Energy Tidbits

EIA's First Look at 2024: Record Oil Consumption +1.72 mmb/d YoY to 102.2 mmb/d ie. No Sign of Peak Oil Demand

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Short-Term Energy Outlook

January 2023

Overview

U.S. energy market indicators	2022	2023	2024
Brent crude oil spot price (dollars per barrel)	**$100.94**	**$83.10**	**$77.57**
Retail gasoline price (dollars per gallon)	**$3.97**	**$3.32**	**$3.09**
U.S. crude oil production (million barrels per day)	**11.86**	**12.41**	**12.81**
Natural gas price at Henry Hub (dollars per million British thermal units)	**$6.42**	**$4.90**	**$4.80**
U.S. liquefied natural gas gross exports (billion cubic feet per day)	**10.7**	**12.1**	**12.6**
Shares of U.S. electricity generation			
Natural gas	39%	38%	37%
Coal	20%	18%	17%
Renewables	21%	24%	26%
Nuclear	19%	19%	19%
U.S. GDP (percentage change)	**1.9%**	**0.5%**	**1.9%**
U.S. CO_2 emissions (billion metric tons)	**4.99**	**4.83**	**4.81**

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

- This edition of STEO is the first to include forecasts for 2024.

- **U.S. GDP growth.** Based on the S&P Global macroeconomic model, we expect U.S. real GDP to grow by 0.5% in 2023, with economic growth returning after contraction in the first quarter of 2023 (1Q23) and 2Q23. In 2024, real GDP grows by 1.9%, driven primarily by an increase in household consumption. Relatively flat economic growth in 2023 results in total U.S. energy consumption falling by 0.9% in our forecast. Total energy consumption then rises by 1.0% in 2024.

- **Global liquid fuels markets.** Global production of liquid fuels in our forecast reaches an average of 102.8 million barrels per day (b/d) in 2024, up from 100.0 million b/d in 2022, driven by large growth in non-OPEC production. However, uncertainty over Russia's oil supply will persist, particularly in early 2023. We expect that global consumption of liquid fuels will increase from an average of 99.4 million b/d in 2022 to 102.2 million b/d in 2024. Ongoing concerns about global economic conditions as well as the easing COVID-19 restrictions in China, however, increase the uncertainty of the outcomes of our demand forecasts. With more global oil production than consumption in our forecast, we expect global oil inventories will increase over the next two years.

- **Crude oil prices.** We forecast that the Brent crude oil price will average $83 per barrel (b) in 2023, down 18% from 2022, and continue to fall to $78/b in 2024 as global oil inventories build, putting downward pressure on crude oil prices.

- **Gasoline prices.** Gasoline prices decline in our forecast as both wholesale refining margins and crude oil prices fall. We forecast U.S. gasoline refining margins will fall by 29% in 2023 and fall by 14% in 2024, leading to retail gasoline prices averaging around $3.30 per gallon (gal) in 2023 and $3.10/gal in 2024.

- **Diesel prices.** We forecast that U.S. refining margins for diesel will fall by 20% in 2023 and by 38% in 2024. We expect retail diesel prices to average about $4.20/gal in 2023, down 16% from 2022. In 2024, we expect prices to continue to fall, and average near $3.70/gal.

- **Natural gas prices.** The Henry Hub natural gas spot price averages slightly less than $5.00 per million British thermal units (MMBtu) in 2023 in our forecast—down close to 25% from last year—as domestic consumption declines and liquefied natural gas (LNG) exports remain relatively flat. In 2024, we expect natural gas prices to again average slightly below $5.00/MMBtu, as dry natural gas production outpaces an increase in LNG exports that results from rising LNG export capacity.

- **Natural gas production.** We expect natural gas production in both the Permian and Haynesville regions to grow with the completion of pipeline infrastructure expansions in 2023 and 2024.

- **Electricity generation.** We expect that the share of electricity generation from coal will fall from 20% in 2022 to 18% in 2023 and 17% in 2024. This decline will be partially offset by an increase in the forecast share of combined utility-scale solar and wind generation from 16% in 2023 to 18% in 2024.

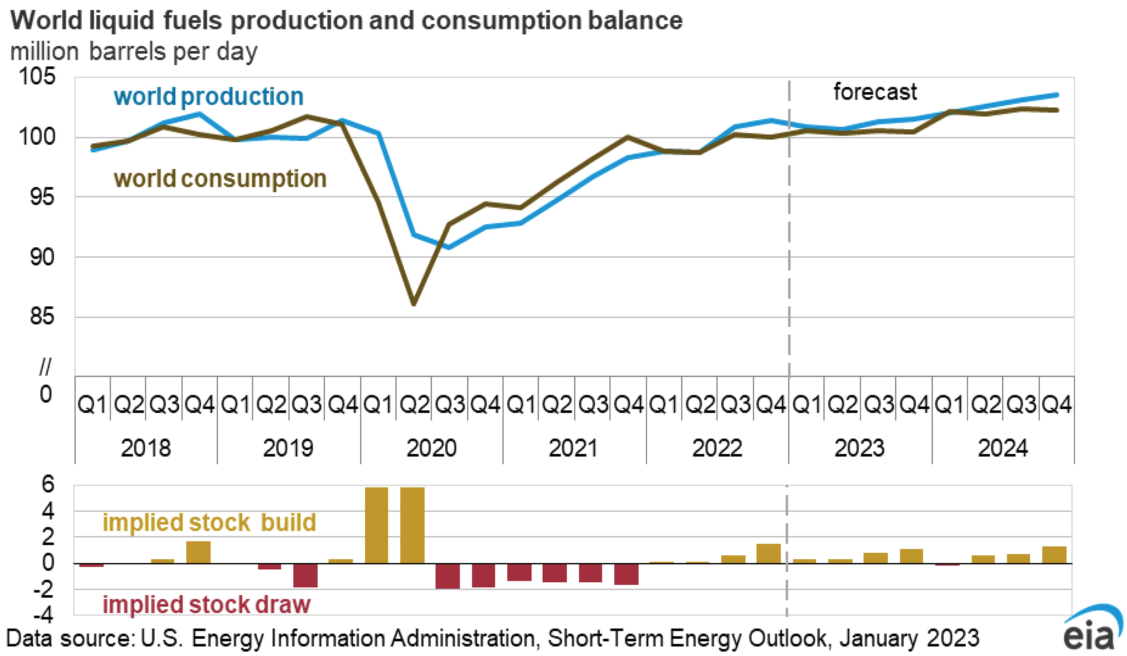
Notable forecast changes

Current forecast: January 10, 2023; previous forecast: December 6, 2022	**2023**	**2024**
Brent spot average (current) (dollars per barrel)	**$83**	**$78**
Previous forecast	$92	---
Percentage change	-10.0%	---
Natural gas price at Henry Hub (current) (dollars per MMBtu)	**$4.90**	**$4.80**
Previous forecast	$5.43	---
Percentage change	-9.8%	---
Gasoline retail prices (current) (dollars per gallon)	**$3.32**	**$3.09**
Previous forecast	$3.51	---
Percentage change	-5.5%	---
U.S. distillate fuel inventories (current) (million barrels)	**127.0**	**125.2**
Previous forecast	123.9	---
Percentage change	2.5%	---
Diesel fuel prices (current) (dollars per gallon)	**$4.22**	**$3.69**
Previous forecast	$4.48	---
Percentage change	-5.7%	---

