Energy Tidbits

Is Russia's Voluntary 500,000 b/d Cut Because the Oil isn't Profitable?

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AMERICAN GAS ASSOCIATION
Interoffice Memorandum

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FROM: Paul Pierson

SUBJECT: Weekly Heating Degree Day Data

HEATING DEGREE DAY SUMMARY

For the week ending February 4, the weather in the United States was 3.9 percent colder than last year and 10.6 percent colder than normal. All regions experienced colder temperatures than last year except the New England, Middle Atlantic, and E. S. Central regions. All regions experienced colder temperatures than normal except the W.S. New England, Middle Atlantic, South Atlantic, and E.S. Central regions. For the month of January, the weather in the United States was 19.1 percent warmer than last year and 18.1 percent warmer than normal.

WEEKLY COMPARISON

Week Ending	2022/ 2023	2021/ 2022	Normal	% Change: 22/23 from 21/22		% Change: 22/23 from Normal	
10/01/22	41	20	36	105.0	Colder	13.9	Colder
10/08/22	50	15	48	233.3	Colder	4.2	Colder
10/15/22	56	30	61	86.7	Colder	8.2	Warmer
10/22/22	89	58	76	53.4	Colder	17.1	Colder
10/29/22	75	77	91	2.6	Warmer	17.6	Warmer
11/05/22	72	111	106	35.1	Warmer	32.1	Warmer
11/12/22	97	95	122	2.1	Colder	20.5	Warmer
11/19/22	194	127	139	52.8	Colder	39.6	Colder
11/26/22	161	152	155	5.9	Colder	3.9	Colder
12/03/22	165	137	170	20.4	Colder	2.9	Warmer
12/10/22	163	161	185	1.2	Colder	11.9	Warmer
12/17/22	188	139	197	35.3	Colder	4.6	Warmer
12/24/22	254	183	209	38.8	Colder	21.5	Colder
12/31/22	200	156	218	28.2	Colder	8.3	Warmer
01/07/23	152	214	223	29.0	Warmer	31.8	Warmer
01/14/23	179	208	226	13.9	Warmer	20.8	Warmer
01/21/23	178	229	225	22.3	Warmer	20.9	Warmer
01/28/23	202	248	222	18.5	Warmer	9.0	Warmer
02/04/23	240	231	217	3.9	Colder	10.6	Colder
Cumulative	**2756**	**2591**	**2926**	**6.4**	**Colder**	**5.8**	**Warmer**

MONTHLY COMPARISON

Month Ending	2022/ 2023	2021/ 2022	Normal	% Change: 22/23 from 21/22		% Change: 22/23 from Normal	
September	66	42	87	57.1	Colder	24.1	Warmer
October	299	205	310	45.9	Colder	3.5	Warmer
November	588	677	676	13.1	Warmer	13.0	Warmer
December	883	688	884	28.3	Colder	0.1	Warmer
January	811	1003	990	19.1	Warmer	18.1	Warmer

HEATING DEGREE DAYS BY CENSUS REGION FOR THE WEEK ENDING February 4, 2023

Region	2022/ 2023	2021/ 2022	Normal	% Change: 22/23 from 21/22		% Change: 22/23 from Normal	
New England	266	285	273	6.7	Warmer	2.6	Warmer
Middle Atlantic	254	276	261	8.0	Warmer	2.7	Warmer
E N Central	323	305	289	5.9	Colder	11.8	Colder
W N Central	370	321	301	15.3	Colder	22.9	Colder
South Atlantic	152	175	176	13.1	Warmer	13.6	Warmer
E S Central	177	177	179	0.0	nc	1.1	Warmer
W S Central	177	138	128	28.3	Colder	38.3	Colder
Mountain	266	254	220	4.7	Colder	20.9	Colder
Pacific	137	125	112	9.6	Colder	22.3	Colder
United States	**240**	**231**	**217**	**3.9**	**Colder**	**10.6**	**Colder**

CUMULATIVE HEATING DEGREE DAYS BY CENSUS REGION

Region	2022/ 2023	2021/ 2022	Normal	% Change: 22/23 from 21/22		% Change: 22/23 from Normal	
New England	3107	3279	3608	5.2	Warmer	13.9	Warmer
Middle Atlantic	2988	3012	3401	0.8	Warmer	12.1	Warmer
E N Central	3509	3406	3832	3.0	Colder	8.4	Warmer
W N Central	4010	3672	4120	9.2	Colder	2.7	Warmer
South Atlantic	2086	1971	2283	5.8	Colder	8.6	Warmer
E S Central	2118	1992	2341	6.3	Colder	9.5	Warmer
W S Central	1537	1225	1620	25.5	Colder	5.1	Warmer
Mountain	3464	2974	3343	16.5	Colder	3.6	Colder
Pacific	1789	1579	1665	13.3	Colder	7.4	Colder
United States	**2756**	**2591**	**2926**	**6.4**	**Colder**	**5.8**	**Warmer**

The regional degree day statistics stated in this memo are weighted by gas home heating customers instead of by population.
A heating degree day is a measure of the coldness of the weather experienced, based on the extent to which the daily mean temperature falls below 65 degrees Fahrenheit. A daily mean temperature represents the sum of the high and low reading, divided by two.
Source: U.S. Department of Commerce, National Oceanic and Atmospheric Administration

Overview

U.S. energy market indicators	2022	2023	2024
Brent crude oil spot price (dollars per barrel)	**$101**	**$84**	**$78**
Retail gasoline price (dollars per gallon)	**$3.97**	**$3.39**	**$3.10**
U.S. crude oil production (million barrels per day)	**11.90**	**12.49**	**12.65**
Natural gas price at Henry Hub (dollars per million British thermal units)	**$6.42**	**$3.40**	**$4.04**
U.S. liquefied natural gas gross exports (billion cubic feet per day)	**10.6**	**11.8**	**12.6**
Shares of U.S. electricity generation			
Natural gas	39%	39%	37%
Coal	20%	17%	17%
Renewables	22%	24%	26%
Nuclear	19%	20%	19%
U.S. GDP (percentage change)	**2.0%**	**0.8%**	**2.1%**
U.S. CO_2 emissions (billion metric tons)	**4.97**	**4.78**	**4.79**

Data source: U.S. Energy Information Administration, *Short-Term Energy Outlook,* February 2023

- **Natural gas prices.** We forecast that the Henry Hub natural gas spot price will average $3.40 per million British thermal units (MMBtu) in 2023, down almost 50% from last year and about 30% from our January *Short-Term Energy Outlook* (STEO) forecast. We revised our outlook for Henry Hub prices as a result of significantly warmer-than-normal weather in January that led to less-than-normal consumption of natural gas for space heating and pushed inventories above the five-year average.

- **Natural gas storage.** As a result of less-than-normal natural gas consumption in January, natural gas inventories ended the month above their five-year (2018−2022) average. We now expect inventories will close the withdrawal season at the end of March at more than 1.8 trillion cubic feet, 16% more than the five-year average.

- **Global liquid fuels consumption.** We expect global liquid fuels consumption to increase by 1.1 million barrels per day (b/d) in 2023 and by 1.8 million b/d in 2024, driven primarily by growth in China and other non-OECD countries. The outcomes of our demand forecast remain uncertain as China shifts away from its zero-COVID-19 policy and global economic conditions evolve.

- **Global liquid fuels production.** We expect oil production in Russia to average 9.9 million b/d in 2023, down 1.1 million b/d from 2022. Our forecast for Russia's 2023 production is 0.4 million b/d more than in the January STEO because crude oil liftings data suggest that Russia's exports have remained higher than we expected following the EU's ban on seaborne imports of crude oil from Russia that began on December 5. However, we still forecast Russia's oil production to fall in the coming months, as we expect the EU's ban on seaborne petroleum products from Russia that began February 5 will cause refineries in Russia to reduce crude oil inputs, which will disrupt crude oil production.

- **Electricity generation.** Electricity generation in our forecast falls by 2% in 2023 and then rises by 2% 2024. The generation mix continues to shift away from coal. The share of U.S. electricity generated from coal falls from 20% in 2022 to 17% in 2024. As the share of coal declines, it will be offset by increases in the share of generation from renewable sources of energy, which rises from 22% in 2022 to 26% in 2024.

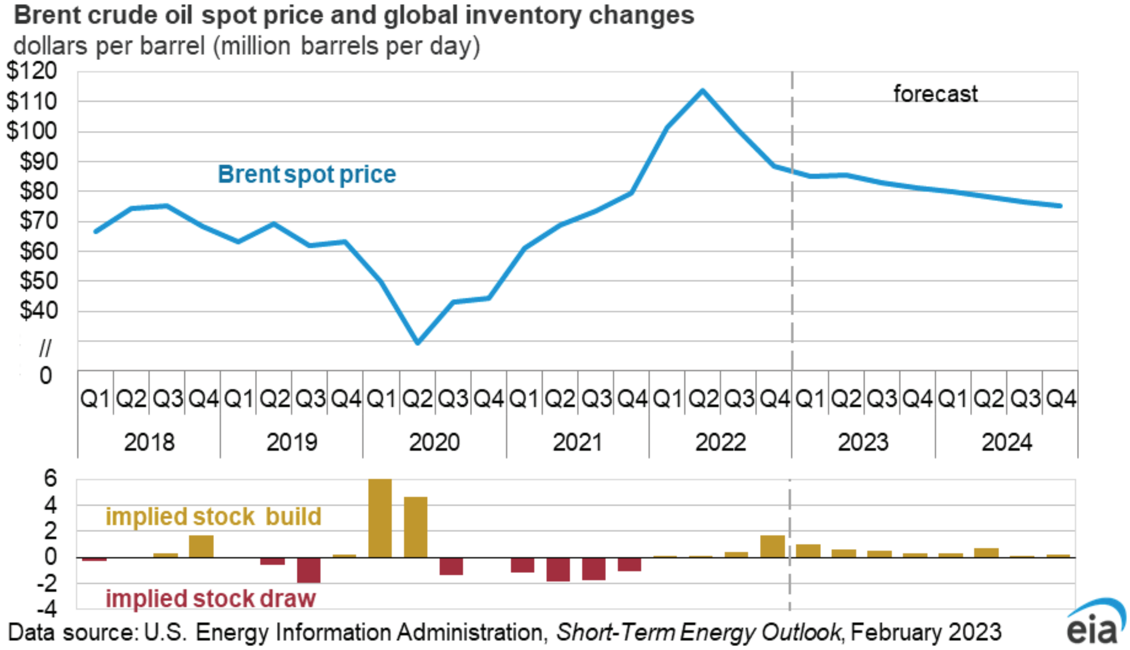
- **U.S. GDP growth.** Based on the S&P Global macroeconomic model, we assume U.S. real GDP will contract slightly in the first half of 2023 (1H23), partly resulting from a decline in residential fixed investment. GDP growth picks up in 2H23 and reaches an annual average of 2.1% in 2024.

Notable forecast changes

Current forecast: February 7, 2023; previous forecast: January 10, 2022	**2023**	**2024**
Natural gas price at Henry Hub (current) (dollars per million British thermal units)	**$3.40**	**$4.04**
Previous forecast	$4.90	$4.80
Percentage change	-30.5%	-15.8%
U.S. coal exports (current) (million short tons)	**88.1**	**96.0**
Previous forecast	83.3	92.6
Percentage change	5.7%	3.7%
Jet fuel margin (current) (dollars per gallon)	**$1.02**	**$0.49**
Previous forecast	$0.86	$0.49
Percentage change	18.7%	0.6%
U.S. crude oil production (current) (million barrels)	**12.5**	**12.6**
Previous forecast	12.4	12.8
Percentage change	0.6%	-1.2%
Russia petroleum and liquid fuels production (current) (million barrels per day)	**9.9**	**9.8**
Previous forecast	9.5	9.4
Percentage change	3.9%	3.8%
China petroleum and liquid fuels consumption (current) (million barrels per day)	**15.8**	**16.2**
Previous forecast	15.7	16.1
Percentage change	1.0%	1.0%
U.S. heating degree days (current)	**4,083**	**4,201**
Previous forecast	4,158	4,265
Percentage change	-1.8%	-1.5%

Data source: U.S. Energy Information Administration, *Short-Term Energy Outlook,* February 2023

Global oil markets



Crude oil prices: The Brent crude oil spot price averaged $82 per barrel (b) in January, about $2/b higher than the average in December 2022. Oil prices rose during January in part because of the expectation of increasing oil demand as a result of relaxing COVID-19 restrictions and increasing mobility in China. Perceptions of a less severe recession and some improving macroeconomic conditions also likely contributed to rising crude oil prices over the past month.

Last month, we highlighted oil demand in China and oil production in Russia as two of the main uncertainties in the oil market this year, and we have revised our outlook for both in this month's forecast. The revisions result from China relaxing COVID restrictions, which have increased our forecast of oil demand growth. At the same time, more oil was produced in Russia than we anticipated during January, and we raised our forecast for Russia's oil production through the end of 2024. We have also lowered our forecast for oil production in OPEC because of rising global oil inventories. These changes have largely offset each other in our forecast global balances, and beyond the first quarter of 2023, we have left our crude oil price forecast largely unchanged from last month's outlook.

We expect that the Brent spot price will average $85/b in the first half of 2023 (1H23). However, we expect global oil production to continue to outpace demand over the forecast period, leading to persistent global oil inventory builds through 2024 and falling oil prices. After increasing by an average of 0.6 million b/d in 2022, we expect global oil inventories to also build by an average of 0.6 million b/d in 2023, with builds moderating to 0.4 million b/d in 2024. Correspondingly, our forecast spot price of Brent crude oil falls to an average of $82/b in 2H23 and $78/b in 2024.

Global oil demand: Global liquids fuel consumption in the forecast increases from an average of 99.4 million barrels per day (b/d) in 2022 to 102.3 million b/d in 2024, driven primarily by growth in China and other non-OECD countries. However, significant uncertainty around our demand forecast remains based on possible outcomes for the evolving global economic conditions and China's pivot away from a zero-COVID strategy. We forecast that the reversal of restrictions will contribute to oil demand in China increasing by 0.7 million b/d in 2023 and by 0.4 million b/d in 2024. We expect OECD oil demand to remain largely flat over the forecast period, as inflationary economic pressures continue to limit GDP and oil demand growth and as the oil intensity of OECD economies declines.

Global oil supply: Global liquid fuels production averaged about 100.0 million b/d in 2022, and we forecast it will increase by an average of 1.1 million b/d in 2023 and 1.5 million b/d in 2024. Growth in non-OPEC production in both 2023 and 2024, as well as increases in OPEC output in 2024, will mostly offset an approximately 1.1 million b/d decline in Russia's production over the forecast period.

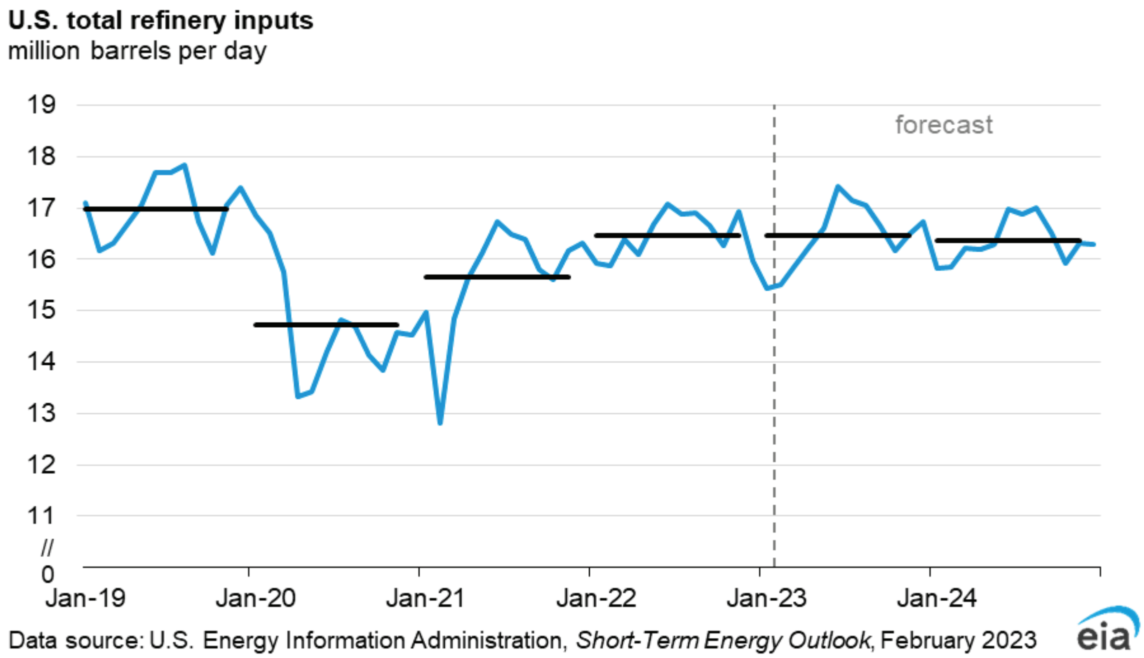
We forecast Russia's production of petroleum and other liquids to decline to 9.9 million b/d in 2023 from more than 10.9 million b/d in 2022 and then average 9.8 million b/d in 2024. For both 2023 and 2024, we forecast about 0.4 million b/d more production in Russia than in last month's STEO. We had previously forecast that the majority of Russia's crude oil exports subject to EU sanctions implemented on December 5 would find new markets, but that the sanctions would lead to some decline in production. However, we assess that Russia's crude oil exports rose in January after a brief decline in December and have since begun to surpass November totals, with little impact to Russia's crude oil production.

The EU ban on seaborne imports of petroleum products from Russia that began on February 5 could be more disruptive than the ban on crude oil imports implemented in December. We assume Russia will be able to reroute some of its petroleum exports subject to EU sanctions. But we do not expect all of its refined product exports will find new destinations because of limited clean tanker availability, which will cause refiners in Russia to reduce crude oil inputs and for Russia's crude oil production to decline.

Petroleum products

U.S. refinery utilization: We forecast domestic refinery maintenance will contribute to reduced refinery utilization in the United States through April. Refinery utilization dropped because of severe cold weather that swept through the midcontinent in late December, contributing to partial unit shutdowns, reductions in run rates, and a few instances of unit damage. December refinery inputs fell below 16 million barrels per day (b/d), marking the largest month-over-month decline in two years when significant cold weather disrupted refinery operations in February 2021.

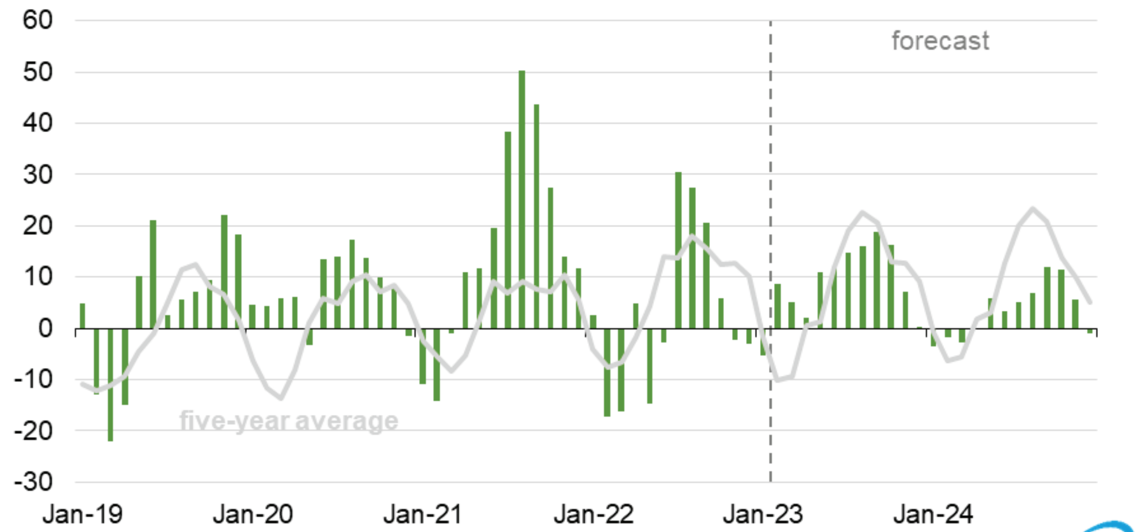
In 2022, many refiners postponed planned maintenance during the spring and fall as low product inventories and high refining margins encouraged refiners to maximize utilization. Although refining margins remain above normal levels, we expect more refiners will undergo deferred maintenance this season. We forecast U.S. distillation inputs will be less than 16 million b/d until April. Utilization remains below 90% until May, which we forecast will keep refining margins for gasoline and diesel above year-ago levels during February and March. However, we expect refinery inputs and utilization to increase after maintenance is completed, and 2023 inputs will likely be similar to 2022 inputs, leading to falling refining margins beginning in the second quarter of 2023. ExxonMobil's planned startup of a 250,000 b/d capacity expansion at its Beaumont refinery in the first half of this year will contribute to the increase. We expect slightly less 2024 refinery inputs compared with 2023, partly due to the expected closure of LyondellBasell's Houston refinery at the end of 2023.



Rocky Mountain retail prices: On December 24, Suncor began repairing its 103,000 b/d Commerce City refinery in Colorado following unit damage related to cold weather. We expect this Colorado refinery will be unavailable until late in the first quarter. This outage will contribute to reduced refinery utilization and gasoline production in the Rocky Mountain region (PADD 4) through March, which we expect will lead to higher retail fuel prices.

We forecast retail gasoline prices in the Rocky Mountains will reach $3.58 per gallon (gal) in February, up from $3.18/gal in December. This increase is more than our forecast increase for the U.S. average retail gasoline price, which rises from $3.21/gal in December to $3.49/gal in February. Rocky Mountain retail fuel prices are normally lower than the U.S. average during the winter months; however, we estimate that they will be at a premium in February and March, compared with averaging a nearly 10 cent/gal discount over the past five years. Although Colorado is more connected to the Midwest and Gulf Coast regions than other parts of the Rocky Mountains, the potential for prolonged refinery outage at the Commerce City refinery could contribute to wider changes in regional retail prices.

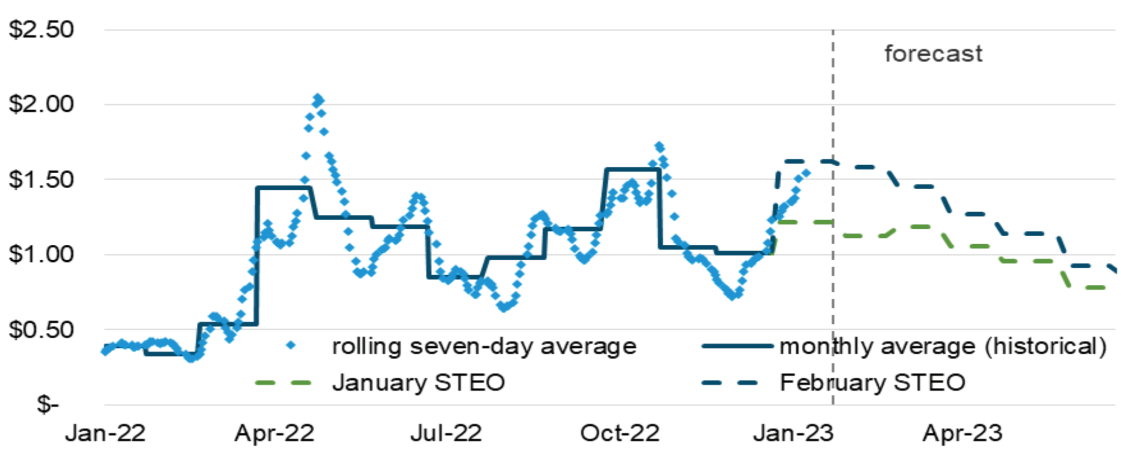
Rocky Mountain minus U.S. average gasoline regular grade retail prices
cents per gallon



Data source: U.S. Energy Information Administration, *Short-Term Energy Outlook*, February 2023

Jet fuel prices: The jet fuel crack spread increased significantly in January, leading us to revise our February STEO forecast compared with our January STEO. The increased jet fuel price is a response to low inventories, less refinery production related to recent weather, and increasing international demand. Jet fuel prices increased sharply at several times in 2022, moving in sync with similar increases in the price of distillate fuel. However, distillate fuel prices in January did not increase as much as jet fuel prices, probably because very mild weather limited demand for heating oil (a type of distillate fuel). As China lessens COVID restrictions, leading to increasing jet fuel demand, we expect jet fuel refining margins will be higher than we previously forecast in the coming months.

Crack spread for kerosene-type jet fuel
dollars per gallon



Data source: , U.S. Energy Information Administration, *Weekly Petroleum Status Report* and *Short-Term Energy Outlook* (STEO), February 2023.
Note: Crack spreads are calculated by subtracting the price for a gallon of Brent crude oil from the refiner price for a gallon of kerosene-type jet fuel

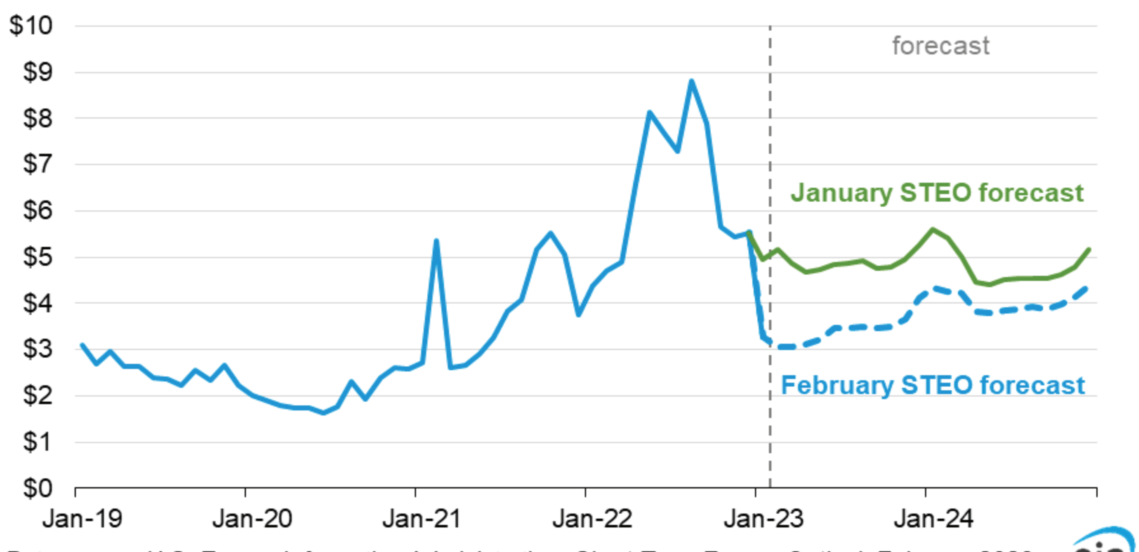
Natural gas

Natural gas prices: Temperatures across the United States in January were the mildest since 2006, which reduced consumption of natural gas for space heating and significantly changed our forecast for natural gas markets in the coming months. The Henry Hub spot price averaged $3.27 per million British thermal units (MMBtu) in January, down more than $2/MMBtu from December. In the United States, there were 16% fewer heating degree days (HDDs) in January than the 10-year average and 9% fewer than forecast in the January STEO. With less-than-expected consumption of natural gas, U.S. stocks of natural gas ended January above our previous forecast.

These developments in January contributed to significant changes in our outlook for the February STEO. We now forecast Henry Hub natural gas prices to average about $3.40/MMBtu for 2023 and to stay below $4.00/MMBtu until December. Our forecast in the January STEO was for Henry Hub prices to average almost $5.00/MMBtu in 2023.

Natural gas prices remain very volatile. Extreme weather events and production freeze-offs could still potentially cause price spikes at both the Henry Hub and in regional markets, but that potential diminishes as spring approaches, particularly now that inventories have moved back above the five-year (2018−2022) average. Although we expect close-to-normal weather for February and March, colder temperatures than expected could put upward pressure on prices. The Freeport LNG export facility, which went offline in June due to a fire, is expected to come back online in the first quarter of 2023 and will likely add over 2 billion cubic feet per day (Bcf/d) of natural gas demand to the U.S. market once fully operational.

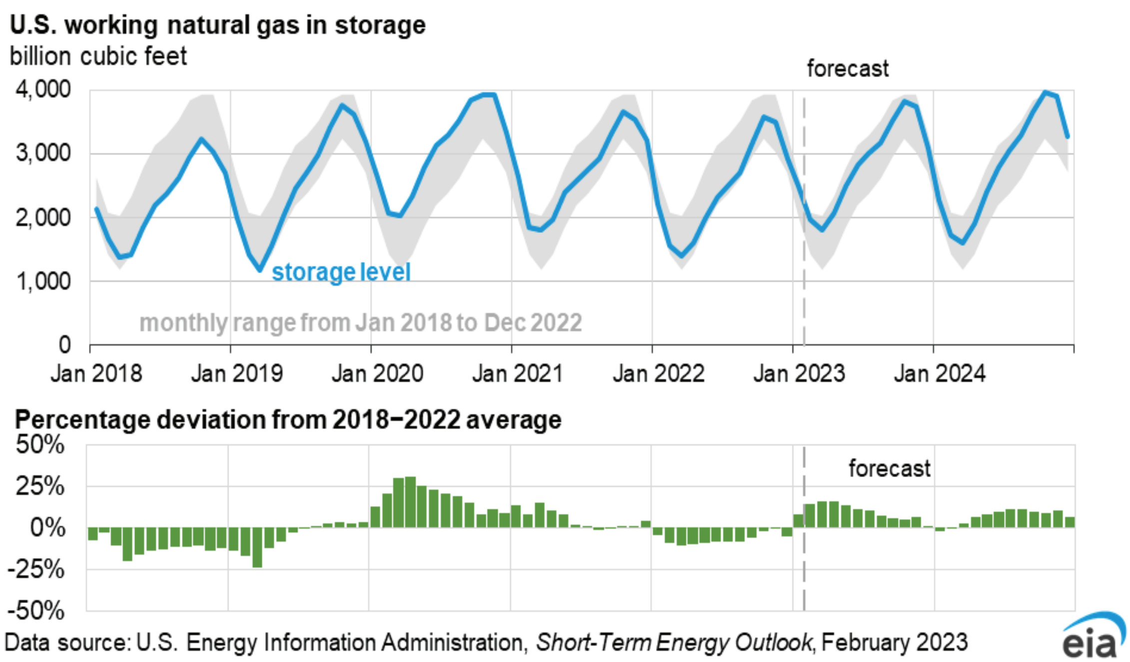
Monthly Henry Hub natural gas spot price
dollars per million British thermal units



Data source: U.S. Energy Information Administration, *Short-Term Energy Outlook*, February 2023

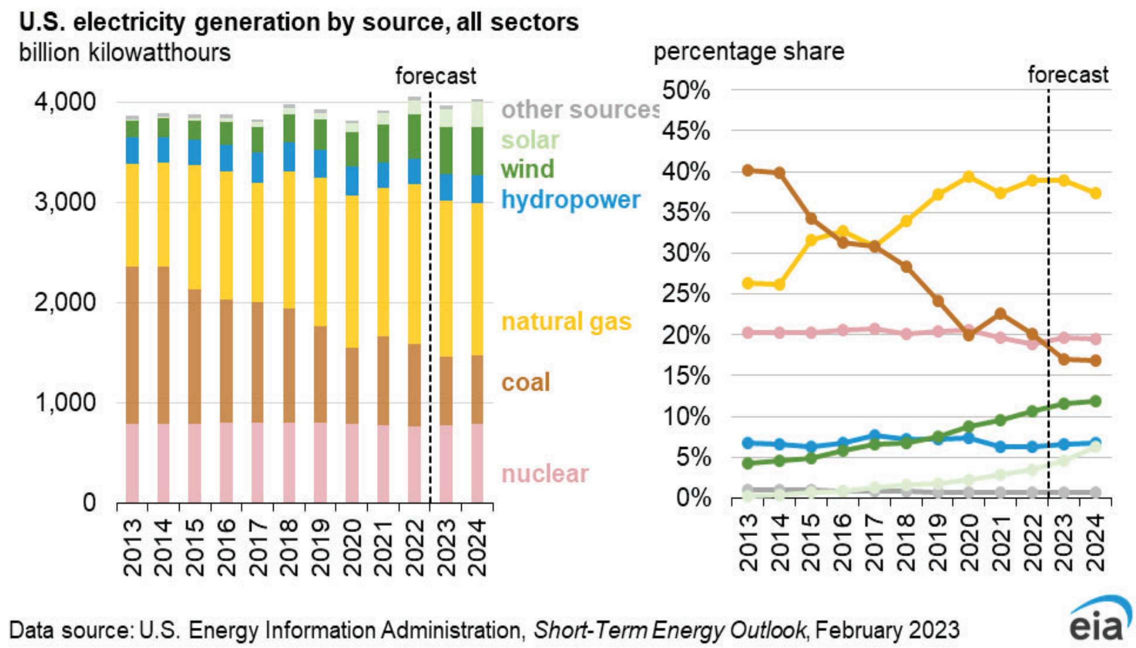
Natural gas markets: U.S. natural gas production growth has been outpacing demand growth the past several months, helping reduce natural gas prices. We estimate that dry natural gas production in the United States established a new record in January at 100.2 Bcf/d. We forecast dry natural gas production to continue to hover around 100 Bcf/d for most of this year; overall, we expect dry natural gas production to average between 100 Bcf/d and 101 Bcf/d in 2023. U.S. consumption of natural gas was below average in January because very mild weather reduced demand for space heating. We expect less demand for natural gas than last year for most of 2023 due to decreased demand in the electric power sector as more renewable electric generation sources come online throughout the year and due to decreased demand in the industrial sector as a result of an expected drop in manufacturing activity. We expect utilization at U.S. liquefied natural gas (LNG) export facilities to be slightly lower in the next few months compared with our previous forecast because of high natural gas stock levels in Europe. But U.S. LNG exports in our forecast rise once the Freeport facility is back online, and LNG exports increase by 11% (1.2 Bcf/d) on an annual basis in 2023 compared with 2022.

Natural gas storage: We forecast that natural gas storage inventories will end the withdrawal season (November through March) at more than 1.8 trillion cubic feet (Tcf), which would be 16% above the five-year average and 19% more than we had forecast in the January STEO. The warmer-than-normal January temperatures reduced natural gas storage withdrawals below average, causing storage inventories to rise above the five-year (2018–2022) average at the end of January. We expect above-average storage inventories to reduce natural gas prices in 2023 from 2022, when end-of-March storage inventories were 1.4 Tcf, 17% below the previous five-year (2017–2021) average.



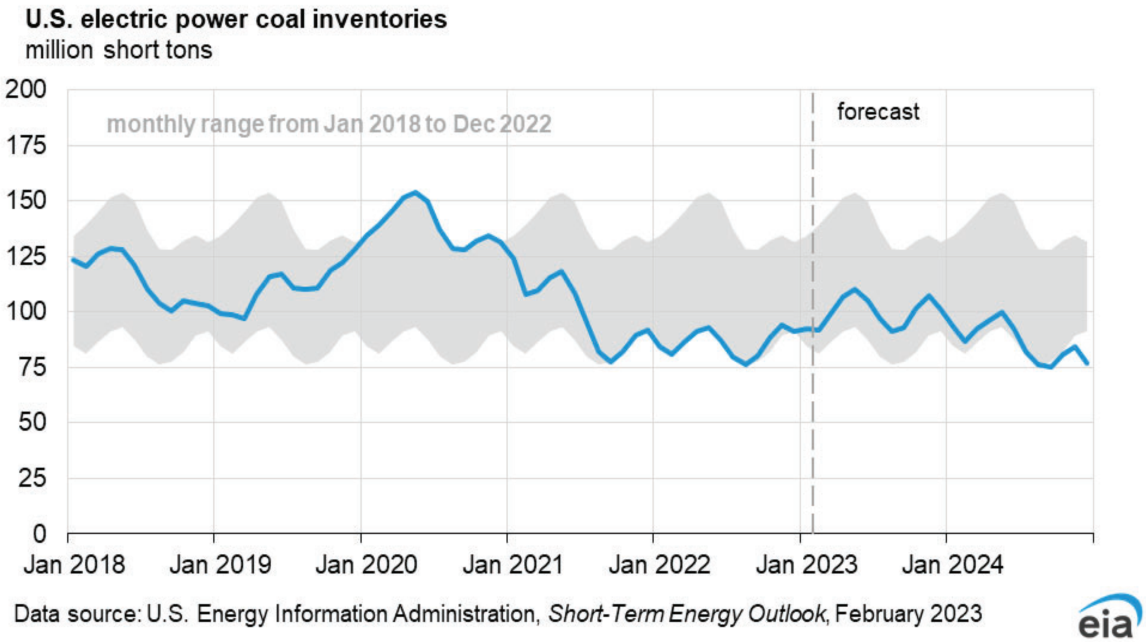
Electricity, coal, and renewables

Electricity generation: We expect U.S. electric power generation to decline by 2% in 2023 before rising by a similar amount in 2024. At the same time, the makeup of the power generation mix will slightly shift. In our forecast, electricity produced from renewable sources rises from 22% of total generation in 2022 to 24% in 2023 and to 26% in 2024. The gains in the share of renewable energy generation will be driven by about 63 gigawatts (GW) of utility-scale solar generating capacity that developers have scheduled to enter service by the end of 2024 and about 13 GW of wind capacity that will come online during the same two years. We expect the new generating capacity from renewable sources to reduce output from fossil fuel-fired power plants. The combined share of U.S. generation provided by natural gas and coal in our forecast falls from 59% in 2022 to 54% in 2024. Coal generation declines the most; coal's share falls from 20% in 2022 to 17% in 2024. Natural gas-fired generation's share drops from 39% in 2022 to 37% in 2024.



