting Decrease
Level of Business Activity	27.7	59.3	53.9	19.9	26.2
Capital Expenditures	37.6	58.4	58.2	21.3	20.6
Supplier Delivery Time	11.5	41.7	38.1	35.3	26.6
Employment	35.2	41.6	43.7	47.9	8.5
Employee Hours	29.6	43.1	34.5	60.6	4.9
Wages and Benefits	63.5	68.3	66.4	30.7	2.9

Indicator	Current Index	Previous Index	% Reporting Improved	% Reporting No Change	% Reporting Worsened
Company Outlook	16.8	57.6	41.2	34.4	24.4

Business Indicators: E&P Firms

Current Quarter (versus same quarter a year ago)

Indicator	Current Index	Previous Index	% Reporting Increase	% Reporting No Change	% Reporting Decrease
Level of Business Activity	12.2	52.7	43.3	25.6	31.1
Oil Production	11.0	44.0	41.8	27.5	30.8
Natural Gas Wellhead Production	15.5	36.7	41.1	33.3	25.6
Capital Expenditures	26.7	53.2	51.1	24.4	24.4
Expected Level of Capital Expenditures Next Year	14.8	58.5	39.8	35.2	25.0
Supplier Delivery Time	5.7	47.8	33.0	39.8	27.3
Employment	23.9	31.1	31.5	60.9	7.6
Employee Hours	15.4	30.5	19.8	75.8	4.4
Wages and Benefits	57.8	64.5	60.0	37.8	2.2
Finding and Development Costs	69.7	75.0	71.9	25.8	2.2
Lease Operating Expenses	64.1	75.8	69.7	24.7	5.6

Indicator	Current Index	Previous Index	% Reporting Improved	% Reporting No Change	% Reporting Worsened
Company Outlook	4.7	54.6	34.5	35.7	29.8

Business Indicators: O&G Support Services Firms

Current Quarter (versus same quarter a year ago)

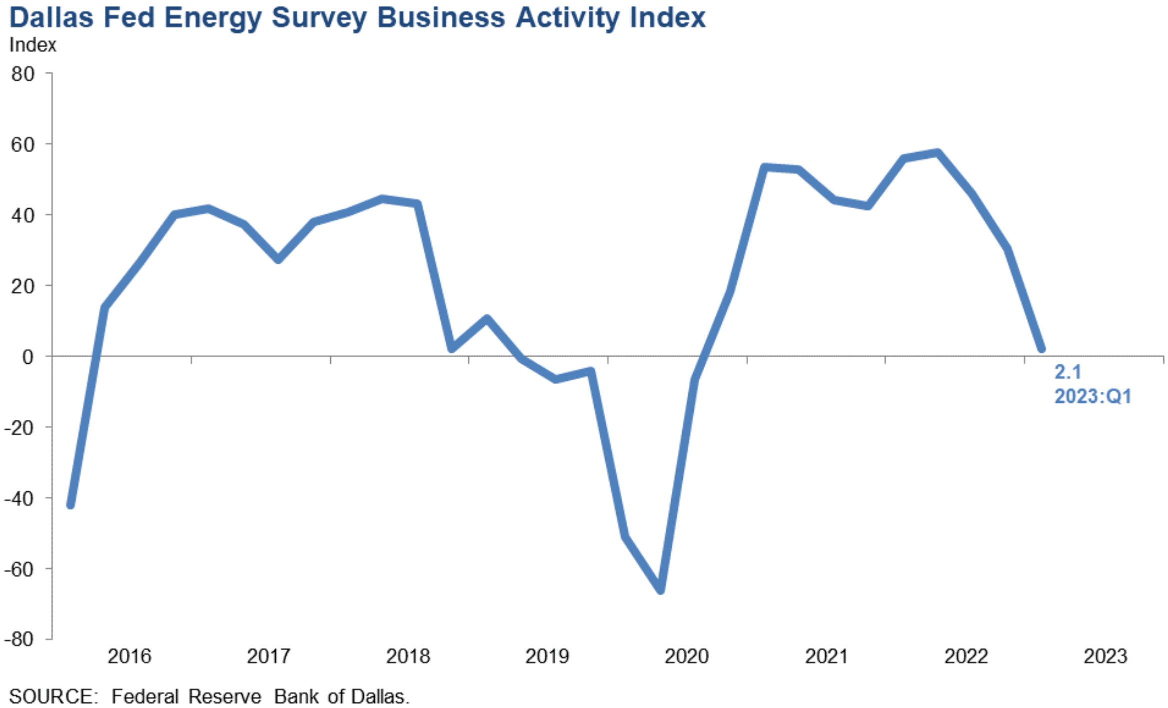
Indicator	Current	Previous	% Reporting	% Reporting	% Reporting

	Index	Index	Increase	No Change	Decrease
Level of Business Activity	54.9	71.1	72.5	9.8	17.6
Utilization of Equipment	54.9	69.2	68.6	17.6	13.7
Capital Expenditures	56.9	67.3	70.6	15.7	13.7
Supplier Delivery Time	21.6	30.7	47.1	27.5	25.5
Lag Time in Delivery of Firm's Services	21.6	42.4	27.5	66.7	5.9
Employment	56.0	59.6	66.0	24.0	10.0
Employment Hours	54.9	65.4	60.8	33.3	5.9
Wages and Benefits	74.0	75.0	78.0	18.0	4.0
Input Costs	76.5	78.9	80.4	15.7	3.9
Prices Received for Services	58.8	69.2	68.6	21.6	9.8
Operating Margin	27.4	47.1	52.9	21.6	25.5

Indicator	Current Index	Previous Index	% Reporting Improved	% Reporting No Change	% Reporting Worsened
Company Outlook	38.3	63.0	53.2	31.9	14.9

First Quarter | March 29, 2023

Activity Chart



First Quarter | March 29, 2023

Comments from Survey Respondents

These comments are from respondents' completed surveys and have been edited for publication. Comments from the Special Questions survey can be found below the special questions.

Exploration and Production (E&P) Firms

- Oil price correction is adding pressure on the continuation of drilling and frac activities. [We] expect the activity level to be flat to down in 2023 versus 2022's exit.
- The dramatic increase in 2022 inflation has severely negatively impacted project economics.
- Uncertainty of the depth and duration of a bank crisis is causing us to be nervous about capital spending plans in 2023.
- Oil in recession trades like a financial product—supply/demand fundamentals matter less. Chickens seem to be coming home to roost; it turns out loaning out trillions of dollars with zero interest rates (or in the case of Europe, paying folks to borrow money) was not our finest hour.
- Regulatory uncertainty continues to be a headwind. Inflation pressures appear to be moderating slightly, but we still have a long way to go.
- Permitting delays by the administration's policies have caused us not to drill two wells we had hoped to drill this year. The BLM [Bureau of Land Management] is holding them hostage.
- The current low oil prices, coupled with the banking scare, will be hard on smaller, undercapitalized companies to conduct business as usual. There will be tougher credit and lower reserve values because of new price decks.
- A growing concern in West Texas is that the reliable generated supply of electricity is not growing, while consumption of power has grown roughly 50 percent over the past 24 months. This could lead to a future moderation of basinwide activity if power supply cannot meet future demand.
- Crude oil is about to join natural gas in contango, which is highlighting a nervous macroeconomic picture. There are plenty of buyers at this calender strip price and not a lot of sellers. Not seeing financial distress with all of the cash accrued since last year. The only way people are in trouble is if hedges are under water or if they blew out authorization for expenditures.
- An estimated 30–40 percent cost increase in field operations, increased interest charges on borrowed money, a drastic collapse in natural gas prices combined with lower crude oil prices produced a noticeable lower cash flow. Service company capacity is quite limited in select basins. Outside investors seem to be losing interest in hydrocarbons. The worldwide macroeconomic and political outlook is cloudy. The road ahead looks difficult but passable. We expect another "muddle through" period in a cyclical business where more players will be winnowed out.
- The uncertainty in oil and gas prices is making it difficult to plan for the future. Between government regulations and oil and gas prices, it is becoming more and more difficult to remain in the oil and gas business.
- We expect oil and gas production to decline in 2023 due to higher drilling and completion costs. The significant factor is the lack of qualified employees. The second [factor] is the negative impact of environmental, social and governance initiatives.
- Government roadblocks are our biggest and most insidious obstacles to overcome. Both the current administration and the governor of California are dreaming up new ways to add costs, delay permits and prevent drilling and leasing.
- Financing unexpected capital calls has gotten more challenging with the Federal Reserve's interest rate increases and the government's war on oil and gas. We're finding more creative ways to get financing.

Current banking is starting to prove "difficult" due to "attitudes" from constantly shifting young bank officers, despite 27 years of business with the same bank. Silicon Valley Bank and associated banking meltdowns are impacting commodity prices. Our operators are reporting that they are having trouble getting materials, parts, pumps, pipe and tubing into West Texas projects. We are also noticing that most of our operators have reduced staffs and have replaced knowledgeable and experienced personnel with apparently cheaper "newbies." Oilfield inflation has to be the No. 1 problem. Capital expenditure increases are soaring well past consumer price index data. I'm noticing apparent quality problems beginning to plague new projects; specifically, I've never seen so many cases of parted tubing with new tubing, particularly with poor quality collars, as I'm seeing in recent months. Is the U.S. importing more inferior-grade oil country tubular goods now?