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

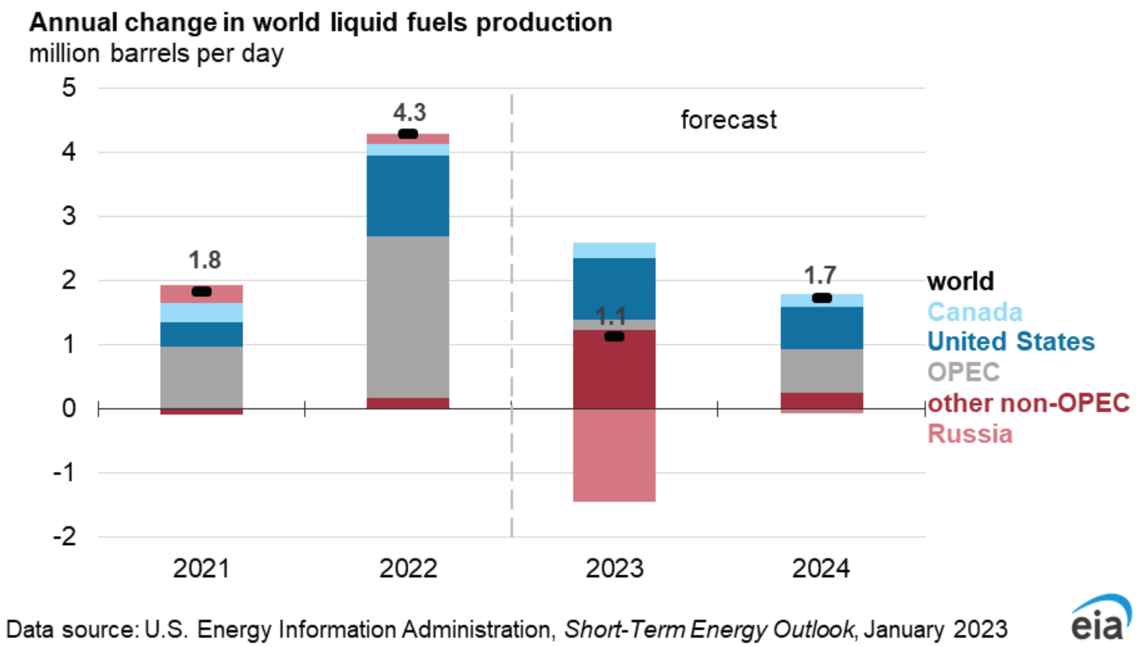
Global oil markets

Crude oil prices: We forecast that Brent crude oil prices will average $83 per barrel (b) in 2023 and $78/b in 2024. Our inaugural edition of *STEO Between the Lines* provides an in-depth summary of our Brent crude oil price assumptions and major risks to our forecast. *Between the Lines* is a new product that will periodically accompany STEO to provide in-depth analysis of issues in our forecast.



Global liquid fuels production: We forecast that world production of petroleum and other liquid fuels will increase by 1.1 million barrels per day (b/d) in 2023 and 1.7 million b/d in 2024. This increase reflects large growth in several non-OPEC countries and in OPEC output that more than offset 1.5 million b/d of declines in Russia's production over the forecast period.

We forecast that the United States and other non-OPEC producers outside of Russia will add 2.4 million b/d of oil production in 2023 and an additional 1.1 million b/d in 2024. The largest source of non-OPEC production growth over the forecast period is the United States, which contributes 40% of growth in 2023 and 60% of growth in 2024. U.S. growth is driven by increases in crude oil production in the Lower 48 states—mostly in the Permian region—as well as a combination of increases to production of hydrocarbon gas liquids and biofuels, which together account for about 40% of U.S. liquid fuels production growth in 2023 and 2024.



Outside of the United States, other major sources of growth in non-OPEC liquid fuels production come from Canada, Brazil, Guyana, and Norway. We expect that increases in Canada's production will be driven by projects to improve distribution bottlenecks, including the start-up of the TransMountain pipeline expansion project. Brazil's increases are driven by new floating production, storage, and offloading (FPSO) deepwater rigs.

A noteworthy new source of world oil supply is Guyana, which first began producing oil in 2019 after the discovery of the new offshore deepwater Liza oil field. Critical investment and new production vessels helped Guyana's oil production increase to an average of 260,000 b/d in 2022. We expect further ramp-ups in output and the development of new oil resources over the next two years, helping oil production in Guyana increase to an average of 540,000 b/d by 4Q24.

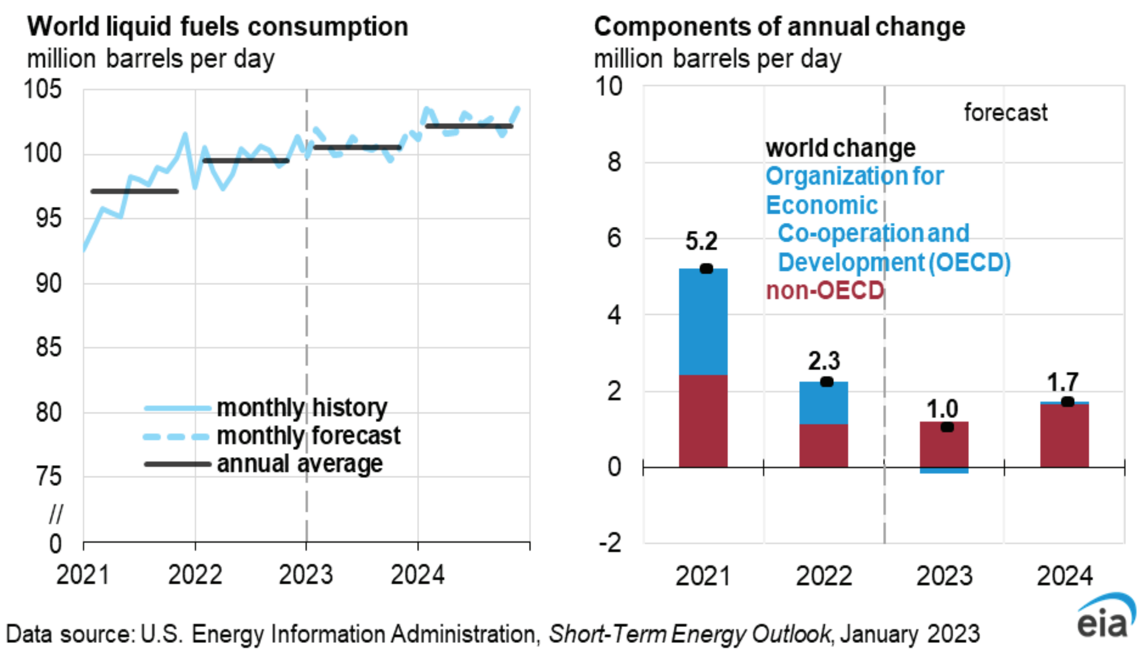
Growth in Norway's oil output in 2023 stems from the recent start-up of the offshore Johan Sverdrup Phase 2 expansion project, which will result in Norway's liquid fuels production rising by more than 500,000 b/d over the forecast to reach almost 2.5 million b/d in 2024.

We expect that these sources of growth in non-OPEC liquid fuels supply will offset declines in Russia's oil production. We forecast that Russia's petroleum and other liquid fuels production will decline to 9.5 million b/d in 2023, from 10.9 million b/d in 2022, and then average 9.4 million b/d in 2024. The extent to which European Union sanctions, other sanctions, and the G7 price cap will affect Russia's crude oil and petroleum product exports and production remains uncertain.

We expect that most crude oil exports from Russia will continue to find buyers. But we expect the sanctions on petroleum products will cause greater disruptions to Russia's oil production and exports because finding alternative buyers as well as transportation and other services to reach those buyers is likely to be more challenging than for crude oil.

OPEC crude oil production in our forecast averages 29.5 million b/d in 2024, up 0.8 million b/d from 2022. Part of this growth is driven by Venezuela. Following the U.S. Department of the Treasury issuing General License (GL) 41 at the end of November, Chevron is resuming oil production in Venezuela for export to the United States. Our OPEC production forecast is subject to considerable uncertainty, driven by a combination of possible outcomes for country compliance to existing OPEC+ production targets and changes to existing OPEC+ targets, as well as ongoing developments in Iran, Libya, and Venezuela.

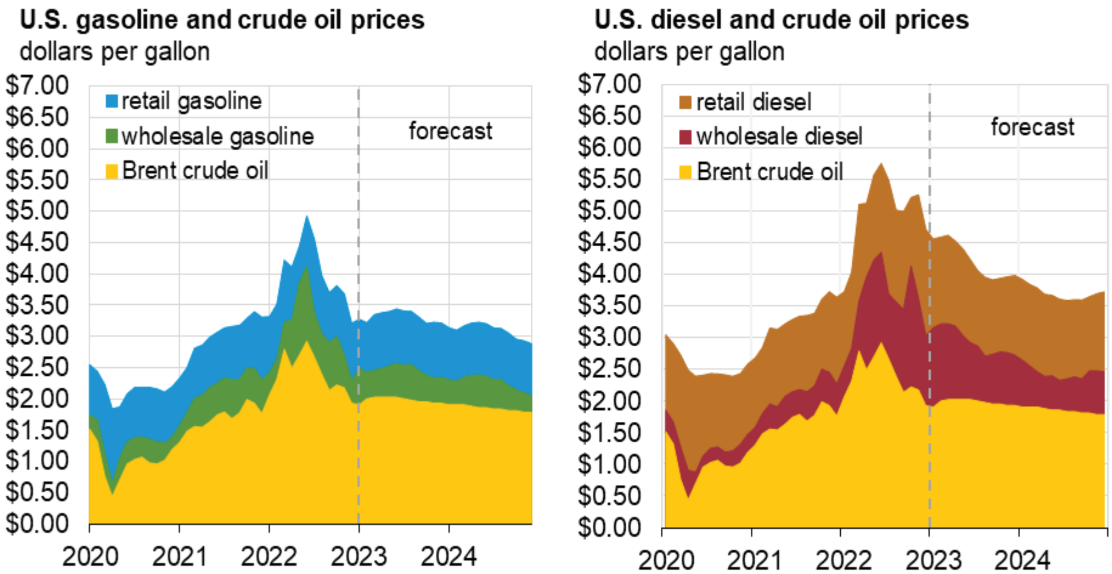
Global liquid fuels consumption: Forecast global consumption of liquid fuels reaches 102.2 million b/d in 2024, driven primarily by growth in non-OECD countries, such as India and China. Trends in oil consumption largely reflect trends in economic activity. We forecast growth in global demand for oil will slow in 2023 before picking up in 2024, as global GDP growth (based on forecasts from Oxford Economics) rises from 1.8% in 2023 to 3.3% in 2024. Although we forecast global oil consumption to increase, our demand forecast remains uncertain as a result of ongoing concerns around global economic conditions and the impact of the easing COVID-19 restrictions and rising case counts in China.