More volatility in fuel costs creates uncertainty around how natural gas and coal-fired generation will respond to increased renewable generating capacity. After lowering our February forecast for near-term natural gas prices, the forecast share of natural gas generation for 2023 is now 39%, up from a forecast 2023 share of 38% in the previous STEO. Upcoming renewable capacity additions will limit the variation in natural gas generation to changes in fuel cost.

Coal Markets: Coal stocks increased 4% in January 2023 with less coal-fired electricity generation after warmer-than-average temperatures reduced overall electricity generation and falling natural gas prices increased natural gas-fired electricity generation. At the same time, monthly coal production rose in late 2022.



We expect U.S. coal production to decline by 13% to 518 million short tons (MMst) in 2023, after increasing in both 2021 and 2022, with a further 5% decline to 494 MMst in 2024. Primarily, we forecast a 16% reduction in coal consumption by the electric power sector in 2023 followed by flat consumption in 2024. That decline largely reflects almost 9.6 GW of coal-fired capacity retirements in 2023, followed by another 2.8 GW closing in 2024. Two other factors will be the lower natural gas prices and 19% increase in renewable generation over those two years. Consequently, coal imports in our forecast decline by 47% from 2022 to less than 4 MMst in 2024.

Exports of steam coal in our forecast increase from 39 MMst in 2022 to 45 MMst in 2024, due largely to greater demand in Europe. Coal from the United States is helping supply Europe following the EU's ban of coal imports from Russia. U.S. coal exports also fulfill demand in Asia.

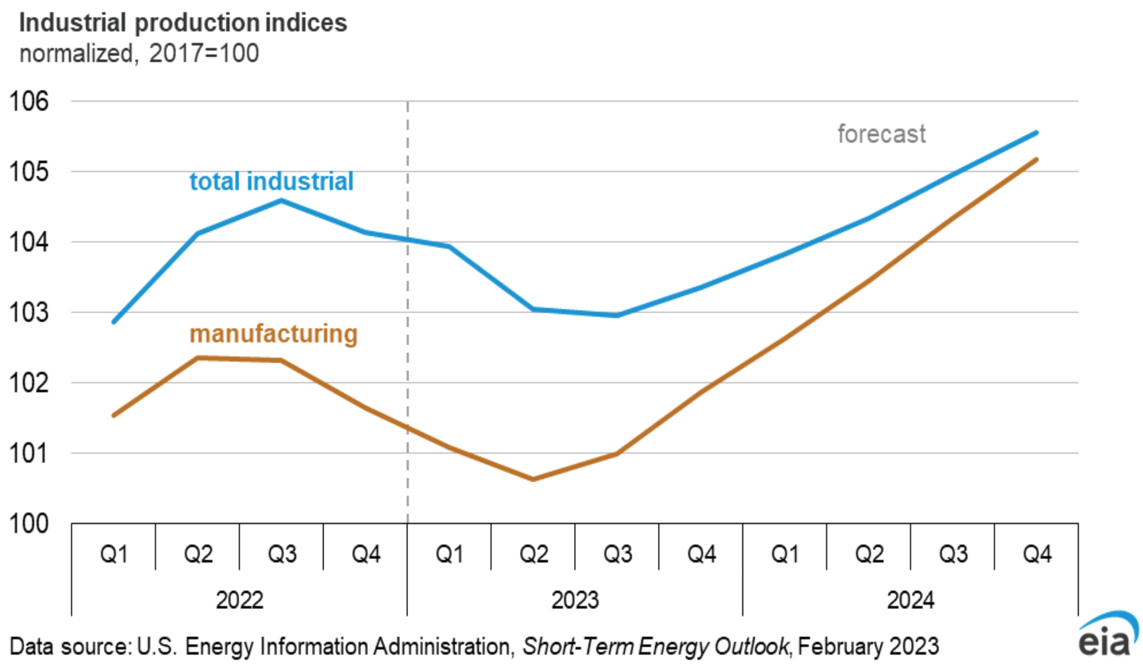
Economy, weather, and CO_2

U.S. macroeconomics: Our U.S. macroeconomic forecasts are based on S&P Global's macroeconomic model. We incorporate STEO energy price forecasts into the model to obtain the final macroeconomic assumptions.

S&P Global continues to forecast a mild recession starting in the first quarter of 2023 (1Q23) through 2Q23. Real U.S. GDP in the forecast contracts at an annualized rate of 1.3% in 1Q23 and 0.3% in 2Q23, mostly due to a decline in residential fixed investment, private business inventories of goods, and industrial production. However, we revised our forecast of 2023 real GDP upward by 0.3 percentage points from the January STEO and 2023 GDP growth now averages 0.8%.

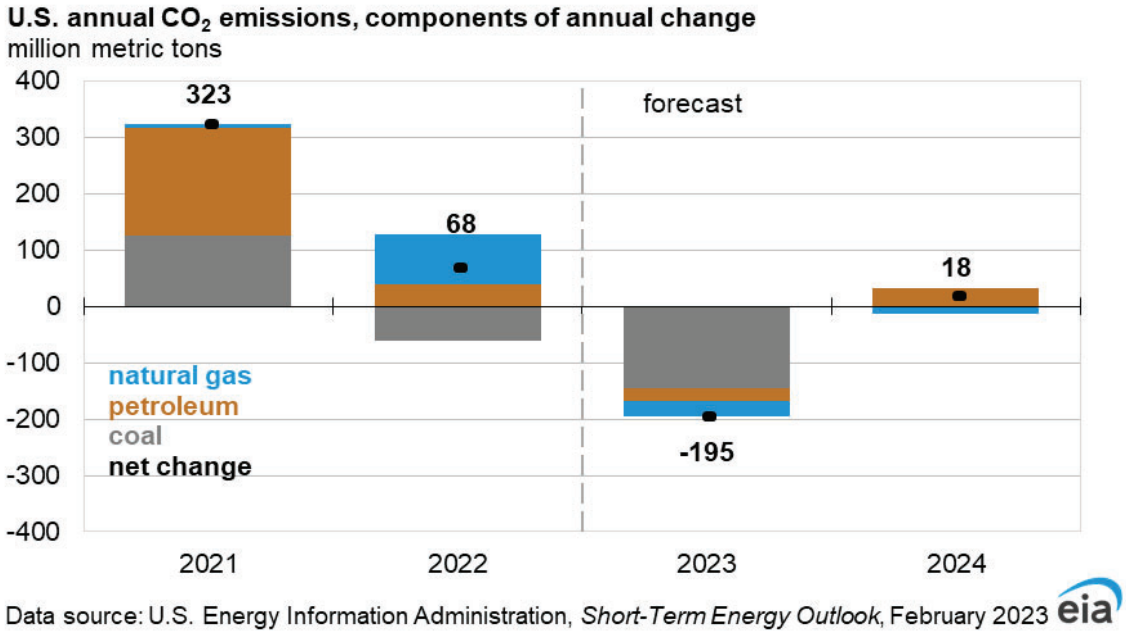
U.S. manufacturing production contracted in November 2022. As a result, the 4Q22 estimate of the Manufacturing Production Index was revised lower by 1.0%. The slowing of manufacturing activity is likely the result of a shift in consumer spending away from goods toward services and resulting in a reduction in diesel fuel consumption in our forecast.

S&P Global expects U.S. GDP to grow by 2.1% in 2024 as the economy shifts out of recession and returns to positive GDP growth beginning in 3Q23. In addition, GDP growth is expected to be led by net exports and personal consumption expenditures in 2Q23, with a more broad-based increase occurring later in the year.



Emissions: We expect U.S. energy-related carbon dioxide (CO_2) emissions to decrease slightly more than previously forecast, declining by almost 4% in 2023. The decrease is driven by slow economic growth and a continuing increase in electricity generation from renewable sources, which reduces fossil fuel-fired generation and associated CO_2 emissions. Among the major fossil fuel categories, CO_2 emissions from coal decline by around 15%, mostly from decreasing coal-fired electricity generation. We forecast natural gas emissions to decrease by around 1% as natural gas-fired electricity generation also decreases. Renewable sources displace generation from both fuels. We expect petroleum emissions to fall by 1% in 2023 compared with 2022.

We expect U.S. energy-related CO_2 emissions in 2024 to remain almost unchanged from 2023. Petroleum CO_2 emissions increase slightly as a result of increases in air and road travel. Coal emissions remain flat as coal-fired electricity generation continues to decrease. Natural gas emissions fall slightly. Although natural gas consumption will likely decrease in the industrial and electric power sectors in 2024, it will be partly offset by an increase in the residential and commercial sectors, driven by our expectation of increased demand for space heating.



Weather: In January, weather in the United States was very mild, with 16% fewer population-weighted HDDs than the 10-year average; the mildest January since 2006. Based on forecasts from the National Oceanic and Atmospheric Administration, in 1Q23 we expect 8% fewer HDDs in the United States compared with 1Q22 and 7% fewer than the 10-year average. We have updated our expectations for winter heating fuel expenditures based on the most recent temperature and price forecasts.

Table 3a. International Petroleum and Other Liquids Production, Consumption, and Inventories

U.S. Energy Information Administration | Short-Term Energy Outlook - February 2023

	2022				2023				2024				Year		
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	2022	2023	2024
Production (million barrels per day) (a)															
OECD	31.62	31.87	32.54	33.28	33.59	33.75	33.93	34.44	34.53	34.38	34.51	35.06	32.33	33.93	34.62
U.S. (50 States)	19.44	20.12	20.60	20.82	20.77	21.18	21.21	21.34	21.33	21.56	21.59	21.73	20.25	21.13	21.56
Canada	5.66	5.51	5.72	5.91	6.00	5.72	5.93	6.14	6.21	5.92	6.13	6.34	5.70	5.95	6.15
Mexico	1.91	1.89	1.90	1.90	1.92	1.95	1.96	1.94	1.96	1.96	1.93	1.89	1.90	1.94	1.93
Other OECD	4.61	4.35	4.32	4.64	4.90	4.90	4.83	5.01	5.03	4.94	4.85	5.10	4.48	4.91	4.98
Non-OECD	67.21	66.87	68.26	68.11	67.11	66.96	67.54	67.05	67.37	68.08	68.47	68.04	67.62	67.17	67.99
OPEC	33.75	33.76	34.71	34.44	33.99	34.11	34.21	34.00	34.76	34.79	34.87	34.65	34.17	34.08	34.77
Crude Oil Portion	28.19	28.33	29.23	28.92	28.50	28.75	28.81	28.57	29.23	29.38	29.43	29.17	28.67	28.66	29.31
Other Liquids (b)	5.56	5.43	5.48	5.52	5.49	5.36	5.40	5.44	5.53	5.40	5.44	5.48	5.50	5.42	5.46
Eurasia	14.39	13.39	13.56	13.92	13.54	12.54	12.80	12.88	12.91	12.88	12.86	12.95	13.81	12.94	12.90
China	5.18	5.18	5.05	5.09	5.21	5.24	5.23	5.27	5.21	5.23	5.23	5.27	5.12	5.24	5.23
Other Non-OECD	13.90	14.54	14.95	14.66	14.38	15.08	15.31	14.90	14.49	15.18	15.50	15.18	14.51	14.92	15.09
Total World Production	98.83	98.75	100.80	101.39	100.70	100.71	101.47	101.50	101.90	102.46	102.97	103.11	99.95	101.10	102.61
Non-OPEC Production	65.08	64.98	66.09	66.94	66.71	66.60	67.26	67.49	67.14	67.68	68.10	68.46	65.78	67.02	67.85
Consumption (million barrels per day) (c)															
OECD	45.78	45.37	46.62	45.97	45.64	45.22	45.80	46.03	45.72	45.30	46.16	46.32	45.94	45.67	45.88
U.S. (50 States)	20.22	20.27	20.47	20.26	19.84	20.38	20.41	20.45	20.26	20.52	20.75	20.69	20.30	20.27	20.56
U.S. Territories	0.14	0.12	0.12	0.13	0.13	0.12	0.12	0.13	0.13	0.12	0.12	0.13	0.13	0.12	0.13
Canada	2.24	2.21	2.38	2.26	2.28	2.23	2.33	2.31	2.30	2.25	2.35	2.33	2.27	2.29	2.31
Europe	13.19	13.42	14.09	13.56	13.39	13.30	13.70	13.47	13.19	13.34	13.74	13.50	13.57	13.46	13.44
Japan	3.70	3.03	3.19	3.53	3.69	3.04	3.06	3.36	3.54	2.93	3.03	3.36	3.36	3.29	3.21
Other OECD	6.30	6.33	6.37	6.23	6.31	6.15	6.18	6.32	6.30	6.14	6.16	6.31	6.31	6.24	6.23
Non-OECD	52.92	53.25	53.76	53.75	54.02	54.83	55.18	55.16	55.84	56.47	56.70	56.53	53.42	54.80	56.39
Eurasia	4.44	4.33	4.69	4.56	4.20	4.35	4.67	4.58	4.38	4.53	4.85	4.76	4.50	4.45	4.63
Europe	0.75	0.75	0.76	0.77	0.74	0.76	0.76	0.76	0.74	0.76	0.77	0.77	0.76	0.76	0.76
China	15.09	15.07	15.06	15.25	15.49	15.83	15.91	16.14	15.99	16.30	16.26	16.34	15.12	15.85	16.22
Other Asia	13.74	13.75	13.46	13.89	14.30	14.27	13.69	13.99	14.88	14.85	14.25	14.56	13.71	14.06	14.64
Other Non-OECD	18.91	19.34	19.79	19.28	19.29	19.62	20.15	19.68	19.85	20.02	20.57	20.09	19.33	19.69	20.13
Total World Consumption	98.71	98.62	100.38	99.72	99.65	100.05	100.99	101.19	101.56	101.77	102.85	102.85	99.36	100.47	102.26
Total Crude Oil and Other Liquids Inventory Net Withdrawals (million barrels per day)															
U.S. (50 States)	0.81	0.51	0.45	0.51	-0.12	-0.49	-0.08	0.36	-0.11	-0.55	-0.11	0.37	0.57	-0.08	-0.10
Other OECD	-0.09	-0.29	-0.48	-0.54	-0.30	-0.06	-0.13	-0.21	-0.07	-0.04	0.00	-0.20	-0.35	-0.17	-0.08
Other Stock Draws and Balance	-0.83	-0.35	-0.39	-1.63	-0.63	-0.12	-0.28	-0.46	-0.16	-0.10	-0.01	-0.43	-0.80	-0.37	-0.17
Total Stock Draw	-0.12	-0.12	-0.42	-1.67	-1.04	-0.67	-0.49	-0.31	-0.34	-0.69	-0.12	-0.26	-0.59	-0.62	-0.35
End-of-period Commercial Crude Oil and Other Liquids Inventories (million barrels)															
U.S. Commercial Inventory	1,154	1,180	1,215	1,213	1,228	1,286	1,297	1,264	1,268	1,312	1,316	1,277	1,213	1,264	1,277
OECD Commercial Inventory	2,604	2,656	2,735	2,783	2,825	2,888	2,911	2,897	2,907	2,956	2,960	2,938	2,783	2,897	2,938

(a) Supply includes production of crude oil (including lease condensates), natural gas plant liquids, biofuels, other liquids, and refinery processing gains.

(b) Includes lease condensate, natural gas plant liquids, other liquids, and refinery processing gain. Includes other unaccounted-for liquids.

(c) Consumption of petroleum by the OECD countries is synonymous with "petroleum product supplied," defined in the glossary of the EIA *Petroleum Supply Monthly* , DOE/EIA-0109. Consumption of petroleum by the non-OECD countries is "apparent consumption," which includes internal consumption, refinery fuel and loss, and bunkering.

\- = no data available

OECD = Organization for Economic Cooperation and Development: Australia, Austria, Belgium, Canada, Chile, the Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Israel, Italy, Japan, Latvia, Lithuania, Luxembourg, Mexico, the Netherlands, New Zealand, Norway, Poland, Portugal, Slovakia, Slovenia, South Korea, Spain, Sweden, Switzerland, Turkey, the United Kingdom, the United States.

OPEC = Organization of the Petroleum Exporting Countries: Algeria, Angola, Congo (Brazzaville), Equatorial Guinea, Gabon, Iran, Iraq, Kuwait, Libya, Nigeria, Saudi Arabia, the United Arab Emirates, Venezuela.

Notes: EIA completed modeling and analysis for this report on February 2, 2022.

The approximate break between historical and forecast values is shown with historical data printed in bold; estimates and forecasts in italics.

Historical data: Latest data available from Energy Information Administration international energy statistics.

Minor discrepancies with published historical data are due to independent rounding.

Forecasts: EIA Short-Term Integrated Forecasting System.

Table 4a. U.S. Petroleum and Other Liquids Supply, Consumption, and Inventories

U.S. Energy Information Administration | Short-Term Energy Outlook - February 2023

	2022				2023				2024				Year		
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	2022	2023	2024
Supply (million barrels per day)															
Crude Oil Supply															
Domestic Production (a)	**11.47**	**11.70**	**12.06**	**12.36**	*12.44*	*12.46*	*12.49*	*12.56*	*12.63*	*12.62*	*12.65*	*12.70*	**11.90**	*12.49*	*12.65*
Alaska	**0.45**	**0.44**	**0.42**	**0.45**	*0.43*	*0.36*	*0.39*	*0.41*	*0.40*	*0.34*	*0.36*	*0.38*	**0.44**	*0.40*	*0.37*
Federal Gulf of Mexico (b)	**1.67**	**1.70**	**1.80**	**1.88**	*2.00*	*1.96*	*1.86*	*1.85*	*1.91*	*1.89*	*1.83*	*1.85*	**1.76**	*1.91*	*1.87*
Lower 48 States (excl GOM)	**9.35**	**9.56**	**9.84**	**10.03**	*10.01*	*10.14*	*10.25*	*10.30*	*10.32*	*10.39*	*10.45*	*10.47*	**9.70**	*10.17*	*10.41*
Crude Oil Net Imports (c)	**3.00**	**2.81**	**2.75**	**2.17**	*2.80*	*3.28*	*3.51*	*3.28*	*2.90*	*3.02*	*3.25*	*2.87*	**2.68**	*3.22*	*3.01*
SPR Net Withdrawals	**0.31**	**0.80**	**0.84**	**0.48**	*0.05*	*0.15*	*0.05*	*0.00*	*-0.07*	*-0.07*	*-0.07*	*-0.07*	**0.61**	*0.06*	*-0.07*
Commercial Inventory Net Withdrawals	**0.08**	**-0.03**	**-0.12**	**0.03**	*-0.53*	*0.12*	*0.15*	*-0.09*	*-0.33*	*0.06*	*0.19*	*-0.10*	**-0.01**	*-0.08*	*-0.04*
Crude Oil Adjustment (d)	**0.71**	**0.81**	**0.74**	**0.82**	*0.52*	*0.56*	*0.50*	*0.44*	*0.54*	*0.61*	*0.50*	*0.46*	**0.77**	*0.50*	*0.53*
Total Crude Oil Input to Refineries	**15.56**	**16.09**	**16.26**	**15.86**	*15.28*	*16.58*	*16.69*	*16.20*	*15.68*	*16.25*	*16.52*	*15.87*	**15.94**	*16.19*	*16.08*
Other Supply															
Refinery Processing Gain	**0.95**	**1.07**	**1.05**	**1.03**	*0.95*	*1.03*	*1.04*	*1.05*	*0.99*	*1.00*	*1.02*	*1.02*	**1.03**	*1.02*	*1.01*
Natural Gas Plant Liquids Production	**5.61**	**5.92**	**6.09**	**5.97**	*5.97*	*6.24*	*6.23*	*6.25*	*6.25*	*6.43*	*6.40*	*6.43*	**5.90**	*6.17*	*6.38*
Renewables and Oxygenate Production (e)	**1.20**	**1.20**	**1.18**	**1.23**	*1.21*	*1.23*	*1.22*	*1.27*	*1.25*	*1.29*	*1.30*	*1.35*	**1.20**	*1.23*	*1.30*
Fuel Ethanol Production	**1.02**	**1.01**	**0.97**	**1.01**	*0.98*	*0.99*	*0.97*	*1.01*	*0.99*	*1.00*	*0.99*	*1.03*	**1.00**	*0.99*	*1.00*
Petroleum Products Adjustment (f)	**0.21**	**0.23**	**0.22**	**0.22**	*0.20*	*0.22*	*0.22*	*0.22*	*0.21*	*0.22*	*0.22*	*0.22*	**0.22**	*0.22*	*0.22*
Product Net Imports (c)	**-3.74**	**-3.99**	**-4.07**	**-4.06**	*-4.13*	*-4.15*	*-4.71*	*-4.97*	*-4.40*	*-4.13*	*-4.48*	*-4.73*	**-3.96**	*-4.49*	*-4.44*
Hydrocarbon Gas Liquids	**-2.14**	**-2.31**	**-2.16**	**-2.25**	*-2.52*	*-2.57*	*-2.58*	*-2.57*	*-2.53*	*-2.74*	*-2.65*	*-2.70*	**-2.21**	*-2.56*	*-2.66*
Unfinished Oils	**0.09**	**0.25**	**0.28**	**0.25**	*0.14*	*0.26*	*0.37*	*0.19*	*0.19*	*0.25*	*0.30*	*0.19*	**0.22**	*0.24*	*0.23*
Other HC/Oxygenates	**-0.09**	**-0.10**	**-0.07**	**-0.03**	*-0.06*	*-0.04*	*-0.03*	*-0.04*	*-0.06*	*-0.05*	*-0.04*	*-0.05*	**-0.07**	*-0.05*	*-0.05*
Motor Gasoline Blend Comp.	**0.40**	**0.60**	**0.48**	**0.37**	*0.39*	*0.71*	*0.39*	*0.41*	*0.40*	*0.65*	*0.39*	*0.37*	**0.46**	*0.48*	*0.46*
Finished Motor Gasoline	**-0.76**	**-0.73**	**-0.81**	**-0.80**	*-0.73*	*-0.78*	*-0.96*	*-1.17*	*-0.95*	*-0.76*	*-0.86*	*-0.98*	**-0.78**	*-0.91*	*-0.89*
Jet Fuel	**-0.04**	**-0.06**	**-0.11**	**-0.05**	*-0.16*	*-0.08*	*-0.05*	*0.01*	*0.14*	*0.16*	*0.18*	*0.16*	**-0.06**	*-0.07*	*0.16*
Distillate Fuel Oil	**-0.81**	**-1.15**	**-1.29**	**-1.02**	*-0.82*	*-1.15*	*-1.34*	*-1.29*	*-1.08*	*-1.18*	*-1.32*	*-1.30*	**-1.07**	*-1.15*	*-1.22*
Residual Fuel Oil	**0.14**	**0.10**	**0.10**	**0.06**	*0.09*	*0.10*	*0.08*	*0.13*	*0.06*	*0.09*	*0.08*	*0.15*	**0.10**	*0.10*	*0.10*
Other Oils (g)	**-0.54**	**-0.59**	**-0.49**	**-0.59**	*-0.46*	*-0.60*	*-0.58*	*-0.64*	*-0.56*	*-0.55*	*-0.56*	*-0.57*	**-0.55**	*-0.57*	*-0.56*
Product Inventory Net Withdrawals	**0.42**	**-0.25**	**-0.26**	**-0.01**	*0.36*	*-0.76*	*-0.28*	*0.44*	*0.28*	*-0.55*	*-0.24*	*0.53*	**-0.03**	*-0.06*	*0.01*
Total Supply	**20.22**	**20.27**	**20.47**	**20.26**	*19.84*	*20.38*	*20.41*	*20.45*	*20.26*	*20.52*	*20.75*	*20.69*	**20.30**	*20.27*	*20.56*
Consumption (million barrels per day)															
Hydrocarbon Gas Liquids	**3.87**	**3.43**	**3.48**	**3.61**	*3.78*	*3.47*	*3.48*	*3.83*	*4.00*	*3.49*	*3.60*	*3.85*	**3.60**	*3.64*	*3.73*
Other HC/Oxygenates	**0.13**	**0.17**	**0.17**	**0.20**	*0.21*	*0.20*	*0.20*	*0.22*	*0.21*	*0.24*	*0.26*	*0.28*	**0.17**	*0.21*	*0.25*
Unfinished Oils	**0.13**	**0.04**	**0.11**	**0.08**	*0.01*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	**0.09**	*0.00*	*0.00*
Motor Gasoline	**8.47**	**9.00**	**8.88**	**8.75**	*8.45*	*8.98*	*8.90*	*8.72*	*8.43*	*8.91*	*8.86*	*8.72*	**8.78**	*8.76*	*8.73*
Fuel Ethanol blended into Motor Gasoline	**0.87**	**0.93**	**0.92**	**0.92**	*0.87*	*0.93*	*0.92*	*0.93*	*0.88*	*0.93*	*0.92*	*0.94*	**0.91**	*0.91*	*0.92*
Jet Fuel	**1.45**	**1.61**	**1.60**	**1.57**	*1.48*	*1.63*	*1.66*	*1.64*	*1.65*	*1.75*	*1.82*	*1.75*	**1.56**	*1.60*	*1.74*
Distillate Fuel Oil	**4.14**	**3.89**	**3.86**	**3.99**	*3.98*	*3.90*	*3.83*	*3.94*	*4.04*	*3.94*	*3.84*	*3.98*	**3.97**	*3.91*	*3.95*
Residual Fuel Oil	**0.38**	**0.31**	**0.39**	**0.28**	*0.34*	*0.36*	*0.37*	*0.38*	*0.32*	*0.35*	*0.38*	*0.39*	**0.34**	*0.36*	*0.36*
Other Oils (g)	**1.65**	**1.82**	**1.99**	**1.77**	*1.60*	*1.85*	*1.99*	*1.73*	*1.62*	*1.84*	*1.99*	*1.73*	**1.81**	*1.79*	*1.80*
Total Consumption	**20.22**	**20.27**	**20.47**	**20.26**	*19.84*	*20.38*	*20.41*	*20.45*	*20.26*	*20.52*	*20.75*	*20.69*	**20.30**	*20.27*	*20.56*
Total Petroleum and Other Liquids Net Imports	**-0.74**	**-1.18**	**-1.32**	**-1.88**	*-1.33*	*-0.86*	*-1.21*	*-1.69*	*-1.50*	*-1.10*	*-1.23*	*-1.86*	**-1.28**	*-1.27*	*-1.42*
End-of-period Inventories (million barrels)															
Commercial Inventory															
Crude Oil (excluding SPR)	**414.4**	**417.5**	**428.8**	**426.1**	*474.0*	*463.0*	*448.7*	*456.7*	*486.9*	*481.1*	*463.2*	*472.8*	**426.1**	*456.7*	*472.8*
Hydrocarbon Gas Liquids	**142.0**	**186.7**	**243.6**	**217.4**	*174.6*	*224.2*	*262.5*	*217.1*	*179.8*	*230.3*	*266.4*	*220.8*	**217.4**	*217.1*	*220.8*
Unfinished Oils	**87.9**	**88.8**	**82.3**	**83.9**	*91.2*	*89.3*	*88.9*	*81.2*	*91.1*	*88.3*	*87.3*	*79.5*	**83.9**	*81.2*	*79.5*
Other HC/Oxygenates	**34.1**	**29.4**	**27.3**	**30.9**	*31.7*	*30.5*	*30.2*	*30.5*	*32.5*	*31.3*	*31.0*	*31.3*	**30.9**	*30.5*	*31.3*
Total Motor Gasoline	**238.5**	**221.0**	**209.6**	**223.8**	*228.4*	*239.2*	*232.1*	*244.8*	*239.9*	*244.2*	*237.2*	*245.8*	**223.8**	*244.8*	*245.8*
Finished Motor Gasoline	**17.3**	**17.1**	**17.6**	**16.4**	*14.9*	*16.8*	*18.8*	*21.5*	*18.5*	*19.6*	*21.3*	*23.5*	**16.4**	*21.5*	*23.5*
Motor Gasoline Blend Comp.	**221.2**	**203.8**	**192.0**	**207.5**	*213.5*	*222.4*	*213.3*	*223.2*	*221.4*	*224.6*	*215.9*	*222.4*	**207.5**	*223.2*	*222.4*
Jet Fuel	**35.6**	**39.3**	**36.2**	**34.1**	*37.0*	*40.1*	*41.1*	*38.0*	*39.1*	*39.1*	*40.7*	*37.2*	**34.1**	*38.0*	*37.2*
Distillate Fuel Oil	**114.6**	**111.4**	**110.5**	**118.5**	*104.9*	*116.9*	*122.3*	*123.6*	*116.1*	*117.8*	*121.8*	*120.2*	**118.5**	*123.6*	*120.2*
Residual Fuel Oil	**27.9**	**29.2**	**27.3**	**29.9**	*31.3*	*30.5*	*28.6*	*28.0*	*29.5*	*28.8*	*27.0*	*26.4*	**29.9**	*28.0*	*26.4*
Other Oils (g)	**58.5**	**56.4**	**49.5**	**48.3**	*55.4*	*53.7*	*44.9*	*46.6*	*56.0*	*54.1*	*45.1*	*46.7*	**48.3**	*46.6*	*46.7*
Total Commercial Inventory	**1153.6**	**1179.7**	**1215.1**	**1212.8**	*1228.7*	*1287.3*	*1299.2*	*1266.4*	*1270.9*	*1315.2*	*1319.7*	*1280.8*	**1212.8**	*1266.4*	*1280.8*
Crude Oil in SPR	**566.1**	**493.3**	**416.4**	**372.2**	*367.3*	*353.7*	*349.5*	*349.5*	*355.6*	*361.6*	*367.6*	*373.6*	**372.2**	*349.5*	*373.6*

(a) Includes lease condensate.

(b) Crude oil production from U.S. Federal leases in the Gulf of Mexico (GOM).

(c) Net imports equals gross imports minus gross exports.

(d) Crude oil adjustment balances supply and consumption and was previously referred to as "Unaccounted for Crude Oil."

(e) Renewables and oxygenate production includes pentanes plus, oxygenates (excluding fuel ethanol), and renewable fuels. Beginning in January 2021, renewable fuels includes biodiesel, renewable diesel, renewable jet fuel, renewable heating oil, renewable naphtha and gasoline, and other renewable fuels. For December 2020 and prior, renewable fuels includes only biodiesel.

(f) Petroleum products adjustment includes hydrogen/oxygenates/renewables/other hydrocarbons, motor gasoline blend components, and finished motor gasoline.

(g) “Other Oils" includes aviation gasoline blend components, finished aviation gasoline, kerosene, petrochemical feedstocks, special naphthas, lubricants, waxes, petroleum coke, asphalt and road oil, still gas, and miscellaneous products.

- = no data available

SPR: Strategic Petroleum Reserve

HC: Hydrocarbons

Notes: EIA completed modeling and analysis for this report on February 2, 2022.

The approximate break between historical and forecast values is shown with historical data printed in bold; estimates and forecasts in italics.

Historical data: Latest data available from Energy Information Administration databases supporting the following reports: *Petroleum Supply Monthly* , DOE/EIA-0109; *Petroleum Supply Annual* , DOE/EIA-0340/2; and *Weekly Petroleum Status Report* , DOE/EIA-0208.

Minor discrepancies with published historical data are due to independent rounding.

Forecasts: EIA Short-Term Integrated Forecasting System.

Table 5a. U.S. Natural Gas Supply, Consumption, and Inventories

U.S. Energy Information Administration | Short-Term Energy Outlook - February 2023

	2022				2023				2024				Year		
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	2022	2023	2024
Supply (billion cubic feet per day)															
Total Marketed Production	103.27	106.18	108.27	108.98	108.60	108.73	109.16	109.76	110.11	110.56	110.92	110.87	106.70	109.07	110.61
Alaska	1.06	1.00	0.96	1.02	1.01	0.93	0.85	0.98	1.00	0.92	0.84	0.97	1.01	0.94	0.93
Federal GOM (a)	2.05	2.11	2.19	2.17	2.28	2.26	2.11	2.05	2.07	2.00	1.87	1.85	2.13	2.17	1.95
Lower 48 States (excl GOM)	100.16	103.07	105.12	105.79	105.31	105.55	106.21	106.74	107.04	107.64	108.20	108.04	103.55	105.96	107.73
Total Dry Gas Production	95.09	97.59	99.46	100.13	99.87	99.95	100.34	100.89	101.21	101.63	101.95	101.91	98.09	100.27	101.68
LNG Gross Imports	0.15	0.01	0.06	0.05	0.10	0.04	0.04	0.06	0.10	0.04	0.04	0.06	0.07	0.06	0.06
LNG Gross Exports	11.50	10.80	9.74	10.49	11.23	11.63	11.97	12.27	12.63	12.50	12.11	13.14	10.63	11.78	12.59
Pipeline Gross Imports	8.89	7.73	7.84	8.15	8.28	6.86	7.05	7.50	8.24	6.81	7.04	7.49	8.15	7.42	7.40
Pipeline Gross Exports	8.45	8.46	8.08	8.32	9.20	8.79	9.14	9.56	9.99	9.38	9.71	10.14	8.33	9.17	9.81
Supplemental Gaseous Fuels	0.21	0.17	0.18	0.16	0.18	0.18	0.18	0.19	0.19	0.19	0.19	0.19	0.18	0.18	0.19
Net Inventory Withdrawals	20.14	-10.25	-8.94	2.45	12.37	-11.14	-7.53	4.54	16.37	-12.89	-9.57	4.19	0.78	-0.48	-0.49
Total Supply	104.54	75.99	80.78	92.13	100.38	75.47	78.97	91.35	103.48	73.90	77.83	90.56	88.30	86.50	86.43
Balancing Item (b)	0.31	0.14	0.01	0.83	0.50	-0.40	1.08	1.00	0.21	-1.32	-0.24	0.04	0.32	0.55	-0.33
Total Primary Supply	104.85	76.13	80.79	92.96	100.88	75.06	80.05	92.35	103.68	72.58	77.59	90.60	88.63	87.04	86.10
Consumption (billion cubic feet per day)															
Residential	26.09	7.85	3.57	17.39	23.99	8.02	4.25	17.53	25.81	8.01	4.31	17.58	13.67	13.41	13.91
Commercial	15.61	6.67	4.74	11.73	14.51	6.86	5.19	11.69	15.37	6.80	5.20	11.73	9.67	9.54	9.77
Industrial	25.46	22.25	21.47	23.67	23.85	21.65	21.66	24.08	24.49	20.91	20.49	22.81	23.21	22.81	22.17
Electric Power (c)	28.41	31.00	42.37	31.03	29.11	30.11	40.30	29.90	28.40	28.43	38.95	29.34	33.24	32.38	31.30
Lease and Plant Fuel	5.26	5.41	5.51	5.55	5.53	5.54	5.56	5.59	5.61	5.63	5.65	5.65	5.43	5.56	5.63
Pipeline and Distribution Use	3.86	2.80	2.98	3.44	3.74	2.75	2.94	3.42	3.85	2.66	2.84	3.35	3.27	3.21	3.18
Vehicle Use	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
Total Consumption	104.85	76.13	80.79	92.96	100.88	75.06	80.05	92.35	103.68	72.58	77.59	90.60	88.63	87.04	86.10
End-of-period Inventories (billion cubic feet)															
Working Gas Inventory	1,401	2,325	3,146	2,922	1,809	2,823	3,515	3,097	1,608	2,780	3,661	3,276	2,922	3,097	3,276
East Region (d)	242	482	759	692	312	614	855	706	255	586	875	726	692	706	726
Midwest Region (d)	296	557	917	837	408	672	988	832	336	666	1,033	889	837	832	889
South Central Region (d)	587	885	1,006	1,044	848	1,128	1,150	1,088	698	1,053	1,168	1,129	1,044	1,088	1,129
Mountain Region (d)	90	137	184	156	82	132	201	183	116	159	222	201	156	183	201
Pacific Region (d)	165	240	247	164	133	251	296	262	176	290	337	305	164	262	305
Alaska	21	25	32	29	26	26	26	26	26	26	26	26	29	26	26

(a) Marketed production from U.S. Federal leases in the Gulf of Mexico.

(b) The balancing item represents the difference between the sum of the components of natural gas supply and the sum of components of natural gas demand.

(c) Natural gas used for electricity generation and (a limited amount of) useful thermal output by electric utilities and independent power producers.

(d) For a list of States in each inventory region refer to *Weekly Natural Gas Storage Report, Notes and Definitions (http://ir.eia.gov/ngs/notes.html)* .

\- = no data available

LNG: liquefied natural gas.

Notes: EIA completed modeling and analysis for this report on February 2, 2022.

The approximate break between historical and forecast values is shown with historical data printed in bold; estimates and forecasts in italics.

Historical data: Latest data available from Energy Information Administration databases supporting the following reports: *Natural Gas Monthly* , DOE/EIA-0130; and *Electric Power Monthly* ,

Minor discrepancies with published historical data are due to independent rounding.

Forecasts: EIA Short-Term Integrated Forecasting System.

https://www.reuters.com/business/energy/us-energy-regulators-questioned-oversight-freeport-texas-lng-plant-2023-02-11/?taid=63e7deb8be05cf00017825ce&utm_campaign=trueAnthem:+Trending+Content&utm_medium=trueAnthem&utm_source=twitter

2 minute readFebruary 11, 202311:54 AM MSTLast Updated 16 min ago

U.S. energy regulators questioned on oversight of Freeport, Texas, LNG plant

By Arathy Somasekhar

[1/2] Residents line up to question U.S. energy and safety regulators during a meeting to review plans to restart the Freeport LNG gas-export facility idled by fire last year in Freeport, Texas, U.S., February 11, 2023. REUTERS/Arathy Somasekhar

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FREEPORT, Texas, Feb 11 (Reuters) - Texas residents grilled U.S. energy regulators on Saturday over their supervision of liquefied natural gas processing plants at a meeting to discuss conditions at the fire-idled Freeport LNG plant.