- Mixed messages sent by the current administration respecting the necessity for fossil fuel production, scarcity of labor, increased cost of materials and supplies, domestic and foreign political risk, demand volatility and economic uncertainty domestically have each contributed to an environment that is difficult to work and make plans in going forward. In addition to those factors, the increased cost of capital has negatively impacted the ability to participate in projects that could enable the organization to grow.
- The rig count has fallen for the past two months. Shale producers have drilled most of their tier 1 quality. The Bakken is seeing itself reach a bubble point, and natural gas is increasing in new completions with less crude oil. Natural economics occurs in the patch. Values drop and so do activity and production levels. Supply and demand are priced accordingly. Global issues also can play a part. Climate change activists are causing disruption.
- The biggest threat to our business is the federal government. The public narrative, directed by Washington, that the world is moving away from oil and gas is a very big problem. It directly affects our ability to raise capital. This must stop. It's easier to finance a vape shop or a tattoo shop than it is to finance oil and gas. There is something seriously wrong here.
- Market risks, both directly and indirectly related and unrelated to oil and gas, have increased significantly and are likely to not be reduced by any action undertaken, suggested or omitted by the administration.
- Frivolous environmental litigation from Bureau of Land Management leases and permits is obstructing our ability to properly develop our properties. Service cost inflation combined with weaker commodity prices will negatively impact future drilling plans, resulting in less activity.
- The low oil and gas prices are impacting investment. Talk by government officials regarding the oil and gas industry makes one wonder why the industry should risk dollars.
- Our industry has been affected negatively by the Russia–Ukraine war, and now there are concerns over the banking system. The continued mixed messages put out by the administration are also contributing to the uncertainty and unwillingness to put additional funds toward development and growth.
- The administration’s policies will continue to affect domestic natural gas and oil production negatively. Oil and gas prices will soar in the next few years, and we'll be at the mercy of nations that hate us.
- [There have been] no direct impacts to our company yet that we know of, but we are monitoring tremors in the banking system that surfaced over the past couple of weeks.
- Volatility in commodity markets and recent banking turmoil continue to play into business dynamics and are leading to a reduction in spending plans. The dramatic pullback in natural gas prices has also led to a decrease in appetite to target gas prospects and has also led to some optional gas-rate curtailments.
- Overall, prices have impacted the revenue but not yet costs. We are still waiting for costs to catch up with the new pricing levels. We do not expect prices to increase significantly.
- It appears as if the war in Ukraine will continue.

Oil and Gas Support Services Firms

- The persistent labor shortage in the Permian Basin shows no signs of easing. It is very difficult to fill mechanical and electrical positions with local residents. Our company is relying on shift workers from out of

state to fill these spots due to the shortage of local qualified workers. The growth of the electrical grid is not keeping up with demand. It will be increasingly difficult for the energy industry to meet stricter environmental regulations without significant investment in power generation and transmission. The infrastructure of the Permian Basin continues to be maxed out. Roads are at capacity, and there are not enough local, state and federal dollars flowing into the area to properly construct and maintain safe roads.
- We're at a crossroads as activity levels are not matching service pricing. There seems to be a disparity at the operator level where their reluctance to allow pricing increases doesn't match with their own internal financial success. What has long been a healthy operator-to-service-provider relationship is beginning to show signs of deterioration.
- [We're] still seeing inflationary pressures (wages and consumables) on a smaller scale. However, E&P companies are not as open to help absorb the increases.
- Labor remains the most significant challenge. Activity and revenues would be higher with additional employees. The lack of labor is also impacting vendors and turnaround times. The lack of labor issue includes both qualified mechanics/welders and general labor for oilfield services who are able to meet employment criteria.
- Regulatory uncertainty is a major overhang. Labor remains tight, with continued wage pressures. Supply-chain issues remain.
- Finding workers is getting harder and harder. The potential pool of workers is probably not so different, but it is more a case of workers being able to collect more governmental assistance, so why work?
- The likelihood of a recession has increased. Government at all levels is out of control. Regulation is killing the nation. Environmental issues are overblown to the point of the absurd.
- We are seeing the vertical natural gas drillers drop rigs and defer projects due to low natural gas prices and high costs, especially casing and tubing. Unlike the horizontal operators, these companies can stop and start very quickly.
- Recent government actions related to backstopping uninsured losses in the wake of the Silcon Valley Bank collapse sets a terrible precedent that greatly increases future policy uncertainty and, therefore, also increases future market volatility as the market will always try to correct course, but with less and less time to respond.
- Bank failures in March 2023 and concerns over the overall financial system have added to concerns over possible recession timing and severity and the possible short-term impact on WTI [West Texas Intermediate]. Gas-directed activity, especially in the Haynesville, is being negatively impacted by takeaway limitations and significant declines in Henry Hub natural gas prices since third quarter 2022. Credit was already tight for oilfield services companies; I expect availability of credit will tighten even more, making business conditions tougher for companies without the necessary operating scale.

Questions regarding the Dallas Fed Energy Survey can be addressed to Michael Plante at Michael.Plante@dal.frb.org or Kunal Patel at Kunal.Patel@dal.frb.org.

KEY MESSAGES

The energy transition is off-track. The aftermath of the COVID-19 pandemic and the ripple effects of the Ukraine crisis have further compounded the challenges facing the transition. The stakes could not be higher - every fraction of a degree in global temperature change can trigger significant and far-reaching consequences on natural systems, human societies and economies. Achieving the necessary course-correction in the energy transition will require bold, transformative measures that reflect the urgency of the present situation.

Current pledges and plans fall well short of IRENA's 1.5°C pathway and will result in an emissions gap of 16 gigatonnes (Gt) in 2050. Nationally Determined Contributions (NDCs), long-term low greenhouse gas emission development strategies (LT-LEDs) and net-zero targets, if fully implemented, could reduce carbon dioxide (CO_2) emissions by 6% by 2030 and 56% by 2050, compared to 2022 levels. However, most climate pledges are yet to be translated into detailed national strategies and plans, implemented through policies and regulations, or supported with sufficient funding. According to IRENA's Planned Energy Scenario,[1] the emissions gap is projected to reach 35 Gt by 2050, underscoring the urgent need for comprehensive action to accelerate the transition.[2]

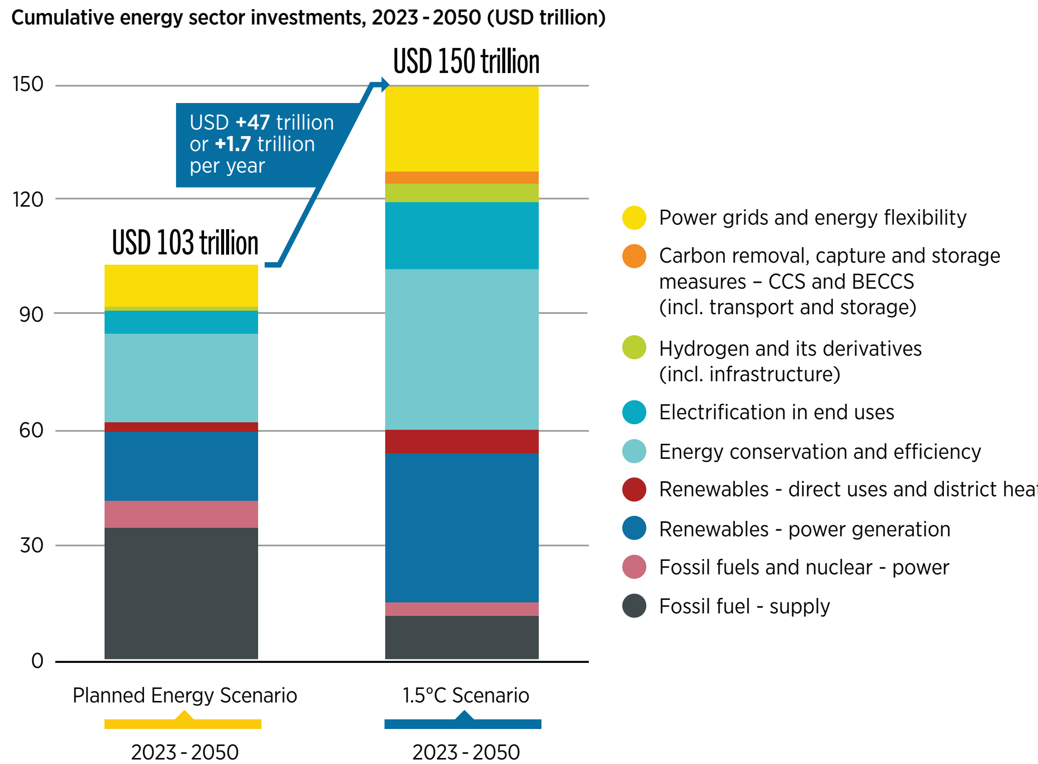
Although global investment across all energy transition technologies reached a record high of USD 1.3 trillion in 2022, annual investment must more than quadruple to remain on the 1.5°C pathway. A cumulative USD 150 trillion is required to realise the 1.5°C target by 2050 (Figure 1), averaging over USD 5 trillion in annual terms. Compared with the Planned Energy Scenario - under which a cumulative investment of USD 103 trillion is required - an additional USD 47 trillion in cumulative investment is required by 2050 to remain on the 1.5°C pathway. Around USD 1 trillion of annual investments in fossil fuel based technologies currently envisaged in the Planned Energy Scenario must therefore be redirected towards energy transition technologies and infrastructure.

Cumulative investments between now and 2030 need to total USD 44 trillion, with energy transition technologies representing 80% of the investment, or USD 35 trillion. Total cumulative energy sector investments in the Planned Energy Scenario until 2030 are USD 29 trillion. An additional cumulative investment of USD 15 trillion - or an annual average investment of USD 1.9 billion - would be needed in the 1.5°C Scenario until 2030. Furthermore, a change in the volume and type of investments is required under the 1.5°C Scenario to prioritise the energy transition and set the stage for a dramatic decrease in the fossil fuel share by 2050 (Figure 1).