Petroleum products

Gasoline and diesel prices: Gasoline and diesel prices in our forecast generally decline as wholesale refining margins and crude oil prices fall. In December 2022, the U.S. retail price for regular-grade gasoline averaged $3.21 per gallon (gal), and the retail diesel price averaged $4.71/gal. Both December prices were the lowest since the beginning of Russia's full-scale invasion of Ukraine in February. In our forecast for 2023 and 2024, U.S. refinery runs and gasoline and diesel production are higher than in 2022, which along with increasing global refinery capacity, will contribute to narrowing U.S. refining margins in 2023 and 2024.

We forecast retail gasoline prices will remain close to current levels and average about $3.30/gal in 2023. In 2024, we forecast retail gasoline prices will average about $3.10/gal and fall below $3.00/gal by the end of the year. We forecast retail diesel prices to average about $4.20/gal in 2023 and near $3.70/gal in 2024. Diesel prices will remain higher than gasoline prices as the market continues to adjust to disruptions largely related to responses to Russia's full-scale invasion of Ukraine. Russia had been a major supplier of diesel fuel to Europe, which is now importing more diesel from the Middle East and India.

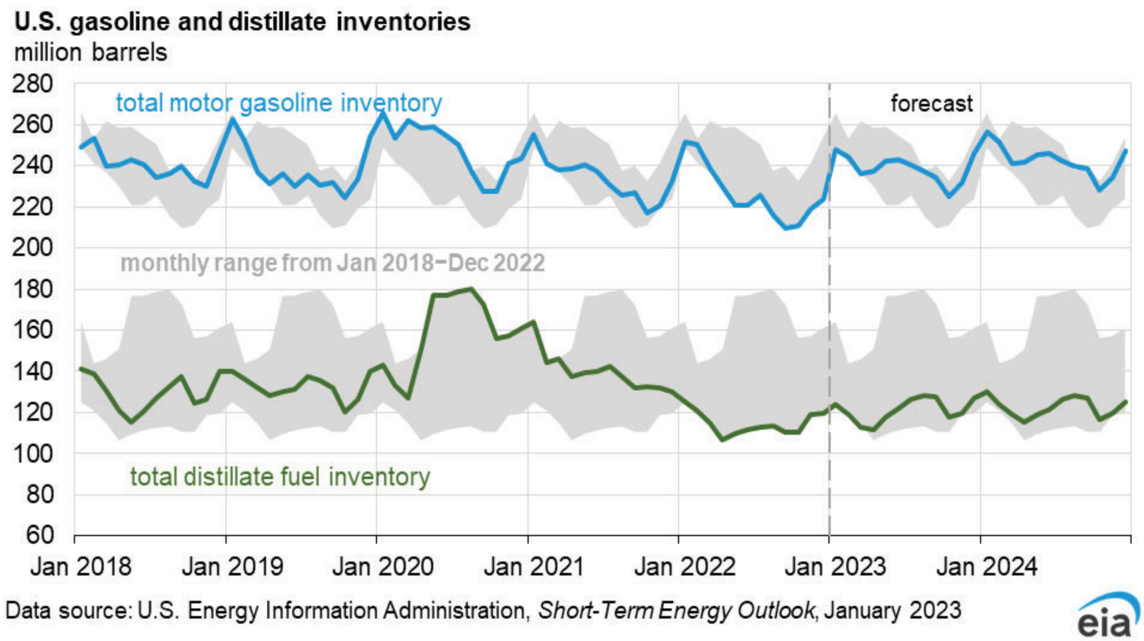


Data source: U.S. Energy Information Administration, *Short-Term Energy Outlook*, January 2023, and Refinitiv, an LSEG Business

Gasoline and distillate inventories: In 2022, both gasoline and distillate inventories in the United States were below their previous five-year (2017–2021) averages for the entire year because of reduced refinery capacity, less-than-average imports, and expanding exports. Higher refinery runs and less consumption contributed to distillate fuel inventories increasing during 4Q22 by more than the previous five-year average. We estimate that 5.1 million barrels per day (b/d) of distillate was produced in the United States during 4Q22, up 5% from a year earlier, as refiners increased production in response to high crack spreads—the difference between the price at which refiners sell fuel and the price of crude oil.

We expect U.S. distillate inventories will increase in 2023 due to increasing refinery runs as refiners capitalize on high distillate crack spreads. Refiners have a limited ability to shift their product yields, so we also expect gasoline production to increase in 2023 alongside distillate production. As a result, we forecast gasoline inventories will rise above their previous five-year average from May 2023 through the end of the year. Although net U.S. exports of gasoline will increase in 2023, we expect these volumes will come from increased gasoline production. We forecast almost no change in U.S. gasoline consumption over the next two years. Our expectation of relatively flat gasoline consumption stems from increases in vehicle miles traveled being offset by increases in the fuel efficiency of the vehicle fleet.

Declining freight activity and declining manufacturing activity in distillate-intensive industries led to decreased U.S. distillate consumption at the end of 2022. Our 4Q22 estimate for U.S. distillate consumption of 3.9 million b/d was the lowest for a fourth quarter since 2015. In our forecast, U.S. distillate consumption declines slightly in 2023. However, we expect distillate consumption will pick up in 2024 as the rate of economic growth increases.

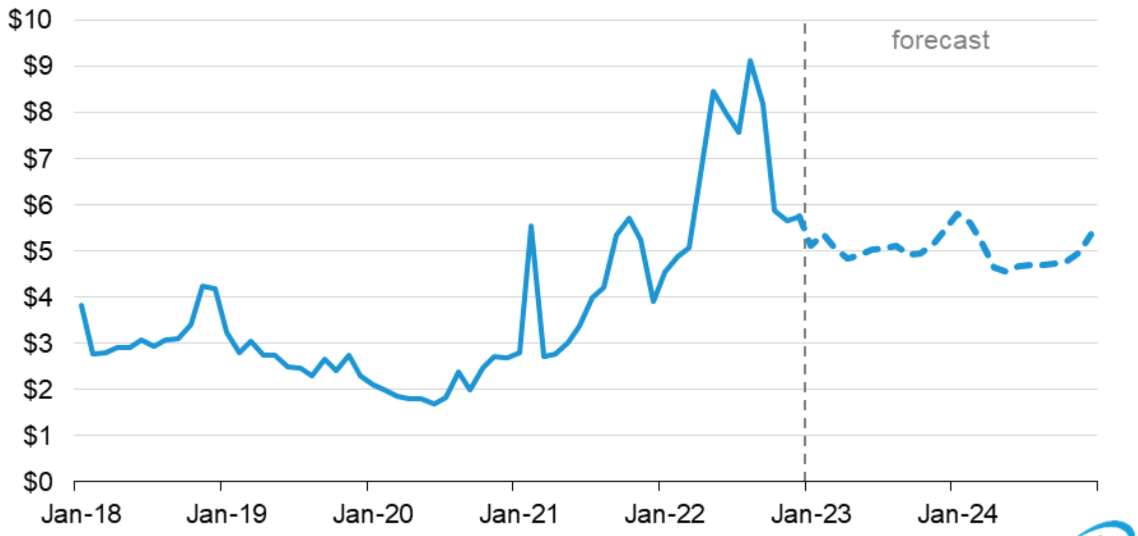


Natural gas

Natural gas prices: We expect the Henry Hub natural gas spot price to average near $5.00 per million British thermal units (MMBtu) in 1Q23. The Henry Hub price began January below $4.00/MMBtu as a result of warmer-than-normal temperatures across much of the country. However, we expect that prices will rise back above $5.00/MMBtu in late-January and stay above that in February as temperatures in our forecast fall and liquefied natural gas (LNG) exports from Freeport LNG resume, increasing demand for natural gas.

Extreme weather events can cause price spikes and volatility at both the Henry Hub and in regional markets. Spot prices reached more than $50.00/MMBtu in some western markets in December, and potential natural gas supply constraints in New England could cause large price increases if extreme cold weather hits the region. Based on the most recent press release from Freeport LNG, we expect the facility to resume partial operations in January, which will increase U.S. LNG exports and put upward pressure on prices. However, any additional delays to the restart of Freeport, which was originally scheduled to restart partial operations in November, will contribute to downward pressure on prices in the near term.