The second-largest U.S. liquefied natural gas (LNG) export facility was knocked offline by a fiery blast last June and operations halted while regulators review operations and staffing.

When fully running, Freeport LNG processes about 2 billion cubic feet per day of natural gas and exports up to 15 million tonnes of LNG per year. Its progress toward reopening is closely watched because of the impact on U.S. natural gas prices.

Bryan Lethcoe, a regional director of regulator Pipeline Hazardous Materials Safety Administration (PHMSA), said it would take "a number of months" for Freeport LNG to return to full operation. PHMSA officials declined to provide an exact estimate.

Residents questioned whether regulators have provided adequate oversight over the plant's repairs, its past emissions or the monitoring of local residents' health.

"We're concerned about them getting close to reopening. I'm hoping FERC and PHMSA kind of slow down the process of allowing them to reopen," said Melanie Oldham, one of about 100 residents who attended the meeting.

A Freeport LNG spokesperson declined to comment.

The blast resulted from inadequate operating and testing procedures, operator fatigue and other shortcomings, a safety audit found. About 10,000 pounds of methane were released, said a PHMSA representative. Methane is the main component of natural gas and a potent greenhouse gas.

The LNG producer has completed all repairs and is working to restart the facility safely once regulators approve its plans, a spokesperson previously has said.

Linda Daugherty, PHMSA's deputy associate administrator, said its reviews continue. Officials declined to comment on whether they uncovered any safety violations.

Reporting by Arathy Somsekhar in Freeport, Texas; Editing by Matthew Lewis and Daniel Wallis

[Mexico Pacific and ExxonMobil Execution of Long-Term LNG Sales and Purchase Agreements | Mexico Pacific]

Mexico Pacific and ExxonMobil Execution of Long-Term LNG Sales and Purchase Agreements

Mexico Pacific announced today the execution of two long-term Sales and Purchase Agreements (“SPAs”) with ExxonMobil LNG Asia Pacific (“EMLAP”) for the sale of a combined 2 million tonnes per annum (“MTPA”) of liquefied natural gas (“LNG”).

HOUSTON (PRWEB) FEBRUARY 07, 2023

Under the SPAs, the ExxonMobil affiliate will purchase LNG on a free-on-board basis from the first two trains of Mexico Pacific’s anchor LNG export facility, Saguaro Energia LNG, located in Puerto Libertad, Sonora, Mexico over a 20-year term. ExxonMobil also has an option for 1 MTPA from Train 3.

“We are pleased to announce these long-term SPAs with ExxonMobil”, said Ivan Van der Walt, Chief Executive Officer of Mexico Pacific.

“We have reached a critical point on contract volumes required for FID on our first two trains and will now shift focus to close contracting on the significant commercial momentum in place for a subsequent Train 3 FID. With natural gas playing a critical role in the quest for global energy security and the energy transition, we remain committed to supplying vital energy for decades. As we position for FID on the first two trains, we will also commence advanced engineering with Bechtel.”

“LNG has an important role to play in helping society reduce emissions by enabling the delivery of lower carbon energy,” said Peter Clarke, Senior Vice President of LNG for the ExxonMobil Upstream Company.

“We look forward to working with Mexico Pacific to continue growing ExxonMobil’s LNG portfolio and deliver Permian natural gas to global markets.”

“Mexico Pacific is a strategic asset in our energy transition infrastructure portfolio”, said Wil VanLoh, Founder and CEO of Quantum Energy Partners, the controlling stakeholder of Mexico Pacific.

“Mexico Pacific’s unparalleled project fundamentals and highly experienced leadership team have established it as a premier LNG solution for customers and Permian producers to provide reliable and cost-effective LNG to support the energy transition.”

About Mexico Pacific

Mexico Pacific’s anchor project, the Saguaro Energia LNG Facility, is a 3 train, 14.1 mtpa West Coast North American LNG export facility located in Puerto Libertad, Sonora, Mexico. The Saguaro Energia LNG Facility achieves significant cost and logistical advantages, including the lowest landed price of North American LNG into Asia, leveraging low-cost natural gas sourced from the nearby Permian Basin, and providing a significantly shorter shipping route that avoids Panama Canal transit for Asian markets. More information can be found at http://www.mexicopacific.com.

About Quantum Energy Partners

Founded in 1998, Quantum Energy Partners is a leading provider of private equity, credit, and venture capital to the global energy and energy transition industry, having managed together with its affiliates more than $19 billion in equity commitments since inception. For more information on Quantum, please visit http://www.quantumep.com.

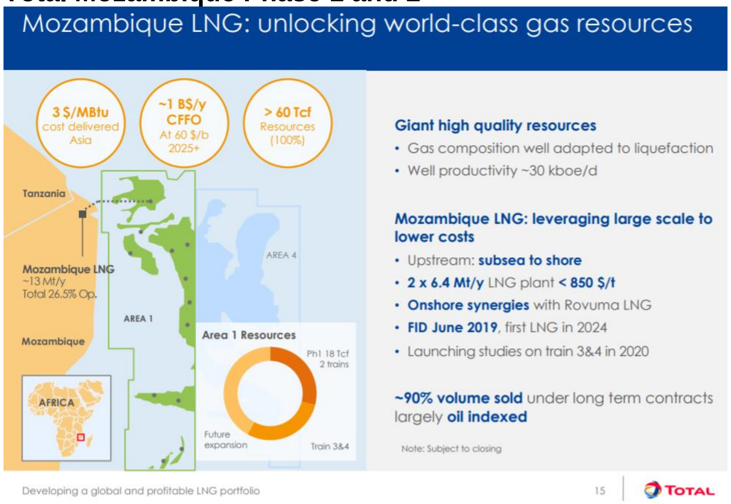
Multiple Brownfield LNG FIDs Now Needed To Fill New LNG Supply Gap From Mozambique Chaos? How About LNG Canada Phase 2?

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

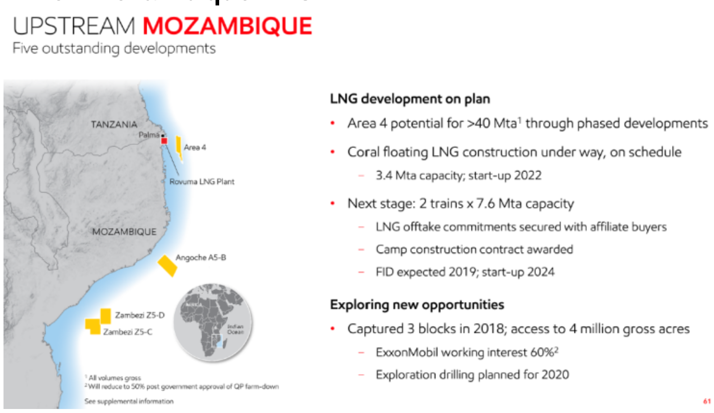
<u>Total's Mozambique force majeure is no surprise, especially the need to the restoration of security and stability "in a sustained manner"</u>. Yesterday, Total announced [LINK] "*Considering the evolution of the security".* No one should be surprised by the force majeure or the sustained manner caveat.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

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

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

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

Source: IEA

On Track   More Efforts Needed   Not on Track

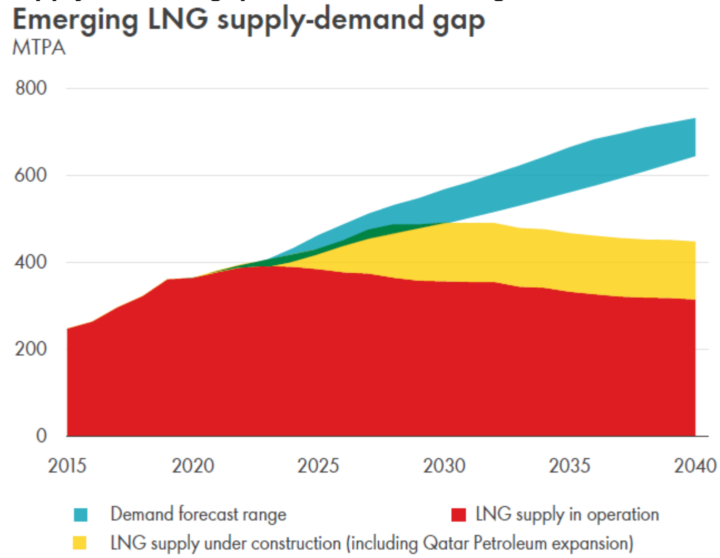
Source: IEA Tracking Clean Energy Progress, June 2020

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

<u>Shell's March 2021 long term outlook for LNG demand was basically unchanged vs 2020 and leads to a LNG supply gap in mid 2020s</u> Shell does not provide the detailed numbers in their Feb 25, 2021 LNG forecast. We would assume they

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

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



Source: Shell LNG Outlook 2021, Feb 25, 2021

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

<u>And does this bigger, nearer supply gap force LNG players to look at what brownfield LNG projects they could advance?</u> A greenfield LNG project would likely take at least until 2027 to be in operations. Its why we believe the Mozambique delays will effectively force major LNG players to look to see if there are brownfield LNG projects they should look to advance. Prior to the just passed winter, no one would think Shell or other major LNG players would be considering any new LNG FIDs in 2021. All the big companies are in capital reduction mode and debt reduction mode. But Brent oil is now solidly over $60 and LNG prices hit record levels in Jan and the world's economic and oil and gas demand outlook are increasing with vaccinations. And we are starting to see companies move to increasing capex with the higher cash flows. We would not expect any major LNG players to move to FID right away. But we see them watching to see if 2021 plays out to still support this increasing LNG supply gap. And unless new mutations prevent vaccinations from returning the world to normal, we suspect that major LNG players, like other oil and gas companies, will be looking to increase

capex as they approve 2022 budgets. The outlook for the future has changed dramatically in the last 5 months. The question facing Shell and others, should they look to FID new LNG brownfield projects in the face of an increasing LNG supply gap that is going to hit faster and harder than expected a few months ago. We expect these decisions to be looked at before the end of 2021. LNG prices will be stronger, but we expect the limiting cap in Asia will be that thermal coal will be used to mitigate some LNG price pressure.

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

A LNG Canada Phase 2 would be a big plus to Cdn natural gas. A LNG Canada Phase 2 FID would be a big plus for Cdn natural gas. It would allow another ~1.8 bcf/d of Cdn natural gas to be priced against Asian LNG prices and not against Henry Hub. And it would provide demand offset versus Trudeau if he moves to make electricity "emissions free" and not his prior "net zero emissions". Mozambique may be in Africa, but, unless sustained peace and security is attained, it is a game changer to LNG outlook creating a bigger and sooner LNG supply gap. And with a stronger tone to oil and natural gas prices in 2021, the LNG supply gap will at least provide the opportunity for Shell to consider FID for its brownfield LNG Canada Phase 2 and provide big support to Cdn natural gas for back half of the 2020s. And perhaps if LNG Canada is exporting 3.6 bcf/d from two phases, it could help flip Cdn natural gas to a premium to US natural gas especially if Biden is successful in reducing US domestic natural gas consumption for electricity. The next six months will be very interesting to watch for LNG markets.

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

Posted 11am on July 14, 2021

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

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

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

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

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

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

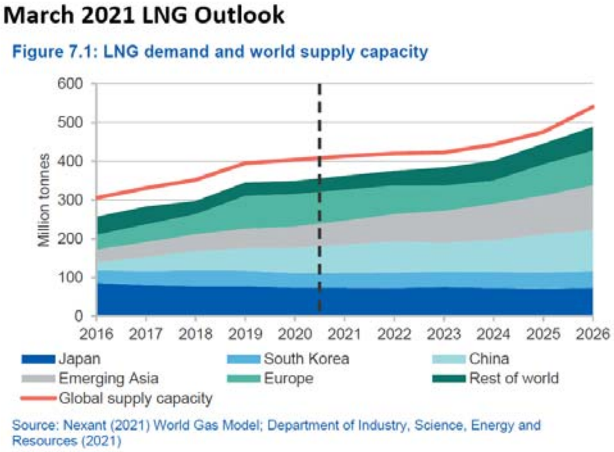
Common theme - new LNG supply is being delayed ie. [Total] Mozambique. Don't forget need capacity>demand due to normal maintenance, etc. Positive for LNG." (ii) Chevron's Gorgon. A big LNG story in H2/20 was the emergence of weld quality issues in the propane heat exchangers at Train 2, which required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

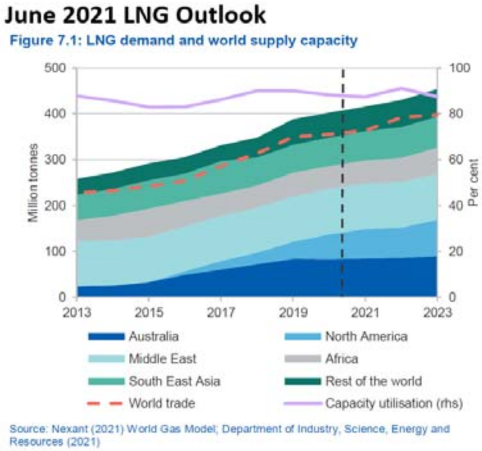
<u>Cheniere stopped the game playing the game on June 30</u>. Our July 4, 2021 Energy Tidbits memo noted that it looks like Cheniere has stopped playing stupid with respect to the strengthening LNG market in 2021. We can't believe they thought they were fooling anyone, especially their competitors. Bu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

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

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

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



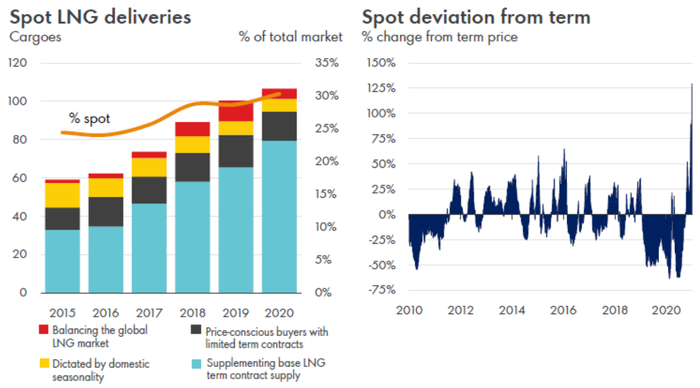


Source: Australia Resources and Energy Quarterly

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

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

Spot LNG deliveries and Spot deviation from term price



Source: Shell LNG Outlook 2021 on Feb 25, 2021

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

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

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

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

<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://www.tcenergy.com/incident/milepost-14-incident/

Updates

TC Energy shares initial investigation findings, revised release volume and actions

Update 18 – February 9, 2023: 8:30 a.m. CT

We continue to progress our remediation and the root cause investigation at our Keystone Milepost-14 incident site in Washington County, Kansas, with the following updates of note:

- We have advanced our root cause investigation with the completion of an independent mechanical and metallurgical analysis of the failed pipe. The analysis concludes that the failure occurred due to a combination of factors, including bending stress on the pipe and a weld flaw at a pipe to fitting girth weld that was completed at a fabrication facility.

Although welding inspection and testing were conducted within applicable codes and standards, the weld flaw led to a crack that propagated over time as a result of bending stress fatigue, eventually leading to an instantaneous rupture. The cause of the bending stress remains under investigation as part of the broader third-party root cause failure analysis.

The metallurgical analysis identified no issues with the strength or material properties of the pipe or manufactured fitting. The pipeline was operating within its operational design and within the pipeline design maximum operating pressure.

Our focus continues to be the safe operation of the pipeline system. Additional operational mitigations, such as reduced operating pressure, are in place to support the safe operations of our system while we continue our response and investigation. Our team is progressing a remediation plan, including an analysis of other areas with potentially similar conditions, the use of additional in-line inspections, and further operational mitigations.

- We have revised the release volume to 12,937 barrels from the original estimated maximum of 14,000 barrels. The revised volume is the actual measured volume of crude oil injected during the re-fill of the pipeline system during its safe restart.

- Our commitment to remediation, investigation and shared learnings is unwavering. To support this, we have arrived at a cost estimate of US$480 million. This estimate may be adjusted as we continue to progress work on site. We are working with our insurers to maximize cost recoveries.

We will continue to provide updates as information becomes available.

Media inquiries can be sent to TC Energy media relations at media@tcenergy.com.

Community related inquiries can be sent to public_affairs_us@tcenergy.com or 1-855-920-4697.

https://www.naturalgasintel.com/corrosion-left-keystone-pipeline-less-than-half-the-thickness-of-a-dime-says-u-s-government-accountability-office/

Corrosion Left Keystone Pipeline ‘Less than Half the Thickness of a Dime,’ Says U.S. Government Accountability Office

BY GORDON JAREMKO

DECEMBER 16, 2022

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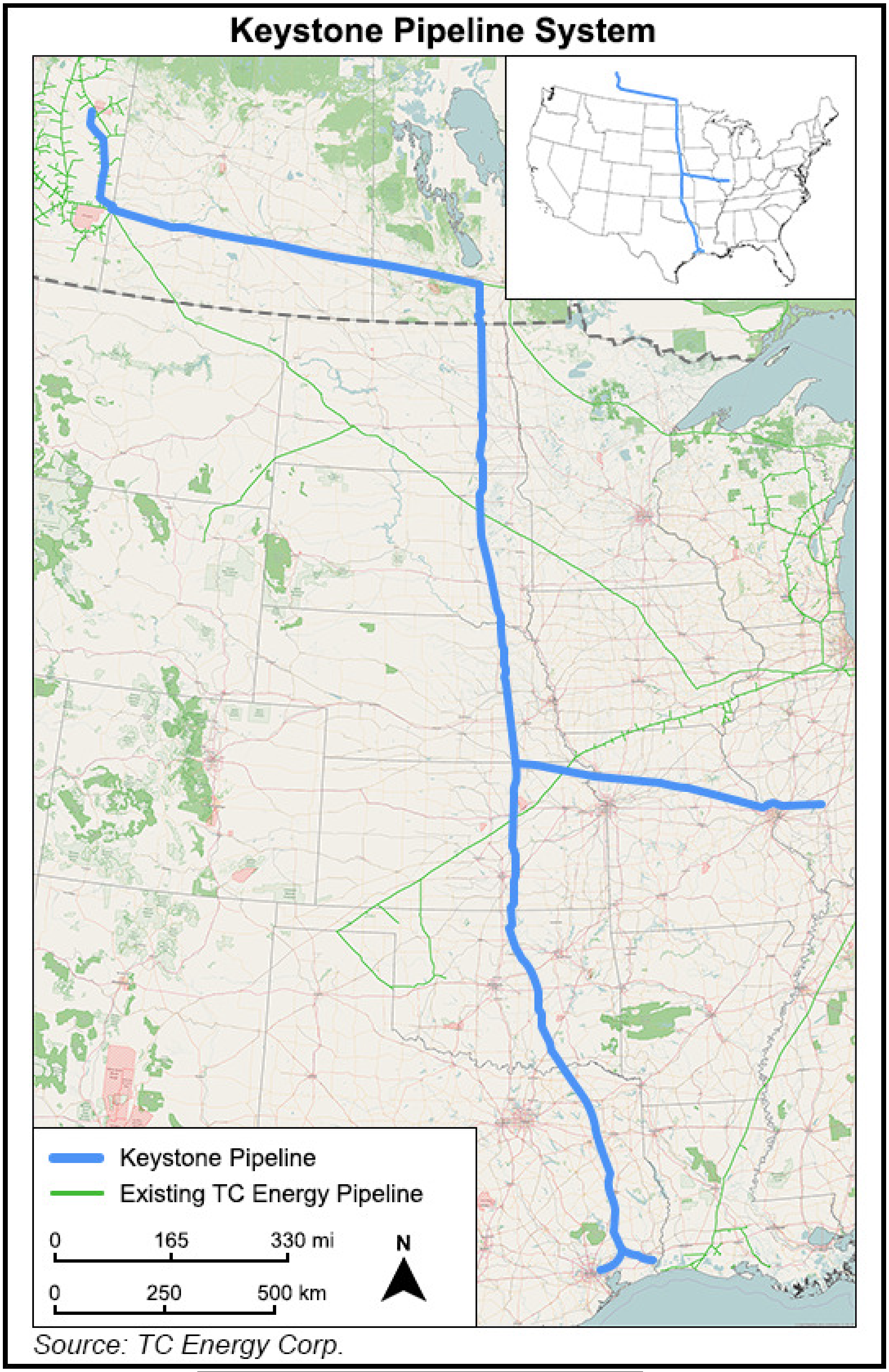
Total oil spills from the Keystone Pipeline have grown to 25,975 bbl since TC Energy Corp. opened the conduit in 2010 to transport Canadian crude south to the Midwest and Gulf of Mexico.



The estimated **14,000 bbl leak began on Dec. 7** into a Kansas creek and farm, halting flows for a week and leaving TC unable to state the cause as of yet. The leak has more than doubled to an 11,975 bbl spill count as of mid-2021 by the U.S. Government Accountability Office (GAO).

The count, in a report titled Pipeline Safety: Information on Keystone Accidents and Department of Transportation Oversight, followed a 17-month performance audit. The GAO examined Keystone as the only U.S. oil line allowed to exceed standard industry operating pressure in its pipe.

The cause of the **Kansas spill remains under investigation**. High pressure did not cause Keystone leaks documented until mid-2021, said the 38-page GAO report to the U.S. House of Representatives' Energy and Commerce Committee and Transportation Committee.

An inquiry for the Pipeline and Hazardous Materials Safety Administration (PHMSA) blamed the mishaps on construction issues such as pump station vibration, a failed weld, a dent inflicted by a work vehicle, and an "atypical" steel seam that weakened the pipe.

Risks caused by corrosion are also severe. The GAO described an October 2012 spill disaster threat that TC and the PHMSA spotted and prevented on four pipe sections in sensitive, populated areas on a Keystone leg across Missouri and Illinois.

"In all four locations, the amount of metal loss – that is, corrosion – was over 60% deep. In one location, 97% of the metal had corroded, leaving a remaining pipeline wall thickness of 0.0120 inch – less than half the thickness of a dime," said the GAO.

The **PHMSA granted Keystone** its lone standing as a high-pressure U.S. line during its design in 2007. The permit lets the conduit work at 80% of specified minimum yield strength (SMYS). The U.S. industry standard is 72%.

Use of the high-pressure permit spread gradually after Keystone deliveries began in 2010 and the entire network qualified as of 2017. The line also had its previous biggest spills, in North Dakota and South Dakota, in 2017 and 2019.

Canada adopted an 80% SMYS rule for high-strength oil pipe in 2004. In the U.S., TC accepted 51 conditions to **secure the Keystone pressure permit**. Others follow the lower SMYS standard as cheaper to obey than the Keystone conditions, reported the GAO. Safer pipelines for natural gas have obtained 94 high-pressure permits.

By a standard that industry critics favor, Keystone spills stand out. The 25,975 bbl total would fill an entire long course or Olympic-sized swimming pool plus nearly two-thirds of a second one, each 50 meters long, 25 meters wide and two meters deep.

But by industrial shipping standards, the spills are small. Total leaks to date work out to 4.3% of one day of traffic on the 2,6875-mile Keystone route for 600,000 b/d of Canadian exports to the U.S. Midwest and Texas coast of the Gulf of Mexico.

As of mid-2021, Keystone delivered more than three billion bbl of Alberta oil and the high capacity flows have continued, noted the GAO. PHMSA has accelerated inspections and about doubled special attention for construction flaws, added the audit agency.

Keystone’s North and South Dakota leaks led to six of 22 mishaps since 2010 that affected people or the environment. “According to PHMSA measures for these more severe types of accidents, from 2010 to 2020 TC Energy performed better than nationwide averages, but worse in the past five years due to the 2017 and 2019 spills,” reported the GAO.

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GAO@100

Highlights

Highlights of GAO-21-588, a report to congressional requesters

Why GAO Did This Study

Since it began operating in 2010, Keystone has transported over 3 billion barrels of crude oil from Canada to refineries in Illinois, Oklahoma, and Texas, according to its operator, TC Energy. Prior to construction, TC Energy requested and obtained a special permit from PHMSA to operate certain portions of the pipeline at a higher stress level than is allowed under PHMSA's regulations. Since TC Energy was the first and remains the only hazardous liquid pipeline operator to request a waiver of this particular regulation, the Keystone special permit is unique.

GAO was asked to review PHMSA's oversight of the Keystone Pipeline. This report discusses: (1) PHMSA's actions to approve the Keystone special permit and allow the pipeline to operate at a higher stress level, (2) how Keystone accidents compare to accidents on all U.S. crude oil pipelines since 2010, and (3) PHMSA's actions in response to Keystone safety issues.

GAO reviewed applicable statutes and regulations, the special permit, and PHMSA enforcement actions. It also analyzed PHMSA's pipeline accident data from 2010 to 2020 to describe Keystone's accidents and compare TC Energy to PHMSA's performance measures. GAO also interviewed TC Energy representatives, PHMSA officials, and 17 stakeholders selected to provide a range of perspectives representing industry associations; pipeline safety and technical stakeholders; and environmental, tribal, and state organizations.

View GAO-21-588. For more information, contact Heather Krause at (202) 512-2834 or KrauseH@gao.gov.

July 2021

PIPELINE SAFETY

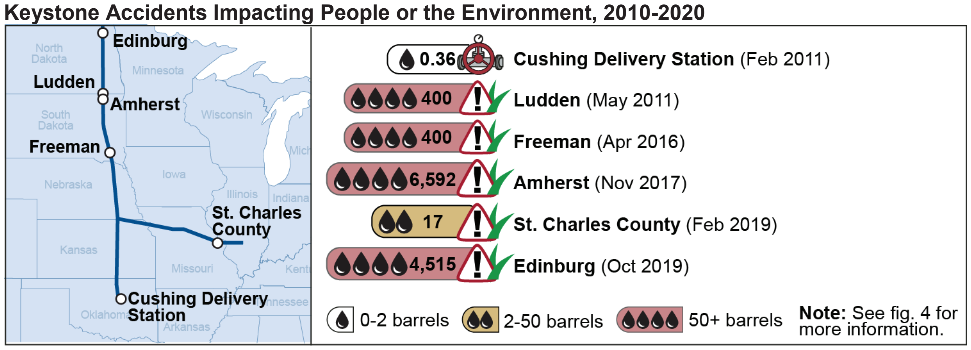
Information on Keystone Accidents and DOT Oversight

What GAO Found

The Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA) required TC Energy to take additional safety measures specified in a special permit as conditions of allowing certain portions of the Keystone Pipeline (Keystone) to operate at a higher stress level than allowed by regulation. PHMSA reviewed technical information and drew on its experience granting similar permits to natural gas pipelines to develop 51 conditions with which TC Energy must comply. Most pipeline safety and technical stakeholders GAO interviewed agreed the conditions offset the risks of operating at a higher stress level. However, PHMSA did not allow TC Energy to fully operate Keystone at this higher stress level until 2017, after TC Energy replaced pipe affected by industry-wide pipeline quality issues.

Keystone's accident history has been similar to other crude oil pipelines since 2010, but the severity of spills has worsened in recent years. Similar to crude oil pipelines nationwide, most of Keystone's 22 accidents from 2010 through 2020 released fewer than 50 barrels of oil and were contained on operator-controlled property such as a pump station. The two largest spills in Keystone's history in 2017 and 2019 were among the six accidents that met PHMSA's criteria for accidents "impacting people or the environment." According to PHMSA's measures for these more severe types of accidents, from 2010 to 2020 TC Energy performed better than nationwide averages, but worse in the past five years due to the 2017 and 2019 spills.

Keystone Accidents Impacting People or the Environment, 2010-2020



Source: PHMSA data and Map Resources. | GAO-21-588

In response to each of Keystone's four largest spills, PHMSA issued Corrective Action Orders requiring TC Energy to investigate the accidents' root causes and take necessary corrective actions. These investigations found that the four accidents were caused by issues related to the original design, manufacturing of the pipe, or construction of the pipeline. PHMSA also issued other enforcement actions and assessed civil penalties to TC Energy for deficiencies found during inspections, such as inadequate corrosion prevention and missing pipeline markers. Based in part on its experience overseeing Keystone, PHMSA officials said they have increased resources to conduct inspections during construction of other pipelines and are establishing a more formal process to document and track the compliance of all special permits, including Keystone's permit.

441 G St. N.W.
Washington, DC 20548

July 22, 2021

The Honorable Frank Pallone, Jr.
Chairman
Committee on Energy and Commerce
House of Representatives

The Honorable Peter A. DeFazio
Chairman
Committee on Transportation and Infrastructure
House of Representatives

The Honorable Bobby L. Rush
Chairman
Subcommittee on Energy
Committee on Energy and Commerce
House of Representatives

The Honorable Donald M. Payne, Jr.
Chairman
Subcommittee on Railroads, Pipelines, and Hazardous Materials
Committee on Transportation and Infrastructure
House of Representatives

About 84,000 miles of pipelines transported crude oil from production areas to refineries in the United States as of 2020. Although pipelines are relatively safe when compared to transportation alternatives such as truck and rail, pipeline accidents can release large amounts of crude oil into the environment, damaging natural resources and wildlife. Within the U.S. Department of Transportation, the Pipeline and Hazardous Materials Safety Administration (PHMSA) oversees safety for pipelines carrying oil, natural gas, and other products.[1] PHMSA's oversight includes setting and enforcing the federal minimum pipeline safety standards for the construction, operation, maintenance, and inspection of interstate pipelines. Operators may apply for—and PHMSA has the authority to issue—special permits that waive compliance with one or more pipeline

[1]PHMSA's general authority is under the Pipeline Safety Laws codified at 49 U.S.C. § 60101 et seq.

safety regulations if PHMSA determines that the permit is not inconsistent with pipeline safety.[2]

The Keystone pipeline runs 2,687 miles from Canada into the United States and according to the operator has transported over 3 billion barrels of crude oil since it began operating in 2010. The oil it transports from Canada to refineries in Illinois, Oklahoma, and Texas is a dense and highly viscous form of crude oil derived from oil sands, called “bitumen.” Prior to Keystone’s construction, the pipeline’s operator, TransCanada (now TC Energy), requested and was granted a special permit from PHMSA that allowed the company to use pipe made of higher grade steel in order to operate some sections of the pipeline at a higher stress level than would otherwise be allowed under regulation.[3]

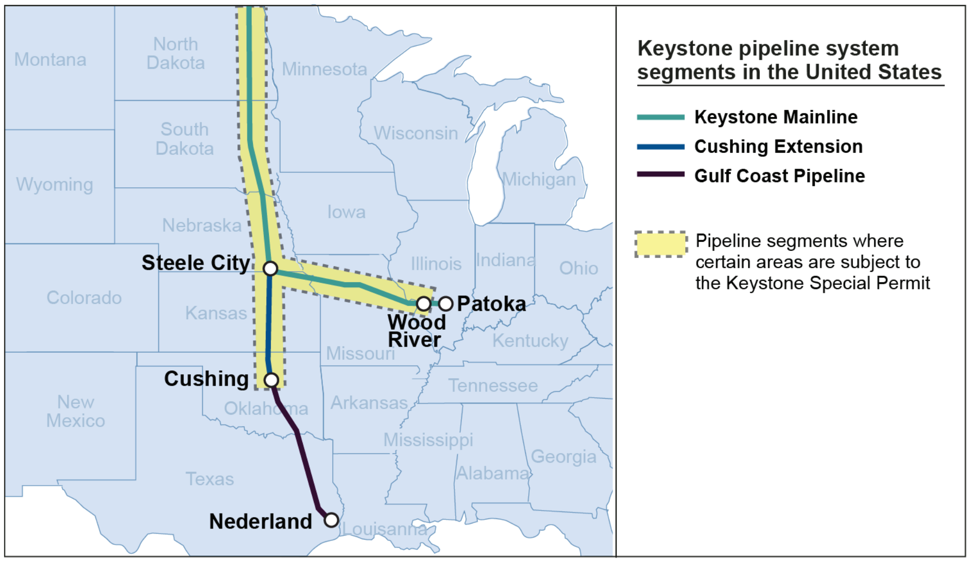
The Keystone special permit applies to certain portions of two pipeline segments, and in this report, we refer collectively to those segments as “Keystone.” The first segment is the 1,025-mile, 30-inch diameter pipeline referred to as the Mainline from the Canadian border at North Dakota, to Wood River, Illinois. The second segment is the 291-mile, 36-inch diameter pipeline referred to as the Cushing Extension from Steele City, Nebraska, to Cushing, Oklahoma. See figure 1. This report focuses on these segments and does not include the Gulf Coast Pipeline or Keystone XL. The Keystone XL pipeline was originally proposed in 2008 and was intended to cross the U.S.-Canada border in Montana and travel through South Dakota and Nebraska before joining the existing Keystone pipeline at Steele City, Nebraska. On June 9, 2021, TC Energy announced that it had terminated Keystone XL, after the project’s presidential permit was revoked in January 2021.[4]

[2]49 U.S.C. § 60118(c); 49 C.F.R. § 190.341.

[3]PHMSA, Grant of Special Permit to TransCanada Keystone Pipeline, Docket No. PHMSA-2006-26617 (Apr. 30, 2007).

[4]Presidential permits are distinct from special permits issued by PHMSA. The Secretary of State has the authority to receive applications for presidential permits for the construction, connection, operation, or maintenance of pipelines and other physical infrastructure at the borders of the United States. The process involves consulting relevant federal agencies, determining whether the application meets the standards for granting a presidential permit, and if so, issuing the permit. Exec. Order No. 11423, § 1 (Aug. 16, 1968), as amended. The presidential permit to construct Keystone XL, issued under the Trump administration in 2019, was revoked by a January 20, 2021 Executive Order under the Biden administration. TC Energy was previously denied a presidential permit for the pipeline under the Obama administration in 2015.

Figure 1: Map of TC Energy Keystone Pipeline System in the United States



Sources: PHMSA and TC Energy data and Map Resources. | GAO-21-588

A number of accidents have occurred on Keystone, including an October 2019 rupture near Edinburg, North Dakota which released more than 4,500 barrels of oil. You asked us to review Keystone accidents and PHMSA's oversight of this pipeline. This report examines (1) PHMSA's actions to approve the Keystone special permit and allow the pipeline to operate at a higher stress level, (2) how Keystone accidents compare to accidents on all U.S. crude oil pipelines since 2010, and (3) PHMSA's actions in response to Keystone safety issues.

To describe the actions that PHMSA took to approve the Keystone special permit and allow the pipeline to operate at a higher stress level, we reviewed applicable statutes and regulations, the 2007 special permit, and related PHMSA and TC Energy documentation. These documents included: TC Energy's application and additional documents the company provided in response to PHMSA requests; a PHMSA-commissioned technical report; PHMSA advisory meeting proceedings; and public comments submitted in response to PHMSA's notice and request for comments on TC Energy's application. We also conducted semi-structured interviews with 17 stakeholders to gain their perspectives on

PHMSA's approval of the special permit.[5] The stakeholders were selected to capture a range of known interests (industry, safety, environmental, state, and tribal interests). These stakeholders were identified by reviewing documentation such as the PHMSA advisory meeting noted above and a National Academies report on the safety of crude oil pipelines, as well as by asking for recommendations in interviews. Stakeholder views cannot be generalized to represent the views of all Keystone stakeholders.

To compare Keystone accidents to all U.S. crude oil pipeline accidents, we analyzed PHMSA accident data. We used these data to describe Keystone accidents from 2010 through 2020 in terms of the amount of oil released, the accident location and cause, and whether the accident met PHMSA's definition for an accident impacting people or the environment.[6] For purposes of this report, we characterize such accidents as "more severe" than those that did not meet PHMSA's definition for impacting people or the environment. We compared the averages of these more severe accidents for Keystone's operator, TC Energy, to national averages for operators of pipelines transporting crude oil, refined petroleum products, and biofuel from 2010 (the first year of Keystone operations) through 2020 (the latest full year of PHMSA data available). Specifically, we used PHMSA's performance measures—accidents impacting people or the environment per 1,000 miles of pipeline and barrels of oil spilled per billion barrel-miles—to compare TC Energy to 3-, 5-, and 11-year averages across pipeline operators nationwide. We assessed the reliability of these data by (1) performing manual testing, (2)

[5]These stakeholders were: representatives from three industry associations (Association of Oil Pipelines, American Petroleum Institute, and Interstate Natural Gas Association of America); seven pipeline technical and safety stakeholders (National Transportation Safety Board's Pipeline and Hazardous Materials Division; Pipeline Safety Trust; Kiefner and Associates; Accufacts, Inc.; Kent Muhlbauer; Evan Vokes; and Jeff Wiese); and representatives from seven environmental, state, and tribal organizations (Dakota Rural Action; Bold Nebraska; Paul Blackburn, Environmental Attorney; Natural Resources Defense Council; South Dakota Public Utilities Commission and South Dakota Department of Environment and Natural Resources, North Dakota Department of Environmental Quality; and Great Plains Tribal Chairmen's Association).