[1] *For a brief overview of the two scenarios employed in the World Energy Transitions Outlook, see inside rear cover, page 23.*

[2] *The present IRENA scenarios include CO_2 emissions from fossil fuel combustion, waste incineration and industrial processes. COP announcements reflected in Nationally Determined Contributions [NDCs] as of 5 November 2022, long-term low greenhouse gas emission development strategies [LT-LEDs] and net-zero targets as of 5 October 2022 also include land-use emissions.*

FIGURE 1 **Total investment by technological avenue from 2023 to 2050 for achieving the 1.5°C Scenario**



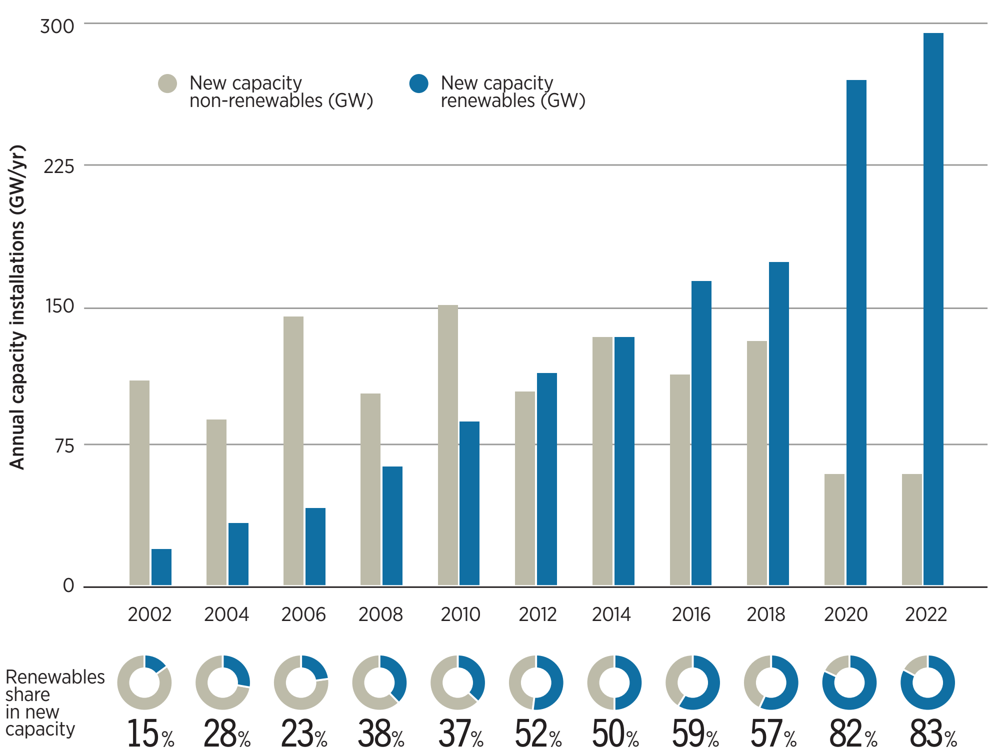
Notes: CCS = carbon capture and storage; BECCS = bioenergy, carbon capture and storage.

Annual investments across all energy transition technologies must more than quadruple to remain on the 1.5°C pathway.

Existing renewable power targets would increase total renewable power capacity to 5.4 terawatts (TW) by 2030, representing less than half of the 11.2 TW needed for a 1.5°C pathway. There is significant scope for aligning and strengthening targets in the short term to provide policy clarity and certainty. In many cases, targets in national energy plans are yet to be aligned with those in NDCs. In addition, targets should be measurable and cover end uses beyond power. Of the 183 Parties with renewable energy components in their NDCs, only 143 had a quantified target - 108 for power and 31 for heating and cooling, transport or cooking (IRENA, 2022).

Some progress is being made, notably in the power sector, with renewables representing 83% of capacity additions and reaching 40% of installed power generation globally in 2022. A total of 295 gigawatts (GW) of renewables was added worldwide in 2022, the largest-ever annual increase in renewable energy capacity (IRENA, 2023a). The strong business case for renewables, coupled with supportive enabling policies, has sustained an upward trend in their share of the global energy mix. However, overall deployment remains centred on a limited number of counties and regions, with China, the European Union and the United States accounting for 75% of capacity additions. Although large-scale deployments of renewable energy are typically associated with countries that have well-developed power systems, it is essential to expand deployment elsewhere, especially in developing nations that lack access to electricity.

FIGURE 2 **Annual power capacity expansion, 2002-2022**



More investments need to flow into developing and emerging markets to make the energy transition more inclusive.

Renewable energy investment remains concentrated in a limited number of countries and focused on only a few technologies. Investment in renewables reached USD 0.5 trillion in 2022; however, this is less than one-third of the average investment needed each year in renewables under the 1.5°C Scenario. Furthermore, in 2022, 85% of global renewable energy investment benefitted less than 50% of the world's population and Africa accounted for only 1% of additional capacity in 2022 (IRENA and CPI, 2023; IRENA, 2023a). Investments in off-grid renewable energy solutions in 2021 amounted to USD 0.5 billion (IRENA and CPI, 2023), far below the USD 15 billion needed annually to 2030. While many technology choices exist, most investments were in solar PV and wind power, with 95% channelled toward these technologies (IRENA *et al.*, 2023). Greater volumes of funding need to flow to other energy transition technologies such as biofuels, hydropower and geothermal energy, as well as to sectors beyond power that have lower shares of renewables in total final energy consumption (*e.g.* heating and transport).

Every year, the gap between what is required and what is implemented continues to grow. IRENA's energy transition indicators (see Table 1) show significant acceleration is needed across energy sectors and technologies, from deeper end-use electrification of transport and heat, to direct renewable use, energy efficiency and infrastructure additions. Delays only add to the already considerable challenge of meeting IPCC-defined emission reduction levels in 2030 and 2050 for a 1.5°C trajectory (IPCC, 2022). The lack of progress will also increase future investment needs and the costs of worsening climate change effects.

TABLE 1 **Tracking progress of key energy system components to achieve the 1.5°C scenario**

	Indicators	Recent years	2030[1)]	2050[1)]	Progress (Off / on track)
RENEWABLES	**ELECTRIFICATION WITH RENEWABLES**				
	Share of renewables in electricity generation	28%[2)]	67%	91%	
	Renewable power capacity additions[27)]	295 GW/yr[3)]	975 GW/yr	1 066 GW/yr	
	Annual solar PV additions[27)]	191 GW/yr[4)]	551 GW/yr	615 GW/yr	
	Annual wind energy additions[27)]	75 GW/yr[5)]	329 GW/yr	335 GW/yr	
	Investment needs for RE generation	486 USD billion/yr[6)]	1 300 USD billion/yr	1 382 USD billion/yr	
	Investment needs for power grids and flexibility	274 USD billion/yr[7)]	548 USD billion/yr	790 USD billion/yr	
	DIRECT RENEWABLES IN END-USES AND DISTRICT HEAT				
	Share of renewables in final energy consumption	19%[8)]	34%	83%	
	Solar thermal collector area	746 million m²/yr[9)]	1 700 million m²/yr	3 700 million m²/yr	
	Modern use of bioenergy (direct use)	1.5 EJ[10)]	44 EJ	56 EJ	
	Geothermal consumption (direct use)	0.4 EJ[11)]	1.3 EJ	2.2 EJ	
	Renewables based district heat generation	0.9 EJ[12)]	4.3 EJ	12 EJ	
	Investment needs for renewables end uses and district heat[28)]	13 USD billion/yr[13)]	269 USD billion/yr	216 USD billion/yr	

▸ continued

(contd.) TABLE 1 Tracking progress of key energy system components to achieve the 1.5°C scenario

	Indicators	Recent years	2030 [1]	2050 [1]	Progress (Off / on track)
ENERGY EFFICIENCY	Energy intensity improvement rate	0.6 %/yr [14]	3.5 %/yr	2.9 %/yr	
	Investment needs [29] for energy conservation and efficiency	295 USD billion/yr [15]	1772 USD billion/yr	1493 USD billion/yr	
ELECTRIFICATION	Share of direct electricity in final energy consumption	22 % [16]	29 %	51 %	
	Passenger electric cars on the road	10.5 million [17]	355 million	2 180 million	
	Investments needs for charging infrastructure of EV's and EV adoption support	30 USD billion/yr [18]	141 USD billion/yr	364 USD billion/yr	
	Investment needs for heat pumps	64 USD billion/yr [19]	266 USD billion/yr	258 USD billion/yr	
HYDROGEN	Clean hydrogen production	0.7 Mt/yr [20]	21.4 Mt/yr	518 Mt/yr	
	Electrolyser capacity	0.5 GW [21]	233 GW	5 722 GW	
	Investment needs [30] for clean hydrogen and derivatives infrastructure	1.1 USD billion/yr [22]	80 USD billion/yr	170 USD billion/yr	
	Clean [31] hydrogen consumption - industry	0.04 EJ [23]	2.4 EJ	40 EJ	
CCS AND BECCS	CCS/CCU to abate emissions in industry	0.01 $GtCO_2$ captured/yr [24]	1.0 $GtCO_2$ captured/yr	3.0 $GtCO_2$ captured/yr	
	BECCS and others to abate emissions in industry	0.002 $GtCO_2$ captured/yr [25]	0.7 $GtCO_2$ captured/yr	1.0 $GtCO_2$ captured/yr	
	Investment needs for carbon removal and infrastructure	6.4 USD billion/yr [26]	18 USD billion/yr	107 USD billion/yr	

▶ Notes: see next page

https://www.aol.com/news/yahoo-news-interview-john-kerry-233955553.html

The Yahoo News Interview: John Kerry

BEN ADLER
Updated March 27, 2023, 7:32 PM

John Kerry: The Yahoo News Interview

John Kerry has spent half a century in the public eye, ever since 1971, when the decorated Vietnam War veteran criticized the war in high-profile Senate testimony. After working as a prosecutor and as lieutenant governor of Massachusetts, he went on to serve as a senator from that state, eventually becoming chair of the Senate Foreign Relations Committee. In 2004, he was the Democratic nominee for president, and later served as secretary of state during then-President Barack Obama's second term.