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

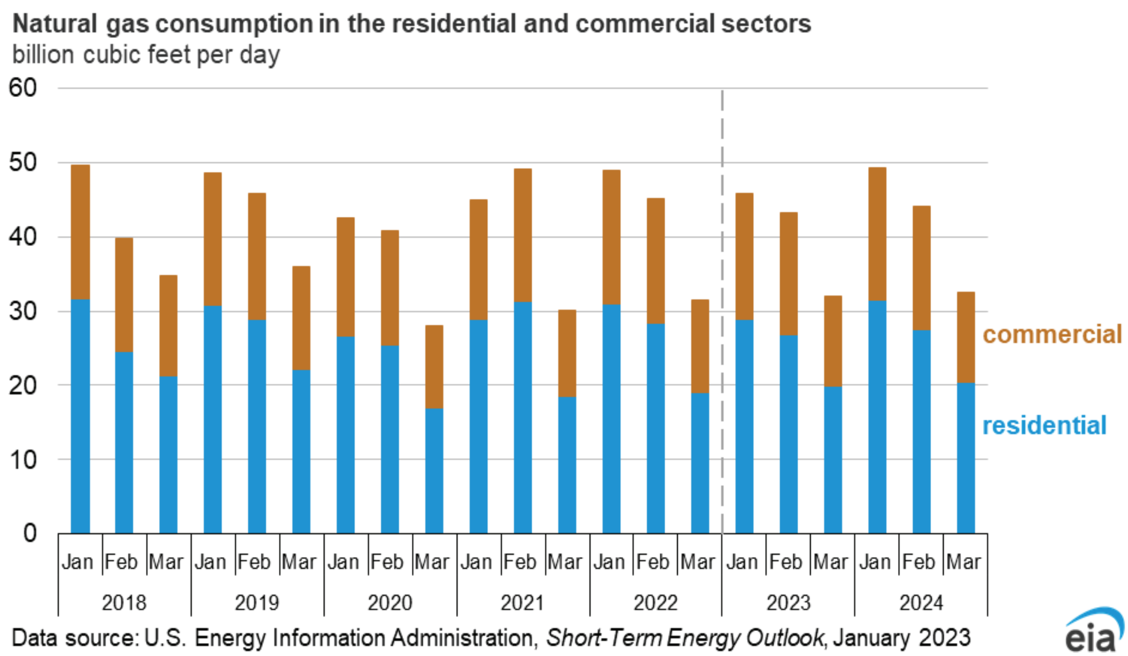


Data source: U.S. Energy Information Administration, *Short-Term Energy Outlook*, January 2023

Once heating demand subsides this winter, we expect prices to average near $5.00/MMBtu for the last three quarters of 2023. Increases in U.S. natural gas production, relatively flat LNG exports, and declining domestic consumption in the electric power and industrial sectors will limit upward pressure on prices in 2023.

Despite our expectation that new LNG export facilities and expansion projects will come online in 2024 we expect natural gas prices to be relatively flat—with the possibility of lower prices—due to continued increases in U.S. natural gas production. We expect production in both the Permian region in West Texas and Southeast New Mexico and in the Haynesville region in Louisiana and East Texas to continue to grow with the completion of new pipeline infrastructure expansions in 2023 and 2024.

Natural gas consumption: During the winter months in the United States, the residential and commercial sectors are large drivers of natural gas consumption because natural gas is used for space heating in homes and commercial buildings and demand for heating rises as the weather gets colder. We expect natural gas consumption in the U.S. residential and commercial sectors to average about 46 billion cubic feet per day (Bcf/d) in January, which is slightly less than the five-year (2018–2022) average. Less-than-average January consumption reflects a relatively mild start to the month across much of the country that reduced space heating demand for natural gas. We expect U.S. residential and commercial natural gas consumption to average 43 Bcf/d in February, which is also less than the five-year average, as forecasts from the National Oceanic and Atmospheric Administration indicate above normal temperatures for February in the eastern part of the United States. Residential and commercial natural gas consumption can be highly variable in winter months due to extreme weather events, such as in February 2021 when extreme cold weather across much of the United States led to increased residential and commercial natural gas consumption.



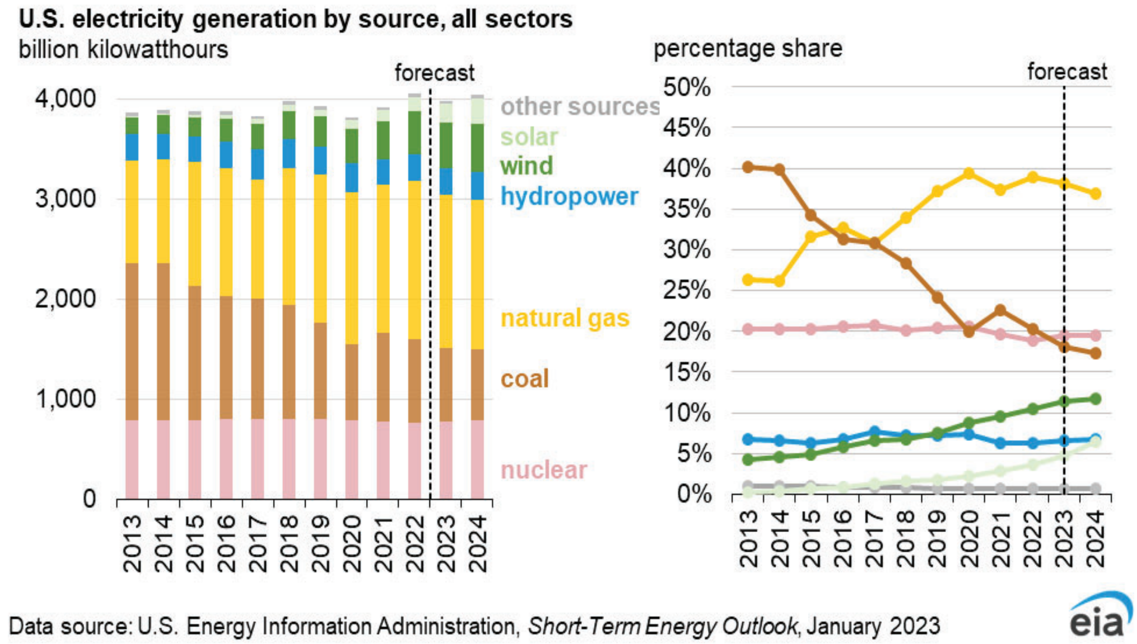
Electricity, coal, and renewables

Electricity consumption: We forecast that total consumption of electricity in the United States will remain fairly stable, falling by 1% in 2023 and then growing by just over 1% in 2024. We estimate that electricity consumption grew by 3% in 2022.

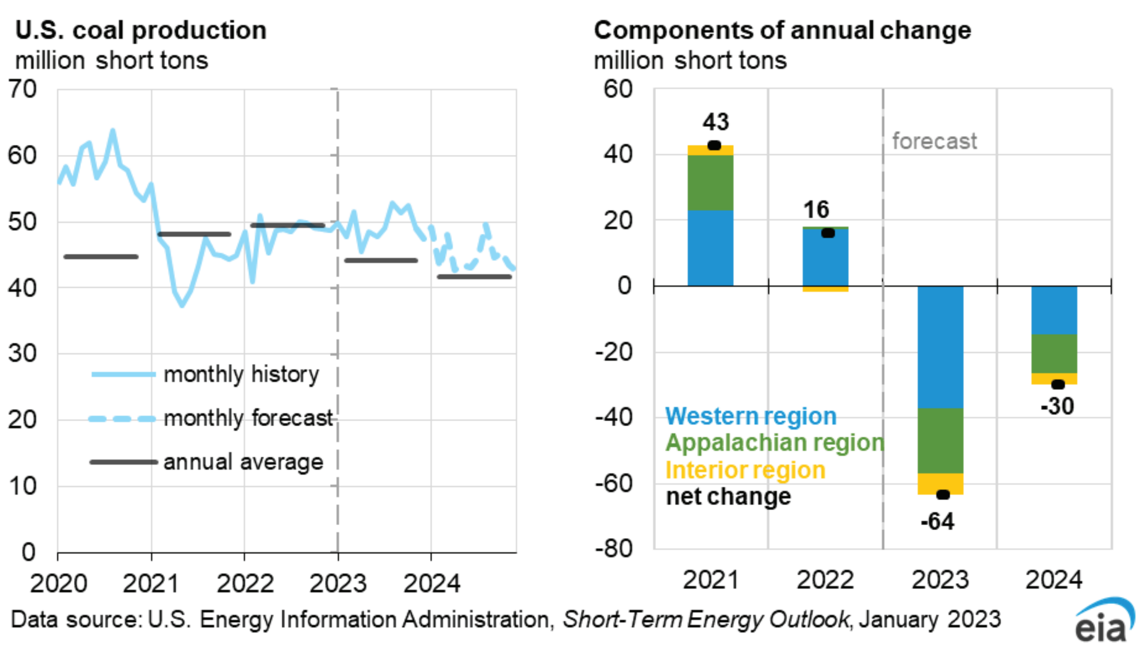
Most of our expected change in U.S. electricity demand occurs in the residential sector, where we expect retail sales will fall as a result of a milder summer in 2023 compared with 2022 with about 10% fewer cooling degree days. Residential electricity sales grow in 2024 because we expect 5% more heating degree days in 1Q24 compared with 1Q23. The forecast also reflects trends in the housing stock. Our forecast assumes the U.S. housing starts resume growing in 2024 after a sharp decline in growth in 2023.