[6]PHMSA defines an accident as impacting people or the environment if it meets one of two criteria: (1) regardless of the accident's location, any of the following occur: a fatality, injury requiring in-patient hospitalization, ignition, explosion, evacuation, wildlife impact, contamination of specific water sources, or damage to public or private, non-operator property or (2) where the accident's location is not totally contained on operator-controlled property, any of the following occur: an unintentional release equal to or greater than 5 gallons in a high consequence area, an unintentional release of 5 barrels or more outside of a high consequence area, surface water contamination, or soil contamination.

reviewing documentation about the data and the system that produced them, and (3) interviewing PHMSA officials and TC Energy representatives. We determined these data were sufficiently reliable for these purposes. To gain their perspectives on Keystone accidents, we interviewed PHMSA officials, TC Energy representatives, and the 17 stakeholders described above.

To identify actions PHMSA has taken in response to Keystone's safety issues, we reviewed PHMSA enforcement actions for Keystone from 2010 through 2020 and TC Energy's responses to these actions. PHMSA's enforcement actions included Warning Letters, Notices of Probable Violations, and Corrective Action Orders. TC Energy's responses to PHMSA's enforcement actions include Root Cause Failure Analysis reports of accidents.[7] We analyzed the enforcement actions against TC Energy to identify the most common issues, such as repeated noncompliance with the same regulations or special permit conditions. To further describe PHMSA's enforcement actions and the actions TC Energy took in response, we interviewed PHMSA officials, TC Energy representatives, and the 17 stakeholders described above for their perspectives.

We conducted this performance audit from April 2020 to July 2021 in accordance with generally accepted government auditing standards. Those standards require that we plan and perform the audit to obtain sufficient, appropriate evidence to provide a reasonable basis for our findings and conclusions based on our audit objectives. We believe that the evidence obtained provides a reasonable basis for our findings and conclusions based on our audit objectives.

Background

The U.S. energy pipeline network includes about 530,000 miles of pipelines transporting hazardous liquids and natural gas over long distances to users. As of 2020, about 228,000 miles of these pipelines carried hazardous liquids such as crude oil, refined oil products, or other liquids such as anhydrous ammonia. Slightly more than one-third of these

[7]We report on the findings of the Root Cause Failure Analyses but did not independently review or evaluate the methodology used in these reports.

hazardous liquid pipelines (about 84,000 miles) transported crude oil to refineries for processing into petroleum products, similar to Keystone.[8]

Pipeline accidents can occur from a variety of causes, including construction damage, corrosion, mechanical failure, control system failure, and operator error. Natural forces, such as floods and earthquakes, can also damage pipelines. Although relatively few people have been injured or killed due to pipeline accidents, a single accident can have catastrophic consequences for public safety and the environment. For example, in July 2010, a pipeline operated by Enbridge ruptured near Marshall, Michigan, releasing an estimated 19,500 barrels of crude oil into a creek, wetlands, and the Kalamazoo River.

PHMSA's Roles and Responsibilities

PHMSA is responsible for setting and enforcing the federal minimum safety standards for the design, construction, operation, maintenance, and inspection of interstate hazardous liquid and natural gas pipelines.[9] These standards include technical requirements such as:

- **Maximum operating pressure as a percentage of Specified Minimum Yield Strength (SMYS).** PHMSA regulations specify that the maximum operating pressure for hazardous liquid pipelines is 72 percent of a pipeline's SMYS.[10] SMYS represents the stress level at which a steel pipeline will begin to deform. It can vary depending on the grade (strength) of steel used to manufacture the pipe, so maximum operating pressure is defined as a percentage of SMYS. For example, higher grade steel allows for thinner but stronger pipeline walls, which in turn allows for operation at a higher percentage of SMYS. Pipelines manufactured using lower-grade steel would need thicker walls to withstand the same pressure as pipelines

[8]In addition to the 530,000 miles of hazardous liquid and natural gas transmission pipelines, the nation's 2.8 million miles of pipeline also includes 2.3 million miles of natural gas distribution pipelines that deliver gas to end users, such as businesses and homes, and about 21,000 miles of regulated gathering pipelines that carry natural gas and hazardous liquids from production areas and wells to processing plants.

[9]PHMSA also has the authority to set the minimum safety standards for intrastate pipelines. However, states may assume some regulatory, inspection, and enforcement responsibilities for those pipelines after certifying to PHMSA that they have adopted and are enforcing the federal minimum safety standards. States with certifications may adopt additional or more stringent safety standards as long as they are compatible with federal standards.

[10]*See* 49 C.F.R. §§ 195.106, 195.406(a). PHMSA's hazardous liquid pipeline safety regulations are located in 49 C.F.R. Part 195.

designed with stronger steel. Operating at a higher SMYS allows operators to reduce overall steel material expense since higher grade steel pipelines have thinner walls.

- **Corrosion prevention technologies.** PHMSA regulations include specifications to protect pipelines from corrosion. For example, PHMSA generally requires pipelines to have external coatings and cathodic protection systems. External coatings are protective layers of plastic material or other chemical compounds that are bonded to the metallic surface of a pipe to protect it from outside elements. Cathodic protection systems help prevent or mitigate external corrosion by applying an electrical current onto a buried pipeline.[11] Corrosion prevention is particularly important for pipelines operating at a higher SMYS using thinner but higher grade steel, as the thinner pipeline walls may have less corrosion allowance—that is, the amount of material that may corrode without affecting the integrity of the pipeline.

In addition, since 2000, PHMSA has required certain pipeline operators to develop and maintain integrity management programs to systematically manage risks in areas where accidents would have the most severe consequences, called high consequence areas.[12] For example, operators must periodically assess the integrity of pipelines in these areas through various methods, including by inserting electronic in-line inspection devices into the pipeline to identify potential risks such as corrosion or other damage.[13]

PHMSA officials periodically inspect pipelines to oversee operators' compliance with federal requirements and may issue enforcement actions when an inspector identifies probable violations of pipeline safety laws, regulations, or a PHMSA order, such as the conditions of a special

[11]Corrosion is an electro-chemical reaction that causes metal loss from a pipe that is in contact with the ground. Cathodic protection provides a substitute electro-chemical reaction to minimize corrosion. Specifically, cathodic protection involves voltage transformers, called rectifiers, and groundbeds that contain anodes, which are highly active metals that "sacrifice" by corroding rather than having the corrosion occur on the pipeline.

[12]High consequence areas generally include high population areas, other populated areas, certain navigable waterways, and areas unusually sensitive to environmental damage. 49 C.F.R. § 195.450.

[13]In 2019, PHMSA issued a final rule requiring hazardous liquid pipeline operators to also conduct these integrity assessments on pipeline segments outside of high consequence areas. Pipeline Safety: Safety of Hazardous Liquid Pipelines, 84 Fed. Reg. 52,260, 52,269 (Oct. 1, 2019).

permit.[14] PHMSA may also issue enforcement actions in the course of investigating an identified safety condition or a pipeline accident. According to officials, PHMSA's Office of Pipeline Safety has 124 authorized inspector positions whose responsibilities include inspecting 555 companies that operate about 530,000 miles of interstate pipelines. PHMSA has broad discretion in deciding what enforcement action, if any, to take against a particular operator to ensure compliance, and the enforcement actions range in severity:[15]

- *Warning Letters* notify operators when PHMSA inspections or other oversight activities reveal less serious violations or program deficiencies. Warning Letters direct the operator to correct the issues or be subject to potential, future enforcement actions.
- *Notices of Amendment* identify alleged inadequacies in the operator's plans and procedures to ensure safe operation of the pipeline, propose revisions to the plans or procedures, and instruct the operator as to how to respond to the allegations.
- *Notices of Probable Violation* allege the existence of one or more probable violations of pipeline safety laws, regulations, or related orders. These notices are accompanied by either a proposed compliance order identifying the remedial actions the operator is required to take, proposed civil monetary penalties, or both.[16] This is the only type of enforcement action that may include proposed civil monetary penalties. If PHMSA finds that a violation was committed, then it issues a final order, which includes the compliance order, the assessment of civil monetary penalties, or both, as applicable.

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[14]The pipeline safety laws are codified at 49 U.S.C. § 60101 et seq., and the pipeline safety regulations are located in 49 C.F.R. Parts 190-199. PHMSA's regulations governing its enforcement of pipeline safety are located in 49 C.F.R. Part 190.

[15]PHMSA officials note that in addition to those listed, there is another enforcement tool that PHMSA can issue but has not issued to TC Energy for Keystone. Specifically, a Notice of Proposed Safety Order alleges that a particular pipeline facility has a condition or conditions that pose a pipeline integrity risk to the public safety, property, or the environment, and proposes requiring the operator to take necessary corrective action. If after issuing such a notice, PHMSA finds that such an integrity risk exists, PHMSA may issue a Safety Order.

[16]These enforcement actions must contain the options available to the operator for responding to the notice. The options include but are not limited to submitting written responses contesting the allegations, requesting mitigation or elimination of the proposed civil penalty, objecting to the compliance order, or requesting a hearing. Failure to respond constitutes a waiver of a right to contest the allegations.

- *Corrective Action Orders* direct an operator to take immediate corrective actions to ensure safe pipeline operation. PHMSA may issue a corrective action order if it finds that the pipeline or pipeline facility is or would be hazardous to life, property, or the environment, such as after an accident occurs. These orders do not allege probable violations.

PHMSA also collects and shares pipeline-related data, including data on accidents. For example, for each accident that releases over 5 gallons of product, PHMSA requires hazardous liquid pipeline operators to submit a report that includes information such as amount, location, timing, impacts, and cause of the release. To provide transparency into pipeline operators' safety records, PHMSA publishes information on its website on pipeline accidents by operator. This information covers each operator's network of pipelines carrying crude oil or refined petroleum products. PHMSA also reports nationwide averages for accidents—such as the average number of accidents and average amount of product spilled per billion barrel transported—which enables comparisons between an individual operator and the industry as a whole.

Keystone Special Permit

PHMSA issued the Keystone special permit in April 2007 after TC Energy applied for a waiver of the regulatory requirement for hazardous liquid pipelines to operate at a maximum stress level of 72 percent of SMYS for certain segments of the pipeline. The special permit allows TC Energy to construct the pipeline using higher-grade steel in order to operate at 80 percent of SMYS along the Keystone Mainline and Cushing Extension. Except for this waived requirement, all other pipeline safety regulations apply to the segments covered by the special permit. Certain portions within those segments are not covered by the special permit, such as those operating in high consequence areas and within pump stations.[17] In those pipeline portions, Keystone remains wholly subject to PHMSA's hazardous liquid pipeline safety regulations. The special permit is in effect for the life of the pipeline, although PHMSA has the authority to modify, suspend, or revoke the permit in certain circumstances designated in regulations.

[17]Pump stations are located at regular intervals along the pipeline to boost pressure to desired levels. Without these pumps, pipelines experience pressure losses over the length of the pipeline. Many pump stations are unstaffed and located in sparsely populated areas.

To grant a special permit, PHMSA must determine that the requested waiver is not inconsistent with safety,[18] which PHMSA officials interpret to mean that the waiver provides a level of safety equal to or greater than that which would be provided if the pipeline were operated under existing regulations. When approving a special permit, PHMSA can also impose conditions to offset the safety risks posed by waiving the operator's compliance with a regulation. Between 2000 and 2020, PHMSA granted 99 special permits: 94 for natural gas pipelines and five for hazardous liquid pipelines. Keystone's special permit is the only one PHMSA has granted that allows a hazardous liquid pipeline to be designed and operated at 80 percent of SMYS. No other hazardous liquid pipeline operator has requested a special permit to waive the same regulation. According to PHMSA officials, during inspections of the Keystone pipeline, the agency evaluates the operator's overall performance data, as well as compliance with the terms of the special permit.

PHMSA Developed Conditions to Offset Safety Risks and Required TC Energy to Replace Low-Quality Pipe

Technical Information and PHMSA's Experience Informed Special Permit Conditions

PHMSA gathered technical information from TC Energy related to the potential operation of the Keystone pipeline at 80 percent of SMYS. PHMSA's regulations require special permit applications to include information spanning 12 categories, including, for example, pipeline design and construction and how proposed safety measures would mitigate safety or environmental risks. TC Energy included this information in its November 2006 application. PHMSA then requested, and TC Energy provided, 22 additional items, such as the pipe's predicted fatigue life at 80 percent of SMYS and the reason TC Energy sought the special permit. TC Energy stated that the special permit would reduce steel costs by approximately 10 percent while still maintaining high standards of safety. TC Energy also proposed additional actions, such as

[18] 49 U.S.C. § 60118(c); 49 C.F.R. § 190.341.

more frequent assessments of the pipeline using in-line inspection tools, to help ensure safety.

PHMSA also requested and incorporated input from a technical advisory committee, an engineering consultant, pipeline safety experts, and the public regarding the technical aspects of the special permit request. For example, it solicited comments from an external technical advisory committee containing members from industry, federal and state government, and pipeline safety groups. It also commissioned a study that analyzed and made recommendations regarding the potential fatigue and fracture of a pipeline operating at 80 percent of SMYS. For example, the study recommended requiring the operator to perform a full in-line inspection within 3 years of the pipeline starting operations, a stipulation that PHMSA later made a condition of the special permit. In addition, according to the special permit, PHMSA requested and incorporated input from experts in areas such as steel fracture mechanics and leak detection. Finally, in response to publishing TC Energy's special permit request in the *Federal Register* in February 2007, PHMSA received two comments. One comment was from a pipeline safety expert who supported the application and recommended a number of conditions, such as quality control practices during pipeline installation, which PHMSA incorporated into the special permit.[19]

In reviewing the Keystone special permit application, PHMSA officials said they also drew on their experience with granting similar special permits for natural gas pipelines, as well as on the experiences of other countries regulating crude oil pipelines operating at a higher stress level. In 2005, PHMSA started receiving requests for special permits that would allow operators to increase the maximum allowable operating pressure to 80 percent of SMYS for certain natural gas pipeline segments. PHMSA evaluated these special permit applications against safety criteria such as pipe design, construction, operations and maintenance, integrity management, and reporting requirements. PHMSA would later require TC Energy to submit information across similar categories. A PHMSA official also said that the Keystone special permit conditions were similar to those the agency included in natural gas special permits, such as addressing risks from corrosion and cracking. In addition, according to officials, PHMSA considered how regulatory agencies in Europe and Australia oversaw crude oil pipelines operating at 80 percent of SMYS. As PHMSA

[19]As PHMSA notes in the Keystone special permit, the other commenter did not provide substantive comments relevant to the special permit request.

noted in Keystone's 2007 special permit, Canadian safety standards already allowed operators there to design and operate hazardous liquid pipelines at 80 percent of SMYS, which TC Energy had been doing since 2004 in Canada.

Based on the technical information and its experience with the natural gas pipeline industry, PHMSA issued the special permit with 51 conditions that the agency determined would offset the risks of operating the relevant Keystone segments at 80 percent of SMYS in non-high consequence areas. The special permit conditions are in effect for the entire lifecycle of the pipeline, from design and construction to ongoing maintenance and reporting. Three quarters (38) of the conditions relate to constructing, operating, and maintaining the pipeline to ensure safety, including three conditions requiring periodic in-line inspections to proactively identify issues such as corrosion and cracking. See Table 1 for a summary of the 51 special permit conditions.

Table 1: Keystone Special Permit Conditions the Pipeline and Hazardous Materials Safety Administration (PHMSA) Developed to Provide for Safe Operation at 80 Percent of Specified Minimum Yield Strength

Condition number	Pipeline lifecycle stage	Description
1 – 10	Planning and Design	Pipe Manufacturing, Coating, Transportation, and Mill Testing Requirements to ensure that the pipe is adequately manufactured, protected, delivered, and inspected before it goes into the ground.
11 – 24	Construction	Field Coating, Fittings, Design, Corrosion, and Construction Requirements to ensure that the pipe is adequately welded and coated in the field, operates at a safe pressure rating for its installation location, and is modified to mitigate potential corrosion issues. In addition, the operator must create a quality assurance plan for the pipe's installation, as construction defects could lead to material failure during operation.
25 – 48	Operations and Maintenance	Operations and Maintenance Requirements to ensure that the pipeline is maintained properly through measures including the installation of a control room system that detects leaks so trained operators can provide remote monitoring and control of the pipeline. The pipeline must also be appropriately marked, inspected, evaluated, and repaired.
49 – 51	Reporting	Reporting and Records Retention Requirements to ensure that the operator submits immediate reports to PHMSA for any leak in the special permit area, as well as longer term reports, such as annual reports addressing 12 specific areas. These areas include inspection results and internal programs for corrosion management and damage prevention.

Source: PHMSA Keystone special permit information. | GAO-21-588

Most safety and technical stakeholders we interviewed regarded the terms of the Keystone special permit as offsetting the risks of operating the pipeline under a higher stress level. All seven of the safety and technical stakeholders we interviewed acknowledged that operating at 80 percent of SMYS poses risks. For example, one noted that the thinner-walled pipe used for Keystone—albeit made of higher-grade steel—could be less resistant to outside forces, cracking, and corrosion than pipe made with thicker walls. However, five of the seven stakeholders generally agreed that PHMSA designed the Keystone special permit conditions in a way that required TC Energy to offset those risks. For example, three noted that the Keystone special permit conditions require TC Energy to conduct more frequent in-line inspections using more advanced technologies. In addition, one industry association stakeholder we interviewed said that the percentage of SMYS is just one of many factors engineers consider to ensure safety. All four environmental stakeholders we interviewed said that although they have safety concerns with Keystone, they could not comment on approval of the special permit because they were not involved during PHMSA's development of the conditions in 2006-2007. For example, one environmental stakeholder said that his organization was more involved with the Keystone XL pipeline, which TC Energy proposed after the Keystone special permit was approved by PHMSA.

One industry stakeholder noted that his organization would prefer PHMSA update the hazardous liquid pipeline regulations to allow all pipelines that meet the conditions to operate at increased SMYS, but PHMSA officials stated they do not intend to take this action. Due to the experience PHMSA gained from natural gas pipeline special permits, the agency amended its regulations in 2008 to allow certain natural gas pipeline segments to operate at 80 percent of SMYS if operators met specific requirements. However, since Keystone's special permit is the only one of its kind, PHMSA has less experience overseeing hazardous liquid pipelines operating above 72 percent of SMYS. PHMSA officials said that because there is low demand from industry for special permits waiving this regulation, they have not sought to amend their regulations to generally allow hazardous liquid pipelines to operate at a higher stress level. These officials speculated the low demand from industry for special permits waiving the regulation was in part because operators do not want to be subject to additional conditions that are more onerous than the safety regulations that would have otherwise applied.

PHMSA Required TC Energy to Replace Low-Quality Pipe before Operating Keystone at a Higher Stress Level

After issuing the special permit in 2007, PHMSA identified industrywide pipeline quality issues and as a result initially prohibited the operation of any Keystone segment at 80 percent of SMYS. Through inspections of new construction in 2008, PHMSA identified pipe manufacturing quality issues across the pipeline industry, including one or more manufacturers that had supplied pipe used to construct Keystone. Specifically, some pipe mills had manufactured pipe that failed to meet strength specifications required by regulations, which could cause the steel to deform at pressures lower than intended and the pipeline to expand as a result. To address these issues, in 2009 PHMSA issued an Advisory Bulletin and accompanying guidance, directing operators to use in-line inspection tools to identify pipeline segments with steel that had expanded. The same year PHMSA required TC Energy, which had started Keystone construction in June 2008, to conduct inspections along its entire U.S. pipeline to identify and replace any affected pipeline sections prior to operating the pipeline at the higher SMYS allowed under the special permit. As a result, Keystone began operating in June 2010 at 72 percent of SMYS.

PHMSA allowed TC Energy to gradually phase in Keystone operations at 80 percent of SMYS as inspections and repairs were completed. More specifically, in 2015, TC Energy completed its inspections to detect areas with the expanded pipe, and began excavating and replacing 32 affected pipeline joints in 2016.[20] PHMSA conducted inspections to verify TC Energy's process for identifying the expanded pipe and conducting the repair work. For segments that TC Energy found unaffected by pipeline quality issues, PHMSA allowed the company to operate Keystone at 80 percent of SMYS beginning in 2016. For segments where TC Energy found expanded pipe, PHMSA approved a phased increase in operating pressure up to 80 percent of SMYS after TC Energy completed the replacements. By 2017, all sections of the pipeline subject to the special permit were operating at 80 percent of SMYS.

[20]According to TC Energy officials, a joint is a segment of the pipe that is welded together in the field to form the pipeline and is typically 40 feet but can be 80 feet depending on the type of pipe.

PHMSA Required TC Energy to Address Construction and Other Issues, and Used Lessons Learned to Improve Oversight Nationwide

PHMSA Issued Corrective Action Orders in Response to Keystone's Largest Accidents

In response to each of Keystone's four largest spills, PHMSA issued Corrective Action Orders requiring TC Energy to take several actions, including engaging a PHMSA-approved independent consultant to conduct a Root Cause Failure Analysis which found the accidents stemmed from construction issues.[29] For each such order—which PHMSA may issue when the agency determines that a pipeline is or would be hazardous to life, property, or the environment—PHMSA required TC Energy to shut down the pipeline and obtain PHMSA approval to restart the pipeline. The Root Cause Failure Analysis, conducted by a third party, indicated that the four accidents were caused by issues related to the original design, manufacturing of the pipe, or construction of the pipeline that are distinct from the issue with low-quality pipe that delayed Keystone from operating at 80 percent SMYS. Table 2 provides a summary of the reports' causation findings, as well as actions TC Energy took in response to the Corrective Action Orders. Examples of TC Energy actions include conducting inspections across the pipeline to detect similar issues and replacing components if needed. In addition, TC Energy representatives note that they have been working to evolve and improve the company's in-line inspection tools in order to detect pipeline flaws before they become accidents.

[29]Three of the four Corrective Action Order cases have been closed by PHMSA, meaning that TC Energy complied with the terms. While PHMSA has not yet closed the Order most recently issued in November 2019, according to TC Energy representatives, PHMSA has removed a temporary pressure restriction and TC Energy has complied with the relevant terms.

Table 2: The Causes of Keystone Accidents Resulting in PHMSA Issuing Corrective Action Orders and TC Energy Actions in Response to the Orders

Accident date and location	Barrels released	Causes according to Root Cause Failure Analysis	TC Energy Actions in response to the PHMSA Corrective Action Orders
May 2011- Ludden Pump Station, North Dakota and Severance Pump Station, Kansas	408.5	Design of the pipeline system did not adequately take into account the vibrations that occurs at pump stations, so pump station components failed as a result.	Between May 2011 and March 2012, replaced damaged components, inspected connections to determine risk areas, modified connections that posed a risk, and conducted verification testing to ensure effectiveness at pump stations.
April 2016- Near Freeman, South Dakota	400	The weld (called a girth weld) joining two pipe segments of differing thicknesses failed and caused a leak.	Conducted in-line inspection to detect defects on similar girth welds across the affected segment by June 2016. No other similar weld defects were detected.
Nov. 2017- Near Amherst, South Dakota	6,592	A fatigue crack, likely originating from mechanical damage to the pipe exterior by a vehicle during installation that grew to a critical size.	Used technology to detect cracks on the affected segment and excavated several anomalies by September 2018 but did not find issues similar to the flaw that caused the accident.
Oct. 2019- Near Edinburg, North Dakota	4,515	The pipe was manufactured with an atypical seam weld geometry severe enough to initiate a fatigue crack.	Launched a crack in-line inspection program with a new technology platform across the system to detect similar cracks. This work is ongoing.

Source: GAO analysis of PHMSA and TC Energy information. | GAO-21-588

Although the relevant pipeline segments were operating at a stress level greater than 72 percent of SMYS at the time of Keystone's two largest accidents, PHMSA officials stated that this did not cause the ruptures. As noted previously, PHMSA did not allow Keystone to operate at 80 percent of SMYS until TC Energy identified and replaced 32 pipe joints that contained low strength steel. For the segment of the pipeline where the two largest spills occurred, TC Energy did not identify any affected pipe joints requiring replacement, and began operating this segment at 80 percent of SMYS in 2016. PHMSA officials stated that based on their review of the Root Cause Failure Analysis reports, they not believe that the operating stress level of the pipeline would have had an effect, as both accidents were caused by a fatigue failure related to pre-existing flaws or defects.

PHMSA's accident data suggest that construction issues may be a more frequent contributor to Keystone's accidents impacting people or the environment when compared to causes for such accidents for pipelines nationwide. PHMSA reports that from 2010 to 2020, 12 percent of all accidents impacting people or the environment (119 of 981) on pipelines carrying crude oil, refined oil products, or biofuels were caused by a material failure of the pipe or weld, such as defects in the steel material or welds used in manufacturing the pipe or joining pipe during construction.

By comparison, half (3 of 6) of Keystone's accidents impacting people or the environment were caused by material failure of pipe or weld. Specifically, the two accidents in South Dakota in 2016 and in 2017 were caused by issues in the construction, installation, or fabrication of the pipeline, while the 2019 North Dakota accident was caused by defects in the original pipe manufacturing.

In contrast to Keystone, PHMSA reports that the leading cause of accidents impacting people or the environment on pipelines carrying crude oil, refined oil products, or biofuels from 2010 to 2020 was corrosion, accounting for 30 percent of such accidents.[30] On Keystone, none of these more severe accidents have been caused by corrosion. However, according to PHMSA officials and TC Energy representatives, a February 2019 Keystone accident in St. Charles County, Missouri, which released 17 barrels, was caused by the failure of a pipeline wrap that was applied in 2012 to address previous corrosion issues.[31]

PHMSA Issued Additional Enforcement Actions for TC Energy to Address Deficiencies in Corrosion Prevention and Other Areas

In addition to the Corrective Action Orders, PHMSA also issued enforcement actions regarding corrosion prevention and other deficiencies discovered during inspections. See table 3.

Table 3: Enforcement Actions PHMSA Issued to TC Energy for Keystone Deficiencies Identified during Inspections

Date enforcement action issued	Type of enforcement action	Topics of Deficiencies Found	Civil monetary penalty assessed
Jan. 13, 2012	Warning Letter	Pipeline markers Cathodic protection	N/A
Aug. 28, 2013	Notice of Amendment	Public awareness program	N/A
Nov. 20, 2015	Notice of Probable Violation	Cathodic protection	$135,400[a]

[30]In addition to corrosion (30 percent) and material failure of pipe or weld (12 percent) mentioned above, the other causes nationally were: equipment failure (23 percent), incorrect operation (12 percent), excavation damage (11 percent), natural force damage and other outside force damage (9 percent), and other causes (3 percent).

[31]The cause for this accident according to PHMSA data was "incorrect operation- wrong equipment specified or installed." Furthermore, the causes for the other two Keystone accidents IPE were: "equipment failure- threaded connection or coupling failure" (for the 2011 release of 400 barrels at Ludden Pump Station in North Dakota) and "incorrect operation- tank or vessel overfill or overflow" (for the 2011 leak of 0.36 barrels at the Cushing Delivery Station in Oklahoma).

Date enforcement action issued	Type of enforcement action	Topics of Deficiencies Found	Civil monetary penalty assessed
June 13, 2019	Notice of Probable Violation	Atmospheric corrosion	N/A
March 11, 2020	Notice of Probable Violation	Pipeline markers	$170,300[b]

Source: PHMSA. | GAO-21-588

[a]This penalty was assessed in a Final Order on May 31, 2017. The proposed amount in the 2015 Notice was $187,200.

[b]This penalty was assessed in a Final Order on November 6, 2020.

Corrosion Prevention

During a 2011 PHMSA inspection in North and South Dakota, PHMSA noted that TC Energy was unable to demonstrate that it had complied with one of the conditions of the special permit. That condition requires TC Energy to conduct a test to find stray currents, such as from nearby power lines or pipelines, which could interfere with the cathodic protection system for the pipeline. As a result of this inspection, PHMSA issued a Warning Letter to TC Energy in January 2012. A couple of months later, in March 2012, TC Energy provided the stray current test results to PHMSA as required by this condition of the special permit and a proposed mitigation plan, such as installing additional groundbed facilities.

Issues with Keystone's cathodic protection culminated months later when thinned pipe was discovered that according to PHMSA came extremely close to causing a pipeline failure that could have impacted a high consequence area. Specifically, during an October 2012 in-line inspection, TC Energy discovered significantly thinned pipe due to accelerated corrosion in four locations along the mainline segment between Salisbury, Missouri and Patoka, Illinois. TC Energy reported that it immediately depressurized the pipeline, isolated the affected section, notified PHMSA, and completed appropriate repairs. In all four locations, the amount of metal loss (i.e., corrosion) was over 60 percent deep. In one location, 97 percent of the metal had corroded, leaving a remaining pipeline wall thickness of 0.0120 inch—less than half the thickness of a dime.

As a result of these issues, PHMSA issued a Notice of Probable Violation and a Final Order determining that TC Energy had committed violations of the regulations and assessing civil monetary penalties of $135,400. A subsequent TC Energy report found the primary cause for the metal loss anomalies was the inadequacy of the original cathodic protection design and electrical current interference from nearby pipelines. PHMSA found that TC Energy began taking corrective measures to address these deficiencies in 2012, and completed this work in 2013. This work included installing 13 additional impressed current systems on the pipeline and adding six groundbeds at pump stations, among other things. TC Energy reported that its repair timeframes were due to factors outside of its control, such as acquiring land access permission and environmental permitting. Representatives from TC Energy acknowledge that the original cathodic protection had problems and noted that their design philosophy has changed since then, a change that has benefitted other pipelines operated by the company.

Other Areas

In addition to the issues with cathodic protection, PHMSA also issued enforcement actions related to additional deficiencies found during inspections.

- **Public awareness program:** PHMSA identified inadequacies with TC Energy's public awareness program and plan during a 2011 inspection and issued a Notice of Amendment in 2013. PHMSA found, among other things, that TC Energy's public awareness plan did not include a written process for conducting an annual implementation review, as required by regulation. Based on feedback the PHMSA inspector provided during the 2011 inspection, TC Energy updated its program in 2012 before the Notice of Amendment was issued. PHMSA closed the case in 2015.
- **Coatings:** PHMSA issued a 2019 Notice of Probable Violation in response to deficiencies PHMSA found in a 2018 inspection of coatings applied to pipe to prevent atmospheric corrosion on above ground pipeline sections, such as at pump stations. In its 2019 response, TC Energy said it began remediating the issue in 2018 and would complete the work in 2019. PHMSA closed the case in September 2020, noting the TC Energy had complied with the terms.
- **Markers:** PHMSA has twice found that TC Energy had not placed all required visual markers along the pipeline.[32] First, in the 2012 Warning Letter, PHMSA found TC Energy had not placed line markers at all road crossings. PHMSA cited condition #40 of the special permit, which requires line-of-sight pipeline markings except in areas

[32]Markers warn that a transmission pipeline is located in the area, identify the product transported in the line, and provide the name of the pipeline operator and a telephone to call in the event of an emergency.

where it is impractical.[33] Second, in a 2020 Notice of Probable Violation, PHMSA alleged 20 instances of missing markers in the special permit area that it observed during a 2018 inspection, which would be a violation of condition #40. It also proposed a civil penalty of $170,300. PHMSA issued a final order in November 2020 finding that TC Energy had committed this violation and assessed a civil penalty of $170,300.[34]

PHMSA Applied Lessons Learned from Keystone to Improve Pipeline Construction and Special Permit Oversight Nationwide

PHMSA officials told us that they have applied "lessons learned" since the time that Keystone was built by increasing the amount of staff resources it devotes to inspecting pipelines under construction. According to PHMSA officials, PHMSA inspectors spent 351 inspection days on site during Keystone's construction, from June 2008 to November 2010.[35] PHMSA did not issue any formal enforcement actions to TC Energy during construction, but PHMSA officials told us that inspectors brought up issues that were addressed at the construction site, such as improper welds and weld inspections. To address common issues such as poor quality control for welding and inadequate construction practices that PHMSA identified across 35 pipeline construction projects in the 2008 construction season, PHMSA held a workshop in April 2009 to alert the industry to construction issues that could affect pipeline integrity. Since then, the agency has placed increased focus on inspections during construction to improve oversight of additional pipelines. Specifically, PHMSA officials said that the agency now expects each of their inspectors to spend 20 to 25 percent of their time on construction inspections. Further, according to these officials, the number of days inspectors have spent on construction inspections has approximately doubled since 2010.

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[33]Line-of-sight refers to being able to stand at one marker and see the next marker in order to determine the path of the pipe below. The special permit is more stringent than 49 CFR § 195.410, which requires pipeline markers at all road crossings but does not require that operators maintain the line-of-sight spacing.

[34]PHMSA closed the enforcement action in January 2021, as it had determined that TC Energy had complied with the terms of the final order and paid the civil penalty amount.

[35]We have previously reported that, given the size of PHMSA's inspection staff relative to the federally regulated pipeline network, PHMSA uses a risk-based inspection approach that allows it to allocate inspection resources to pipelines considered higher risk. GAO, *Pipeline Safety: Additional Actions Could Improve Federal Use of Data on Pipeline Materials and Corrosion,* GAO-17-639 (Washington, D.C.: Aug. 3, 2017).

Excerpt Bloomberg Transcript Plains All American Q4/22 call on Feb 8, 2023

Company Name: Plains All American Pipeline LP
Company Ticker: PAA US Equity
Date: 2023-02-08

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the same push there for exports and subsequently movement to Corpus versus Houston this year?

A - Jeremy Goebel {BIO 19271634 <GO>}

I would say those are somewhat independent. Because last year lite crude imports -- exports increased by just a bit more than light crude production growth from the Permian -- from the like basins including the Permian. The SPR was 70% heavy, and that more impacted imports from Canada and imports from other locations. So the real need for replacement from those refineries, the roughly the average of 450,000 barrels a day of SPR releases over the calendar year is going to be on the heavy side. They're going to need to find replacements for that distillate yield.

So it's really not a replacement and yields there. We look at that more of an impact to the heavy markets than it is to the light markets. So we still think the best logistics and the best quality will draw the additional barrels for export. So we kind of look at those as independent. Because of domestic refiners increased last year exports of product and exports of lights. And so we just look at those independently.

https://www.spr.doe.gov/dir/dir.html

STRATEGIC PETROLEUM RESERVE INVENTORY

CURRENT SPR INVENTORY AS OF February 3, 2023 (MMB)

SWEET	SOUR				TOTAL
168.6 million bbls	203 million bbls				371.6 million bbls

SPR OIL MOVEMENTS in Millions of Barrels*

MONTH	OIL EXCHANGE/PURCHASE RECEIPT BARRELS		DRAWDOWN/SALES/OIL EXCHANGE RETURN BARRELS		NET MOVEMENT
Jan-23	0.0		(0.5)	M	(0.5)

*Although Current Inventory captures all oil movements, monthly total oil movements are captured after inventory is closed for each month.

( ) = Barrels released from SPR
M = FY22 Emergency Drawdown 3D

https://www.energy.gov/sites/default/files/2022-11/EXEC-2021-004325%20-%202020%20SPR%20Annual%20Report%20to%20Congress%20-%20August%202022.pdf

Table 1. Authorized Storage Capacity and Sustained Drawdown Capability (As of December 31, 2020)

CURRENT SITE CAPABILITY			
Storage Facility	**Authorized Storage Capacity (MMbbl)**	**Crude Mix Sweet/Sour (MMbbl)**	**Sustained Drawdown Capability (MMbbl/d)**
Bryan Mound	**247.14**	**67/164**	**1.5**
West Hackberry	**220.38**	**102/91**	**1.3**
Big Hill	**170.0**	**64/79**	**1.1**
Bayou Choctaw	**76.00**	**19/52**	**0.515**
Total Program	**713.52**	**252/386 (39%/61%)**	**4. 415**

Sweet = Sulfur content < 0.5 percent; Sour = Sulfur content > 0.5 percent
MMbbl = Million Barrels

https://tass.ru/ekonomika/17016905
February 10, 01:24,
updated February 10, 02:57

Russia in March will voluntarily reduce oil production by 500 thousand barrels per day

© Egor Aleev/ TASS

Russian Deputy Prime Minister Alexander Novak noted that the country will not sell oil to supporters of the "price ceiling"

MOSCOW, February 10. /TASS/. Russia plans in March to voluntarily reduce oil production by 500 thousand barrels per day. This was reported to journalists by Deputy Prime Minister of the Russian Federation Alexander Novak.

"To date, we fully sell the entire volume of oil produced, however, as was stated earlier, we will not sell oil to those who directly or indirectly adhere to the principles of the "price ceiling", he said.

"In this regard, Russia in March will voluntarily reduce production by 500 thousand barrels per day. This will contribute to the restoration of market relations," Novak added.

The representative of Novak said that the reduction in production will affect only oil, excluding gas condensate. According to a TASS source in the industry, the reduction in production will be counted from the real level of production, and not from russia's quota under the OPEC + deal. He said that Russia made this decision on its own, there were no consultations with OPEC+.

"The decision was made by Russia unilaterally, there were no consultations with OPEC+," he said.

The Deputy Prime Minister noted that the mechanism of the "price ceiling" can affect the shortage of oil and products in other industries.

"In the future, it can not only lead to a decrease in investment in the oil sector and, accordingly, a shortage of oil in the future, but also be extended to other sectors of the world economy with similar consequences," Novak said.

Russia believes that the mechanism of the "price ceiling" in the sale of Russian oil and petroleum products is an interference in market relations and a continuation of the destructive energy policy of the countries of the collective West, he added.

"As one of the steps to neutralize the threat to the global oil market, Russia has introduced a ban on directly or indirectly applying references to any illegitimate restrictions in oil supply contracts," the deputy prime minister recalled.