In 2021, President Biden appointed Kerry to be the first-ever special presidential envoy for climate. In that capacity, the 79-year-old statesman travels constantly, meeting with his foreign counterparts to negotiate joint actions to reduce the greenhouse gas emissions that are causing climate change.

He recently sat down with Yahoo News in New York to talk about Biden's climate agenda, his hopes for collaboration with China and other adversaries, whether Americans need to sacrifice to prevent catastrophic climate change and the world that his grandchildren will inherit.

> **"We have to work with China, we have to work with India. We even have to find a way, ultimately, if we can resolve the war in Ukraine, to work with Russia."**
>
> – John Kerry

Yahoo News: President Biden signed the Inflation Reduction Act, which is the most ambitious climate legislation in history, but it still is only projected to get a 40% reduction in greenhouse gas emissions by the end of the decade, and the U.S. has promised a 50% reduction by the end of the decade.

John Kerry: We're doing a lot more than just the IRA. The IRA is a package that in and of itself could get the 40%. But in addition to that, the president is issuing executive orders. There'll be changes on automobile, on light truck, heavy truck, heavy duty [vehicle regulations]. There'll be a number of initiatives that are being taken by states, subnational [governments], cities. They really kept us in the game, frankly, during the Trump administration, when he pulled out of the [Paris] agreement. But 75% of the new electricity that came online during the Trump administration came from renewable resources. So we have a lot of other options, tools, if you will, in the toolkit — besides the IRA, the IRA is a huge leap forward, and it's already having a major impact.

Yahoo News:

You mentioned the Trump administration, when you meet with other countries —

John Kerry:

Reluctantly.

Yahoo News:

I'm sure it is. So you must be asked sometimes, "How can you guarantee us that you will stay on track and see all these policies through some of which are [through] presidential executive authority, like the [clean] car rules, if Trump or another Republican wins in 2024?"

John Kerry:

Well, I think what's important for everybody to note is that achieving our goal is not exclusively dependent on what the federal government says or does. It's critical, but not wholly dependent on corporations all around America, the largest corporations in the country, Apple, Microsoft, Google, Salesforce and a whole bunch of other disciplines. I mean, you've got Boeing, you've got Delta Airlines, United Airlines, a whole bunch of folks have adopted a net-zero 2050 target, and they're moving on it. They're doing their, what's called Scope 1, Scope 2 emissions reductions, the emissions that they're directly responsible for and so forth. So there are a lot of things happening, and nobody can guarantee this right now. We're behind. I mean, we're seriously behind.

And that was the meaning of the IPCC report that just came out. It's another kick in the you-know-what to get people moving. So, that's our fight is to get people to do all the things we can do. Another example: buildings. Buildings lend themselves to remarkable gains and efficiency just by retrofitting them. And efficiency is perhaps the largest gain at our disposal, efficiency in vehicles, efficiency in appliances and so forth. I find that the marketplace writ large has bought into this. They're on board. Look at what we're doing with electric vehicles at this point. General Motors and Ford have said that by 2035, the only vehicle they're going to make is electric. And I think there's a massive movement now in this transition that is bigger than any one administration or one policy. And I don't think anybody in the future could get away with trying to reverse that. It's just not going to happen.

It could be slowed down. You can have somebody not accelerate, not push the way President Biden is. I mean, President Biden's been way ahead of every other president in accelerating activity, showing leadership, setting aside land, putting out major renewable resources, whether it's solar farms or offshore wind. I mean, there's an enormous amount that is taking place. And I think if you're a good corporate executive today, you are taking note that it's irresponsible not to be moving in that direction.

"I know that the world can get there, but I am not convinced that we will."

– John Kerry

Yahoo News:

You mentioned President Biden's record, including land use management, but he's also done some things that have increased fossil fuel production — the recent approval of the Willow Project in Alaska, for example.

John Kerry:

For the moment — remember, we have seven years before the 2030 target, and the president is determined that we will stay on that target, but in the immediate moment while we transition, you don't want to crash your whole economy. You have to be able to keep things moving. That's part of the engine of transition. I mean, if people are earning income and companies are making money, we have the ability to be able to make the transition. If the economy crashes, everything will come to a dead halt. So it's critical that we keep some [fossil fuel] production levels moving in order to do this. But he's been very, very clear. This is not a long-term strategy to keep something alive that is not in line with meeting our environmental goals.

Yahoo News:

What about exporting liquified natural gas, which is not for our economy?

John Kerry:

Again, critical to the economy of Europe. Europe, these are our allies. NATO is critical. What is happening in Ukraine is an abomination. It's grotesque. It is a violation of everything we have worked to achieve since World War II, where we put in place rule of law, international law. You don't go crashing in and forcibly changing the borders of another country by force. And so we have to stand up against that as a matter of principle. And I think if we didn't do that, then how much easier would it be for President Xi to decide he's going to invade Taiwan, or someone else to do it somewhere? So this is an important fight, but it's not an exclusive fight. We also have to deal with climate at the same time. It's not, "Oh, let's deal with Ukraine for the time being, and then we come along and we'll deal with the other." No, climate is already accelerating in its destructive force, and we have to meet this second crisis, third crisis, whatever you want to call it. We have to meet it at the same time, and we have to win.

Yahoo News:

You recently switched, I read, from flying private to flying commercial.

John Kerry:

No, I didn't fly private while I was in this job. It's just a misnomer. I've had one, maybe two private flights, which were U.S. military flights in order to get to China during COVID, where we were forced into that. But I fly commercially.

"Our president has tried hard to separate climate from the other issues that are real that we obviously have with China... because this is a universally felt existential challenge to the planet."

– John Kerry

Yahoo News:

The reason I bring that up is that private aviation is an example of something where people are starting to pay more attention. People who go to Davos to talk about climate change, fly private, it seems like they don't want to make any sacrifice.

John Kerry:

I've talked to them about it. They offset, they buy offsets, they offset, and they are working harder than most people I know to be able to try to affect this transition. Aviation as a whole, all of aviation in the world, is about 3% of our emissions in the world. And if we're able to move fast enough in these other areas that we're already moving on sustainable aviation fuel. Boeing and United and others have joined in a pledge to use now 5% of the fuel they're going to use is going to be sustainable aviation fuel, even though it's far more expensive than other fuel available, they're paying the green premium in order to accelerate the transition. So I think it's important to note, do they need to be part of the transition? Yes. Do they need to make good on their word about net zero? Of course they do. But we have to be thoughtful about — you know, you're not going to suddenly wipe out every aircraft in the world and not fly.

Yahoo News:

There certainly are people — and you saw this in the U.S. with the uproar at the suggestion that we might ban sales of new gas stoves — there are some people who don't want to change their lifestyle. And we're going to have to switch at some point from gas for heating and cooking to electricity if we're going to reach net zero. Right?

John Kerry:

Unless somebody were able to provide that with zero carbon intensity. That's not doable today. So yes, gas at a certain point becomes a serious challenge. Let's say you're going take a coal plant, you want to shut it, and you're going to do gas instead for about the next seven, eight years or so. That's something that you could do because it's an immediate 30% to 50% reduction in the emissions. But after that period of time, we have to meet the net-zero 2050 [target]. So you've got to be able to reduce gas emissions also, right? That's the challenge for the industry, to capture their emissions.

Yahoo News:

Are you saying people aren't going to have to change their lifestyle at all to prevent catastrophic climate change?

John Kerry:

I think you have to frame that the right way. When you say change your lifestyle, people feel, "Oh, you're challenging me to have a lower quality of life." No, we don't have to have a lower quality of life. But do you have to change some of the choices you make in your life? Yes. I have, now, a solar field outside the house that's feeding the house. I drive an electric car now. I didn't do that five years ago and when I got in the electric car, I said to myself, "Why did I wait so long?" It's a fabulous drive. So I think that yes, we have to make different decisions, but they do not have to and shouldn't, absolutely shouldn't, reduce the quality of life of citizens.

Yahoo News:

You've traveled all over the world for this position, and you were previously secretary of state and chairman of the Senate Foreign Relations Committee. Is there anything that you've seen up close in terms of climate change or maybe someone you've met who's been affected by climate change that has really stuck with you or changed the way you look at the issue?

John Kerry:

Absolutely. I mean, I was just in Brazil and I met with the Indigenous population of the Amazon. And in many parts of the world now, we always try to meet with Indigenous people because they actually have been the greatest curators, preservers, if you will, of land mass around the world. And they have a lot to teach us about nature-based solutions. And in many parts of the world, there are people now affected in food production. Farmers are not able to farm the way they used to be. They can't grow the same crops. I've met people who are deeply affected by the kind of work they do, who — because intense heat limited the amount of time they could work outdoors — over 140 degrees in some places last year — and you had three continents that recorded the hottest day in their history, simultaneously, same day, [on] three different continents.

We are seeing changes that are just beyond unprecedented. They're frightening. The Arctic, the Antarctic, the melting of ice, the rate of the melting. Scientists are now surprised by the intensity and levels that they're seeing — not that they didn't predict them, but they didn't predict them for so soon. And everything is sort of happening faster. So we have a fundamental responsibility, certainly as public people, but every citizen has a responsibility to try to make sure that we're doing a better job for future generations. And right now, I have to tell you that despite all the efforts, we're not at the pace we need to be to meet the goals we've set. So we have to pick up the scale, pick up the efforts of transition. And, frankly, nobody should fear this. This is not, as I said, it's not a challenge to our quality of life.

There are great jobs in this transition. I mean, last year, the year before, the fastest-growing job in America was wind turbine technician. And the third-fastest-growing job was solar panel installer. There are jobs in this transition. We have to build a grid in America — or several grids. We do not have the ability to send electrons from one part of the country to another where we might need to. Yet they can do that in Mexico, they can do that in Europe, we're behind. And what the president is trying to do is accelerate America's transition because the evidence is absolutely clear. It can result in a safer and a healthier and a cleaner life for all of us.