Electricity generation: U.S. generation in our forecast largely follows consumption, declining in 2023 then rising in 2024. Generation from renewable sources is the main contributor of growth in U.S. electricity generation. The forecast share of U.S. renewables generation rises from 21% in 2022 to 24% in 2023 and to 26% in 2024. About two-thirds of this forecast increase in renewables generation comes from new utility-scale solar photovoltaic capacity, and most of the rest is from new wind projects. We expect the share of electricity generation supplied by natural gas to decrease from 39% in 2022 to 38% in 2023 and 37% 2024 while the share of electricity generated by coal will fall from 20% in 2022 to 18% in 2023 and 17% in 2024. The share of nuclear power generation remains close to 19% over the next two years.

Power generators plan to add 32 gigawatts (GW) of utility-scale solar photovoltaic (PV) in 2023 and another estimated 32 GW in 2024. We forecast that small-scale solar capacity will grow by 9 GW in 2023 and by 12 GW in 2024. Wind capacity increases by 6 GW in both 2023 and 2024. Battery storage additions to capacity in our forecast are 10 GW in 2023 and 9 GW in 2024.



Coal Markets: After increasing in both 2021 and 2022, we expect U.S. coal production to decline by 11% to about 530 million short tons (MMst) in 2023, and a further 6% to 500 MMst in 2024. The primary reason for the decrease is our forecast of an 11% reduction in coal consumption in the electric power sector in 2023 followed by a 3% reduction in 2024. That decline largely reflects almost 10 GW of coal-fired capacity retirements in 2023 and another 4 GW in 2024. At the same time, renewable generation increases by 20% between 2022 and 2024, reducing coal-fired generation.

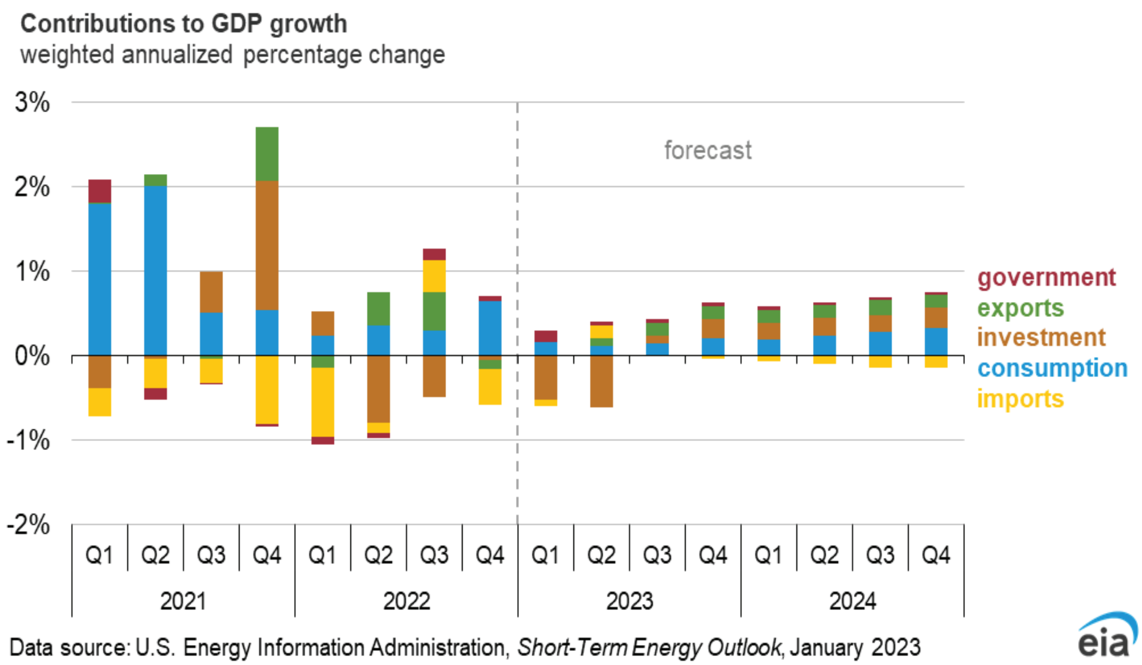


Economy, weather, and CO_2

U.S. macroeconomics: We incorporate STEO energy price forecasts into our S&P Global macroeconomic model to obtain the final U.S. macroeconomic outlook for our forecast,

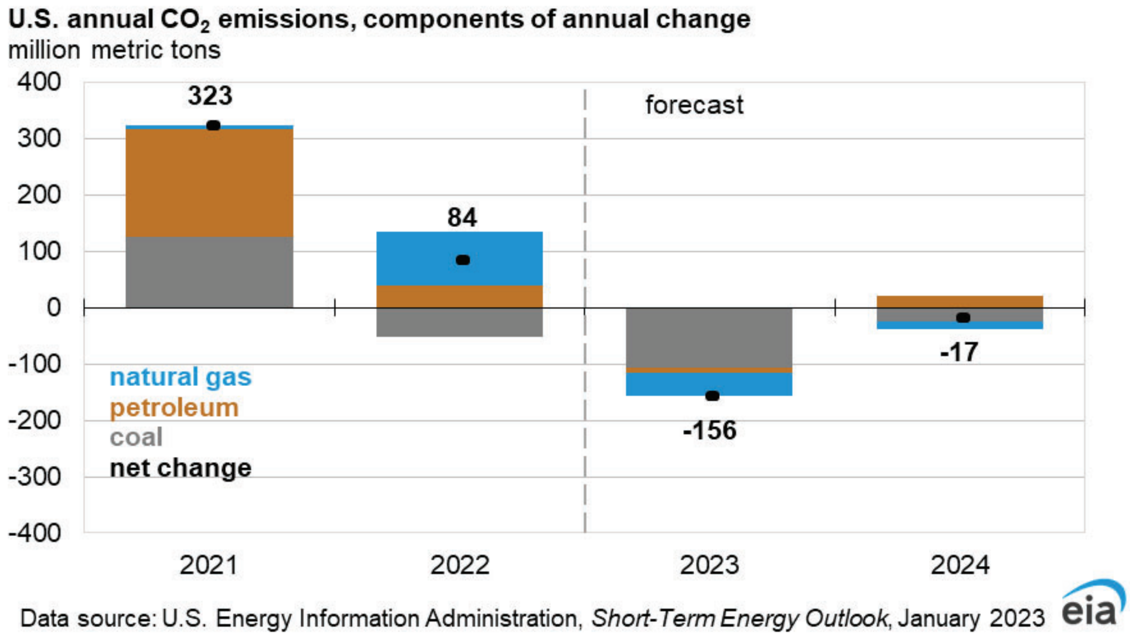
S&P Global is forecasting a mild recession, starting in 1Q23. As a result, we forecast GDP to grow by 0.5% in 2023, with the economy recovering from the recession and returning to positive GDP growth in 3Q23. In 1Q23, real GDP contracts at an annual rate of 0.7%, mostly due to a decline in residential fixed investment and private business inventories of goods. We expect the recovery to be led by net exports and personal consumption expenditures in 2Q23, with the entire economy returning to growth later in the year.

We expect personal consumption expenditures to grow through 2024, despite an increase in consumer savings from historically low levels. Throughout 2023, we expect the labor market to weaken, with the unemployment rate reaching a peak of 5.2% in 4Q23.



Emissions: We forecast total energy-related carbon dioxide (CO_2) emissions to decrease in the United States by more than 3% in 2023. Relatively flat economic growth and an increase in electricity generation from renewable sources decreases fossil fuel consumption, and therefore emissions. Among the major fossil fuel categories, CO_2 emissions from coal decline the most in the United States at around 11%, mostly from decreasing coal-fired electricity generation. More renewable generation contributes to decreases in natural gas-fired electricity generation, which in turn decreases CO_2 emissions from natural gas by 2%. We expect petroleum emissions to remain about the same.

U.S. energy-related CO_2 emissions in 2024 remain unchanged from 2023 in our forecast because increasing emissions from petroleum products offsets decreasing emissions from natural gas. Petroleum CO_2 emissions increase slightly as a result of increases in air and road travel, as well as increasing hydrocarbon gas liquid consumption, particularly propane. More consumption of propane arises from increased industrial activity, as propane is used as a petrochemical feedstock.