From December 5, 2022, the EU embargo on maritime oil supplies from the Russian Federation came into force, the G7 countries, the EU and Australia introduced a "ceiling" on prices for Russian oil supplied by the sea at the level of $ 60 per barrel for their subordinate vessels and territories. And from February 5, 2023, similar restrictions on the supply of petroleum products from Russia began to operate. The size of the "ceiling" was determined at $ 100 and $ 45 dollars per barrel, depending on the category of petroleum products.

https://tass.ru/ekonomika/12290253

SEP 2, 17:44

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

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

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

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

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

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

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

27 JAN, 04:40

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

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

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

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

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

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

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

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

Investments in the further development of Western Siberia

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

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

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

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

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

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

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

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

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

Oil price outlook – Snapshot: February 6, 2023

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

Category	Indicator	Signal	Comment
Fundamentals	**Refinery margins**		• Global refinery margins were **lower** over the past week, putting an end to three weeks of consecutive growth, as middle distillate cracks weakened significantly.
Fundamentals	**Crude stocks**		• In the week ending January 27, land crude-oil storage levels in BloombergNEF's tracked regions (the US, ARA and Japan) were virtually flat at 571.8 million barrels (m bbl). The stockpile **deficit** against the five-year average (2016-19 and 2022) **widened from 6.1m bbl to 6.6m bbl.** • Including global floating crude stockpiles from the same week, total crude oil inventories decreased 2.0% to 645.9m bbl, while the stockpile **surplus of 25.4m bbl narrowed to 13.8m bbl**.
Fundamentals	**Product stocks**		• In the week ending January 27, gasoline and light distillate stockpiles in BNEF's tracked regions (the US, ARA, Singapore, Japan and Fujairah) grew 1.2% week-on-week to 281.7m bbl, with the stockpile **deficit** against the four-year average (2017-19 and 2022) **narrowing from 14.1m bbl to 13.7m bbl**. Gasoil and middle distillate stockpiles in BNEF's tracked regions were up 1.7% to 155.5m bbl, with the stockpile **deficit** against the four-year average **narrowing from 32.6m bbl to 30.1m bbl.** • Oil product stockpiles in tracked regions dropped by 0.3% to 955.9m bbl, with the stockpile **deficit** against the four-year seasonal average **narrowing from 16.7m bbl to 16.6m bbl.** Altogether, crude and product stockpiles decreased 1.0% to 1,601.8m bbl, with the stockpile **surplus of 8.6m bbl flipping to a deficit of 2.8m bbl**.
Fundamentals	**Demand indicators**		• In the week to February 13, global jet fuel demand from commercial passenger flights is set to **rise** 0.4% to 5.50m b/d (million barrels per day). Jet fuel consumption by international passenger flight departures is on course to **grow** 22,300 barrels per day (or +0.7%) week-on-week, while consumption by domestic passenger flight departures will **rise** 1,800 barrels per day (or +0.1%). In the week to February 4, flights in the Eurocontrol area **dropped** to 85.4% of the equivalent week in 2019, down from 84.0% last week. The four-week moving average also **slipped** to 84.8%, from 86.9% in the prior week. Meanwhile, in the week to February 2, US TSA passenger throughput **grew** to 104.6% of the average week in 2019, up from 101.0% last week. The four-week moving average, however, **rose** to reach yet another post-pandemic seasonal high of 104.2%, breaking the record of 102.8% set the previous week. • In the week to February 4, congestion levels showed **growth** in Asia Pacific excluding mainland China (+20.5%), North America (+3.2%) and Europe (+0.7%). On a four-week moving average basis, Europe (+8.1%), North America (+9.1%) and APAC ex-China (+3.8%) **all experienced growth**. Against the same week last year, Asia Pacific ex-mainland China **rose** 56.3 percentage points to 147.8% of the same week last year amid the post-Lunar New Year holidays rebound, while Europe **fell** 12.9 percentage points to 110.0%, and North America **slipped** 10.4 percentage points to 119.1%. In the week to February 5, road congestion in China's 15 key cities **surged** by 64.3 percentage points to 102.2% of January 2021 levels, according to BNEF's calculation based on Baidu data. Month-to-date, traffic congestion in China's 15 key cities was 1% higher than January 2021 levels. • Weather in several cities across Western Europe and East Asia were largely **unchanged** over the past week and was still significantly warmer than historical trends.
Financial	**Macro indicators**		• The dollar index averaged 102.1 in the week to February 3, and was **up** 0.2% from the week prior. The Global Manufacturing PMI **rose** for the first time since February 2022, to 49.1 in January 2023 from 48.7 in December 2022.
Financial	**Hedge fund positioning**		• The Commitments of Traders report for publication dated February 3, 2023, will be delayed according to the Commodity Futures Trading Commission (CFTC).
Financial	**Options and volatility**		• Brent and WTI 1M volatility **rose slightly** over the past week.
Outlook	**Weekly call**		• BNEF is **bullish** on oil prices for the week ahead, with Brent Apr-23 trading at \$80.50/bbl and WTI Mar-23 trading at \$73.72/bbl at the time of writing. • The Global Manufacturing PMI index **rose** to 49.1 in January 2023, registering its first monthly growth since February 2022 although it remained in the **contractionary** territory. Manufacturing PMI for the US, euro zone and China all saw increases but stood below 50, while India saw a decline but stood at 55.4. • Global road mobility appears to be on an uptrend in key regions as levels in Asia Pacific rebounded after the Lunar New Year holidays ended. Congestion levels in Asia Pacific (including China), Europe and North America were all **higher** on a weekly and four-week moving average basis. Asia Pacific ex-China and North America registered **accelerating growth** on a four-week moving average against the same week last year, while growth in Europe **decelerated**. • Road congestion levels in China has rebounded back to normal levels, in-line with the post-Lunar New Year holidays trend in 2022. • Air travel demand continues to show signs of **strength**. The US TSA passenger throughput against the same week in 2019 reached a yet another new **post-pandemic seasonal high** on a four-week moving average basis, although flights in the Eurocontrol area have **declined** for the third consecutive week by the same measure. Global jet fuel demand estimates based on flight schedules for the week to February 6 **rose** 0.4% from the week before. • Oil inventories saw a net **bullish** move over the past week, driven by a strong reduction in crude stockpile surplus against the five-year average (2016-19 and 2022). Growth in US commercial crude inventories were offset by declines in the ARA, Japan and global floating storage. • A key **downside risk** for flat prices in the week ahead is a continued strengthening of the US dollar index, as the market may price in a more hawkish US Federal Reserve following the strong jobs report released in the past week.

Past outlooks

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

Date of report	Refinery margins	Crude stocks	Product stocks	Demand indicators	Commitment of traders	Options chain and volatility	BNEF week ahead call	Brent/WTI price at time of writing ($/bbl)	Web Link
February 6	↓	↑	↔	↑	↔	↑	↑	Brent-Apr: 80.50 WTI-Mar: 73.72	
January 30	↑	↑	↓	↔	↑	↔	↔	Brent-Apr: 86.17 WTI-Mar: 79.41	
January 23	↑	↔	↑	↔	↑	↔	↔	Brent-Mar: 88.25 WTI-Mar: 82.16	
January 17	↑	↔	↑	↑	↓	↔	↑	Brent-Mar: 84.52 WTI-Mar: 79.41	
January 9	↓	↓	↑	↔	↓	↔	↔	Brent-Mar: 80.88 WTI-Feb: 76.09	
January 3	↑	↓	↑	↔	↑	↔	↔	Brent-Mar: 85.00 WTI-Feb: 79.39	
December 20	↑	↔	↓	↓	↓	↑	↓	Brent-Feb: 80.56 WTI-Feb: 76.42	
December 13	↓	↑	↔	↔	↓	↑	↔	Brent-Feb: 79.12 WTI-Jan: 74.19	
December 6	↓	↔	↓	↓	↓	↔	↓	Brent-Feb: 81.80 WTI-Jan: 76.04	
November 28	↔	↓	↓	↓	↓	↔	↔	Brent-Feb: 81.42 WTI-Jan: 74.17	
November 21	↑	↔	↓	↓	↓	↔	↓	Brent-Jan: 83.07 WTI-Jan: 76.03	
November 16	↔	↑	↔	↔	↑	↑	↔	Brent-Jan: 93.91 WTI-Dec: 86.81	
November 2	↔	↔	↓	↔	↑	↑	↔	Brent-Jan: 94.43 WTI-Dec: 88.22	
October 26	↔	↓	↔	↓	↓	↔	↔	Brent-Jan: 91.89 WTI-Dec: 85.77	

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

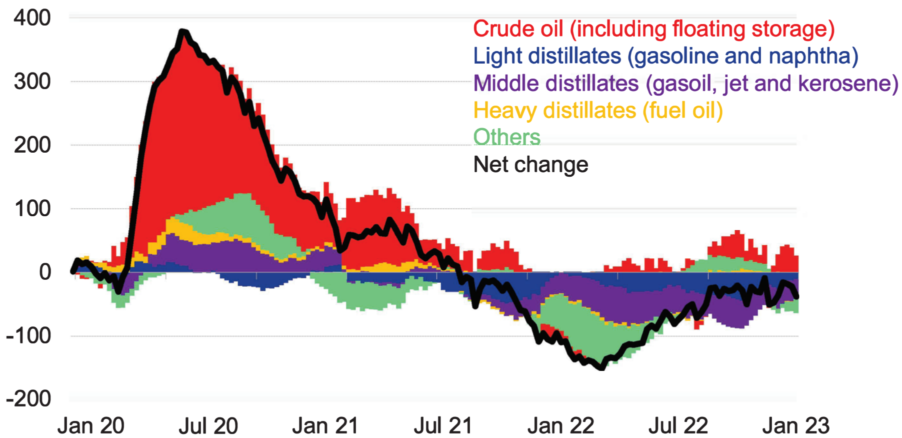
Fundamentals Financial

Weekly oil inventories

Oil inventories fell 1% over the past week

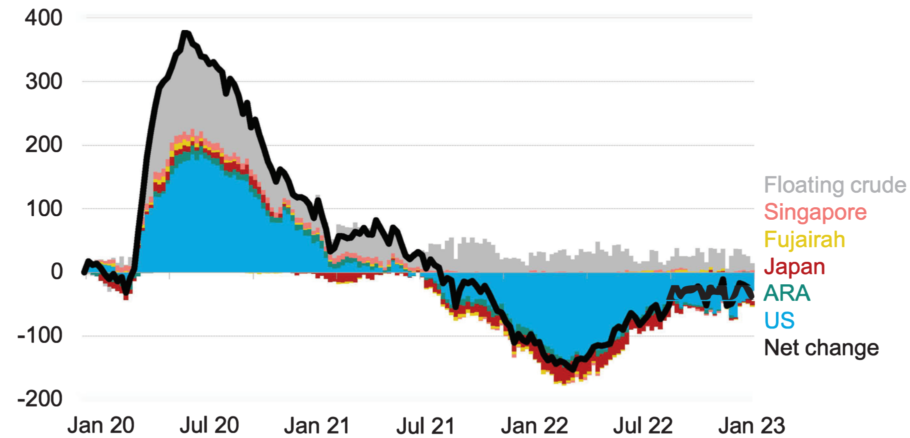
Weekly oil inventories by type

Million barrels (indexed to January 1, 2020)



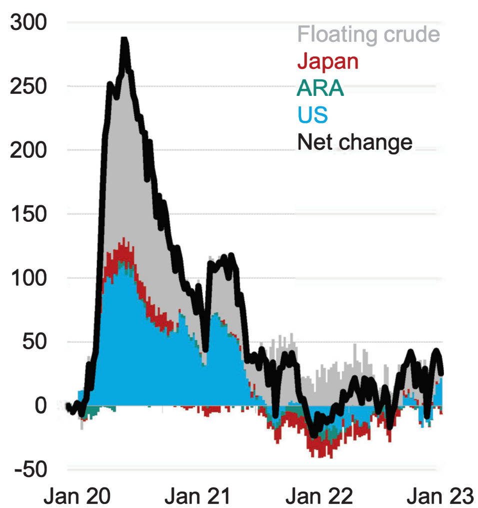
Weekly oil inventories by region

Million barrels (indexed to January 1, 2020)



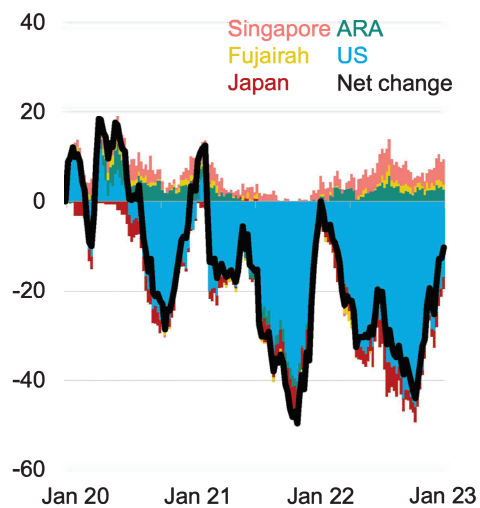
Crude inventories

Million barrels (indexed to January 1, 2020)



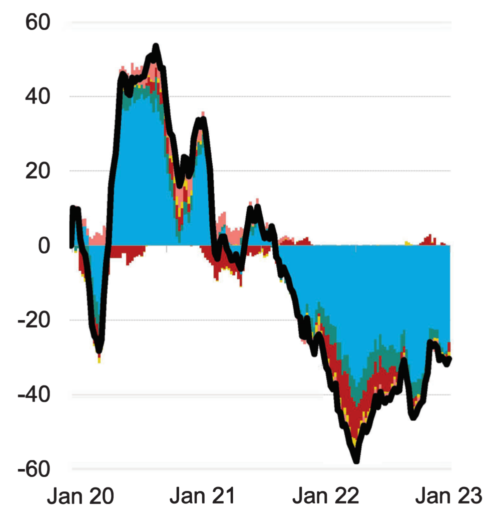
Light distillate inventories

Million barrels (indexed to January 1, 2020)



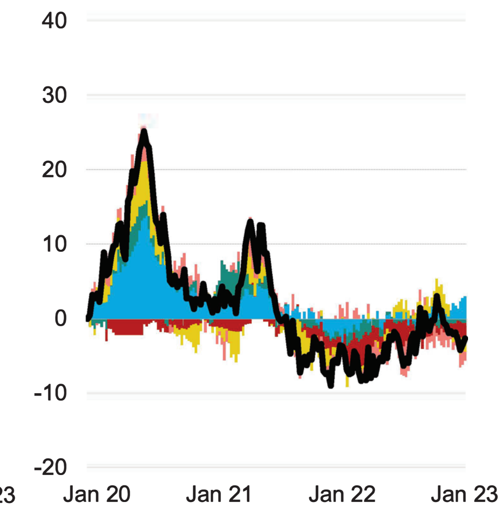
Middle distillate inventories

Million barrels (indexed to January 1, 2020)



Heavy distillate inventories

Million barrels (indexed to January 1, 2020)



*Source: BloombergNEF, US EIA, PJK, IE Singapore, FEDCom/Platts, PAJ ,Vortexa, Genscape. Note: As of the week ending **January 27, 2023**.*

Methodology update: Inventory data

Key changes highlighted in blue *(Changes effective from report dated January 17, 2023)*

	Chart average and range		Seasonal averages for stockpile comparison
	Before change	After change	After change
Aggregated oil stockpiles	2017-19 (three years)	2017-19 and 2022 (four years)	• All inventory data in 2023 will be compared against 2017-19 and 2022 (four years) • All inventory data in 2022 will be compared against 2017-19 (three years)
Crude stocks: Land	2016-19 (four years)	2016-19 and 2022 (five years)	• All inventory data in 2023 will be compared against 2016-19 and 2022 (five years) • All inventory data in 2022 will be compared against 2016-19 (four years)
Crude stocks: Floating	2016-19 (four years)	2016-19 and 2022 (five years)	• All inventory data in 2023 will be compared against 2016-19 and 2022 (five years) • All inventory data in 2022 will be compared against 2015-19 (five years)
Oil product stocks – the US, ARA and Singapore	2015-19 (five years) for the US, ARA and Singapore	2016-19 and 2022 (five years) for the US, ARA and Singapore	• All inventory data in 2023 will be compared against 2016-19 and 2022 (five years) • All inventory data in 2022 will be compared against 2015-19 (five years)
Oil product stocks – Fujairah and all tracked regions	2017-19 (three years) for Fujairah and all tracked regions	2017-19 and 2022 (four years) for Fujairah and all tracked regions	• All inventory data in 2023 will be compared against 2017-19 and 2022 (four years) • All inventory data in 2022 will be compared against 2017-19 (three years)

Source: BloombergNEF

Fundamentals Financial

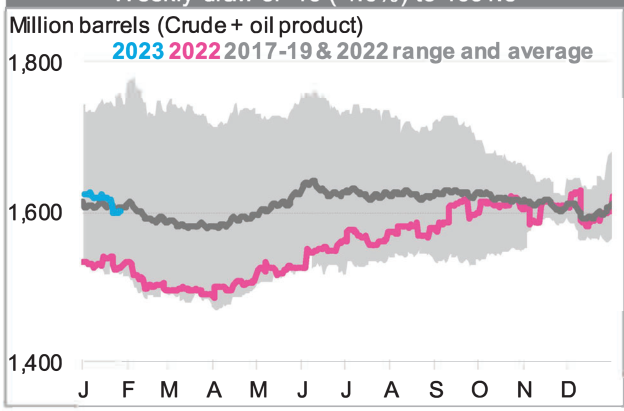
Aggregated oil stockpiles

Bullish: Stockpile surplus of 8.6m bbl flipped to a deficit of 2.8m bbl

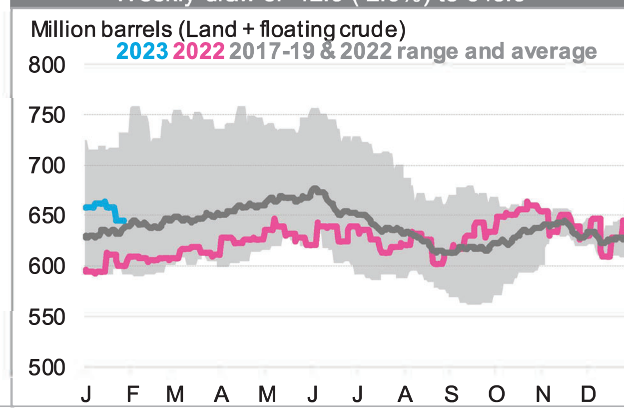
- All inventories in 2023 are compared against the **2017-19 and 2022** (four-year) seasonal stockpiles. Calculations are recalibrated to measure against their respective four-year seasonal averages, so the values below may differ from the subsequent slides.
- Land crude inventories include the US, ARA, and Japan. Floating storage data are global. Oil product storage includes the US, ARA, Japan, Singapore and Fujairah. Floating crude inventories tend to be revised retroactively.

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

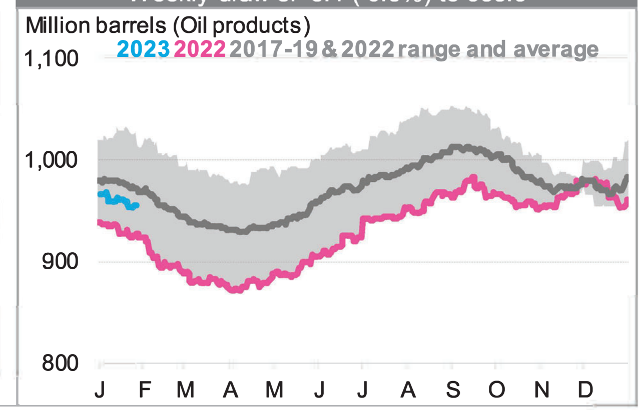
Weekly draw of -16 (-1.0%) to 1601.8



Weekly draw of -12.9 (-2.0%) to 645.9

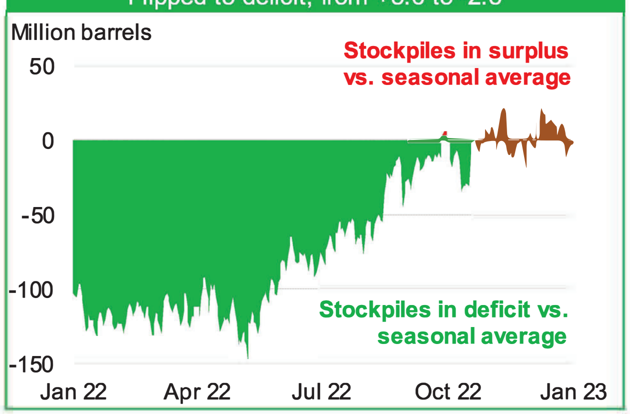


Weekly draw of -3.1 (-0.3%) to 955.9

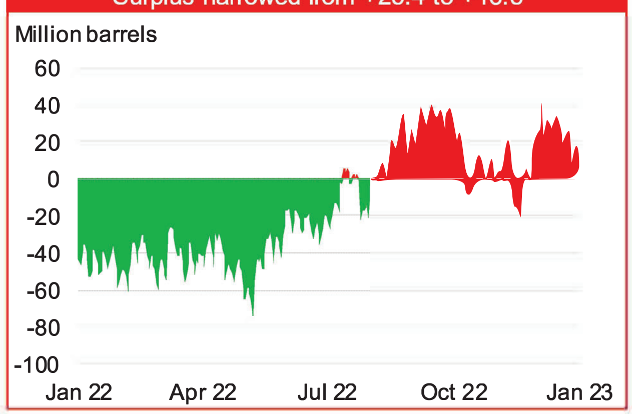


Charts below subtract current stockpiles by the 2017-19 & 2022 (four-year) seasonal average

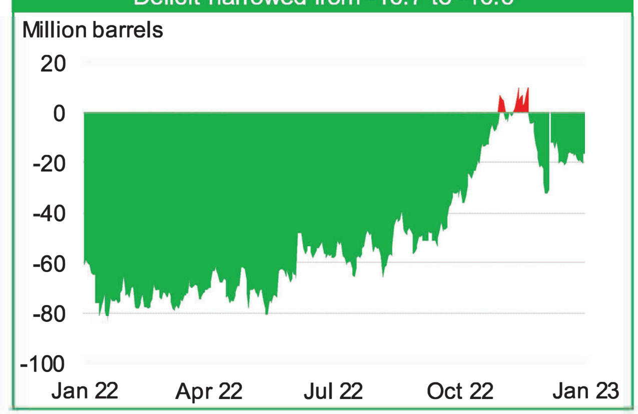
Flipped to deficit, from +8.6 to -2.8



Surplus narrowed from +25.4 to +13.8



Deficit narrowed from -16.7 to -16.6



*Source: BloombergNEF, US EIA, PJK, IE Singapore, FEDCom/Platts, PAJ ,Vortexa, Genscape. Note: As of the **week ending January 27, 2023.***

Fundamentals | Financial

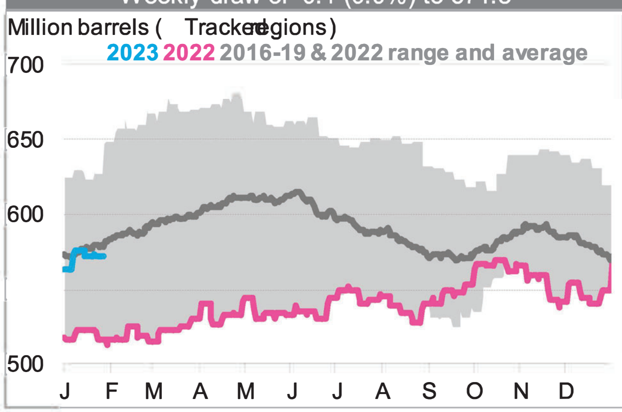
Crude stocks: Land

Neutral: Stockpile deficit widened from 6.1m bbl to 6.6m bbl

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

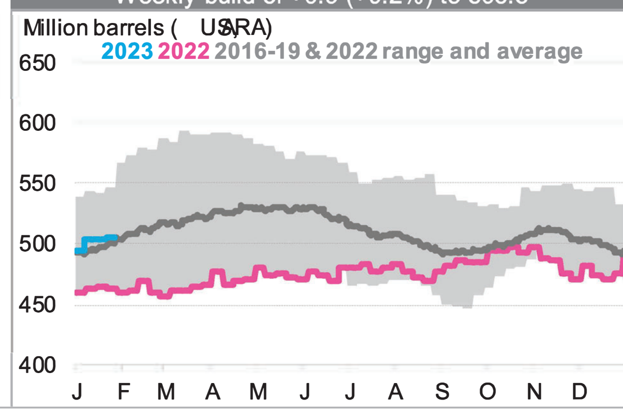
Land storage: Total

Weekly draw of -0.1 (0.0%) to 571.8



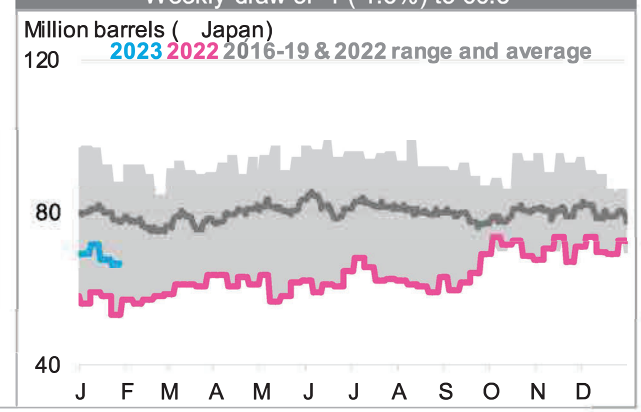
Land storage: West of Suez

Weekly build of +0.9 (+0.2%) to 505.5



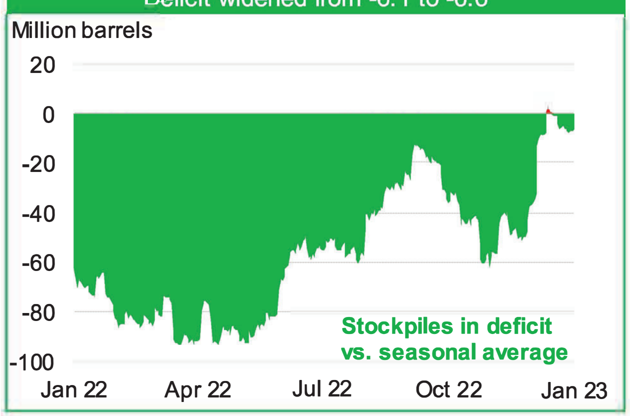
Land storage: East of Suez

Weekly draw of -1 (-1.5%) to 66.3

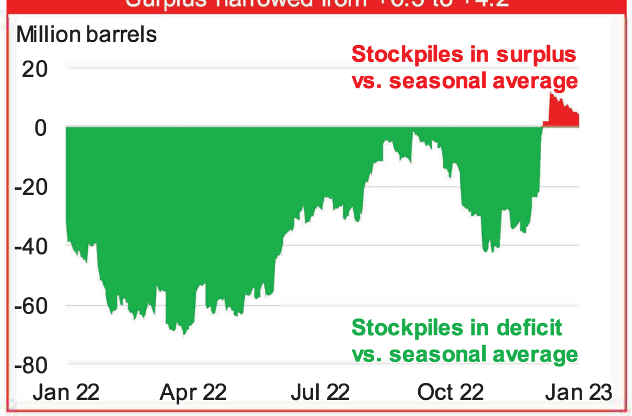


Charts below subtract current stockpiles by the 2016-19 & 2022 (five-year) seasonal average

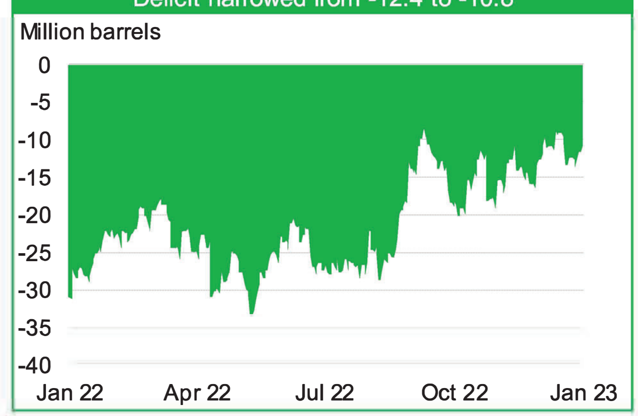
Deficit widened from -6.1 to -6.6



Surplus narrowed from +6.3 to +4.2



Deficit narrowed from -12.4 to -10.8



Source: BloombergNEF, US EIA, Genscape, PAJ. Note: As of the ***week ending January 27, 2023.***

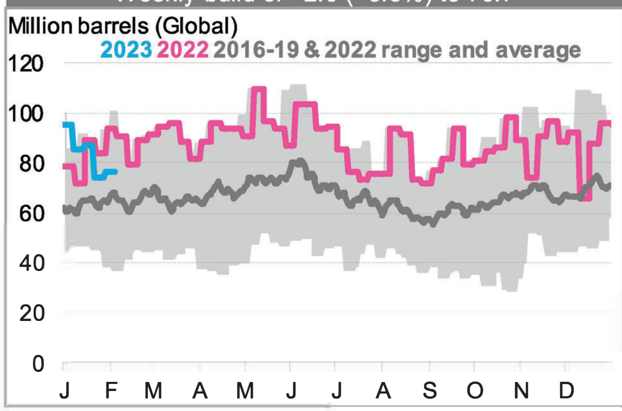
Crude stocks: Floating

Neutral: Stockpile surplus narrowed from 11.3m bbl to 10.4m bbl

- Floating storage is only profitable if the strength of contango (future versus prompt price) is greater than the tanker costs. Therefore, tankers become floating storage when the profit from a storage play exceeds the cost of the forward freight agreement (FFA).
- The floating storage data used in the “Oil Price Outlook” slide is for the previous week (which is the week before the latest data shown below).

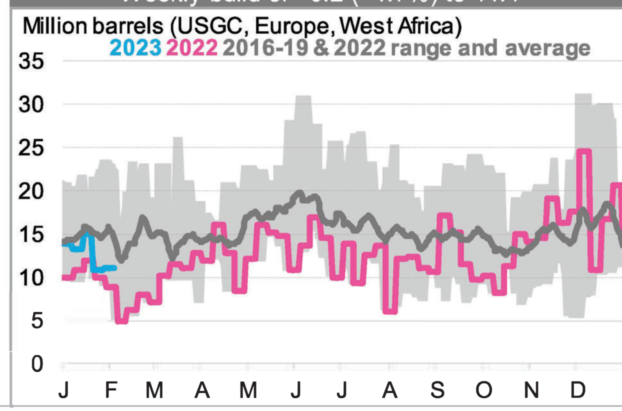
Floating storage: Total

Weekly build of +2.6 (+3.5%) to 76.7



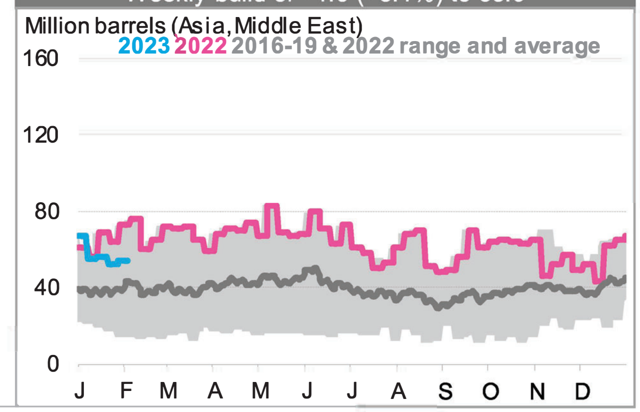
Floating storage: West of Suez

Weekly build of +0.2 (+1.7%) to 11.1



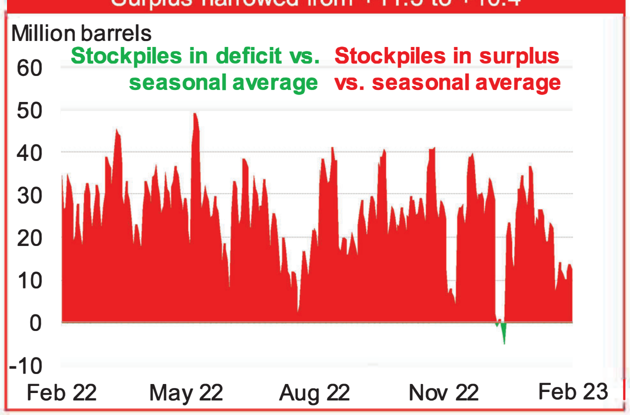
Floating storage: East of Suez

Weekly build of +1.6 (+3.1%) to 53.9

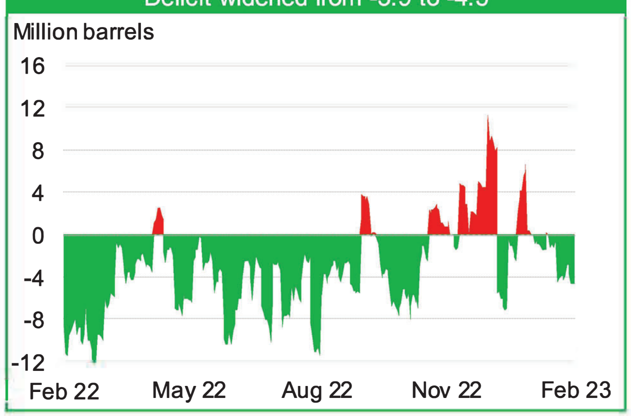


Charts below subtract current stockpiles by the 2016-19 & 2022 (five-year) seasonal average

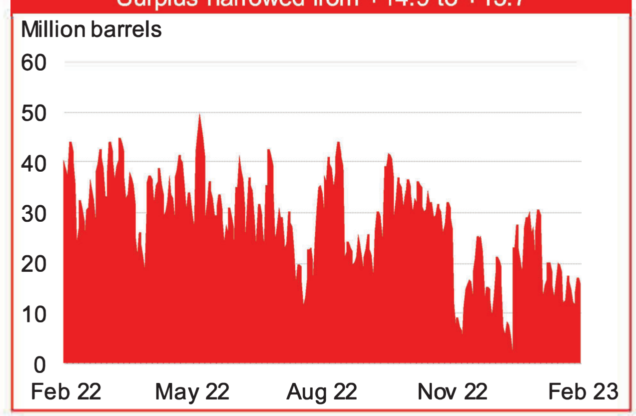
Surplus narrowed from +11.3 to +10.4



Deficit widened from -3.9 to -4.5



Surplus narrowed from +14.9 to +13.7

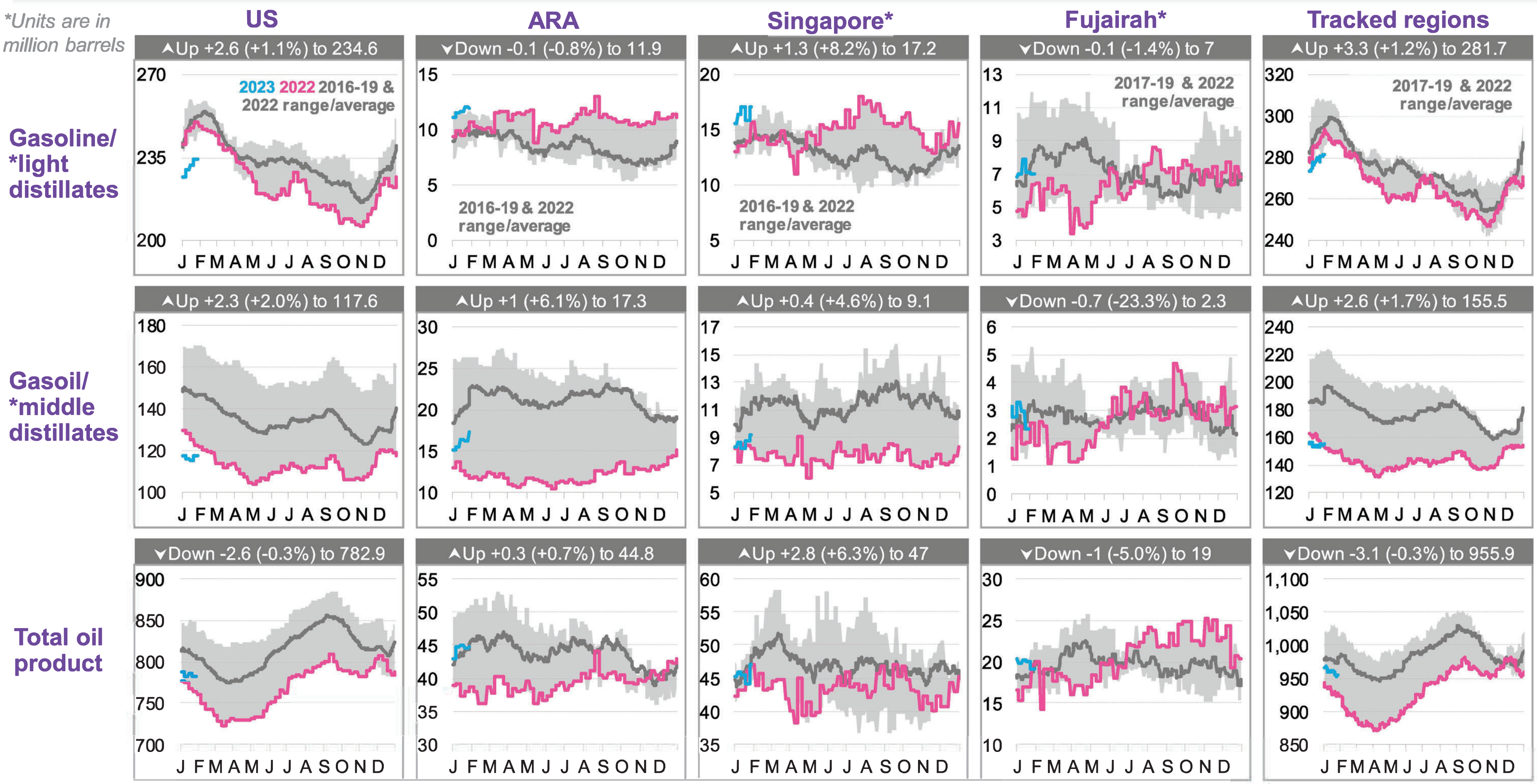


*Source: BloombergNEF, Vortexa. Note: As of the **week ending February 3, 2023**. ***Data from Vortexa are revised frequently, so the data in this report might change week-to-week.***

Product stocks: Current versus seasonal average

Neutral: Oil product stockpiles in tracked regions dropped 0.3% over the past week

- Chart legend are as follows: 2023, 2022 and the 2016-19 and 2022 (five-year) range and average (except for Fujairah and tracked regions).
- For Fujairah and tracked regions, the 2017-19 and 2022 (four-year) seasonal range and average are shown. Tracked regions include US, ARA, Singapore, Japan and Fujairah.