Yahoo News:

You mentioned the world not being on pace to meet the 2030 targets that have been laid out to avert catastrophic climate change, in terms of how much we need to reduce emissions. The single biggest emitter right now is China, and every expert that I've talked to says China is going to have to make bigger cuts than they've currently planned for the world to hit that cut.

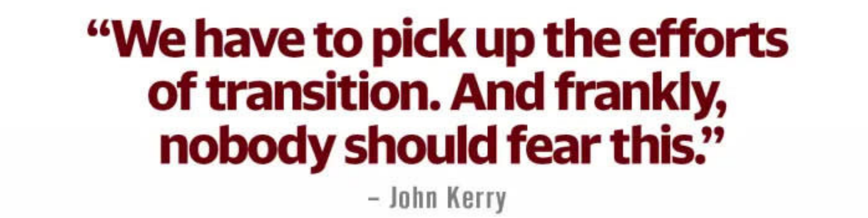
John Kerry:

If we're going to meet our goal, which is why President Biden empowered me to reach out to China and work with China, which we have done for two years, and with some effect, not as much as we need ultimately. And I talked to my counterpart in China, who unfortunately has been sick in the last weeks, or month or so. So that's been somewhat delayed. But we have to work with China, we have to work with India. We even have to find a way, ultimately, if we can resolve the war in Ukraine to work with Russia, because Russia is a huge emitter. And any one of these countries has an ability, if it doesn't move to, to change its energy base, to make it much harder for the rest of the world, if not impossible, to reach the goals we've set.

I don't want to leave them feeling that we're just saying they have to do more. India, for instance, has a major goal. They're really working at this. They understand that they've got to try to find a way to reduce coal, but they're also fighting this question of keeping their folks employed and being able to keep their economy moving. China has 1.4 billion people. Its economy is not a bigger economy than ours, but it's growing. Ultimately it's growing and it's the second-largest economy in the world. They have the same feeling that, you know, they can't suddenly "unemploy" their entire population and survive. So they're trying to mix it. Now, China is the largest maker of renewable energy in the world. They are the biggest supplier of solar panels, biggest deployer of solar panels. In China, they have deployed far more renewable energy than we have or than Europe has. So yes, they're behind and it's a problem. Coal is a problem, but that's why it's important. We work with China. We reach out to China, and that's what we're trying to do. And the president has tried very hard. Our president has tried hard to separate climate from the other issues that are real that we obviously have with China, but we can't get bogged down by that because this is a universally felt existential challenge to the planet. And it's important that the two largest economies in the world work to try to resolve it.

Yahoo News:

You mentioned the recent IPCC report came out Monday and, obviously, it's very sobering, like those reports always are. And the big news out of it was that, in addition to the 43% cut in greenhouse gas emissions by 2030, that they've already said we need to make, in addition, they say now a 60% reduction by 2035. So that's a steep drop in the early 2030s. And obviously what happens in the early 2030s is really being determined by the policy that we make right now. How do you see the world getting there? Do you think that these next few climate conferences, the COPs, will bring forth pledges that big and plans to actually meet those pledges?



John Kerry:

I know that the world can get there, but I am not convinced that we will. And the biggest reason is there's a business-as-usual attitude in too many places in the world. There are still some CEOs of major corporations who have not moved their companies or haven't bought into scientific facts. There are sort of different cultures and different universes of facts that are passing each other day and night. And that's a challenge.

It's a serious challenge, but I think a lot is happening. Let me give you an example. For the first time, there's more than a trillion dollars, probably about $1.4 trillion — we need about four-and-a-half trillion every year to be invested in this transition, but we're up to about a million and a half, much of it venture capital, exploring green hydrogen battery storage, direct air, carbon capture, carbon capture and storage, utilization of carbon in different forms.

Someone's going to break through. Now, you can't sit there and bank on that and say, "we don't have to do anything because someone's going to break through." That would be really kind of stupid. But we have to include in our equation the possibilities of human ingenuity coming through, with different results. And I'm seeing that. I mean, right now, I'm seeing batteries that get much longer storage. Those can be game changesrs. We're making advances in electrolyzers, which separate water and hydrogen, and the commercial scale of hydrogen is moving. We're not there yet. We need to do more, but there really is a lot happening in the field of innovation, and research and development.

Yahoo News:

You have children, do you have grandchildren?

John Kerry:

I do.

Yahoo News:

What do you think the world will be like in terms of climate change and the planet that they'll have to live on, let's say when they're your age?

John Kerry:

It depends entirely on the decision that their parents and grandparents make today. We have it in our hands to guarantee them a healthy and strong future. We also — by virtue of indifference, arrogance, inattention — we have it in our capacity also to really foul the planet beyond recognition. And that's what motivates me and a lot of people I know to be working hard at this.

Yahoo News:

I want to ask you about the next COP, in the UAE. Some environmentalists are critical of the fact that the CEO of Abu Dhabi's national oil company is going to be the president of that climate conference. But you actually praised his selection. I'm curious to know how you respond to those critics.

John Kerry:

Well, I understand the skepticism, and I can understand why people would raise the question, but you know the old saying, Don't judge a book by its cover. The fact is that Dr. Sultan Al Jaber, who is the designated president, has been a leader within the United Arab Emirates for the last 20 years in helping them to build one of the largest solar systems in the world. They've built a city that is energy-efficient and clean. He's been the CEO of that operation. The UAE has invested billions of dollars into renewable energy around the world. They've helped countries be able to install solar and other forms of renewable energy, even as they do produce gas and oil. But they're looking at their future as not being an oil company, but being an energy company and providing clean energy as it is needed.

So I think that knowing what they've been doing — you know, when I came into this job, the UAE hosted the first-ever regional climate conference in the UAE. And 11 Middle Eastern countries — five of them gas producers, oil producers — came and signed on to major revisions in their policies and in their movements. So look, the proof will be in the pudding, as we also say. But I really believe that the UAE wants their COP to be successful, and it can only be measured as successful if it brings the industry to the table, if it helps us to be able to accelerate this transition and meet the goals. And I anticipate progress.

I think also there were three mandated outcomes already from this next COP that came out of the last one. One is that there's going to be an adaptation report that will advise everybody about the pace and needs for adaptation. Two, there's a taking stock of all of the world and where we are, and that will create greater focus and intensity. And three, there's a loss and damage provision that now has to be filled out more, which will have an impact on the less-developed world, on the global south, in a positive way. And I think that beyond that, mitigation is going to be on the table and finance is goint to be on the table. So I look forward to an extremely broad-based engagement at this COP.

Yahoo News:

I have to ask a couple quick politics questions before we wrap up. The first is just that Donald Trump called for you to be prosecuted a few years ago [and] now he's facing a whole bunch of prosecutions. What do you make of this situation where the former president is potentially going to be under indictment while running for reelection?

John Kerry:

I'm not trying to duck you, but I'm telling you that I'm trying to keep what I'm doing free and clear from the daily hurly-burly of our politics. We need everybody on board, and I just don't want to get into the political stuff.

Yahoo News:

Fair enough. Let me ask you something that you might be more comfortable with. You were a major party nominee for president. Do you have any advice to a young person who wants to go into politics, maybe even run for president themselves one day?

John Kerry:

Go for it. Get involved. We need you desperately. I mean, young people have historically in our country, in the United States — but in many other parts of the world also — been the agents of change. I don't herald the 1960s as the be-all and end-all of anything, but I'll tell you what: It was kids at college who went down South and helped to break the back of Jim Crow. It was the civil rights movement that engaged young people all around our country. The voting rights movement, the women's rights movement, the environment movement, the peace movement — people really took a stake and they planted their flag and they took risks, major risks in some cases. So I think that we need young people again to make sure they're talking to their parents, to their grandparents, and going out and acting on their beliefs. In the last election, young people made an enormous difference and they made climate the No. 2 voting issue in that election. So I just say, there are all kinds of ways to be involved in public life, but choose one.

Cover thumbnail photo illustration: Yahoo News; photo: Ethan Hill for Yahoo News.

https://marketing.rlpnetwork.com/Communications/Royal_LePage_2023_Spring_Recreational_Property_Price_Forecast_and_2022_Price_Data_Chart.pdf

2023 Recreational Single-Family Home Price Forecast

	2022 (Actual)	2023 (Forecast $)	2023/2022 (Forecast %)
National	$619,900	$592,005	-4.5%
Atlantic Canada	$279,900	$271,503	-3.0%
Quebec	$373,400	$343,528	-8.0%
Ontario	$634,800	$603,060	-5.0%
Prairies	$271,300	$263,161	-3.0%
Alberta	$1,165,500	$1,171,328	0.5%
British Columbia	$1,071,300	$1,049,874	-2.0%