Weather: In December, the United States experienced 27% more population-weighted heating degree days (HDDs) than last year and 9% more than the 10-year average. Based on forecasts from the National Oceanic and Atmospheric Administration, we expect 1Q23 to be milder than last winter, with 5% fewer HDDs in the United States compared with 1Q22 and 4% 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 - January 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	33.23	33.86	33.72	33.87	34.55	34.65	34.56	34.81	35.62	32.32	34.00	34.91
U.S. (50 States)	19.44	20.12	20.59	20.77	21.01	21.14	21.16	21.46	21.44	21.74	21.90	22.29	20.24	21.19	21.85
Canada	5.66	5.51	5.72	5.94	6.01	5.72	5.93	6.14	6.21	5.92	6.13	6.34	5.71	5.95	6.15
Mexico	1.91	1.89	1.90	1.92	1.94	1.94	1.94	1.92	1.94	1.93	1.91	1.87	1.91	1.93	1.91
Other OECD	4.61	4.35	4.33	4.60	4.90	4.92	4.85	5.03	5.06	4.97	4.87	5.12	4.47	4.93	5.00
Non-OECD	67.21	66.87	68.30	68.21	67.00	66.94	67.46	67.00	67.38	68.00	68.32	67.95	67.65	67.10	67.91
OPEC	33.75	33.76	34.71	34.48	34.18	34.41	34.46	34.30	35.06	35.04	35.07	34.91	34.18	34.34	35.02
Crude Oil Portion	28.19	28.33	29.23	28.96	28.64	29.00	29.01	28.82	29.48	29.58	29.58	29.38	28.68	28.87	29.51
Other Liquids (b)	5.56	5.43	5.48	5.52	5.54	5.41	5.45	5.49	5.58	5.45	5.49	5.53	5.50	5.47	5.51
Eurasia	14.39	13.39	13.58	13.94	13.13	12.17	12.43	12.51	12.54	12.52	12.49	12.58	13.82	12.56	12.53
China	5.18	5.18	5.05	5.12	5.21	5.24	5.23	5.27	5.21	5.23	5.22	5.26	5.13	5.24	5.23
Other Non-OECD	13.90	14.54	14.96	14.68	14.49	15.12	15.34	14.92	14.57	15.21	15.53	15.19	14.52	14.97	15.13
Total World Production	98.83	98.75	100.85	101.45	100.87	100.65	101.33	101.55	102.03	102.56	103.13	103.57	99.98	101.10	102.83
Non-OPEC Production	65.08	64.98	66.14	66.97	66.69	66.25	66.87	67.25	66.97	67.53	68.06	68.66	65.80	66.77	67.81
Consumption (million barrels per day) (c)															
OECD	45.84	45.45	46.47	46.23	46.13	45.28	45.82	46.10	45.79	45.33	46.17	46.40	46.00	45.83	45.92
U.S. (50 States)	20.22	20.27	20.47	20.14	20.12	20.53	20.52	20.60	20.34	20.57	20.79	20.79	20.27	20.44	20.63
U.S. Territories	0.22	0.19	0.20	0.21	0.21	0.19	0.20	0.21	0.21	0.19	0.20	0.21	0.21	0.20	0.20
Canada	2.25	2.21	2.41	2.33	2.28	2.23	2.33	2.30	2.30	2.25	2.35	2.33	2.30	2.28	2.31
Europe	13.15	13.43	13.93	13.85	13.59	13.20	13.60	13.37	13.15	13.30	13.70	13.46	13.59	13.44	13.40
Japan	3.70	3.03	3.19	3.51	3.69	3.05	3.07	3.37	3.54	2.94	3.04	3.36	3.36	3.29	3.22
Other OECD	6.30	6.33	6.28	6.19	6.24	6.08	6.11	6.25	6.24	6.08	6.10	6.25	6.27	6.17	6.17
Non-OECD	52.96	53.25	53.76	53.73	54.43	55.06	54.71	54.37	56.39	56.60	56.24	55.89	53.43	54.64	56.28
Eurasia	4.42	4.29	4.64	4.57	4.18	4.33	4.64	4.55	4.37	4.52	4.84	4.75	4.48	4.42	4.62
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	0.75	0.76
China	15.13	15.11	15.10	15.29	15.92	16.06	15.44	15.36	16.49	16.38	15.74	15.66	15.16	15.69	16.06
Other Asia	13.75	13.76	13.47	13.90	14.31	14.28	13.71	14.00	14.89	14.86	14.26	14.58	13.72	14.07	14.65
Other Non-OECD	18.91	19.34	19.79	19.21	19.28	19.63	20.17	19.69	19.90	20.08	20.63	20.14	19.31	19.70	20.19
Total World Consumption	98.80	98.71	100.23	99.97	100.56	100.34	100.53	100.47	102.18	101.93	102.41	102.29	99.43	100.48	102.20
Total Crude Oil and Other Liquids Inventory Net Withdrawals (million barrels per day)															
U.S. (50 States)	0.81	0.51	0.45	0.69	-0.04	-0.41	-0.10	0.32	-0.08	-0.53	-0.17	0.30	0.61	-0.06	-0.12
Other OECD	-0.09	-0.29	-0.52	-0.71	-0.09	0.03	-0.22	-0.45	0.07	-0.03	-0.17	-0.50	-0.40	-0.18	-0.16
Other Stock Draws and Balance	-0.75	-0.27	-0.54	-1.46	-0.18	0.07	-0.47	-0.96	0.15	-0.07	-0.38	-1.08	-0.75	-0.39	-0.35
Total Stock Draw	-0.03	-0.04	-0.61	-1.48	-0.31	-0.31	-0.79	-1.09	0.14	-0.63	-0.72	-1.28	-0.55	-0.63	-0.62
End-of-period Commercial Crude Oil and Other Liquids Inventories (million barrels)															
U.S. Commercial Inventory	1,154	1,180	1,215	1,197	1,202	1,253	1,266	1,236	1,237	1,279	1,289	1,255	1,197	1,236	1,255
OECD Commercial Inventory	2,604	2,656	2,739	2,786	2,800	2,848	2,880	2,892	2,887	2,932	2,957	2,969	2,786	2,892	2,969