Source: BloombergNEF, US EIA, PJK, IE Singapore, FEDCom/Platts, PAJ. Note: As of the **week ending January 27, 2023.**

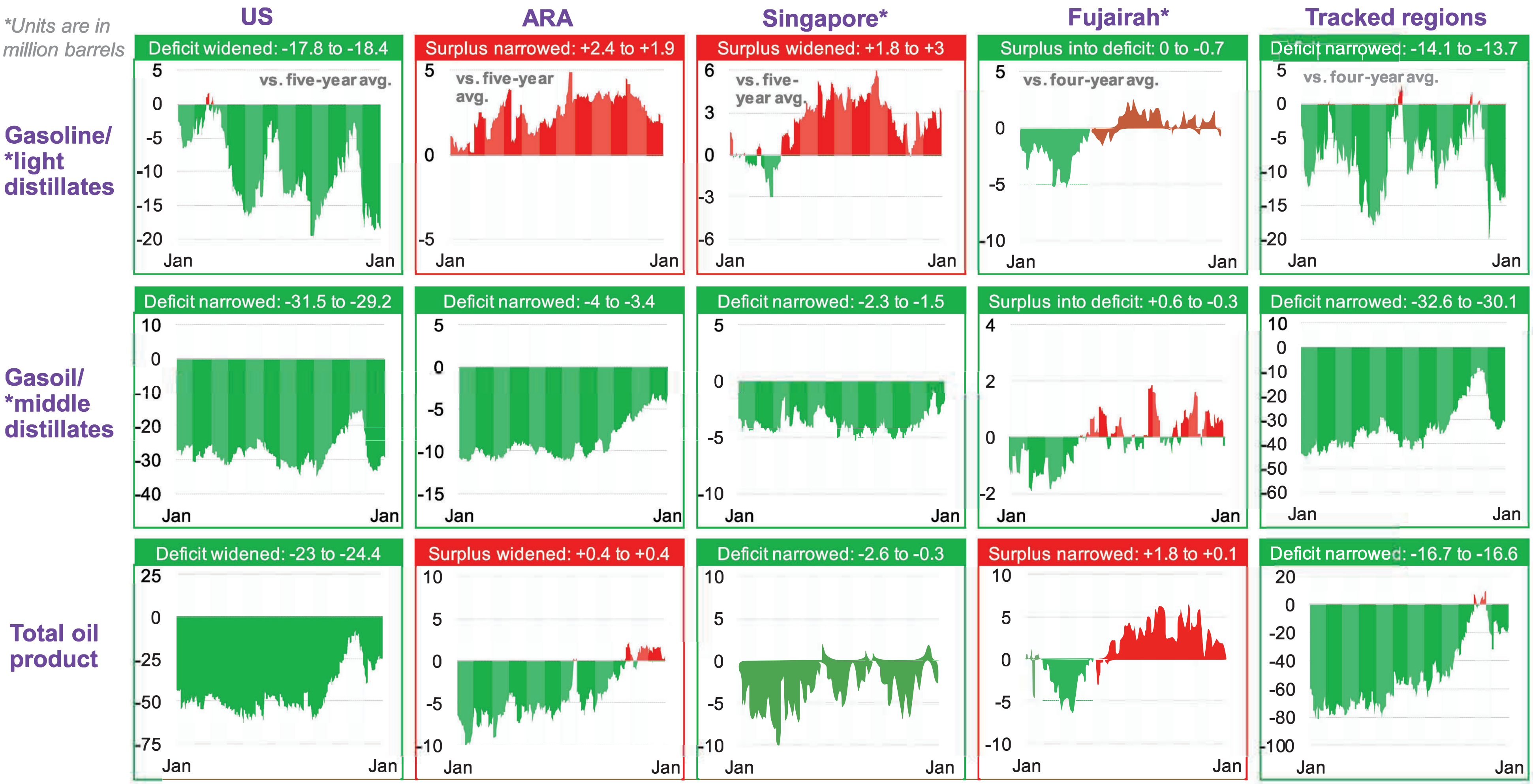
Fundamentals Financial

Product stocks: Current versus seasonal average

Neutral: Oil product stockpile deficit narrowed from 16.7m bbl to 16.6m bbl

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

**Units are in million barrels*



Source: BloombergNEF, US EIA, PJK, IE Singapore, FEDCom/Platts, PAJ. Note: As of the **week ending January 27, 2023.**

BloombergNEF

Feb 08, 2023 12:07:26

OIL DEMAND MONITOR: China Covid Exit Is Key to Fuels Outlook

- Analysts see Asian nation's appetite for oil growing strongly
- Jet fuel to play pivotal role in broader demand acceleration

By John Deane

(Bloomberg) -- China's jettisoning of its Covid Zero policies and a pick-up in economic activity looks set to drive a marked acceleration in oil demand in the world's second-largest economy as the year progresses.

There are some "first indications" that China's growth will accelerate faster than previous expectations, and the nation is projected to account for about half of the increase in global oil demand this year, according to International Energy Agency Executive Director Fatih Birol. The Paris-based organization pegs that gain at almost 2 million barrels a day.

Jet fuel consumption in the country is already "very, very strong," and that's likely to increase overall oil demand if it continues to grow at the same pace, Birol said in Bengaluru, India earlier this week.

Oil consumption in China, the world's biggest importer, is rising strongly following the ending of coronavirus lockdowns, according to OPEC member Kuwait, a major supplier to the nation.

"With the opening up, we're seeing an increase in demand that is sustainable," Sheikh Nawaf Al-Sabah, chief executive officer of Kuwait Petroleum Corp., told Bloomberg TV. "This is not a dead-cat bounce."

Those insights were echoed by analysts. Chinese oil demand will recover strongly from the second quarter and is expected to increase by more than 1 million barrels a day from the first quarter to the fourth, according to FGE Chairman Fereidun Fesharaki. Jet fuel consumption will increase sharply following the end of virus-related travel restrictions.

Goldman Sachs Group Inc. upgraded forecasts for China's oil consumption in the final quarters of this year and 2024. Demand projections for the fourth quarters of 2023 and 2024 were raised to 16 million and 16.6 million barrels a day, or 400,000 and 700,000 higher than previous estimates, according to the Feb. 5 note.

Read More: Revival in China Oil Demand Fired by Covid Exit and Exports

In the skies, China's airline passenger traffic jumped almost 50% month-on-month in December, though the numbers remained far below the pre-Covid era. On the roads, traffic started to pick up after the Lunar New Year holidays, according to BNEF calculations from Baidu data.

Traffic congestion shows signs of edging higher elsewhere too. Among 13 major world cities regularly tracked each Monday morning in this monitor, 10 were either stable or saw mostly modest week-onweek increases. And five - Berlin, London, Paris, Los Angeles and Taipei - showed congestion above typical 2019 levels, according to data from navigation technology company TomTom NV.

In India, gasoline and diesel sales by state-owned refiners, while slipping in January, were nonetheless 18%-19% higher year-on-year, according to officials with knowledge of the matter. Jet fuel demand was 45% higher than the same time a year earlier.

In the US, gasoline demand measured by product supplied dipped in the period to Feb. 3. East Coast jet fuel stockpiles remained at their lowest on record for this time of year.

The Bloomberg oil-demand monitor uses a range of high-frequency data to help identify emerging trends. Following are the latest indicators. The first two tables shows fuel demand and road congestion, the next shows air travel globally and the last is refinery activity:

Demand Measure	Location	%vs 2022	% vs 2021	% vs 2020	% vs 2019	% m/m	Freq	Latest Date	Latest Value	Source
Gasoline product supplied	US	-7.6	+7.3	-5.7	-7.1	+12	w	Feb. 3	8.43m b/d	EIA
Distillates product supplied	US	-12	-13	-11	-19	-1.5	w	Feb. 3	3.76m b/d	EIA
Jet fuel product supplied	US	+9.8	+22	-7	-16	+9.6	w	Feb. 3	1.54m b/d	EIA
Total oil products supplied	US	-6.1	+1.7	-1.3	-5.9	+17	w	Feb. 3	20.54m b/d	EIA
All motor vehicle use index	UK	+6.9	+48		-7	+2.2	m	Jan. 9	93	DfT
Car use	UK	+7.3	+57		-12	+2.3	m	Jan. 9	88	DfT
Heavy goods vehicle use	UK	-1	+4.1		+1	-2.9	m	Jan. 9	101	DfT

Gasoline (petrol) avg sales per filling station	UK	+5.7	+67		-6.2	+21	m	Week to Jan. 29	6,744 liters/d	BEIS
Diesel avg sales per station	UK	-2.1	+20		-14	+62	m	Week to Jan. 29	8,956 liters/d	BEIS
Total road fuels sales per station	UK	+1.1	+37		-11	+41	m	Week to Jan. 29	15,700 liters/d	BEIS
Gasoline	India	+18				-5.1	m	January	2.62m tons	Bberg
Diesel	India	+19				-8.6	m	January	6.68m tons	Bberg
Jet	India	+45				+1.2		January	0.62m tons	Bberg
LPG	India	+0.2				-3.2	m	January	2.64m tons	Bberg
Toll roads volume	France		+0.9		-3.3		m	December	n/a	Atlantia
Toll roads volume	Italy		+2.3		-1.2		m	December	n/a	Atlantia
Toll roads volume	Spain		-0.9		-7.2		m	December	n/a	Atlantia
Toll roads volume	Brazil		-4.3		-2.4		m	December	n/a	Atlantia
Toll roads volume	Chile		-8.8		+5.3		m	December	n/a	Atlantia
Toll roads volume	Mexico		+0.8		+12.6		m	December	n/a	Atlantia
Gasoline	Spain		+19.7			+18.5	m	December	564k m3	Exolum
Diesel (and heating oil)	Spain		+9.6			+15.5	m	December	2,634k m3	Exolum
Jet fuel	Spain		+17.4			+3.5	m	December	445k m3	Exolum
Total oil products	Spain		+11.9			+14.3	m	December	3,643k m3	Exolum
Road fuel sales	France		-4			+1.7	m	December	4.11m m3	UFIP
Gasoline	France		+5.6				m	December	n/a	UFIP
Road diesel	France		-7.2				m	December	n/a	UFIP
Jet fuel	France		+17		-11	+8	m	December	594k m3	UFIP
All petroleum products	France		-4.2			+2.4	m	December	4.636m tons	UFIP

All vehicles traffic	Italy		+1			-1	m	December	n/a	Anas
Heavy vehicle traffic	Italy		-3%			-13	m	December	n/a	Anas
Gasoline	Portugal		+7.7	+26	+5	+9.4	m	December	93.8k tons	ENSE
Diesel	Portugal		+2.2	+13	-1.1	+5.3	m	December	414.9k tons	ENSE
Jet fuel	Portugal		+16	+119	-5.2	-2.1	m	December	112.5k tons	ENSE

Notes: Click here for a PDF with more information on sources, methods. The frequency column shows w for data updated weekly, 2/m for twice a month and m for monthly.

In DfT UK daily data the column showing versus 2019 is actually showing the change versus the first week of February 2020, to represent the pre-Covid era.

In BEIS UK daily data, the column showing versus 2019 is actually showing the change versus the average of Jan. 27-March 22, 2020, to represent the pre-Covid era. The publication frequency switched from weekly to monthly, after July 28.

Atlantia is publishing toll road data on a monthly basis, rather than the weekly format seen in 2021.

City congestion:

Measure	Location	% chg vs avg 2019	% chg m/m	Feb 6	Jan 30	Jan 23	Jan 16	Jan 9	Jan 2	Dec 26	Dec 19	Dec 12	Nov 28	Nov 21	Nov 14
Congestion	Tokyo	-3	+300	36	38	37	38	9	6	38	38	38	37	47	37
Congestion	Taipei	+10	+14	39	38	5	37	34	5	35	35	46	37	34	34
Congestion	Jakarta	0	+10	39	39	1	39	35	11	10	19	31	34	31	33
Congestion	Mumbai	-58	-8	20	20	20	20	22	18	10	17	21	20	23	23
Congestion	New York	-12	+2	28	24	29	3	27	1	1	26	32	30	32	33
Congestion	Los Angeles	+2	+7	36	35	36	6	34	2	2	19	34	28	21	36
Congestion	London	+17	+1	44	44	38	50	44	1	1	20	41	47	40	45
Congestion	Rome	-11	-33	43	44	56	50	65	7	0	50	52	47	49	50
Congestion	Madrid	-34	+5	23	22	22	26	22	3	1	29	40	28	26	29
Congestion	Paris	+14	+4	50	50	50	58	49	14	7	30	48	49	51	49
Congestion	Berlin	+54	+46	52	18	30	30	35	10	1	22	30	27	35	30
Congestion	Mexico City	-100	-100	0	40	38	36	34	5	4	17	14	35	0	29
Congestion	Sao Paulo	-15	+110	37	28	27	23	17	6	7	22	33	22	35	10

Source: TomTom. Click here for a PDF with more information on sources, methods

Congestion minutes added to 1 hour trip at 8am local time. 9am statistics are used for Mumbai

% change vs average 2019 column compares against latest data

NOTE: TomTom has been unable to provide data on most Chinese cities since April 2021. Taipei and Jakarta were added to the table in December 2021

NOTE: M/m changes are for Feb. 6 vs Jan. 9. A public holiday on Feb. 6 depressed traffic volumes in Mexico City on that day.

Air Travel:

Measure	Location	vs 2022	vs 2021	vs 2020	vs 2019	m/m	w/w	Freq.	Latest Date	Latest Value	Source
		changes shown as %									
All flights	Worldwide	+15	+37	+6.9	+13	+5.5	+13	d	Feb. 6	182,411	Flightradar24
Commercial flights	Worldwide	+28	+74	+2.2	+0.3	+1.2	+3.6	d	Feb. 6	105,392	Flightradar24
Seat capacity per week	Worldwide	+23	+101	+1.8	-8.6		+0.2	w	Feb. 6 week	96.7m seats	OAG
Air traffic (flights)	Europe				-14	-0.3	+2.1	d	Feb. 6	22,945	Eurocontrol
Air passenger traffic per month	China		-31	-56	-65	+48		m	December 2022	18.7m	CAAC
Heathrow airport passengers	UK		+90	+420	-11	+6.9		m	December 2022	5.94m	Heathrow

NOTE: Comparisons versus 2019 are a better measure of a return to normal for most nations, rather than y /y comparisons.

FlightRadar24 data shown above, and comparisons thereof, all use 7-day moving averages, except for w/w which uses single day data.

Refineries:

Measure	Location	vs 2022	vs 2021	vs 2019	m/m chg	Latest as of Date	Latest Value	Source
		Changes are in ppt unless noted						
Crude intake	US	-1.1%	+4.2	-7.4	+5.2%	Feb. 3	15.41m b/d	EIA
Utilization	US	-0.3	+4.9	-2.8	+3.8	Feb. 3	87.9%	EIA
Utilization	US Gulf	-0.7	+2.9	-2.7	+3.9	Feb. 3	88.2%	EIA
Utilization	US East	+5.6	+23	+16	+1.8	Feb. 3	90.8%	EIA
Utilization	US Midwest	-1.2	+7.2	-0.3	+7.8	Feb. 3	92.6%	EIA
Utilization (indep. refs)	Shandong, China		-7.8	-0.9	-1.8	Feb. 3	64.2 %	Oilchem

NOTE: US refinery data is weekly. China Shandong utilization is updated twice a month. Changes are shown in percentages for the row on crude intake, while refinery utilization changes are shown in percentage points. SCI99 data on Chinese refinery run rates was discontinued in late 2021.

Air Passenger Market Analysis

December 2022

The year ends on a strong note for the global industry

- In 2022, air passenger traffic gained momentum globally and recovered substantially from 41.7% of 2019 revenue passenger-kilometers (RPKs) in 2021 to 68.5% in 2022.
- Domestic RPKs recovered to 79.6% of pre-pandemic passenger traffic in 2022 and grew 10.9% year-on-year (YoY) from 2021 levels. International RPKs recovered to 62.2% of 2019 traffic and grew 152.7% YoY from 2021 levels.
- Industry-wide RPKs increased by 39.7% YoY in December and reached 76.9% of pre-pandemic levels for the same month. Compared to December 2021, domestic passenger traffic grew 2.6% while international traffic grew 80.2%.
- Monitored domestic markets continued to show resilience and steady traffic levels. International passenger traffic within and between the Asia Pacific region and the rest of the world also continued to show positive trends.
- Total domestic ticket sales have seen an uptick over the month of January 2023. This positive development is mainly attributable to China PR reopening. On the other hand, international ticket sales have caught up to domestic in terms of recovery to 2019 sales volumes.

	RPK, 2022 % change versus		ASK, 2022 % change versus		PLF		
	2019	2021	2019	2021	2022 level	%-pt versus 2019	%-pt versus 2021
TOTAL	**-31.5%**	**64.4%**	**-28.1%**	**39.8%**	**78.7%**	**-3.9%**	**11.8%**
Africa	-31.3%	84.9%	-31.8%	51.8%	72.3%	0.5%	12.9%
Asia Pacific	-55.6%	34.0%	-49.4%	16.8%	71.8%	-10.1%	9.2%
Europe	-22.2%	100.2%	-18.4%	66.8%	81.2%	-4.0%	13.5%
Latin America & Caribb.	-14.2%	62.7%	-12.9%	54.6%	81.3%	-1.3%	4.0%
Middle East	-25.9%	144.4%	-25.2%	67.0%	75.4%	-0.7%	23.9%
North America	-11.3%	45.5%	-9.9%	28.5%	83.5%	-1.3%	9.8%

Positive trend remained strong throughout 2022

Over the course of 2022, global air passenger traffic gained momentum and recovered substantially as travel restrictions were taken down and passengers expressed a very strong willingness to travel. Passenger traffic recovered from 41.7% of 2019 volumes in 2021 to 68.5% in 2022.

At the industry level, passenger demand was met by offered seat capacity in 2022, as available seat-kilometers (ASKs) recovered to 71.9% of 2019 levels, while maintaining industry-wide passenger load factors of 78.7%. Passenger load factors for 2022 were only 3.9 percentage points (ppts) below the load factors achieved before the pandemic in 2019. Similar observations can also be made at the regional level.

Globally, domestic operations ramped up quicker than international as domestic travel policies offered more certainty to passengers. Despite the setbacks caused by lingering travel restrictions, international traffic took off significantly in 2022 wherever these restrictions were taken down. As a result, international RPKs surged from 26.8% of 2019 levels in 2021 to 62.2% in 2022.

Airlines faced uneven outcomes in 2022. North American carriers led the industry by achieving close-to pre-pandemic passenger traffic levels with total RPKs 11.3% under 2019 volumes, followed by Latin American and European carriers at 14.2% and 22.2%, respectively, below 2019 levels.

Over the past year, re-openings in many economies of the Asia Pacific region allowed for passengers and airlines to return to the skies, greatly accelerating traffic growth in both domestic and international markets. While performed RPKs in 2022 were 54.4% under the levels of 2019 for this region's airlines, the recent developments related to the reopening of international travel in China PR give a positive outlook for the months to come.

Air passenger market overview - December 2022

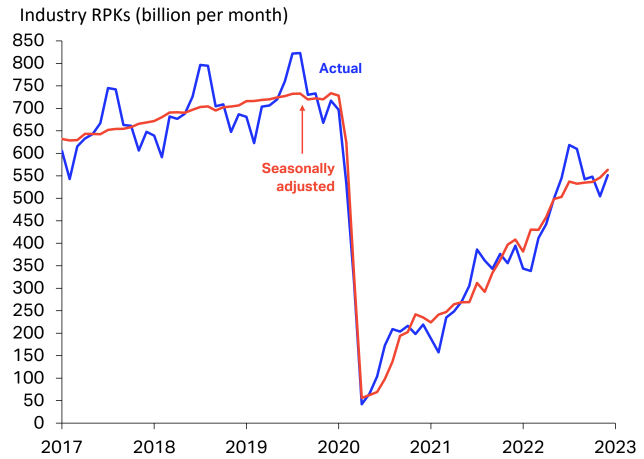
	World share [1]	December 2022 (% ch vs the same month in 2019)				December 2022 (% year-on-year)			
		RPK	ASK	PLF (%-pt)[2]	PLF (level)[3]	RPK	ASK	PLF (%-pt)[2]	PLF (level)[3]
TOTAL MARKET	***100.0%***	**-23.1%**	**-22.1%**	**-1.1%**	**81.1%**	**39.7%**	**23.0%**	**9.7%**	**81.1%**
International	*58.0%*	-24.9%	-25.2%	0.3%	82.0%	80.2%	47.8%	14.7%	82.0%
Domestic	*42.0%*	-20.1%	-16.8%	-3.3%	79.6%	2.6%	-2.5%	3.9%	79.6%

[1]% of industry RPKs in 2022 [2]Change in load factor vs same month in 2019 [3]Load factor level

The year ends on a strong note for the global industry

In December, industry-wide RPKs grew by 39.7% YoY and stood at 76.9% of December 2019 levels (**Chart 1**), a 2ppts increase from the month prior. Following the seasonal drop in demand of November, the month of December usually presents higher passenger traffic due to the year-end holidays. In seasonally adjusted terms, global RPKs grew by 3.1% from November and 5.0% from October 2022, signaling sustained momentum globally.

Chart 1: Global air passengers, RPK billion

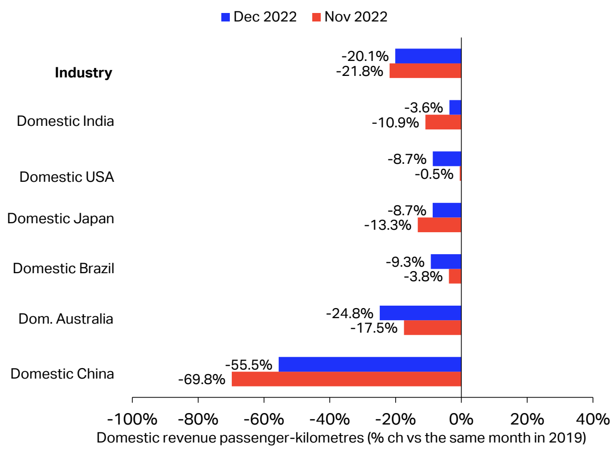


Sources: IATA Economics, IATA Monthly Statistics

Global passenger load factors (PLF) remained close to pre-pandemic levels this month with only 1.1ppts down on December 2019 levels at 81.1%. The aggregate load factor for domestic and international markets reached 79.6% and 82.0%, respectively.

Early signs of recovery for China's domestic markets, stable outcomes for other monitored markets

Chart 2 – Domestic RPK growth (airline region of registration basis), YoY% change versus 2019



Sources: IATA Economics, IATA Monthly Statistics

In December, industry-wide domestic markets steadied. Total domestic RPKs grew 2.6% while ASKs contracted by 2.5% YoY. In China PR, domestic traffic has shown signs of recovery once again, now sitting 55.5% under December 2019 levels, a substantial uptick from the previous month (**Chart 2**).

The US domestic market demand remained strong in December and throughout the year. RPKs reached 94.1% of 2019 traffic in 2022 and the month of December fell 8.7% short of December 2019 traffic levels.

In Brazil, domestic traffic was close to pre-pandemic levels in 2022 with RPKs totaling 94.6% of 2019 levels. December 2022 RPKs were 9.3% lower than December 2019 RPKs.

India saw domestic RPKs increase substantially in 2022 with concerns of new Covid-19 outbreaks fading away. Domestic RPKs for 2022 accounted for 85.7% of 2019 levels while December 2022 stood 3.6% below traffic for the same month in 2019.

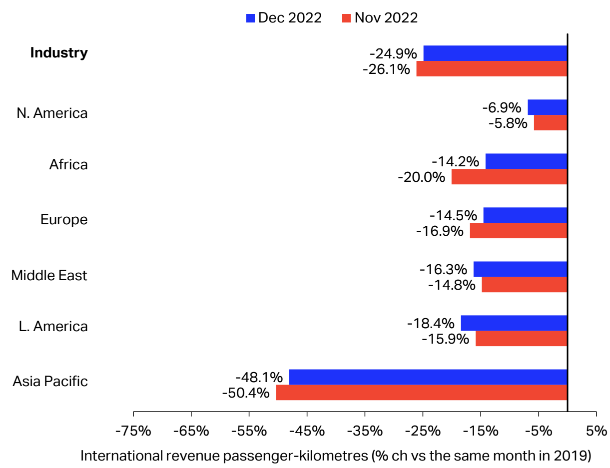
In Japan, domestic traffic quickly rebounded in 2022 and achieved 74.1% of the recovery to 2019 levels. December RPKs for the domestic market were 8.7% under those of December 2019. Australia experienced a similar rebound, with RPKs recovering to 81.2% of 2019 levels, a substantial 42.8 ppts increase from 2021.

Insufficient data prevent us from reporting on developments in Russia's domestic market.

International passenger traffic recovered substantially in 2022

In 2022, international passenger traffic more than doubled with 152.7% YoY growth. All regions experienced strong growth propelled by pent-up demand for air travel and easing restrictions globally. In December 2022, international RPKs tracked 24.9% under the same month in 2019 and conserved momentum with steady performance from all regions (**Chart 3**).

Chart 3: International RPK growth (airline region of registration basis), YoY% change versus 2019

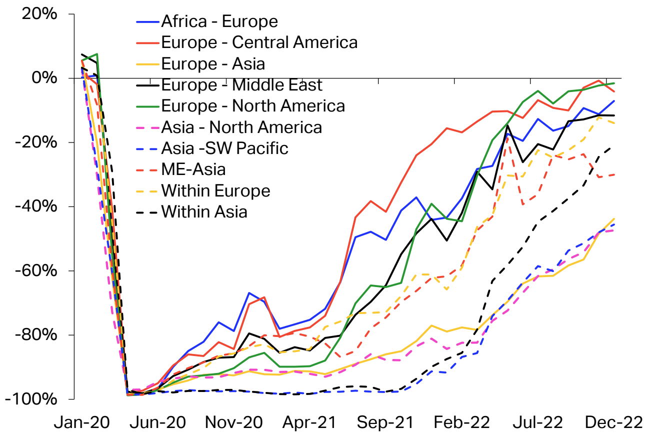


Sources: IATA Economics, IATA Monthly Statistics

Airlines of the Asia Pacific region continue to display the highest YoY growth rates. In December, international RPKs increased 302.7% YoY.

International traffic within Asia maintained its growth momentum this month and increased to 79.1% of December 2019 levels. Although, different route areas between this region and the rest of the world present uneven levels of recovery, a strong positive trend persisted until the end of 2022 (**Chart 4**).

Chart 4: International RPKs, YoY% change versus 2019 – Top 10 route areas in 2019, ranked by performed traffic volume



Source: IATA Statistics

In Europe, international RPKs performed well and grew by 46.5% YoY and are now 14.5% under December 2019 RPKs.

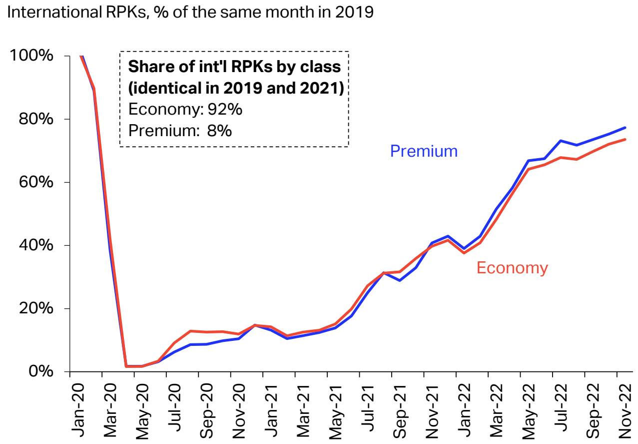
Latin America has seen 37.0% YoY growth in international RPKs while North America posted 61.3% YoY growth. December 2022 RPKs were 18.4% and 6.9% below December 2019 levels for Latin American and North America, respectively.

Middle Eastern carriers recorded 69.8% YoY growth this month and international RPKs are now 16.3% under pre-pandemic levels. For African carriers, international RPKs grew by 118.8% YoY, positioning the latest results 14.2% under December 2019 levels.

Aligned recovery for Premium and Economy

Recovery trends for traffic in the Premium and Economy cabin classes remain broadly aligned. Economy class RPKs – which include premium economy (and accounts for 92% of total RPKs) – reached 73.6% of their November 2019 level in November 2022. Premium RPKs – which capture travel in first and business class cabins – fared nearly as well at 77.3% of November 2019 level (**Chart 5**).

Chart 5: International RPKs by cabin class

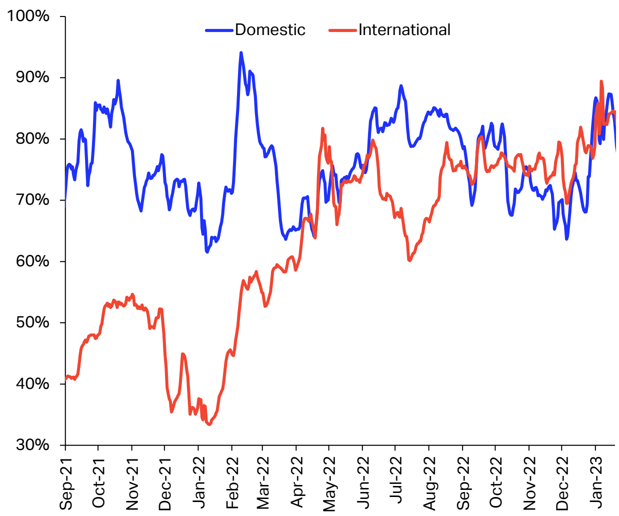


Source: IATA Monthly Statistics

International and domestic ticket sales align

Domestic ticket sales in 2022 have roughly followed a sideways trend while international ticket sales began to rise over that year (**Chart 6**). The most recent data show an uptick in domestic ticket sales in January 2023, mainly attributable to the domestic China PR market reopening. Meanwhile international ticket sales have caught up to, and maintained their recovery with, domestic ticket sales.

Chart 6: Passenger ticket sales, Domestic and International, YoY% versus 2019



Source: IATA Economics, DDS

Get the data

Access data related to this briefing through IATA's Monthly Statistics publication:
www.iata.org/monthly-traffic-statistics

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Air passenger market in detail - December 2022

	World share [1]	December 2022 (% year-on-year) RPK	ASK	PLF (%-pt)[2]	PLF (level)[3]
TOTAL MARKET	***100.0%***	**39.7%**	**23.0%**	**9.7%**	**81.1%**
Africa	*2.1%*	108.0%	72.5%	13.1%	76.9%
Asia Pacific	*22.4%*	63.3%	31.9%	14.8%	77.2%
Europe	*30.4%*	38.8%	18.9%	11.9%	83.6%
Latin America	*6.4%*	16.2%	20.0%	-2.6%	78.5%
Middle East	*9.8%*	65.1%	35.9%	14.1%	80.0%
North America	*28.8%*	18.4%	11.8%	4.7%	84.2%
International	***58.0%***	**80.2%**	**47.8%**	**14.7%**	**82.0%**
Africa	*1.8%*	118.8%	77.5%	14.5%	76.8%
Asia Pacific	*8.9%*	302.7%	153.5%	30.2%	81.5%
Europe	*26.4%*	46.5%	23.1%	13.3%	83.4%
Latin America	*2.8%*	37.0%	39.9%	-1.7%	79.0%
Middle East	*9.4%*	69.8%	38.8%	14.7%	80.2%
North America	*8.7%*	61.3%	37.5%	12.3%	83.6%
Domestic	***42.0%***	**2.6%**	**-2.5%**	**3.9%**	**79.6%**
Dom. Australia[4]	*1.0%*	72.7%	19.5%	25.1%	81.6%
Domestic Brazil[4]	*1.5%*	-5.7%	0.3%	-4.9%	77.4%
Dom. China P.R.[4]	*6.5%*	-26.4%	-27.4%	0.9%	64.3%
Domestic India[4]	*2.0%*	12.9%	0.9%	9.4%	88.9%
Domestic Japan[4]	*1.2%*	23.9%	5.5%	10.6%	71.5%
Domestic US[4]	*19.2%*	4.3%	2.2%	1.7%	84.3%

[1]% of industry RPKs in 2022 [2]Year-on-year change in load factor [3]Load factor level

Air passenger market in detail - December 2022

	World share [1]	December 2022 (% ch vs the same month in 2019) RPK	ASK	PLF (%-pt)[2]	PLF (level)[3]
TOTAL MARKET	***100.0%***	**-23.1%**	**-22.1%**	**-1.1%**	**81.1%**
Africa	*2.1%*	-12.2%	-17.4%	4.6%	76.9%
Asia Pacific	*22.4%*	-43.5%	-40.2%	-4.4%	77.2%
Europe	*30.4%*	-13.5%	-14.0%	0.6%	83.6%
Latin America	*6.4%*	-10.5%	-6.2%	-3.8%	78.5%
Middle East	*9.8%*	-16.0%	-18.9%	2.7%	80.0%
North America	*28.8%*	-8.2%	-6.9%	-1.3%	84.2%
International	***58.0%***	**-24.9%**	**-25.2%**	**0.3%**	**82.0%**
Africa	*1.8%*	-14.2%	-19.3%	4.6%	76.8%
Asia Pacific	*8.9%*	-48.1%	-47.9%	-0.2%	81.5%
Europe	*26.4%*	-14.5%	-14.3%	-0.3%	83.4%
Latin America	*2.8%*	-18.4%	-15.5%	-2.9%	79.0%
Middle East	*9.4%*	-16.3%	-19.2%	2.9%	80.2%
North America	*8.7%*	-6.9%	-5.7%	-1.1%	83.6%
Domestic	***42.0%***	**-20.1%**	**-16.8%**	**-3.3%**	**79.6%**
Dom. Australia[4]	*1.0%*	-24.8%	-23.6%	-1.3%	81.6%
Domestic Brazil[4]	*1.5%*	-9.3%	-1.5%	-6.6%	77.4%
Dom. China P.R.[4]	*6.5%*	-55.5%	-43.5%	-17.4%	64.3%
Domestic India[4]	*2.0%*	-3.6%	-4.5%	0.8%	88.9%
Domestic Japan[4]	*1.2%*	-8.7%	-10.8%	1.6%	71.5%
Domestic US[4]	*19.2%*	-8.7%	-7.0%	-1.6%	84.3%

[1]% of industry RPKs in 2022 [2]Change in load factor vs same month in 2019 [3]Load factor level

	RPK, 2022 % change versus		ASK, 2022 % change versus		PLF		
	2019	**2021**	**2019**	**2021**	**2022 level**	**%-pt versus 2019**	**%-pt versus 2021**
TOTAL	**-31.5%**	**64.4%**	**-28.1%**	**39.8%**	**78.7%**	**-3.9%**	**11.8%**
Africa	-31.3%	84.9%	-31.8%	51.8%	72.3%	0.5%	12.9%
Asia Pacific	-55.6%	34.0%	-49.4%	16.8%	71.8%	-10.1%	9.2%
Europe	-22.2%	100.2%	-18.4%	66.8%	81.2%	-4.0%	13.5%
Latin America & Caribb.	-14.2%	62.7%	-12.9%	54.6%	81.3%	-1.3%	4.0%
Middle East	-25.9%	144.4%	-25.2%	67.0%	75.4%	-0.7%	23.9%
North America	-11.3%	45.5%	-9.9%	28.5%	83.5%	-1.3%	9.8%
INTERNATIONAL	**-37.8%**	**152.7%**	**-35.0%**	**85.2%**	**78.5%**	**-3.5%**	**21.0%**
Africa	-34.1%	89.2%	-34.5%	51.0%	71.7%	0.4%	14.5%
Asia Pacific	-68.2%	363.3%	-65.2%	129.9%	74.0%	-6.9%	37.3%
Europe	-24.5%	132.2%	-19.8%	84.0%	80.6%	-5.0%	16.7%
Latin America & Caribb.	-26.9%	119.2%	-26.3%	93.3%	82.2%	-0.6%	9.7%
Middle East	-26.5%	157.4%	-26.0%	73.8%	75.8%	-0.5%	24.6%
North America	-20.9%	130.2%	-17.7%	71.3%	80.8%	-3.2%	20.7%
DOMESTIC	**-20.4%**	**10.9%**	**-15.7%**	**4.3%**	**78.9%**	**-4.7%**	**4.7%**
Africa	-13.8%	66.7%	-14.5%	56.2%	75.5%	0.7%	4.8%
Asia Pacific	-40.3%	-8.4%	-29.4%	-10.6%	70.4%	-12.7%	1.6%
Europe	-3.1%	4.6%	-6.7%	1.0%	85.1%	3.2%	2.9%
Latin America & Caribb.	-0.5%	35.0%	1.6%	33.7%	80.6%	-1.7%	0.8%
Middle East	-10.0%	14.0%	-4.0%	-7.5%	68.6%	-4.6%	13.0%
North America	-6.3%	25.5%	-5.8%	15.4%	84.7%	-0.4%	6.8%
DOMESTIC MARKETS							
Dom. Australia	-18.8%	111.7%	-17.7%	63.1%	79.7%	-1.1%	18.3%
Dom. Brasil	-5.4%	29.9%	-1.2%	31.8%	79.2%	-3.5%	-1.2%
Dom. China PR	-54.4%	-39.8%	-40.9%	-35.2%	65.3%	-19.3%	-5.0%
Dom. India	-14.3%	48.8%	-8.1%	30.1%	81.4%	-5.9%	10.2%
Dom. Japan	-25.9%	75.9%	-11.5%	43.4%	61.8%	-12.0%	11.4%
Dom. United States	-5.9%	23.7%	-5.2%	14.0%	84.7%	-0.6%	6.7%

Note: the total industry and regional growth rates are based on a constant sample of airlines combining reported data and estimates for missing observations. Airline traffic is allocated according to the region in which the carrier is registered; it should not be considered as regional traffic. Historical statistics are subject to revision.