Recreational Property Prices*

	Single-Family			Single-Family Waterfront			Standard Condominium		
	2021 ($)	2022 ($)	% Change (2022/2021)	2021 ($)	2022 ($)	% Change (2022/2021)	2021 ($)	2022 ($)	% Change (2022/2021)
National	$555,000	$619,900	11.7%	$672,700	$736,900	9.5%	$370,600	$432,000	16.6%
Atlantic Canada	$238,800	$279,900	17.2%	$356,000	$388,500	9.1%	$291,000	$345,000	18.6%
Annapolis Valley, NS	$271,300	$320,000	18.0%	$355,000	$395,000	11.3%	$223,500	$247,500	10.7%
Cape Breton, NS	$175,000	$200,000	14.3%	$350,000	$427,500	22.1%	$265,500	$359,000	35.2%
South Shore, NS	$258,000	$311,000	20.5%	$367,500	$450,000	22.4%	$340,000	$367,500	8.1%
Avalon Peninsula, NL	$295,000	$302,000	2.4%	$275,000	$299,000	8.7%	$210,000	$229,000	9.0%
Central Newfoundland, NL	$186,000	$200,000	7.5%	$229,000	$200,000	-12.7%	$105,000	$160,000	52.4%
Shediac, NB	$272,000	$337,300	24.0%	$569,300	$464,500	-18.4%	$236,700	$341,300	44.2%
St. Stephen & St. Andrews, NB	$157,000	$184,200	17.3%	$487,800	$336,200	-31.1%	-	-	-
Quebec	$321,500	$373,400	16.1%	$409,500	$480,200	17.3%	$279,500	$341,900	22.3%
Antoine-Labelle (RCM)	$227,000	$275,000	21.1%	$308,000	$360,000	16.9%	-	-	-
Argenteuil (RCM)	$276,000	$323,800	17.3%	$400,000	$440,000	10.0%	-	-	-
Baie-Saint-Paul	$289,000	$301,000	4.2%	-	-	-	-	-	-
Bromont	$625,000	$662,000	5.9%	-	-	-	$383,000	$512,000	33.7%
Gaspé	$205,000	$249,500	21.7%	-	-	-	-	-	-
La Côte-de-Beaupré (RCM)	$273,300	$320,000	17.1%	-	-	-	$155,000	$161,800	4.4%
La Jacques-Cartier (RCM)	$359,000	$385,000	7.2%	$455,000	$472,000	3.7%	$217,400	$240,000	10.4%
Les Appalaches (RCM)	$150,000	$169,000	12.7%	-	-	-	-	-	-
Les Laurentides (RCM)	$355,000	$400,000	12.7%	$423,000	$530,000	25.3%	$317,000	$425,000	34.1%
Les Pays-d'en-haut (RCM)	$425,000	$492,000	15.8%	$575,000	$600,000	4.3%	$278,000	$345,000	24.1%
Matawinie (RCM)	$260,000	$325,000	25.0%	$350,000	$423,000	20.9%	$225,000	$275,000	22.2%
Memphrémagog (RCM)	$428,500	$516,000	20.4%	$690,000	$860,000	24.6%	$237,000	$300,000	26.6%
Montcalm (RCM)	$300,000	$375,500	25.2%	$285,500	$378,500	32.6%	-	-	-
Papineau (RCM)	$255,000	$306,300	20.1%	$365,000	$400,500	9.7%	-	-	-
Ontario	$591,400	$634,800	7.3%	$924,700	$1,006,600	8.9%	$443,800	$510,900	15.1%
Bruce Peninsula	$605,000	$685,000	13.2%	$895,000	$870,000	-2.8%	-	-	-
Haliburton County	$462,000	$492,500	6.6%	$801,000	$875,000	9.2%	$498,500	$555,800	11.5%
Honey Harbour	$650,000	$810,000	24.6%	$800,000	$1,050,000	31.3%	-	-	-
Kawartha Lakes	$764,400	$747,900	-2.2%	$894,500	$980,700	9.6%	$432,300	$544,100	25.9%
Lake Erie Shoreline	$654,500	$750,000	14.6%	$1,090,000	$1,035,800	-5.0%	-	-	-
Land O'Lakes	$340,000	$345,000	1.5%	$735,000	$652,500	-11.2%	-	-	-
Mid Lake Huron/Huron & Perth County	$545,400	$602,000	10.4%	$835,000	$1,002,600	20.1%	$405,000	$512,500	26.5%
Muskoka	$699,500	$692,500	-1.0%	$1,260,000	$1,062,500	-15.7%	$435,000	$452,000	3.9%
The North Channel (Echo Bay, Desbarats, Bruce Mines, Thessalon, Iron Bridge, North Shore, Huron Shore, Blind River, Algoma Mills, Elliot Lake, Splanish)	$260,800	$300,000	15.0%	$397,500	$400,000	0.6%	-	-	-
Orillia & surrounding townships	$637,000	$640,000	0.5%	$1,125,000	$1,377,000	22.4%	$502,000	$650,000	29.5%
Ottawa Valley	$408,000	$467,000	14.5%	$604,300	$679,800	12.5%	-	-	-
Peterborough County (Peterborough & the Kawarthas)	$645,000	$719,900	11.6%	$907,000	$1,005,000	10.8%	$490,500	$529,000	7.8%
Rideau Lakes	$609,000	$585,000	-3.9%	$614,000	$757,100	23.3%	$240,000	$295,000	22.9%
Southern Georgian Bay (Meaford, Thornbury, Wasaga Beach and Collingwood)	$675,000	$735,000	8.9%	$1,400,000	$1,500,000	7.1%	$465,000	$503,000	8.2%
St. Joseph Island	$293,500	$400,500	36.5%	$362,000	$567,500	56.8%	-	-	-
Tweed	$450,000	$490,000	8.9%	$540,000	$652,500	20.8%	-	-	-
Prairies	$255,900	$271,300	6.0%	$479,900	$507,000	5.6%	-	-	-
Interlake, MB	$217,500	$219,000	0.7%	$452,000	$450,000	-0.4%	$158,900	$170,000	7.0%
Lac du Bonnet, MB	$293,000	$350,000	19.5%	$500,000	$550,000	10.0%	-	-	-
North Central Saskatchewan, SK (Christopher Lake, Emma Lake, Candle Lake, Waskesiu Lake & Elk Ridge)	$365,000	$375,000	2.7%	$569,000	$688,000	20.9%	-	-	-
Alberta	$1,028,900	$1,165,500	13.3%	$675,600	$641,900	-5.0%	$548,700	$646,000	17.7%
Canmore	$1,316,500	$1,527,800	16.1%	-	-	-	$618,500	$747,000	20.8%
Lac St. Anne	$429,700	$360,700	-16.1%	$600,000	$534,700	-10.9%	-	-	-
Pigeon Lake	$390,000	$386,300	-0.9%	$679,500	$674,500	-0.7%	$265,000	$235,000	-11.3%
Wabamun Lake	$424,000	$439,800	3.7%	$888,800	$820,200	-7.7%	-	-	-
British Columbia	$949,000	$1,071,300	12.9%	$1,008,300	$1,065,000	5.6%	$386,100	$441,400	14.3%
Central Okanagan	$886,000	$1,030,000	16.3%	-	-	-	$415,000	$482,300	16.2%
Comox Valley, Denman Island, Hornby Island & Mt. Washington	$791,000	$875,000	10.6%	$1,293,000	$1,350,000	4.4%	$375,000	$395,000	5.3%
Invermere	$584,000	$652,000	11.6%	$1,600,000	$2,025,000	26.6%	$323,000	$397,000	22.9%
East Kootenays (Cranbrook, Kimberley, Fernie, Sparwood, Creston, Elkford)	$440,000	$510,000	15.9%	$773,300	$774,500	0.2%	$227,000	$250,000	10.1%
Pemberton	$1,225,000	$1,330,000	8.6%	-	-	-	$536,000	$640,000	19.4%
Whistler	$3,451,500	$3,598,600	4.3%	-	-	-	$592,500	$661,600	11.7%

* Median price data was compiled and analyzed by Royal LePage for the period between January 1, 2022 to December 31, 2022 and January 1, 2021 to December 31, 2021. Data was sourced through local brokerages and boards in each of the surveyed regions. Royal LePage's aggregate home price is based on a weighted model using median prices. Data availability is based on a transactional threshold and whether regional data is available using the report's standard housing types. Aggregate prices may change from previous reports due to a change in the number of participating regions. All prices have been rounded to the nearest hundred.

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https://www.royallepage.ca/en/realestate/news/canadas-recreational-real-estate-rush-comes-to-a-close-prices-expected-to-soften-amid-waning-activity/ \

Canada’s recreational real estate rush comes to a close: Prices expected to soften amid waning activity

National aggregate house price forecast to dip 4.5% in national recreational market in 2023 as sidelined buyers wait for more inventory, economic stability

Highlights:

- The aggregate price of a single-family home in Canada’s recreational property market increased 11.7% year-over-year to $619,900 in 2022
- Nationally, the aggregate price of a single-family waterfront and condominium property increased 9.5% and 16.6% year-over-year, respectively, in 2022
- Condominiums in Quebec’s recreational property market recorded the highest provincial year-over-year aggregate price appreciation in 2022, rising 22.3%
- Alberta is the only provincial recreational market expected to see price appreciation in 2023 (+0.5%)
- Quebec and Ontario expected to see the largest recreational property price decreases in 2023, with forecasted declines of 8% and 5%, respectively, compared to 2022
- More than half (57%) of recreational property experts across the country reported lower inventory than last year in their respective regions, and 65% reported reduced inventory compared to typical pre-pandemic levels

TORONTO, ON, March 28, 2023 – According to Royal LePage, the aggregate price of a single-family home in Canada’s recreational regions is forecast to decrease 4.5 per cent in 2023 to $592,005, compared to 2022, as activity in the market wanes. This is due to reduced demand as a result of economic uncertainty and a lack of available housing stock, which has helped to keep prices stable. Despite a modest decrease expected this year, the national aggregate price would remain more than 32 per cent above 2020 levels, after two years of double-digit price gains in the country's recreational real estate market.

With the exception of Alberta, which is expected to see a 0.5 per cent increase, all of Canada's provincial recreational markets are forecast to see a decrease in single-family home prices in 2023. The province of Quebec is forecasting the greatest price depreciation, at -8.0 per cent.

In 2022, the aggregate price of a single-family home in Canada's recreational property regions increased 11.7 per cent year-over-year to $619,900. This follows year-over-year price gains of 26.6 per cent in 2021. When broken out by housing type, the aggregate price of a single-family waterfront property increased 9.5 per cent year-over-year to $736,900 in 2022, and the aggregate price of a condominium rose 16.6 per cent to $432,000 during the same period.

"After two years of relentless year-round competition, Canada's recreational property markets have slowed and returned to traditional seasonal sales patterns," said Phil Soper, president and CEO, Royal LePage. "While interest rate hikes have less of an impact on the recreational market than homes in urban settings, because families typically put more money down and borrow less, general consumer inflation combined with a severe lack of inventory has dampened sales activity. Buyers who are active in today's market appear willing to wait for the right property – a sharp contrast to what we experienced during the pandemic."