(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 January 5, 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 - January 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	12.05	12.23	12.37	12.34	12.40	12.51	12.63	12.72	12.86	13.03	11.86	12.41	12.81
Alaska	0.45	0.44	0.42	0.45	0.43	0.36	0.39	0.42	0.40	0.34	0.36	0.40	0.44	0.40	0.37
Federal Gulf of Mexico (b)	1.67	1.70	1.80	1.82	1.92	1.90	1.82	1.82	1.89	1.87	1.81	1.84	1.75	1.87	1.85
Lower 48 States (excl GOM)	9.35	9.56	9.83	9.95	10.02	10.08	10.19	10.27	10.34	10.51	10.68	10.79	9.67	10.14	10.58
Crude Oil Net Imports (c)	3.00	2.81	2.75	2.12	2.84	3.49	3.88	3.60	2.93	2.95	3.10	2.60	2.67	3.46	2.89
SPR Net Withdrawals	0.31	0.80	0.84	0.49	0.02	0.15	0.04	0.00	-0.07	-0.07	-0.07	-0.07	0.61	0.05	-0.07
Commercial Inventory Net Withdrawals	0.08	-0.03	-0.12	0.10	-0.29	0.13	0.15	-0.13	-0.32	0.07	0.17	-0.16	0.00	-0.03	-0.06
Crude Oil Adjustment (d)	0.71	0.81	0.75	0.98	0.49	0.59	0.50	0.48	0.56	0.63	0.52	0.52	0.81	0.52	0.56
Total Crude Oil Input to Refineries	15.56	16.09	16.26	15.91	15.43	16.70	16.98	16.46	15.73	16.29	16.58	15.92	15.96	16.40	16.13
Other Supply															
Refinery Processing Gain	0.95	1.07	1.05	1.02	1.03	1.03	1.04	1.07	1.05	1.03	1.03	1.05	1.02	1.04	1.04
Natural Gas Plant Liquids Production	5.61	5.92	6.09	6.07	6.20	6.32	6.26	6.37	6.29	6.47	6.47	6.60	5.93	6.29	6.46
Renewables and Oxygenate Production (e)	1.19	1.20	1.17	1.23	1.21	1.23	1.24	1.29	1.26	1.31	1.33	1.39	1.20	1.24	1.32
Fuel Ethanol Production	1.02	1.01	0.97	1.01	0.99	0.99	0.98	1.01	1.00	1.00	0.99	1.03	1.00	0.99	1.01
Petroleum Products Adjustment (f)	0.22	0.23	0.23	0.22	0.21	0.22	0.22	0.23	0.22	0.22	0.22	0.22	0.23	0.22	0.22
Product Net Imports (c)	-3.74	-3.99	-4.07	-4.42	-4.17	-4.28	-4.92	-5.27	-4.51	-4.21	-4.57	-4.92	-4.06	-4.66	-4.55
Hydrocarbon Gas Liquids	-2.14	-2.31	-2.16	-2.43	-2.61	-2.54	-2.56	-2.60	-2.61	-2.81	-2.75	-2.85	-2.26	-2.58	-2.75
Unfinished Oils	0.09	0.25	0.28	0.16	0.13	0.25	0.37	0.19	0.19	0.25	0.30	0.18	0.20	0.24	0.23
Other HC/Oxygenates	-0.09	-0.10	-0.07	-0.04	-0.06	-0.05	-0.04	-0.05	-0.07	-0.06	-0.05	-0.06	-0.07	-0.05	-0.06
Motor Gasoline Blend Comp.	0.40	0.60	0.48	0.39	0.55	0.68	0.37	0.41	0.40	0.66	0.39	0.37	0.47	0.50	0.46
Finished Motor Gasoline	-0.76	-0.73	-0.81	-0.84	-0.82	-0.80	-1.07	-1.28	-0.96	-0.77	-0.88	-1.02	-0.79	-0.99	-0.91
Jet Fuel	-0.04	-0.06	-0.11	-0.06	-0.09	-0.04	0.00	0.00	0.11	0.16	0.17	0.14	-0.07	-0.03	0.15
Distillate Fuel Oil	-0.81	-1.15	-1.29	-1.10	-0.79	-1.28	-1.44	-1.38	-1.09	-1.17	-1.28	-1.28	-1.09	-1.22	-1.20
Residual Fuel Oil	0.14	0.10	0.10	0.05	0.08	0.11	0.08	0.13	0.06	0.10	0.08	0.16	0.10	0.10	0.10
Other Oils (g)	-0.54	-0.59	-0.49	-0.56	-0.55	-0.61	-0.64	-0.69	-0.56	-0.56	-0.57	-0.56	-0.54	-0.62	-0.56
Product Inventory Net Withdrawals	0.42	-0.25	-0.26	0.10	0.22	-0.69	-0.29	0.46	0.31	-0.53	-0.26	0.53	0.00	-0.07	0.01
Total Supply	20.22	20.27	20.47	20.14	20.12	20.53	20.52	20.60	20.34	20.57	20.79	20.79	20.27	20.44	20.63
Consumption (million barrels per day)															
Hydrocarbon Gas Liquids	3.87	3.43	3.48	3.67	4.01	3.56	3.50	3.90	4.01	3.49	3.57	3.91	3.61	3.74	3.74
Other HC/Oxygenates	0.13	0.17	0.17	0.22	0.20	0.20	0.21	0.24	0.22	0.25	0.27	0.31	0.17	0.21	0.26
Unfinished Oils	0.13	0.04	0.11	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.08	0.00	0.00
Motor Gasoline	8.47	9.00	8.88	8.69	8.42	8.97	8.88	8.70	8.46	8.92	8.86	8.69	8.76	8.74	8.73
Fuel Ethanol blended into Motor Gasoline	0.87	0.93	0.92	0.90	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	1.47	1.62	1.68	1.64	1.63	1.74	1.80	1.74	1.56	1.60	1.73
Distillate Fuel Oil	4.14	3.89	3.86	3.91	4.00	3.92	3.86	4.00	4.08	3.96	3.89	4.01	3.95	3.94	3.99
Residual Fuel Oil	0.38	0.31	0.39	0.27	0.36	0.38	0.38	0.39	0.32	0.35	0.39	0.40	0.34	0.38	0.37
Other Oils (g)	1.65	1.82	1.99	1.76	1.66	1.88	2.00	1.74	1.63	1.85	2.00	1.74	1.80	1.82	1.81
Total Consumption	20.22	20.27	20.47	20.14	20.12	20.53	20.52	20.60	20.34	20.57	20.79	20.79	20.27	20.44	20.63
Total Petroleum and Other Liquids Net Imports	-0.74	-1.18	-1.32	-2.30	-1.34	-0.79	-1.04	-1.66	-1.58	-1.27	-1.47	-2.32	-1.39	-1.21	-1.66
End-of-period Inventories (million barrels)															
Commercial Inventory															
Crude Oil (excluding SPR)	414.4	417.5	428.8	419.9	445.9	434.0	419.9	432.2	461.5	455.1	439.8	454.5	419.9	432.2	454.5
Hydrocarbon Gas Liquids	142.0	186.7	243.6	208.9	158.1	208.3	248.4	203.8	164.9	212.6	249.1	203.8	208.9	203.8	203.8
Unfinished Oils	87.9	88.8	82.3	82.3	92.0	89.5	88.9	81.0	91.2	88.5	87.4	79.3	82.3	81.0	79.3
Other HC/Oxygenates	34.1	29.4	27.3	30.2	32.3	31.0	30.8	31.0	33.1	31.9	31.6	31.9	30.2	31.0	31.9
Total Motor Gasoline	238.5	221.0	209.6	223.8	235.9	243.1	234.0	246.2	240.9	245.8	238.7	247.3	223.8	246.2	247.3
Finished Motor Gasoline	17.3	17.1	17.6	16.1	15.2	16.9	18.8	21.5	18.4	19.6	21.3	23.5	16.1	21.5	23.5
Motor Gasoline Blend Comp.	221.2	203.8	192.0	207.7	220.7	226.2	215.3	224.7	222.5	226.2	217.4	223.7	207.7	224.7	223.7
Jet Fuel	35.6	39.3	36.2	34.0	37.5	40.4	42.1	39.3	40.2	40.3	42.1	38.3	34.0	39.3	38.3
Distillate Fuel Oil	114.6	111.4	110.5	119.4	113.0	121.8	127.5	127.0	119.1	121.4	126.7	125.2	119.4	127.0	125.2
Residual Fuel Oil	27.9	29.2	27.3	29.9	30.1	29.4	27.7	27.2	28.8	28.0	26.3	25.8	29.9	27.2	25.8
Other Oils (g)	58.5	56.4	49.5	48.3	57.7	55.8	46.8	48.4	57.6	55.6	46.5	48.0	48.3	48.4	48.0
Total Commercial Inventory	1153.6	1179.7	1215.1	1196.7	1202.6	1253.3	1266.0	1236.1	1237.2	1279.1	1288.1	1253.9	1196.7	1236.1	1253.9
Crude Oil in SPR	566.1	493.3	416.4	371.5	369.6	356.0	352.6	352.6	358.7	364.7	370.7	376.7	371.5	352.6	376.7

(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 January 5, 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 - January 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	108.25	108.67	109.58	108.60	108.83	109.42	109.96	110.65	111.70	112.63	106.61	109.11	111.24
Alaska	1.06	1.00	0.96	1.03	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	2.21	2.29	2.22	2.09	2.04	2.14	2.08	1.97	2.00	2.14	2.16	2.05
Lower 48 States (excl GOM)	100.16	103.07	105.10	105.43	106.28	105.44	105.90	106.40	106.83	107.64	108.88	109.66	103.46	106.01	108.26
Total Dry Gas Production	95.10	97.59	99.44	99.87	100.82	99.87	100.08	100.62	101.12	101.75	102.72	103.57	98.02	100.34	102.29
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	10.60	11.88	12.14	11.96	12.28	12.63	12.46	12.12	13.17	10.65	12.06	12.59
Pipeline Gross Imports	8.89	7.73	7.84	7.90	8.28	6.85	7.05	7.50	8.31	6.86	7.05	7.50	8.09	7.42	7.43
Pipeline Gross Exports	8.43	8.45	8.06	8.48	9.27	8.81	9.15	9.56	9.99	9.38	9.71	10.14	8.35	9.20	9.81
Supplemental Gaseous Fuels	0.21	0.17	0.18	0.18	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.20	0.18	0.19	0.19
Net Inventory Withdrawals	20.14	-10.25	-8.94	2.72	15.28	-11.99	-8.25	3.52	16.97	-13.13	-9.78	3.93	0.84	-0.41	-0.51
Total Supply	104.56	76.01	80.78	91.65	103.52	74.01	78.00	90.05	104.06	73.87	78.40	91.96	88.19	86.34	87.06
Balancing Item (b)	0.33	0.27	0.37	1.12	-1.32	0.65	0.84	1.41	-0.09	-1.86	-1.67	-1.44	0.52	0.41	-1.27
Total Primary Supply	104.89	76.27	81.15	92.77	102.20	74.66	78.84	91.47	103.97	72.01	76.73	90.52	88.72	86.74	85.79
Consumption (billion cubic feet per day)															
Residential	26.09	7.85	3.56	17.22	25.18	8.02	4.26	17.59	26.40	8.09	4.31	17.65	13.63	13.71	14.10
Commercial	15.61	6.68	4.74	11.71	15.05	6.76	5.26	11.84	15.50	6.72	5.25	11.86	9.66	9.70	9.83
Industrial	25.50	22.38	21.83	23.59	23.96	21.43	21.29	23.66	24.17	20.65	20.24	22.62	23.31	22.58	21.92
Electric Power (c)	28.41	31.00	42.37	31.12	28.46	30.01	39.42	29.25	28.24	28.11	38.26	29.13	33.26	31.81	30.95
Lease and Plant Fuel	5.26	5.41	5.51	5.53	5.58	5.53	5.54	5.57	5.60	5.64	5.69	5.74	5.43	5.56	5.67
Pipeline and Distribution Use	3.86	2.81	2.99	3.46	3.83	2.76	2.92	3.42	3.90	2.66	2.84	3.38	3.28	3.23	3.19
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	104.89	76.27	81.15	92.77	102.20	74.66	78.84	91.47	103.97	72.01	76.73	90.52	88.72	86.74	85.79
End-of-period Inventories (billion cubic feet)															
Working Gas Inventory	1,401	2,325	3,146	2,897	1,521	2,612	3,371	3,047	1,503	2,698	3,597	3,236	2,897	3,047	3,236
East Region (d)	242	482	759	686	296	597	844	726	254	581	871	727	686	726	727
Midwest Region (d)	296	557	917	832	343	635	966	843	325	655	1,024	890	832	843	890
South Central Region (d)	587	885	1,006	1,033	715	1,032	1,079	1,035	627	1,003	1,129	1,096	1,033	1,035	1,096
Mountain Region (d)	90	137	184	155	57	108	183	170	107	152	217	197	155	170	197
Pacific Region (d)	165	240	247	163	82	213	271	245	162	279	329	298	163	245	298
Alaska	21	25	32	28	28	28	28	28	28	28	28	28	28	28	28