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06 February 2023

Air Cargo Market Analysis

December 2022

Air cargo activity continued to decline in December

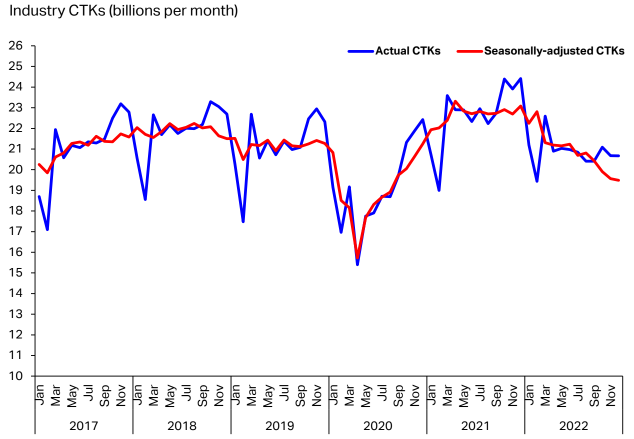
- Global air cargo tonne-kilometers (CTKs) dropped by 15.3% year-on-year (YoY) in December. This is also 7.4% lower than the CTKs for the same month in 2019. The industry did not perform as well as expected in a traditional peak season due to multiple headwinds in the current global economy. For the full 2022 calendar year, industry-wide CTKs were 8.0% below 2021 levels and 1.6% below 2019 levels.
- Available cargo tonne-kilometers (ACTKs) contracted by 2.2% YoY in December – the tenth YoY contraction in a row since March 2022. This is mainly a result of airlines responding to supply imbalances from the softening demand.
- Compared to December 2019, North America continued to be the only region fully recovered to pre-pandemic levels in terms of total CTKs. Latin America sustained its lead in the growth of international CTKs among all regions, registering a 2.3% YoY growth in December.
- Inflation in the G7 countries pulled back to 6.8% in December from 7.4% in November - the greatest decline in 2022. Both oil and jet fuel prices declined in December, slightly decreasing the unusually wide jet crack spread.

Air cargo demand slowed further in December

Industry-wide air cargo demand, measured by cargo tonne-kilometers (CTKs), remained broadly unchanged at 20.6 billion in December. This represents a 15.3% decline compared to the same month in 2021 and is also 7.4% lower than the corresponding pre-pandemic level **(Chart 1)**.

Seasonally adjusted (SA) air cargo demand also declined in December. Industry-wide SA CTKs contracted by 15.6% compared with December 2021, following the decline of 13.8% YoY in November.

Chart 1: Global CTKs, actual and seasonally adjusted (SA)



Sources: IATA Economics, IATA Monthly Statistics

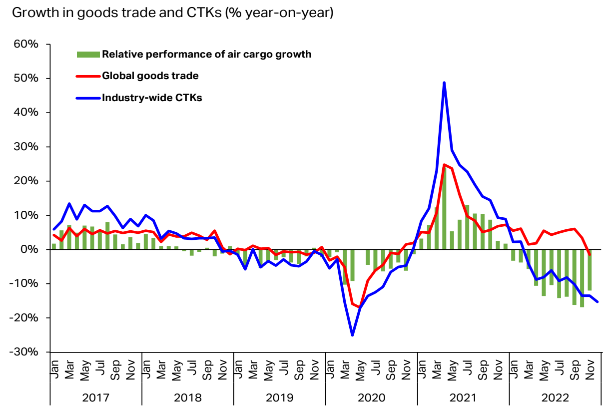
From a year-to-date (YTD) perspective, the global air cargo industry has achieved 250.2 billion CTKs. Although this is 8.0% lower than the same period in 2021, it still tracks close to the 2019 pre-pandemic level with a 1.6% contraction YTD.

The weaker air cargo demand is a result of multiple headwinds. Inflation remains high, curtailing the spending capacity of households. The ongoing war in Ukraine disrupts trade flows, and the unusual strength of the US dollar makes commodities traded in US dollars more expensive in local currency terms.

Global goods trade growth and air cargo activity

In November, global goods trade decreased by 1.5% YoY, down from a 3.4% increase YoY in October **(Chart 2)**.

Chart 2: Growth in global goods trade and CTKs



Sources: IATA Statistics, Netherlands CPB

Air cargo market - December 2022

	World share [1]	December 2022 (% ch vs the same month in 2019)				December 2022 (% year-on-year)			
		CTK	ACTK	CLF (%-pt)[2]	CLF (level)[3]	CTK	ACTK	CLF (%-pt)[2]	CLF (level)[3]
TOTAL MARKET	***100.0%***	**-7.4%**	**-7.0%**	**-0.2%**	**47.2%**	**-15.3%**	**-2.2%**	**-7.3%**	**47.2%**
International	*86.8%*	-7.7%	-7.1%	-0.3%	52.7%	-15.8%	-0.5%	-9.6%	52.7%

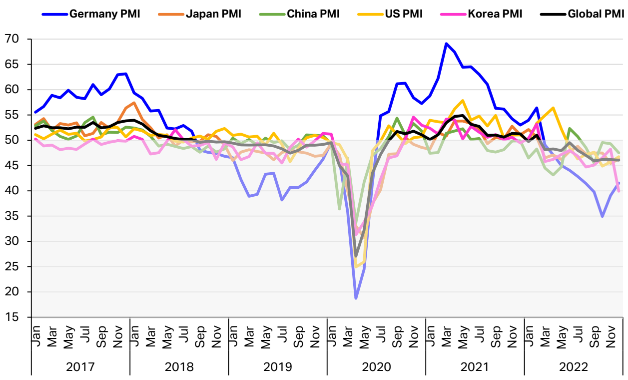
[1]% of industry CTKs in 2022 [2]Change in load factor vs same month in 2019 [3]Load factor level

Given that global CTKs declined 13.5% in November, this would suggest that air cargo is more affected by the shrinking global trade compared to maritime transport (**Chart 2**). However, air cargo's relative growth performance compared with maritime improved slightly from -16.9% in October to -12.0% in November.

New export orders – historically a leading indicator for air cargo shipments – remained below the critical 50 (no change) line for major economies. Global export orders stayed at the same level since October, suggesting continued deceleration on average. Germany's export orders continued to improve in December, signalling a degree of normalization after the months-long impact of the war in Ukraine. Other major economies that showed slight improvements in their export orders in December were the US and Japan, while South Korea and China registered lower new export orders in December compared to November (**Chart 3**).

Chart 3: New export orders, manufacturing PMIs

New export order manufaturing PMIs (50 = No change, seasonally adjusted)

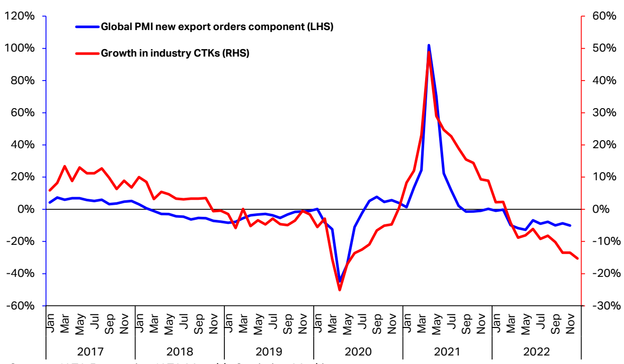


Sources: Markit

The YoY change in new export orders has been hovering around -10% since September. Owing to the historical relationship between this indicator and the industry wide CTKs, the relative stability of the former could point to a stabilization also in air cargo demand going forward (**Chart 4**).

Chart 4: CTK growth versus global new export orders

CTK growth versus global new export orders (year-on-year)



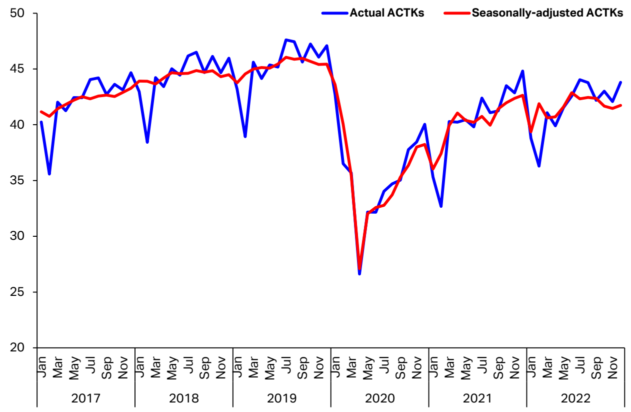
Sources: IATA Economics, IATA Monthly Statistics, Markit

Air cargo capacity continued to decline

Global air cargo capacity, measured by available cargo tonne-kilometers (ACTKs), contracted by 2.2% YoY, marking the third month in a row of YoY contraction since October 2022. Similarly, SA ACTKs in December were 2.1% lower than the same month in 2021 (**Chart 5**).

Chart 5: ACTK levels, actual and seasonally adjusted

Industry ACTKs (billions per month)



Sources: IATA Economics, IATA Monthly Statistics

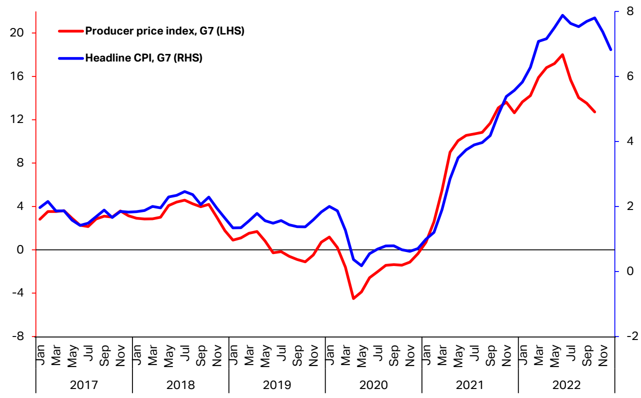
Airlines reduced air cargo capacity mainly to respond to the supply imbalance that has emerged as demand has fallen YoY since March. The industry SA cargo load factor (CLF) in December was 47.2%, dropping from 49% in previous two months.

Inflation rates stabilized in December as the oil price fell

Year-on-year inflation, as measured by the Consumer Price Index (CPI) for the G7 countries, dropped to 6.8% in December, marking greatest decline in the rate of inflation in 2022. Producer (input) prices continued to retreat by 0.8 ppts to 12.7% in October 2022 (**Chart 6**), recording the lowest rate year-to-date.

Chart 6: G7 headline CPI and PPI inflation

CTK growth versus global new export orders (year-on-year)

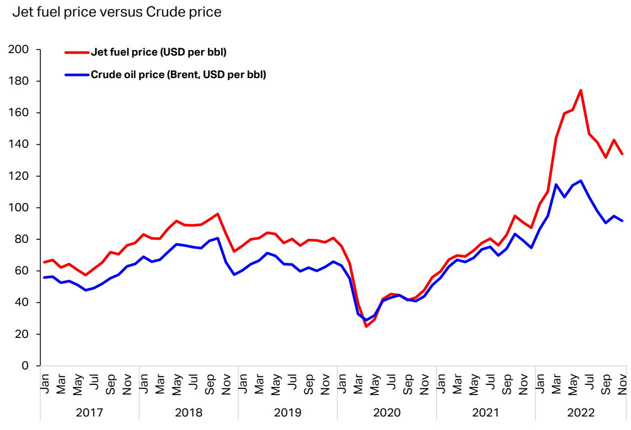


Source: Refinitiv Eikon

The declines in CPI in the G7 countries in December, in part, reflects the decline in the price of oil over the same period. Oil is an important contributor to producer prices, and a major cost to airlines directly.

The average Brent crude oil price decreased to USD 81.6 per barrel (bbl) in December from USD 90.9 per bbl in November. However, the jet crack also retreated. The average spread was USD 38.5 per bbl in December, compared with the peak level of USD 57.1 per bbl in June 2022 **(Chart 7)**.

Chart 7: Global oil price, monthly average



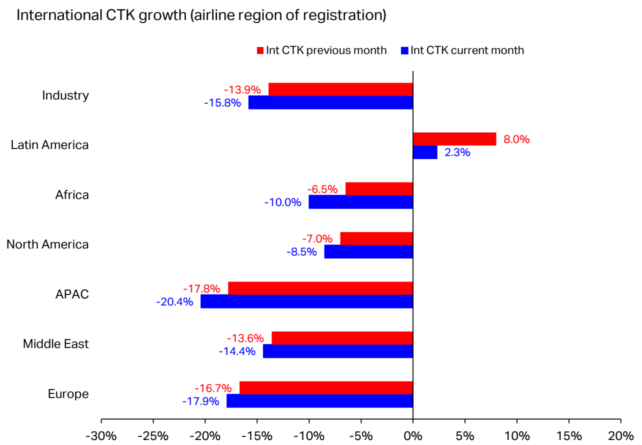
Source: S&P Global, Refinitiv Eikon

Int'l CTKs – Latin America regained momentum while APAC saw the regions' greatest decline

Industry-wide international CTKs contracted by 15.3% YoY in December, compared with a 13.9% YoY decline in the previous month. This is the biggest drop in YoY growth this year (**Chart 8**).

After the 8.0% YoY growth in international CTKs for November, airlines in Latin America continued their momentum in international CTKs in December, and registered a 2.3% YoY growth. In comparison, all other regions saw negative YoY growth in international air cargo activity, contrasting their outstanding performance in 2021.

Chart 8: YoY growth in international CTK by region



Sources: IATA Economics, IATA Monthly Statistics

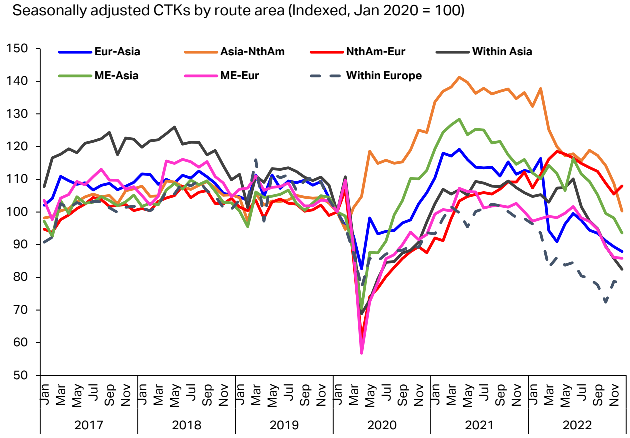
Asia Pacific, which accounts for the largest share of international CTKs globally, saw the greatest YoY decline among the regions at -20.4% in December. This was also the biggest drop of the year, mainly a result of China's rising Covid cases, which led to a drop in export orders, cargo output delays, and disruptions in supply chains.

North America showed a smaller decline of 8.5% YoY in international CTKs in December, which is 1.5 ppts lower than in November. Airlines in Europe continued to be most affected by the Ukraine war in December, suffering a 17.9% YoY contraction in international air cargo demand. Airlines in the Middle East faced a decrease of 14.4% YoY in international CTKs, while airlines in Africa saw a smaller decline in international CTKs of 10.0% YoY compared with December 2021.

Air cargo activity between regions maintained downward trends

The seasonally adjusted air cargo demand by route area in December saw declines in all major region-pair markets except for the North America-Europe market. This market registered the first positive month-on-month growth since April this year, and led among all routes in terms of the recovery since the beginning of the pandemic. **(Chart 9)**.

Chart 9: Seasonally adjusted CTKs by route area



Source: IATA Economics, IATA Monthly Statistics by Route

The air cargo demand between Asia-North America, in spite of recent detoriation, remains the only other route that stays above its level achieved in January 2020.

The Within Europe region remained broadly unchanged at 78% of the pre-pandemic levels in December, and continued to be the least recovered route compared to its levels achived in January 2020.

All other routes, including Europe-Asia, Within Asia, Middle East-Asia, and Middle East-Europe, saw their cargo traffic decline from November to December, and remained between 5% to 20% below Jan 2020 level in terms of seasonally adjusted air cargo demand.

Air cargo market in detail - December 2022

	World share[1]	December 2022 (% year-on-year) CTK	ACTK	CLF (%-pt)[2]	CLF (level)[3]
TOTAL MARKET	***100.0%***	**-15.3%**	**-2.2%**	**-7.3%**	**47.2%**
Africa	*2.0%*	-10.0%	1.3%	-5.4%	43.2%
Asia Pacific	*32.4%*	-21.2%	-3.9%	-11.6%	52.8%
Europe	*21.9%*	-17.4%	-7.0%	-7.0%	55.9%
Latin America	*2.7%*	0.0%	27.6%	-8.9%	32.2%
Middle East	*13.0%*	-14.4%	2.8%	-9.2%	45.4%
North America	*28.0%*	-8.5%	-2.9%	-2.5%	40.6%
International	***86.8%***	**-15.8%**	**-0.5%**	**-9.6%**	**52.7%**
Africa	*2.0%*	-10.0%	0.2%	-5.0%	44.4%
Asia Pacific	*29.7%*	-20.4%	-1.4%	-13.8%	58.0%
Europe	*21.5%*	-17.9%	-7.4%	-7.3%	57.4%
Latin America	*2.3%*	2.3%	32.7%	-11.3%	38.0%
Middle East	*13.0%*	-14.4%	3.0%	-9.3%	45.7%
North America	*18.4%*	-8.5%	1.8%	-5.5%	49.5%

[1]% of industry CTKs in 2022 [2]Change in load factor [3]Load factor level

	CTK, 2022 %		ACTK, 2022 %		CLF		
	2019	2021	2019	2021	2022 level	%-pt versus 2019	%-pt versus 2021
TOTAL	**-1.6%**	**-8.0%**	**-8.2%**	**3.0%**	**50.1%**	**3.3%**	**-6.0%**
Africa	8.3%	-1.4%	-15.3%	0.3%	46.3%	10.1%	-0.8%
Asia Pacific	-7.8%	-8.8%	-17.2%	0.5%	58.3%	6.0%	-5.9%
Europe	-8.7%	-11.5%	-16.5%	0.5%	56.7%	4.9%	-7.7%
Latin America & Caribb.	-4.3%	13.1%	-14.3%	27.1%	39.2%	4.1%	-4.9%
Middle East	-1.6%	-10.7%	-6.3%	4.3%	49.0%	2.3%	-8.2%
North America	13.7%	-5.1%	8.2%	4.2%	41.5%	2.0%	-4.1%
INTERNATIONAL	**-1.6%**	**-8.2%**	**-9.0%**	**4.5%**	**56.1%**	**4.2%**	**-7.8%**
Africa	9.4%	-1.4%	-14.2%	-0.2%	47.3%	10.2%	-0.6%
Asia Pacific	-3.9%	-7.4%	-12.2%	5.8%	64.5%	5.5%	-9.2%
Europe	-9.1%	-11.8%	-17.3%	0.5%	58.9%	5.3%	-8.2%
Latin America & Caribb.	-2.6%	15.0%	-10.8%	27.8%	47.1%	4.0%	-5.3%
Middle East	-1.6%	-10.7%	-6.1%	4.5%	49.3%	2.2%	-8.4%
North America	12.7%	-6.3%	5.1%	4.9%	50.0%	3.4%	-6.0%

Note: the total industry and regional growth rates are based on a constant sample of airlines combining reported data and estimates for missing observations. Airline traffic is allocated according to the region in which the carrier is registered; it should not be considered as regional traffic. Historical statistics are subject to revision.

IATA Economics
economics@iata.org
06 February 2023

Get the data

Access data related to this briefing through IATA's Monthly Statistics publication:
www.iata.org/monthly-traffic-statistics

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www.iata.org/consulting

https://www.beehive.govt.nz/release/government-takes-new-direction-policy-refocus
8 FEBRUARY 2023

Government takes new direction with policy refocus

RT HON CHRIS HIPKINS

Prime Minister

- Work on the TVNZ/RNZ public media entity to stop; Radio NZ and NZ on Air to receive additional funding
- Social insurance scheme will not proceed this term
- The Human Rights (Incitement on Ground of Religious Belief) Amendment Bill to be withdrawn and not progressed this term. The matter to be referred to the Law Commission for guidance
- Biofuels mandate to be stopped
- Government to consider changes to 3 Waters programme soon
- Minimum wage to increase by rate of inflation from 1 April

Prime Minister Chris Hipkins has announced a suite of programmes that are being cancelled or delayed in order to put the Government's focus on the cost of living.

"The Government is refocusing its priorities to put the cost of living front and centre of our new direction," Chris Hipkins said.

"I said the Government is doing too much too fast, and that we need to focus on the cost of living. Today we deliver on that commitment.

"Work on the TVNZ-RNZ public media entity will stop entirely. Support for public media needs to be at a lower cost and without such significant structural change.

"Cabinet has agreed to provide Radio New Zealand with additional funding to strengthen its public media role. New Zealand on Air will also receive additional funding to support public media content and that funding will be available to a wider range of broadcasters. Remaining funding will be redirected to other Government priorities.

"The social insurance scheme is off the table and will not proceed as proposed. We will need to see a significant improvement in economic conditions before anything is advanced.

"Work will continue to explore ways to best address these inequities in the long term when the economy is better placed to make change. But it is off the table for now.

"The Human Rights (Incitement on Ground of Religious Belief) Amendment Bill will be withdrawn and the matter referred to the Law Commission. This will allow the Law Commission the opportunity to consider a difficult and highly contested area of law in totality.

“Cabinet also agreed that the biofuels mandate will not proceed. The mandate would have increased the price of fuel, and given the pressure on households that’s not something I’m prepared to do.

“Cabinet considered the 3 Waters programme. The need for reform is unquestionable. The events in Auckland have once again demonstrated the limits of our existing infrastructure and the need for change. But careful consideration is required.

“This is the first and most significant set of decisions that reprioritises the Government agenda and sets out our new direction. It will help to provide greater bandwidth and resource for where focus is needed most – the cost of living.

“When I became leader I promised that the Government would do more to help families with the cost of living. With this in mind, Cabinet today also set a new minimum wage in line with CPI.

“Cabinet has agreed to lift the minimum wage by $1.50 – to $22.70 per hour. It will apply from 1 April, 2023. The Starting-Out and Training minimum wage rates will be maintained at 80 per cent of the adult minimum wage.

“In tough times, it’s critical to support those who struggle the most to make ends meet. Those on low incomes make impossible trade-offs between food and medical care, dry homes and a pair of shoes. These families need our support now more than ever and an inflation-adjusted lift in the minimum wage will means thousands of New Zealanders do not go backwards.

“We’ve tried to find the right balance. Analysis from MBIE that fed into our decision suggests this increase is unlikely to have a significant impact on unemployment, because it is broadly in line with existing average wage growth across the economy.

“The impact on inflation is negligible. In the 2022 Review, MBIE estimates that an increase of 7 per cent in the minimum wage will have only a minor inflationary impact of 0.1% on the wages portion of GDP.

“These decisions are a start and show the new direction of our Government. Increased support for business, increased support for those on low incomes and a reprioritisation of our work programme to shift it to the bread and butter issues New Zealanders want us focused on,” Chris Hipkins said

bp Integrated Energy Company strategy update: Growing investment, growing value, growing distributions

7 February 2023

- **Performing while transforming:**
    - Performing: 2022 EBITDA $60.7 billion; full year operating cash flow $40.9 billion; net debt $21.4 billion, lowest for almost a decade; ROACE 30.5%; full year tax $15.1 billion; strongest upstream plant reliability on record; lowest production costs in 16 years
    - Transforming: investment in transition growth engines c. 30% of 2022 total investment, up from c. 3% in 2019
- **Leaning further into bp's strategy:**
    - Investing more in the energy transition and bp's transition, investing more in supporting energy security and energy affordability today
    - Up to $8 billion more into transition growth engines by 2030 – growing in higher-return bioenergy, and convenience & EV charging; focusing hydrogen and renewables & power where bp can leverage integration
    - Up to $8 billion more into oil and gas by 2030 – targeting short-cycle fast-payback opportunities with lower additional operational emissions
    - Aim to materially increase earnings through 2030 – aiming for $51-56 billion group EBITDA in 2030
- **Delivering for shareholders:**
    - Growing dividends: 10% increase in dividend per ordinary share for fourth quarter, representing 21% growth from 4Q 2021
    - Growing buybacks: further $2.75 billion buybacks announced today; total of $11.25 billion buybacks announced from 2022 surplus cash flow
    - Increasing targets: over 12% annual EBIDA per share growth to 2025; over 18% ROACE in 2025 and 2030

Since introducing its new purpose, net zero ambition, organisation and strategy in 2020, bp has built strong momentum across its strategy and delivered value for shareholders. The major global uncertainties experienced in the past three years – from the pandemic and its aftermath to the impact of Russia's attack on Ukraine – have increased the world's focus on energy security and affordability as well as accelerated the drive towards a lower carbon energy system.

bp chief executive Bernard Looney said: "It's clearer than ever after the past three years that the world wants and needs energy that is secure and affordable as well as lower carbon – all three together, what's known as the energy trilemma. To tackle that, action is needed to accelerate the transition. And – at the same time – action is needed to make sure that the transition is orderly, so that affordable energy keeps flowing where it's needed today.

"As an integrated energy company, bp is very deliberately set up to help on both counts. With three years of delivery and track record – we have increased confidence our strategy is working. And with today's announcement we are leaning further in. We are growing our investment into our transition and, at the same time, growing investment into today's energy system. In doing so - we see tremendous opportunity to create value. And it's what governments and customers are asking of companies like us."

bp now aims to accelerate the growth in earnings from its transition growth engines (TGEs) while also delivering higher earnings than previously expected from its oil and gas businesses through 2030 - both compared to bp's previous aims(1).

bp plans to support this growth by disciplined increases in investment over the period to 2030 of up to $8 billion in the TGEs and up to $8 billion in oil and gas. bp is adjusting its target capital expenditure range to $14-18 billion a year out to 2030(2), from the previous range of $14-16 billion. All investments will remain subject to disciplined application of bp's balanced investment and returns criteria.

bp expects this additional incremental investment to deliver around $3 billion additional group EBITDA in 2025 and is aiming for that to grow to $5-6 billion in 2030. This would comprise an additional $2 billion from the TGEs and $3-4 billon from oil and gas projects in 2030. bp has also raised its oil and gas price and refining margin assumptions(3).

As a result of both factors, bp is now targeting group EBITDA of $46-49 billion in 2025 and is aiming for $51-56 billion in 2030, in a $70/barrel (2021 real) oil price environment. These compare to its previous target and aim, from May 2022, of around $38 billion in 2025 and $39-46 billion in 2030 at $60/barrel (2020 real).

Performing while transforming

After setting out its new purpose, net zero ambition, structure and strategy in 2020, bp's focus is now on delivering its transformation into an Integrated Energy Company.

Bernard Looney: "Throughout 2022, bp continued to focus on delivery of our Integrated Energy Company strategy. We are helping provide the energy the world needs today and – at the same time – investing with discipline into our transition and the energy transition – as demonstrated by the Archaea

Energy acquisition. We are strengthening bp, with our strongest upstream plant reliability on record and our lowest production costs in 16 years, helping to generate strong returns and reducing debt for the 11th quarter in a row. Importantly, we are delivering for our shareholders – with buybacks and a growing dividend. This is exactly what we said we would do and will continue to do – performing while transforming.”

In 2022, bp delivered EBITDA of $61 billion, operating cash flow of $41 billion, including around $7 billion working capital build, and reported underlying replacement cost profit of $28 billion.

It continued to strengthen its finances, reducing net debt by $9.2 billion over the year to $21.4 billion – the lowest for over nine years. ROACE for the year was 30.5%. For 2022, bp incurred a total tax charge of $15.1 billion on an underlying basis, representing an effective tax rate of 34%.

bp also delivered sector-leading distributions for its shareholders in 2022. bp today announced a 10% increase in the quarterly dividend for the fourth quarter of 2022, to 6.61c per ordinary share. Together with the 10% rise in the second quarter of 2022, this represents 21% growth in the dividend compared to the fourth quarter of 2021.

With plans for $2.75 billion share buybacks from fourth quarter surplus cash flow announced today, bp has also announced a total of $11.25 billion share buybacks from 2022 surplus cash flow.

Through 2022, bp also continued to deliver its transformation, notably with the acquisition of biogas producer Archaea Energy, forming Azule Energy with Eni in Angola, and adding significant potential opportunities for hydrogen, including in Australia, Abu Dhabi, Egypt, Oman and Mauritania.

In 2022, it invested $4.9 billion, around 30% of its total $16.3 billion capital expenditure, into its transition growth engines □ including the acquisition of Archaea Energy. This compares to around 3% in 2019. bp continues to expect this proportion to grow to around 50% in 2030.

Leaning further into bp’s strategy

More investment in bp’s transition:

bp aims to increase investment in its TGEs by up to $1 billion a year on average, or up to a cumulative additional $8 billion to 2030. bp’s investment in its TGEs is now expected to reach $7-9 billion a year in 2030[4] - with cumulative investment over 2023-2030 around $55-65 billion.

bp aims to invest around half of this cumulative total in the TGEs where bp has established businesses, capabilities and track record – in bioenergy, and in convenience and EV charging; the other half in hydrogen and renewables & power.

bp expects to achieve returns of greater than 15% from bioenergy, and from convenience and EV charging combined, and double digit returns from hydrogen. It expects 6-8% unlevered returns in renewables.

Earnings from bp's TGEs are expected to grow as a result of these changes. bp now expects the TGEs to deliver $3 4 billion EBITDA in 2025, and is aiming for $10-12 billion in 2030, comprising: over $4 billion from bioenergy; over $4 billion from convenience and EV charging; and $2-3 billion from hydrogen and renewables & power.

Bernard Looney: "We will increase our focus on the transition growth engines able to deliver nearer-term solutions – like EV chargers and sustainable aviation fuels – that can help people and businesses decarbonise sooner. And we will continue to build our hydrogen and renewables and power businesses for the longer term, based around projects where bp's integrated approach can create significant additional value."

Bioenergy: bp plans to grow its established bioenergy businesses materially. It plans to increase its supply of biogas six-fold, underpinned by Archaea Energy, to up to 70,000 barrels of oil equivalent a day in 2030. bp aims to increase biofuel production to around 100,000 barrels a day by 2030, supported by five major new projects at bp refineries, focused on production of sustainable aviation fuel.

Convenience and EV charging: expansion of bp's strategic convenience site networks is expected to drive growth in bp's convenience gross margin by around 10% a year to 2030. Together with EV charging they are expected to help grow bp's ability to offer lower carbon transport solutions for customers. Today bp has 22,000 EV charge points and aims for more than 100,000 by 2030 - around 90% rapid or ultra-fast. It is developing leading positions in key geographies worldwide, underpinned by partnerships with major fleet operators.

Hydrogen and renewables & power: through this decade bp aims to establish the foundations of a material business for the future. bp aims to build a leading position globally in hydrogen, initially supplying its own refineries, scaling up to meet growing customer demand and in parallel, as markets develop, developing global export hubs for hydrogen and its derivatives. By 2030 bp aims to produce between 0.5-0.7 million tonnes a year of primarily green hydrogen, also pursuing selected blue hydrogen opportunities.

In **renewables & power**, bp will focus investment on opportunities where it can create integration value and enhance returns. bp aims to build a portfolio – including a global position in offshore wind - in support of green hydrogen, e-fuels, EV charging and power trading, together with continued growth in its self-funded solar joint venture Lightsource bp. bp remains on track to deliver its aim of having developed 50GW renewable power to FID by 2030; of this it aims to have around 10GW net installed capacity – largely operated. bp also expects to have assets under construction and for Lightsource bp to contribute materially.

More investment in today's energy system:

bp also aims to increase investment into resilient high-quality oil and gas projects - again by an average of up to $1 billion a year, or up to a cumulative $8 billion to 2030. The investment will help to meet near-term demand for secure supplies of oil and gas, generating additional earnings that can further strengthen bp and support investment in its transition.

The incremental investment to 2025 will target shorter-term, fast-payback projects that maximise value and can deliver rapidly, with minimal new infrastructure. While bp will continue to high-grade its global oil and gas portfolio, due to improving operational reliability and commerciality over the past four years it also now anticipates retaining some oil and gas assets longer than previously envisaged.

Bernard Looney: "We need continuing near-term investment into today's energy system – which depends on oil and gas – to meet today's demands and to make sure the transition is an orderly one. We have high-quality options throughout our portfolio, allowing us to choose only the best. We will prioritise projects where we can deliver quickly, at low cost, using our existing infrastructure, allowing us to minimise additional emissions and maximise both value and our contribution to energy security and affordability."

As a result of these changes, bp anticipates its oil and gas production will be around 2.3 million barrels of oil equivalent a day (mmboe/d) in 2025 and aims for it to be around 2.0 mmboe/d in 2030. This 2030 production would be around 25% lower than bp's production in 2019, excluding production from Rosneft, compared to bp's previous expectation of a reduction of around 40%. bp correspondingly now aims for a fall of 20% to 30% in emissions from the carbon in its oil and gas production[5] in 2030 compared to a 2019 baseline, lower than the previous aim of 35-40%.

From the first quarter of 2022, bp has no longer reported oil and gas production from Russia. With the removal of this Russian production, bp's full year average reported production in 2022 was around 40% lower than the total production bp reported in 2019.

Delivering for shareholders

bp remains focused on the disciplined delivery of its financial frame. Through the financial frame and bp's business plans out to 2025, in a $70 per barrel price environment, bp aims to offer:

- **Accelerating growth**: with a compound average growth rate for EBIDA per share of over 12% between 2H 2019/1H2020 to 2025 at $70 per barrel 2021 real.

- **Competitive returns**: expecting to achieve a return on average capital employed (ROACE) of over 18% in both 2025 and 2030 at $70 per barrel 2021 real.

- **Debt reduction**: intending to allocate around 40% of 2023 surplus cash flow to further strengthening the balance sheet.

- **Compelling shareholder distributions**:

    - **Dividends**: bp expects to maintain a resilient cash balance point of around $40 per barrel Brent oil price, with $11 per barrel refining marker margin and $3 per million BTU Henry Hub gas price. bp continues to see the capacity to continue to grow its dividend per ordinary share by around 4% a year at around $60/barrel, subject to the board's discretion[6].

- Buybacks[6]: bp is committed to allocating 60% of 2023 surplus cash flow to share buybacks, expecting a buyback of around $4 billion a year - at around $60 a barrel, at the lower end of its capital expenditure range and subject to maintaining a strong investment grade credit rating. The buyback commitment offers leverage to higher price environments.

This announcement contains inside information. The person responsible for arranging the release of this announcement on behalf of BP p.l.c. is Ben Mathews, Company Secretary.

bp's fourth quarter and full year 2022 results can be seen at www.bp.com/results.

Notes

(1) Compared to aims set out by bp in February 2022.

(2) Capital expenditure in 2023 planned to be in range $16-18 billion.

(3) Assumptions to 2030, all 2021 real: Brent oil price $70/barrel; Henry Hub gas price $4/million Btu; bp refining marker margin, $14/barrel. See also note 1 of bp 4Q and full year results 2022.

(4) bp's investment in TGEs is expected to be $6-8 billion in 2025.

(5) bp's aim to reach net zero* CO_2 emissions, in accordance with bp's Aim 2, from the carbon in our oil and gas production, in respect of the estimated CO_2 emissions from the combustion of upstream production of crude oil, natural gas and natural gas liquids on a bp equity share basis based on bp's net share of production, excluding bp's share of Rosneft production and assuming that all produced volumes undergo full stoichiometric combustion to CO2. Aim 2 is bp's Scope 3 aim and relates to Scope 3, category 11 emissions. Any interim target or aim in respect of bp's Aim 2 is defined in terms of absolute reductions relative to the baseline year of 2019.

(6) In setting the dividend per ordinary share and the buyback each quarter the board will take into account factors including the cumulative level of and outlook for surplus cash flow, the cash balance point and the maintenance of a strong investment grade credit rating.

- For the purposes of this announcement, each of the following terms has the meaning given to it in bp's fourth quarter and full year 2022 financial results announcement: operating cash flow; net debt; ROACE; upstream plant reliability; EV charge points; surplus cash flow; cash balance point; capital expenditure; refining marker margin (RMM); strategic convenience sites and underlying replacement cost (RC) profit.