While low inventory poses a challenge for buyers looking for that special cabin or lakeside cottage, the coinciding contraction in demand has resulted in a return to more normal market conditions.

Return to balance: Supply and demand decline in recreational regions

According to a survey of more than 200 Royal LePage recreational real estate professionals across the country,[1] 57 per cent of respondents reported less inventory this year, compared to last year. At the same time, 51 per cent of respondents said they have witnessed less demand for recreational properties in their region, compared to this time last year. When compared to typical pre-pandemic levels, 65 per cent of recreational property experts nationally reported less inventory, while a majority reported similar (38%) or more (38%) demand.

"Recreational homebuyers tend to purchase for leisure and life-enriching purposes. Call it a want versus a need," added Soper. "Unlike many city buyers who may need to acquire a principal residence quickly, secondary home purchasers often have the benefit of time to find the right property for their specific needs."

Nationally, 28 per cent of recreational property experts surveyed said that the trend of homeowners moving back to urban or suburban communities after relocating to their region full-time during the pandemic is somewhat common; 56 per cent of experts reported this trend was not common in their market. Atlantic Canada, a pandemic relocation hotspot, recorded the highest percentage of experts who said the return to urban or suburban areas is somewhat common in their region, at 46 per cent.

"During the pandemic, with offices closed and people working from home, Canadians discovered that a recreational property could double as a principal residence, complete with capital gains exempt status," added Soper. "With high-speed internet now readily available in many rural markets, families flocked to recreational regions to put extra space between themselves and their neighbours and to take advantage of nature; particularly when cultural and sporting venues, shops and restaurants in cities were closed. Many urban businesses now require employees to be in the office at least a few days a week, making long commutes challenging. For many, living in cottage country full-time has lost its romantic shine, meaning we are back to viewing the cottage, cabin and chalet as a weekend and summer escape from urban living."

Royal LePage 2023 Spring Recreational Property Price Forecast and 2022 Price Data Chart (national and regional):rlp.ca/table_2023springrecreationalpropertyreport

Atlantic Canada

In 2022, the aggregate price of a single-family home in the East Coast's recreational property market increased 17.2 per cent year-over-year to $279,900, compared to 2021. During the same period, the aggregate price of a single-family waterfront property increased 9.1 per cent to $388,500, while the aggregate price of a condominium increased 18.6 per cent to $345,000.

According to a Royal LePage survey of recreational property experts, 62 per cent of respondents in Atlantic Canada reported less inventory this year compared to last year, and 69 per cent reported less inventory compared to typical pre-pandemic levels. Demand for recreational properties in the region has also decreased significantly. Forty-six per cent reported less demand this year than last year.

“Parties on both sides of the transaction are waiting for a better deal – recreational buyers are sitting on the sidelines waiting for more inventory to become available, while sellers are holding out for higher offers and competitive bids. But, the multiple-offer scenarios and homes selling over-asking are not as common today as they were during the pandemic boom,” said Corey Huskilson, sales representative, Royal LePage Atlantic in South Shore, Nova Scotia. “As we enter the spring market, I expect activity to pick up but prices to stay stable, as supply and demand remain relatively balanced.”

During the pandemic, Canadians from all across the country who were forced to work remotely flocked to Atlantic Canada for the opportunity to enjoy the Maritime lifestyle and own a home at a much more affordable price point than in major cities. According to the survey, 46 per cent of recreational property experts in Atlantic Canada said that the trend of homeowners moving back to urban or suburban communities after relocating to their region full-time during the pandemic was somewhat common; an additional 8 per cent said it was very common. Meanwhile, an equal number of respondents (46%) said that this trend was not common in their area.

“The majority of recreational property buyers in Avalon Peninsula are either looking for a retirement property, or are locals moving back from other parts of the country who want a secondary property to enjoy in their downtime,” said Tim Crosbie, broker and owner, Royal LePage Property Consultants in St. John’s, Newfoundland. “Home prices have risen here over the past year, as have interest rates, which has given some buyers reason to halt their purchase plans. While most secondary homebuyers looking in the region are motivated to find a property that fits their specific needs, they are prepared to wait for the right home to fall within their financial reach.”

Crosbie noted that the reduced buyer demand is a result of higher interest rates, and that a reduction in borrowing costs would likely encourage more purchasers back into the buying pool.

The aggregate price of a single-family home in Atlantic Canada’s recreational regions is forecast to decrease a modest 3.0 per cent in 2023 to $271,503.

Royal LePage 2023 Spring Recreational Property Price Forecast and 2022 Price Data Chart (national and regional):rlp.ca/table_2023springrecreationalpropertyreport

Quebec

In 2022, the aggregate price of a single-family home in Quebec's recreational property market increased 16.1 per cent year-over-year to $373,400, compared to 2021. During the same period, the aggregate price of a single-family waterfront property increased 17.3 per cent to $480,200, and the aggregate price of a condominium increased 22.3 per cent to $341,900.

According to a Royal LePage survey of recreational property experts, 53 per cent of respondents in the province of Quebec reported less inventory this year compared to last year, and 79 per cent reported less inventory compared to typical pre-pandemic levels. Demand for recreational properties in the region has also decreased significantly. Seventy-six per cent reported less demand this year compared to last year, and 35 per cent reported less demand than a typical pre-pandemic year.

"We are in a two-speed market with sharply contrasting scenarios," said Éric Léger, chartered real estate broker, Royal LePage Humania. "On one hand, the inventory of properties for sale is steadily increasing and so is the number of motivated sellers willing to lower their asking price. But on the other hand, we're seeing multiple-offer scenarios with properties that are ideally located, well-maintained and listed at a fair price," he continued. "It can be challenging for consumers to stay on top of the market trends because we're still in a transition. Over the next few months, owners of secondary homes in the region may need to rethink their priorities as their mortgages come up for renewal at substantially higher interest rates."

Léger noted that the spring market in the area may be less buoyant this year because of current economic uncertainty. However, demand in the lower price ranges will remain strong.

According to the survey, 26 per cent of recreational property experts in Quebec said that they have witnessed a slight increase in buyers who intend to use their recreational property for rental purposes in their region compared to last year, while 18 per cent of respondents reported a significant increase in this trend.

"The real estate market in the Eastern Townships today is vastly different from what we saw during the past three years," said Véronique Boucher, residential real estate broker, Royal LePage Au Sommet. "Buyers are more patient; they're negotiating and they're taking time to carefully assess their needs and their financial capacity before taking the plunge. Conditional offers to purchase, which were practically unheard of during the pandemic real estate boom, made a big comeback in the latter half of 2022, a sign of a much more balanced and fair market.

The aggregate price of a single-family home in Quebec's recreational regions is forecast to decrease 8.0 per cent in 2023 to $343,528.

Royal LePage 2023 Spring Recreational Property Price Forecast and 2022 Price Data Chart (national and regional):rlp.ca/table_2023springrecreationalpropertyreport

Ontario

In 2022, the aggregate price of a single-family home in Ontario's recreational property market increased 7.3 per cent year-over-year to $634,800, compared to 2021. During the same period, the aggregate price of a single-family waterfront property increased 8.9 per cent to $1,006,600, while the aggregate price of a condominium increased 15.1 per cent to $510,900.

According to a Royal LePage survey of recreational property experts, 61 per cent of respondents in Ontario reported less inventory this year compared to last year, and 59 per cent reported less inventory compared to typical pre-pandemic levels. Demand for recreational properties in the region has also decreased significantly. Fifty-two per cent reported less demand this year compared to last year, however 39 per cent said demand was higher than a typical pre-pandemic year.

"After two years of historically high pandemic-driven sales, activity in the recreational market came to a comparative standstill in the last half of 2022. Rising interest rates, buyer fatigue, and lack of inventory all played a role," said John O'Rourke, broker, Royal LePage Lakes of Muskoka. "Early signs this spring point to a more balanced market where inventory levels and sales are trending in line with historical norms. Traditional cottage buyers – end users that plan on enjoying their property – are still engaged and seem eager to jump back into a market in which they are not competing with the investment-focused buyer; a prominent player during the pandemic boom."

According to the survey, 35 per cent of recreational property experts in Ontario said that the trend of homeowners moving back to urban or suburban communities after relocating to their region full-time during the pandemic was somewhat common. Forty-nine per cent of respondents said this trend was not common in their area.

"Buying a recreational property is like a marathon, not a sprint. Secondary homebuyers in Rideau Lakes have the luxury of time and are looking for a very specific lifestyle property. A shortage of recreational homes makes this process even more difficult," said Pauline Aunger, broker of record, Royal LePage Advantage Real Estate. "Due to the high demand for renovation services, recreational buyers today are looking for a move-in ready property that requires less work. This includes high-speed internet and good cell service for those who want peace of mind or the option to work remotely. As we head into the spring months, we are expecting market activity to pick up, although not at the levels experienced over the last two years."

While home prices in a select few recreational markets in Ontario, including the ever-popular Southern Georgian Bay area, may increase marginally over the next year, a decline in activity overall is expected to dampen price growth.

The aggregate price of a single-family home in Ontario's recreational regions is forecast to decrease 5.0 per cent in 2023 to $603,060.

Royal LePage 2023 Spring Recreational Property Price Forecast and 2022 Price Data Chart (national and regional):rlp.ca/table_2023springrecreationalpropertyreport

Prairies

In 2022, the aggregate price of a single-family home in the Prairie provinces' recreational property market increased 6.0 per cent year-over-year to $271,300, compared to 2021. During the same period, the aggregate price of a single-family waterfront property increased 5.6 per cent to $507,000.

According to a Royal LePage survey of recreational property experts, 56 per cent of respondents in the Prairies reported less inventory this year compared to last year, and more than three quarters (78%) of respondents said that demand levels are comparable to last year.

"Business is faring as usual in our recreational markets. Demand and inventory are proportional to one another, creating balanced market conditions. Reduced supply has kept recreational property prices buoyant," said Lou Doderai, broker and owner, Royal LePage Icon Realty, in Prince Albert, Saskatchewan. "The North Central recreation areas are only a couple hours drive from two of the province's major urban areas, meaning many of our buyers are locals looking for secondary residences that provide an escape for the weekend. Although higher interest rates have halted some purchasers' decisions to buy a property – at least temporarily – I expect we'll see a modest pick up in market activity once the warmer weather arrives."

According to the survey, 44 per cent of recreational property experts in the Prairies said that they have witnessed a significant increase in buyers who intend to use their recreational properties for rental purposes in their region, compared to last year. An additional 33 per cent of respondents reported a slight increase in this trend.

“The recreational market in Lac du Bonnet is the healthiest it’s been in 15 years. The pandemic caused more Manitoba buyers to purchase recreational properties in-province as opposed to south of the border; a level of demand that has caused the average days on market to shrink considerably,” said Rolf Hitzer, broker and owner, Royal LePage Top Producers Real Estate, in Winnipeg, Manitoba. “More than ever, buyers crave a getaway to the countryside, a desire that was intensified by the pandemic and increased demand for all-season properties. As market conditions continue to normalize, I expect to see an active, but not overheated, spring and summer recreational buying season.”

The aggregate price of a single-family home in the Prairies’ recreational regions is forecast to decrease a modest 3.0 per cent in 2023 to $263,161, as sidelined buyers remain cautious amid evolving economic conditions.

Royal LePage 2023 Spring Recreational Property Price Forecast and 2022 Price Data Chart (national and regional):rlp.ca/table_2023springrecreationalpropertyreport

Alberta

In 2022, the aggregate price of a single-family home in Alberta’s recreational property market increased 13.3 per cent year-over-year to $1,165,500, compared to 2021. During the same period, the aggregate price of a single-family waterfront property decreased 5.0 per cent to $641,900, while the aggregate price of a condominium increased 17.7 per cent to $646,000. As a large and popular recreational destination, Canmore’s real estate market has a significant impact on prices in Alberta, with its proximity to Banff National Park and luxury properties.

According to a Royal LePage survey of recreational property experts, 59 per cent of respondents in Alberta reported less inventory this year compared to last year, and 71 per cent reported less inventory compared to typical pre-pandemic levels. Meanwhile, demand for recreational properties in the region has remained stable. Thirty-five per cent of respondents reported similar demand this year compared to last year, and an additional 35 per cent reported more demand.

“Buyer demand for recreational properties in Canmore continues to be driven by retirees and Albertans living in the surrounding cities, as well as residents from Ontario and Quebec. As Canmore attracts many cash buyers, higher interest rates have had little impact on this market, a factor that has kept prices stable,” said Brad Hawker, associate broker, Royal LePage Solutions. “Low supply continues to be a challenge, an issue that has been underscored by the lack of new construction projects. This has caused many buyer hopefuls to sit on the sidelines, waiting for their ideal property to become available.”

According to the survey, 65 per cent of recreational property experts in Alberta said that the trend of homeowners moving back to urban or suburban communities after relocating to their region full-time during the pandemic was not common, another factor contributing to the supply shortage.

“We are experiencing a lack of turnover in the Wabamun Lake and Lac Ste. Anne markets. Coveted recreational homes, especially those on the water, are more likely to be passed down through the generations, a trend that is exacerbating the region’s low level of supply,” said Tom Shearer, broker, Royal LePage Noralta Real Estate. “Those shopping for a recreational home are often locals from nearby cities who already have a personal connection to the area and are looking for a retreat to enjoy with family on the weekends and in the summer months. Unlike a primary residence, most buyers shopping for a vacation home can afford to wait for the perfect property to present itself.”

The aggregate price of a single-family home in Alberta’s recreational regions is forecast to increase modestly by 0.5 per cent in 2023 to $1,171,328. This is the only region in Canada forecasting price growth over the next year.

Royal LePage 2023 Spring Recreational Property Price Forecast and 2022 Price Data Chart (national and regional):rlp.ca/table_2023springrecreationalpropertyreport

British Columbia

In 2022, the aggregate price of a single-family home in British Columbia’s recreational property market increased 12.9 per cent year-over-year to $1,071,300, compared to 2021. During the same period, the aggregate price of a single-family waterfront property increased 5.6 per cent to $1,065,000, while the aggregate price of a condominium increased 14.3 per cent to $441,400.

According to a Royal LePage survey of recreational property experts, 49 per cent of respondents in British Columbia reported less inventory this year compared to last year, and 71 per cent reported less inventory compared to typical pre-pandemic levels. Demand for recreational properties in the region has also decreased significantly. Forty-nine per cent reported less demand this year compared to last year.

“Like many recreational markets across the country, Pemberton and Whistler continue to experience low inventory. Come springtime, I anticipate that supply levels will rise as more sellers move into the market, but I don’t expect there to be a huge wave of relief,” said Frank Ingham, associate broker, Royal LePage Sussex. “Many buyers continue to wait on the sidelines for prices to fall or for borrowing costs to become more affordable, especially those purchasers who are buying for their retirement or for their adult children to enjoy. This trend is creating more pent-up demand on the sidelines, and is causing properties to stay on the market twice as long as last year. However, as the spring market gains momentum, I expect more homes that have been sitting on the shelves will start to move into the hands of buyers.”

According to the survey, 54 per cent of recreational property experts in British Columbia said that the trend of homeowners moving back to urban or suburban communities after relocating to their region full-time during the pandemic was not common, a factor contributing to the supply shortage.

The aggregate price of a single-family home in British Columbia’s recreational regions is forecast to decrease a modest 2.0 per cent in 2023 to $1,049,874, as moderate activity is expected while buyers wait for more product to come onto the market.

Royal LePage 2023 Spring Recreational Property Price Forecast and 2022 Price Data Chart (national and regional):rlp.ca/table_2023springrecreationalpropertyreport

About the Royal LePage Recreational Property Report

The Royal LePage Recreational Property Report compiles insights, data and forecasts from 50 markets. Median price data was compiled and analyzed by Royal LePage for the period between January 1, 2022 and December 31, 2022, and January 1, 2021 and December 31, 2021. Data was sourced through local brokerages and boards in each of the surveyed regions. Royal LePage’s aggregate home price is based on a weighted model using median prices. Data availability is based on a transactional threshold and whether regional data is available using the report’s standard housing types. Aggregate prices may change from previous reports due to a change in the number of participating regions.

About the Royal LePage Recreational Property Advisor Survey

A national online survey of 202 brokers and sales representatives serving buyers and sellers in Canada's recreational property regions. The survey was conducted between March 1, 2023 and March 18, 2023.

About Royal LePage

Serving Canadians since 1913, Royal LePage is the country's leading provider of services to real estate brokerages, with a network of approximately 20,000 real estate professionals in over 670 locations nationwide. Royal LePage is the only Canadian real estate company to have its own charitable foundation, the Royal LePage Shelter Foundation, which has been dedicated to supporting women's shelters and domestic violence prevention programs for 25 years. Royal LePage is a Bridgemarq Real Estate Services Inc. company, a TSX-listed corporation trading under the symbol TSX:BRE. For more information, please visit www.royallepage.ca.

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https://www.bloomberg.com/news/newsletters/2023-03-28/how-to-tip-in-2023-expert-guidance-on-tipping-in-america

Work Shift: The New Rules of Tipping Mean Everyone Expects 20% to 25%

Photographer: Al Drago/Bloomberg

By
Arianne Cohen
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The New Rules of Tipping
On a recent work trip, my wallet was continually open: the Uber driver, the bellhop, the luggage storage assistant, the barista, the lunch delivery person. Their glances gave me the distinct sense that I was tipping less than they expected. As a former table busser who always tips well—or so I thought—this was a surprise. Have tipping expectations jumped since the pandemic?

We asked two dozen service workers how much they receive in tips, and the numbers are eye popping.

“If I don’t get at least 20%, I struggle to pay my bills,” says Kathleen Caspersen, a server at Bull City Ciderworks in Greensboro, North Carolina, who says that the ever-rising cost of living is ripping her budget to ribbons. “The right amount is 20% to 30%.”
The expectation for decent service, it seems, has risen from 15% to 20%, with 18% as the bare minimum. “If you can’t afford to tip 18% on your bill, you can’t afford to go out,” says Paul Kushner, a pub owner and bartender who has worked in restaurants for 25 years.

Here’s how much various service workers expect in tips and why.

Cleaners: 20%
“We’re noticing restaurants asking for an 18% to 25% tip on takeout orders without service, waiting or cleaning tables, ” says Paulo Filho, owner of Celestial Cleaning Service in San Francisco. “We spend three to five hours scrubbing and cleaning a home. People usually tip 20% of their service total.”
Hair Stylists, Barbers and Aestheticians: 25%
“One of our clients offers a $100 bill for each $65 haircut he receives,” says Alexia Donovan, director of client services for the Barber Surgeons Guild in New York City and Los Angeles. “Our barbers typically see tips starting at 25%, at a minimum.”
Private Pilots and Crew: 20% to 30%
“The pilots spend years perfecting the art of flying so that you can trust them with your life,” says Eliav Cohen, chief pilot of Seattle Ballooning hot air balloon company. He says that individual tips average $77 for $350-per-person trips for pilots and crew combined (yes, that’s 22%).
Waitstaff and Bartenders: 20% of the pre-tax total
“When I first started almost a decade ago, a 15% tip was normal. Now if I received that, I would be questioning what I did wrong,” says Neil Gallagher, a longtime server and bartender who still moonlights for special events. “For exceptional service, more is greatly appreciated.”

The verdict is in: 25 is the new 15. To be sure, much can be said about the shift from employers to customers in compensating service employees, but in the meantime, tip well. “Expecting your service worker to make the financial sacrifice for inflation is a jerk move, period,” says Kushner.