- For the purposes of this announcement, each of the following terms has the meaning given to it in the bp Annual Report and Form 20-F 2021: convenience gross margin.

- EBIDA: has the meaning given to the term Adjusted EBIDA in bp's fourth quarter and full year 2022 financial results announcement.

- EBIDA per share: share buybacks are modelled across a range of share prices in this calculation and EBIDA is after impact of planned divestments.

- EBITDA: has the meaning given to the term Adjusted EBITDA in bp's fourth quarter and full year 2022 financial results announcement.

- Net zero: References to net zero for bp in the context of our ambition and Aims 1, 2 and 3 mean achieving a balance between (a) the relevant Scope 1 and 2 emissions (for Aim 1), Scope 3 emissions (for Aim 2) or product lifecycle emissions (for Aim 3), and (b) the aggregate of applicable deductions from qualifying activities such as sinks under our methodology at the applicable time.

- Rapid or ultra-fast: rapid charging ≥50kW and ultra-fast charging ≥150kW.

Further information

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Cautionary statement

In order to utilize the 'safe harbor' provisions of the United States Private Securities Litigation Reform Act of 1995 (the 'PSLRA') and the general doctrine of cautionary statements, bp is providing the following cautionary statement: The discussion in this results announcement contains certain forecasts, projections and forward-looking statements - that is, statements related to future, not past events and circumstances - with respect to the financial condition, results of operations and businesses of bp and certain of the plans and objectives of bp with respect to these items. These statements may generally, but not always, be identified by the use of words such as 'will', 'expects', 'is expected to', 'aims', 'should', 'may', 'objective', 'is likely to', 'intends', 'believes', 'anticipates', 'plans', 'we see', 'focus on' or similar expressions.

In particular, the following, among other statements, are all forward looking in nature: plans and expectations regarding bp's performance, earnings, returns, capital expenditure, targets and market position through 2025 and/or 2030; expectations related to oil and gas prices and refining margins; expectations regarding bp's plans to invest up to an additional $8 billion in its transition growth engines and up to additional $8 billion in oil and gas projects, both by 2030; plans and expectations related to earnings growth, including the aim of group EBITDA of $51-56 billion in 2030 at oil prices of $70 per barrel in 2021 real terms; plans and expectations related to bp's target of growing EBIDA per share at over 12% compound average growth rate through 2025, and growing ROACE to over

18% in both 2025 and 2030; plans, expectations and assumptions regarding oil and gas demand, supply and prices; plans and expectations regarding bp's transition growth engines of bioenergy, convenience, EV charging, hydrogen and renewables and power, including plans and expectations related to allocation of capital expenditure, returns and EBITDA growth; expectations regarding earnings from incremental investments including the delivery of $5-6 billion of additional EBITDA in 2030; plans and expectations regarding the growth of bp's bioenergy business; plans and expectations related to the expansion of strategic convenience site networks and EV charge points; plans and expectations regarding hydrogen, including aims to establish a future material business and build a leading global position, customer demand, the development of global export hubs, and aims relating to green and blue hydrogen; plans and expectations in renewables and power, including the target of developing 50 gigawatts to FID and having 10 gigawatts net installed capacity mainly bp operated, both by 2030 and Lightsource bp's contribution to bp's targets and aims; plans and expectations regarding investment into resilient high-quality oil and gas projects; bp's plans to continue to high-grade its global oil and gas portfolio; plans and expectations regarding the retention of certain oil and gas assets; plans and expectations relating to bp's future oil and gas production; plans and expectations relating to taxes, including the effective tax rate; plans regarding future quarterly dividends and the amount and timing of share buybacks; plans and expectations regarding the allocation of surplus cash flow and cash balance point; and plans and expectations relating to the reduction of debt and maintenance of an investment grade credit rating.

By their nature, forward-looking statements involve risk and uncertainty because they relate to events and depend on circumstances that will or may occur in the future and are outside the control of bp.

Actual results or outcomes, may differ materially from those expressed in such statements, depending on a variety of factors, including: the extent and duration of the impact of current market conditions including the volatility of oil prices, the effects of bp's plan to exit its shareholding in Rosneft and other investments in Russia, the impact of COVID-19, overall global economic and business conditions impacting bp's business and demand for bp's products as well as the specific factors identified in the discussions accompanying such forward-looking statements; changes in consumer preferences and societal expectations; the pace of development and adoption of alternative energy solutions; developments in policy, law, regulation, technology and markets, including societal and investor sentiment related to the issue of climate change; the receipt of relevant third party and/or regulatory approvals; the timing and level of maintenance and/or turnaround activity; the timing and volume of refinery additions and outages; the timing of bringing new fields onstream; the timing, quantum and nature of certain acquisitions and divestments; future levels of industry product supply, demand and pricing, including supply growth in North America and continued base oil and additive supply shortages; OPEC+ quota restrictions; PSA and TSC effects; operational and safety problems; potential lapses in product quality; economic and financial market conditions generally or in various countries and regions; political stability and economic growth in relevant areas of the world; changes in laws and governmental regulations and policies, including related to climate change; changes in social attitudes and customer preferences; regulatory or legal actions including the types of enforcement action pursued and the nature of remedies sought or imposed; the actions of prosecutors, regulatory authorities and courts; delays in the processes for resolving claims; amounts ultimately payable and timing of payments relating to the Gulf of Mexico oil spill; exchange rate fluctuations; development and use of new technology; recruitment and retention of a skilled workforce; the success or otherwise of partnering; the actions of competitors, trading partners, contractors, subcontractors, creditors, rating agencies and others; bp’s access to future credit resources; business disruption and crisis management; the impact on bp’s reputation of ethical misconduct and non-compliance with regulatory obligations; trading losses; major uninsured losses; the possibility that international sanctions or other steps or actions taken by any competent authorities or any other relevant persons may impact Rosneft’s business or outlook, bp’s ability to sell its interests in Rosneft, or the price for which bp could sell such interests; the actions of contractors; natural disasters and adverse weather conditions; changes in public expectations and other changes to business conditions; wars and acts of terrorism; cyber-attacks or sabotage; and other factors discussed elsewhere in this report, as well as those factors discussed under “Risk factors” in bp’s Annual Report and Form 20-F 2021 as filed with the US Securities and Exchange Commission and those factors discussed under “Principal risks and uncertainties” in bp’s Report on Form 6-K regarding results for the six-month period ended 30 June 2022 as filed with the US Securities and Exchange Commission.

Transforming to an integrated energy company

Resilient hydrocarbons

- Oil and gas
- Refining

Convenience and mobility

- Retail fuels
- Castrol, aviation, B2B/midstream

Low carbon energy

Transition growth engines

- Bioenergy[1]
- Convenience
- EV Charging
- Hydrogen
- Renewables & Power

Sustainability

Integration

(1) *Bioenergy includes biofuels marketing reported in convenience and mobility*

Investing more into our transition growth engines

up to **$8bn**

additional capital by 2030

- Investing more into higher return Bioenergy, and Convenience & EV Charging

…while building a leading position globally in Hydrogen and focusing on creating integration value in Renewables & Power

+

Investing more into today's oil and gas system

up to **$8bn**

additional capital by 2030

- Investing more in high-quality oil and gas projects
- Retaining certain oil and gas assets for longer

Accelerating EBITDA growth to 2030

Investing ~$1bn p.a. more into our transition growth engines[1]

Additional EBITDA

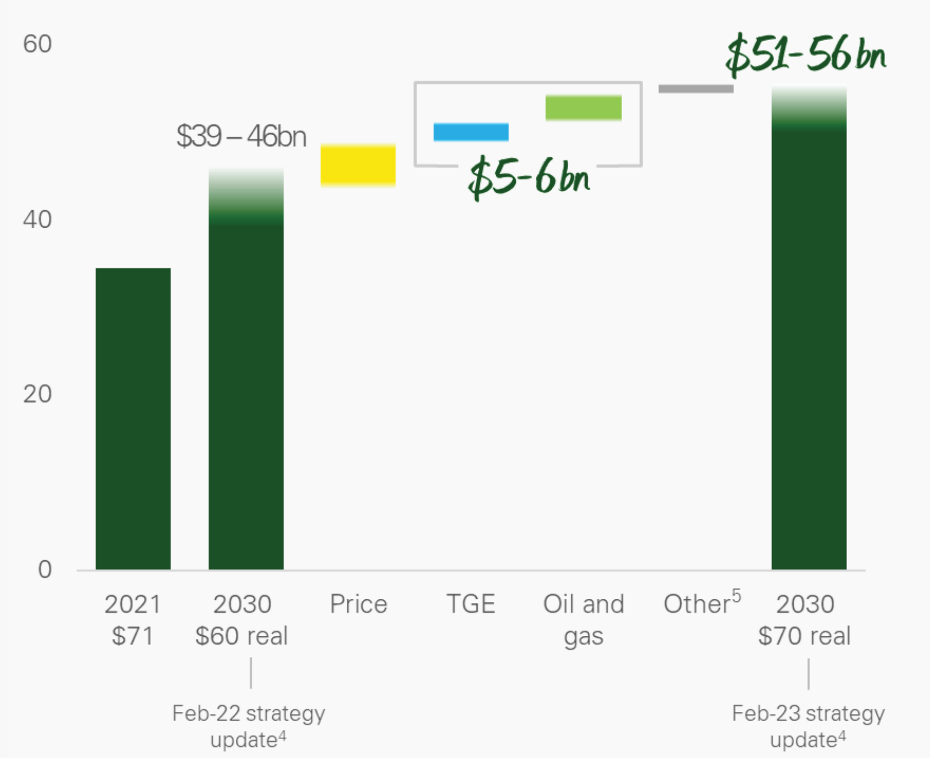
~$1bn in 2025[2] → ~$2bn in 2030[2]

Investing ~$1bn p.a. more into today's oil and gas system[1]

Additional EBITDA

~$2bn in 2025[3] → $3-4bn in 2030[3]

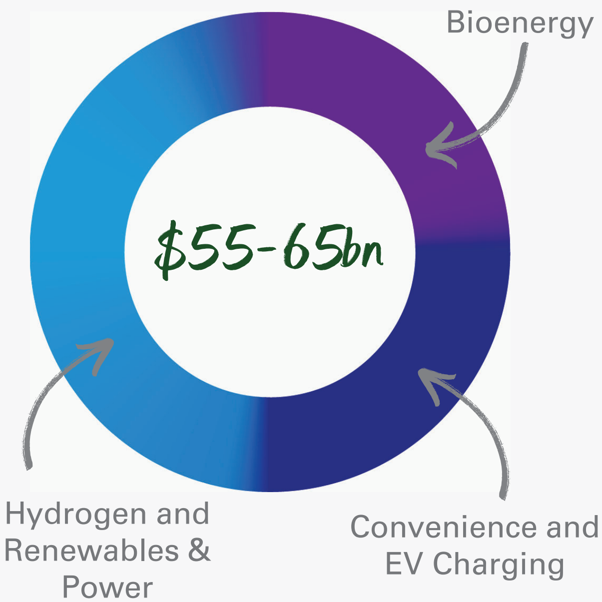
Uplift to 2030 Group EBITDA* aim $bn



(1) 2023-30 average (2) At the upper end of the relevant capex range
(3) $70/bbl 2021 real, previous price assumption $60/bbl 2020 real, and at the upper end of the relevant capex range
(4) 8 Feb 2022's 2030 aim at $60/bbl 2020 real and restated to exclude Rosneft; 7 Feb 2023's 2030 aim at $70/bbl 2021 real, and at the upper end of the relevant capex range (5) Includes revisions from other businesses since 8 Feb 2022 update

Investing more to accelerate our transition growth engines

2023-30 cumulative capex*

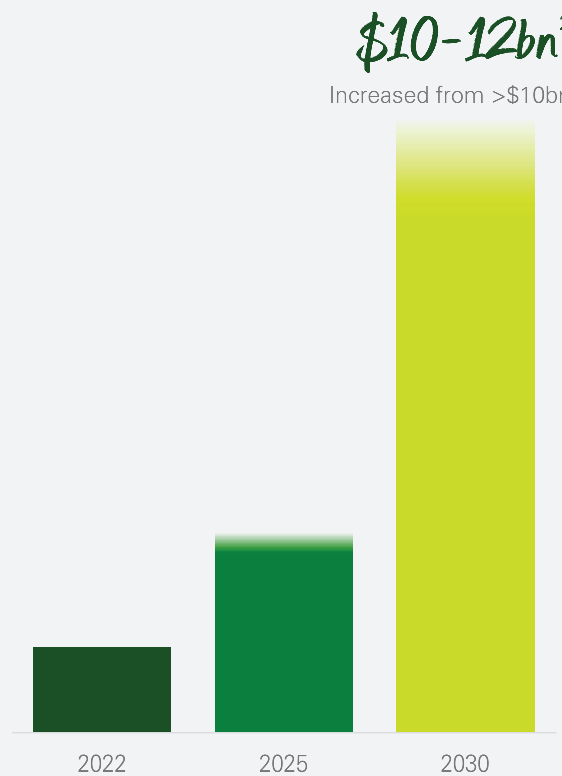


Up to $8bn incremental investment

Returns and EBITDA*

	Returns[1]	2030 EBITDA*[2]
Bioenergy	>15%	>$4bn
Convenience	>15%	>$4bn
EV Charging		
Hydrogen	Double digit (unlevered)	$2-3bn
Renewables & Power	6-8%[3] (unlevered)	

EBITDA $bn



(1) Expected return (IRR)
(2) 2030 EBITDA aim at $70/bbl 2021 real and bp planning assumptions, and at the upper end of the relevant capex range
(3) Renewables

Bioenergy – deepening investment

2025 target ~$2bn | 2030 aim >$4bn
EBITDA*[1]

>15%
expected returns[2]

~$15bn
cumulative capex 2023-30

Rapidly growing demand, attractive fiscal incentives

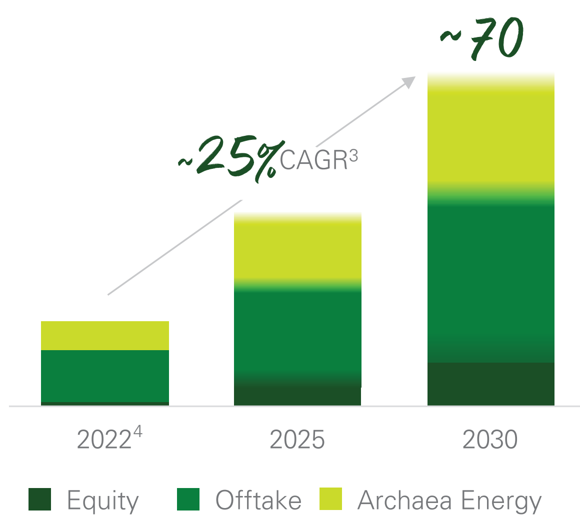
Established, global biogas & biofuels businesses today – well positioned

World-class trading capabilities – capturing enhanced value

Archaea acquisition a 'game changer'

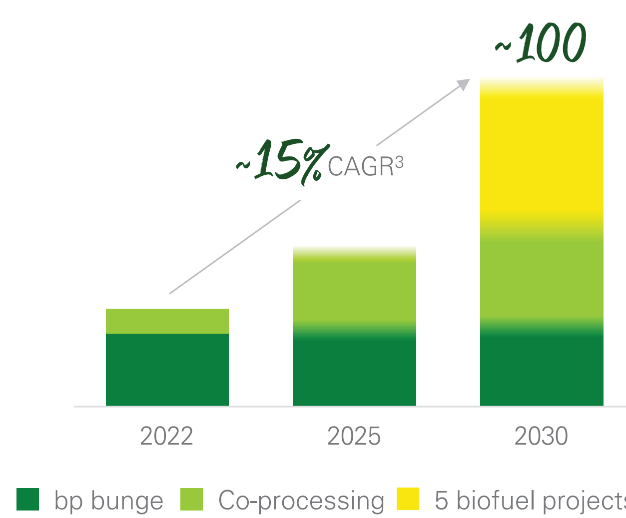
Five new biofuel projects – leveraging global refining footprint

Biogas supply volumes mboed



~6x increase in biogas supply by 2030[5]

Biofuel production volumes mbd



~3x co-processing volumes by 2030[6]

~50mbd production from 5 biofuel projects by 2030

(1) Includes EBITDA* from customer facing biofuels reported in C&M and assumes capex at the upper end of the range (2) IRR
(3) 2022-2030; biogas CAGR excluding Archaea Energy in 2022 (4) Includes Archaea Energy which closed on 28 December 2022
(5) Expected increase in biogas supply volumes from 2022 prior to Archaea Energy acquisition to 2030 (6) Compared to 2022

Convenience and EV Charging – deeper conviction

2025 target	2030 aim
>$1.5bn	>$4bn

EBITDA*1

>15%
expected returns[2]

~$15bn
cumulative capex 2023-30

Convenience

Global growth in sector continues

Resiliency, with proven track record of growth

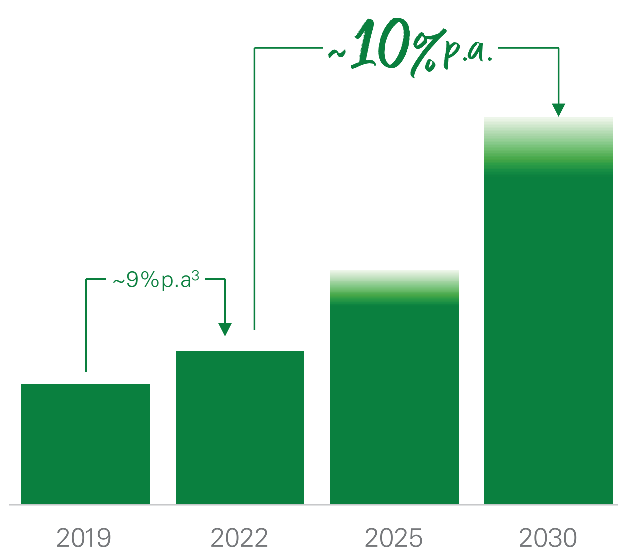
EV Charging

Moving at pace – high growth opportunity

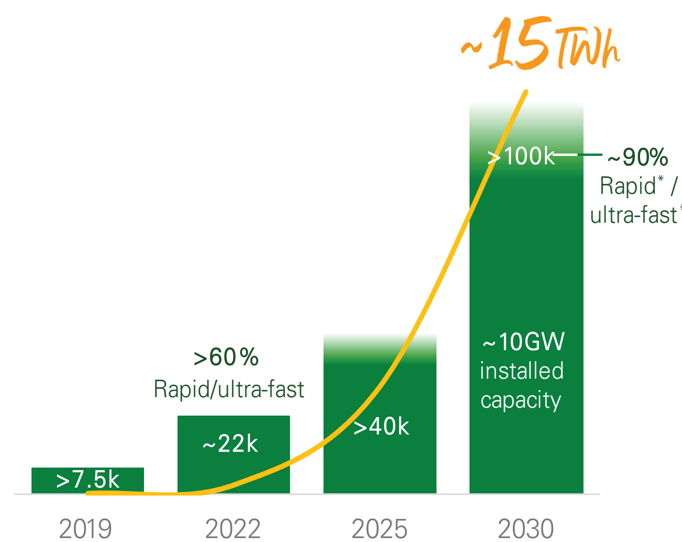
Focused on fast charging* – our customers' preferred choice

Strong momentum in fleets

Convenience gross margin* $bn



EV charge points* and energy sales[4]



(1) At the upper end of the relevant capex range (2) IRR (3) At constant forex
(4) Operated on the go EV charge points, energy sales TWh

Hydrogen and Renewables & Power – focusing investment

2030 aim	Hydrogen / Renewables	
$2-3bn EBITDA*	Hydrogen: double digit unlevered; Renewables: 6-8% unlevered; expected returns[1]	~$30bn cumulative capex 2023-30

Hydrogen

Key enabler to decarbonise hard to abate sectors

Early stage, fast growing sector with high barriers to entry

Renewables & Power

Integration increasingly a key value driver

Scale and complexity in offshore wind supports enhanced returns

(1) IRR

Hydrogen

Building a leading position globally

- Starting with own operations – bp's refining demand
- Scaling-up refining facilities to regional hubs in US and Europe
- Building export hubs for hydrogen and hydrogen derivatives

Aim to deliver
0.5-0.7mtpa
hydrogen production by 2030

Renewables & Power

Creating value through integration

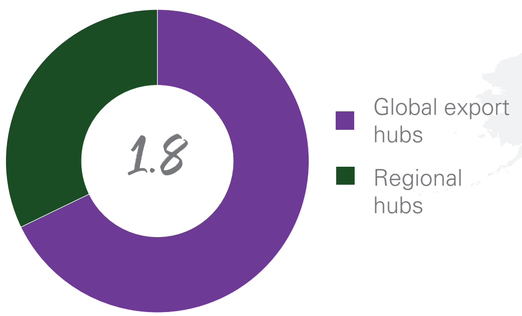
- Focusing investment in service of integration with hydrogen, trading, EVs and e-fuels
- Building our capability in offshore wind
- Scaling Lightsource bp: world class solar developer, self funding

Aim to deliver
50GW net
developed to FID by 2030

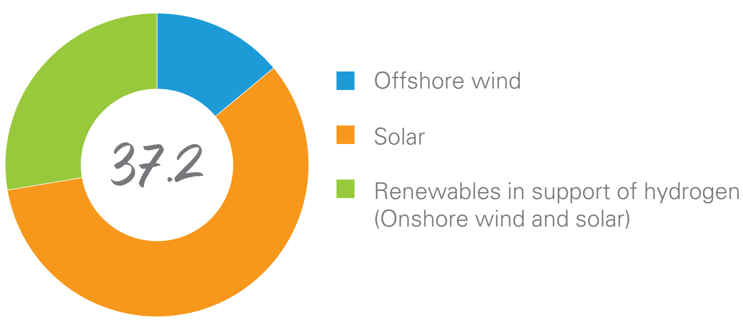
Aim to deliver
~10GW net
installed capacity by 2030

Hydrogen and Renewables & Power – building scale

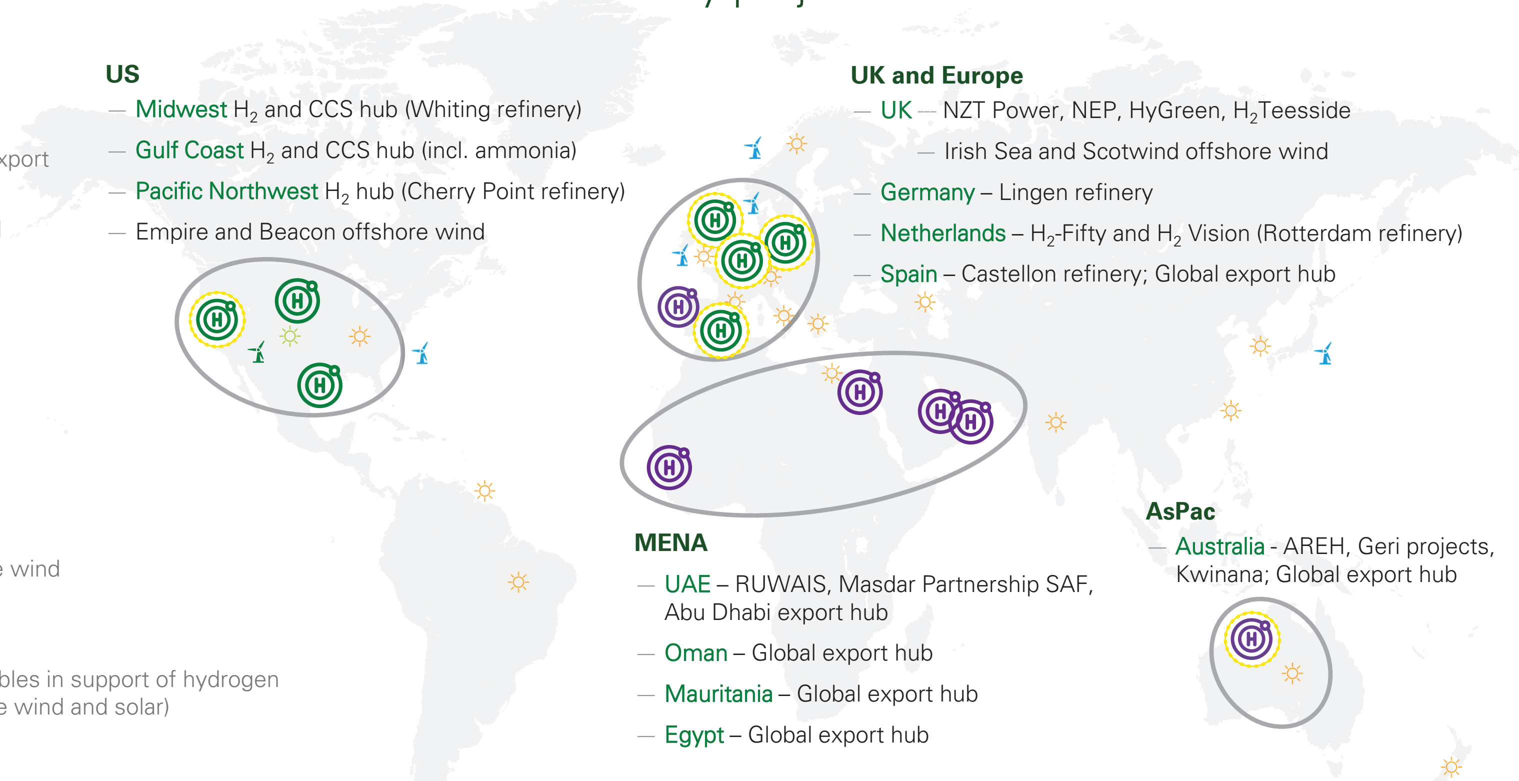
Hydrogen pipeline[1] mtpa net
4Q 2022



Renewables pipeline*[2] GW net
4Q 2022



Key projects



US
- Midwest H_2 and CCS hub (Whiting refinery)
- Gulf Coast H_2 and CCS hub (incl. ammonia)
- Pacific Northwest H_2 hub (Cherry Point refinery)
- Empire and Beacon offshore wind

UK and Europe
- UK — NZT Power, NEP, HyGreen, H_2Teesside
  - Irish Sea and Scotwind offshore wind
- Germany – Lingen refinery
- Netherlands – H_2-Fifty and H_2 Vision (Rotterdam refinery)
- Spain – Castellon refinery; Global export hub

MENA
- UAE – RUWAIS, Masdar Partnership SAF, Abu Dhabi export hub
- Oman – Global export hub
- Mauritania – Global export hub
- Egypt – Global export hub

AsPac
- Australia - AREH, Geri projects, Kwinana; Global export hub

Hydrogen global export hub[3] | Hydrogen regional hub[4] | Included in Hydrogen pipeline as of 4Q22 | Offshore wind | bp US Solar | Lightsource bp | Onshore wind

(1) *Includes projects in concept design*
(2) *Includes projects with land access*
(3) *Primarily green hydrogen, supplied by solar and onshore wind*
(4) *Blue and green hydrogen for local industry, leveraging refineries*

Investing more into today's oil and gas system

Focus on safe and reliable operations
- Target no major process safety incidents or life changing injuries
- Maintain plant reliability* at ~96%

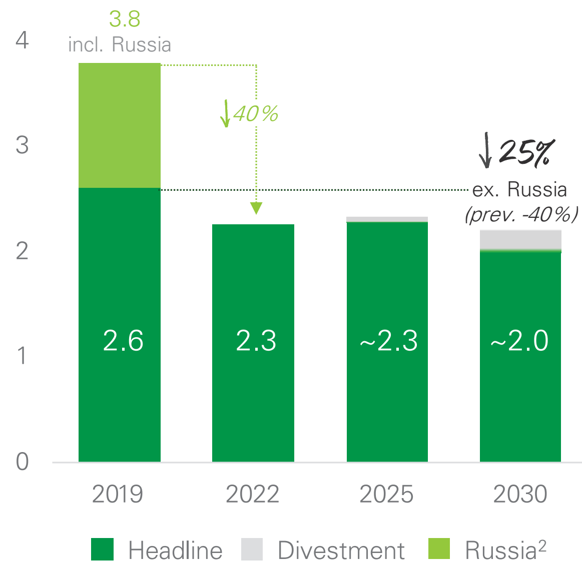
Deep resource base provides optionality
- ~18bn boe of resource in plan[1]
- $10/boe average point-forward development cost[1]

Growing underlying production* to 2025
- ~200mboed production from nine high-margin major project start-ups by end-2025
- 30-40% increase in bpx production by 2025
- 3-5% base decline to 2025
- Retaining certain assets for longer

Portfolio high-grading
- Aim for ~200mboed divestments to 2030
- New hub investment options 2030+

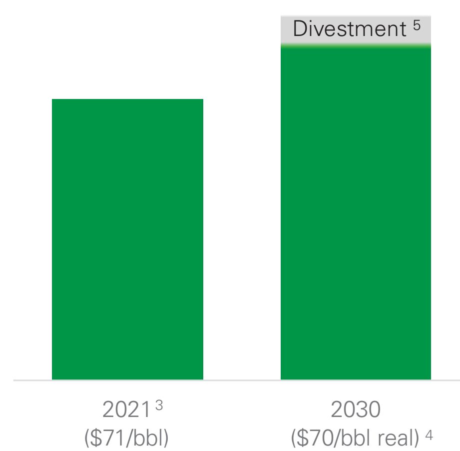
Driving cost efficiencies
- ~$6/boe unit production costs to 2025

Oil and gas production mmboed



Up to **$8bn** incremental investment

Oil and gas EBITDA* $bn



15-20% Investment hurdle rate[6]

(1) Before future divestments (2) Includes Rosneft and other businesses in Russia (3) Excludes Rosneft and other businesses in Russia
(4) 2021 real , and assumes capex at the upper end of the range (5) Includes deals announced (6) bp investment IRR hurdle rate at $60/bbl

Leveraging our advantaged refining portfolio

Drive competitiveness through digitisation and business improvement plans

Improving safety & operational emissions

- Target no major process safety incidents or life changing injuries
- Through energy efficiency, emission reduction and carbon capture projects

Delivering portfolio performance

- Retaining increasingly competitive refining portfolio
- ~96% Solomon availability* by 2025
- Maintain Solomon 1st quartile net cash margin*

Foundation for Biofuels and Hydrogen

- Expanding opportunities for refinery conversion or consolidation

Biofuels strategy leverages our refineries

~3x
co-processing volumes by 2030[1]

~50 mbd
production from 5 biofuel projects by 2030

Hydrogen strategy anchored by our refinery demand

~450 ktpa[2]
existing refining hydrogen demand

(1) Compared to 2022
(2) Based on 2020 data – includes Toledo Refinery
(3) Sale of bp's 50% interest in Toledo Refinery to JV partner Cenovus Energy announced 8 August 2022
(4) Kwinana conversion to an Integrated Clean Energy Hub announced 19 April 2022
SAPREF not shown as refinery operations have been paused; Whangarei not shown as converted to import terminal
Map excludes terminals and pipelines

Getting bp to net zero – our evolving pathway

	Scope	2025 target	2030 aim	2050 or sooner aims
Aim 1 Net zero operations*[1]	Scope 1+2	20%	↑ 50% 30-35%[3]	100%
Aim 2 Net zero production*[1]	Scope 3	↓ 10-15% 20%[3]	↓ 20-30% 35-40%[3]	100%
Aim 3 Net zero sales*[1]	Carbon intensity[4]	5%	↑ 15-20% >15%[3]	↑ 100% 50%[3]
Aim 4 Reducing methane	Methane intensity	0.20% (measurement approach)		
Aim 5 More $ into transition[2]	Transition growth engines	$6-8bn $3-4bn[5]	$7-9bn ~$5bn[5]	

(1) 2025 target and 2030 aim for Aims 1-3 are against our 2019 baseline. 100% means to net zero* by 2050 or sooner
(2) Aim 5 now aligned with our transition growth engines
(3) Target/aim set in 2020
(4) Aim 3 relates to the carbon intensity for the energy products that we sell*. Aim 3 emissions can be thought of as combining elements of bp Scopes 1, 2 and 3
(5) Target/aim set in 2020 for low carbon investment

Arrows indicate updates to 2025 and 2030 target and aim since 2020

Excerpts Siemens Gamesa Q1/23 release on Feb 2 in their press release titled “*Siemens Gamesa ends complex quarter while addressing challenges through Mistral program”.* https://www.siemensgamesa.com/en-int/-/media/siemensgamesa/downloads/en/newsroom/2023/02/siemens-gamesa-press-release-results-q1-2023.pdf?ste_sid=85d5be889d350d10ae58988c631dcede

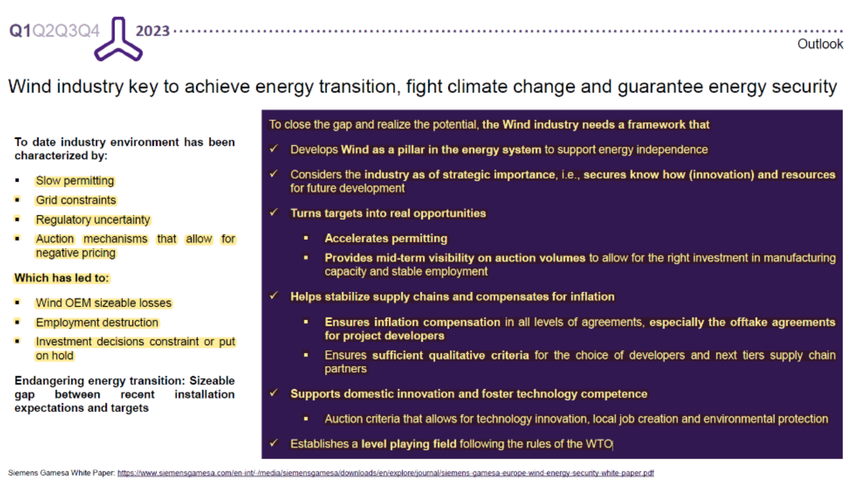
- *“Between October and December 2022, Siemens Gamesa’s revenue amounted to €2.0 billion (+9.8% year over year) and EBIT pre PPA and before integration and restructuring costs amounted to -€760 million, with an EBIT margin of -37.8%. The company ended the quarter with a net loss of €884 million.”*
- *“Siemens Gamesa announced the financial results for the first quarter of fiscal year 2023 today. The economic performance during this period was severely impacted by the outcome of the evaluation of the installed fleet, mostly affecting the service business.”*
- *““The negative development in our service business underscores that we have much work ahead of us to stabilize our business and return to profitability.”*
- *“The beginning of fiscal year 2023 saw a further increase in global wind demand prospects for the next ten years, but further governmental action is needed to close the gap between ambitious targets and actual installations. The Inflation Reduction Act (IRA) in the U.S. and the REPowerEU program in the European Union strengthen the good outlook for future growth in demand and the wind industry’s potential.”*

Excerpt from Siemens Gamesa Q1/23 call management prepared comments and slides.

“Please remember that not only we have difficulties on our profit line, but also our competition has similar effects. To date, our industry, the development has been characterized by slow permitting. We continue to observe grid constraints, we continue to have regulatory uncertainties in many cases and also the auction mechanism still do not focus enough on the overall political target which is behind that. So that means that in total the OEMs have seen sizable losses, we have had reduction in employment, in many cases and also observe that investment decisions are slowed down or the speed of that has slowed down or investment decisions are postponed. So, so far, we continued to observe that the political wills which I expressed all over, are not really materializing.

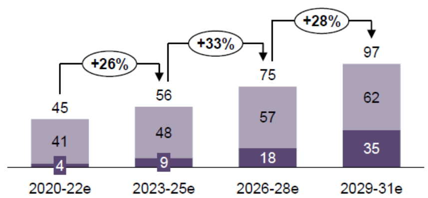
So if we would want to make -- to move forward in the line with those targets, in our view, it needs to be understood that wind is a pillar in the energy system of the future [ph] and important one. And the size of that pillar continues to be too small in relation to our overall ambition level. We need to consider our industries when it comes to other aspects of the political discussion these days. We need to consider our industry as of strategic importance. In other words, we need to make sure, specifically in Europe, that's the know how on innovation and the resources for scaling up the wind pillar that that -- that those structures are in place and so far, it continues to be rather difficult.

We have to make sure that the targets really turn in real opportunities, so permitting needs to be accelerated. There is in -- for instance European Union member states rather fragmented view on these situations and also when it comes to auctions, which are one way to define which developer is looking after which wind farm, this needs to be made clear that the secondary effects like those ones related to manufacturing and employment also can be considered.”

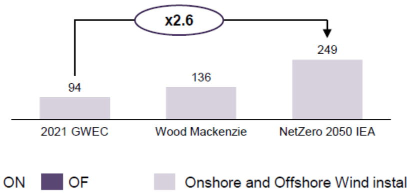


Secular long-term wind demand potential likely to be higher than market expected installation levels

Global wind installations (GW excl. China)[1]



Required average annual global wind installations (GW)



- **Double digit growth in the short-, medium- and long-term average annual installations**
  - Materialization of concrete regulatory measures still needed
- **Strong long-term demand growth driven by role of the energy market in the decarbonization**
  - Electricity demand to grow by 30% between 2020 and 2030 under announced pledged scenarios[2]
  - Offshore market to more than triple from 2023 expected level by end of decade
    - Expected to reach **more than 30 GW by 2030**
    - **Strong demand visibility** through 100 GW+ in auctions until 2027
- **NetZero in 2050 would require c. 2.5x the current level of annual wind installations each year of this decade**

1) Wood Mackenzie: Global Wind Power Market Outlook Update: Q3 2022
2) IEA October 2021