(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 January 5, 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://news.gov.bc.ca/releases/2022LWRS0067-001800

Ministers’ joint statement on status of negotiations with Blueberry River First Nations

Joint Statement

Victoria
Saturday, November 26, 2022 4:45 PM

Josie Osborne, Minister of Land, Water and Resource Stewardship; Murray Rankin, Minister of Indigenous Relations and Reconciliation; and Bruce Ralston, Minister of Energy, Mines and Low Carbon Innovation, have issued the following statement about the status of negotiations with Blueberry River First Nations:

“We continue to engage in respectful negotiations with Blueberry River First Nations in response to the BC Supreme Court’s direction in June 2021 to find a new approach to natural resource development that protects the Nations’ treaty rights and addresses cumulative impacts.

“Our negotiating teams have been working incredibly hard to develop solutions that address healing and restoration on the land and provide predictability for industry, while including Blueberry River First Nations in how natural resources are planned and authorized in their territory

.

“From the start, our joint focus has been on ensuring we arrive at an agreement that protects Blueberry River First Nations' Treaty 8 rights and that provides for a sustainable economy with good jobs and opportunity for people in northeastern B.C.

“We wish to affirm that we are very close to an agreement and are discussing final issues. As such, we have initiated early engagement with select industry groups and other Treaty 8 Nations on a proposed agreement to hear their feedback and consider adjustments.

“Our commitment is to share more with British Columbians as soon as possible.”

SAF Group created transcript of excerpts from Kishida/Trudeau press conference post their meeting on Jan 12. https://www.youtube.com/watch?v=Ikglg7NY45w

Note Kishida's comments and Trudeau's French comments are via the translator.

Items in "italics" are SAF Group created transcript

At 9:02 min mark, Kishida *"… in the area of economy, we agreed to strengthen cooperation in economic areas including energy and food, including LNG Canada and critical mineral resources*"

At 16:48 min mark, National Post "… *Prime Minister Kishida, you came here looking, I'm sure, for commitments from Canada for more LNG export. I know it is central to the expansion of your economy. I am wondering Prime Minister Trudeau, what commitment you made to the Japanese in regards to that and whether or not you're looking at easing regulatory hurdles so a project like the Phase 2 expansion of LNG Canada can get approved and start shipping natural gas?*" Trudeau "*Obviously, we talked a lot about how Canada can be a reliable supplier, not just of energy, but of critical minerals, of commodities and resources including agricultural resources that the world is going to need as we move towards a Net Zero economy around the world. We're very excited about the LNG Canada project, which is the largest private investment in Canada. A project led by Shell on the west coast, in which a Japanese company, Mitsubishi, is a significant partner. Because we know that being a reliable supplier of energy is important and we're going to continue to look for ways to be that reliable supplier of energy. But even as we do talk about things like LNG and other traditional sources of energy, we know the world is moving aggressively and meaningfully towards decarbonizing. Towards diversifying. Towards more renewables. That's where the agreements that we've already seen develop between Japanese and Canadian companies on hydrogen, on ammonia, on various new technologies are really exciting. As I mentioned, there's gong to be a number of Japanese CEOs coming to Canada in the coming months from the battery association, an industry association around batteries in Japan. Very interested in becoming part of our battery supply chain, which was recently recognized as the second most important in the world. We're also going to be going to Japan with a trade mission in the fall that will continue to deepen those things. So there's a lot of conversations we've had and Canada is going to make sure we're doing what creates good jobs in Canada and more sustainable, reliable futures for people around the world in providing energy in all sorts of different ways in a way that helps us all build a strong future*." Then Trudeau in French via a translator "*the reality is that we will continue to work to together to respond and to meet the energy needs of our partners throughout the world, whether that's thru the LNG Canada project on the west coast. And in this project, we have a Japanese company that is a significant investor. And whether it's hydrogen projects or other technologies, renewables, we will be there to work together. We need to ensure that this transition towards lower carbon emission fuels create good jobs for Canadian workers, but also help to create solutions that the whole world needs. And those are discussions that we will continue to hold together*. Kishida "*well, last year, there was a [?] by Russia into the Ukraine, and since then, the world is facing an energy crisis. Under such a situation, the major countries, each are trying to have a stable supply of energy and also to decarbonize. Countries must fulfill these two objectives. So the current global energy situation, Canada a country which is a country abundant in resources will further increase its presence, that is my impression. And Japan, in terms of our relations with Canada, we also want to have a closer relationship with Canada in the area of energy. Under such a situation, LNG or LNG Canada business and other cooperations between Japan and Canada should develop. I welcome such developments. So your question also included some commitment about regulations, but we didn't make any concrete commitment but, in any event, business between Japan and Canada is important and to develop an environment which will promote business between the two countries. The Japanese government will try to cooperate in developing such an environment. That is all*."

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

https://www.mofa.go.jp/na/na1/ca/page4e_001315.html

Japan-Canada Summit Meeting

January 12, 2023
Japanese

(Photo: Cabinet Public Affairs Office)

On January 12, commencing at 11:30 am (local time; January 13, 1:30 am Japan Time), for 75 minutes, Mr. KISHIDA Fumio, Prime Minister of Japan, held a summit meeting with the Right Honourable Justin Trudeau, Prime Minister of Canada, while visiting Ottawa, Canada. The overview of the meeting is as follows.
After the summit meeting, Prime Minister Kishida attended a luncheon with business leaders hosted by Prime Minister Trudeau, where they exchanged views on the potential of economic relations between Japan and Canada in a friendly atmosphere.

1. At the outset, Prime Minister Trudeau welcomed Prime Minister Kishida's visit to Canada in the positon and stated that he would like to cooperate to further strengthen Japan-Canada relations. In response, Prime Minister Kishida expressed his gratitude for the warm welcome, and said it is a great pleasure to visit Canada for the first time in seven years since he visited as Minister for Foreign Affairs in 2016 and for the first time as Prime Minister. Prime Minister Kishida also expressed that he would like to collaborate with Canada to maintain and strengthen the peace and stability of the region and international community as Japan and Canada are both G7 members and Canada is an important strategic partner in the Indo-Pacific region that shares universal values such as freedom, democracy, human rights, and the rule of law.

2. Prime Minister Kishida explained to Prime Minister Trudeau that Japan has decided to fundamentally reinforce its defense capabilities including the possession of a counterstrike capabilities and to increase its defense budget based on the new “National Security Strategy” (NSS) and other documents formulated last month, to which Prime Minister Trudeau gave his full support.

3. Prime Minister Kishida also welcomed Canada's announcement of the "Indo-Pacific Strategy" last November and stated that the Strategy is in line with the "Japan-Canada Action Plan contributing to a free and open Indo-Pacific region," which was announced last October. The Prime Minister expressed his intention to work together with Canada, a country strengthening its engagement in the Indo-Pacific region as a Pacific nation, toward the realization of a "Free and Open Indo-Pacific (FOIP)" through a steady implementation of the "Action Plan.”

4. The two leaders exchanged their views on regional issues, including Ukraine, North Korea, and China.

- (1) Regarding Russia's aggression against Ukraine, the two leaders concurred to maintain the unity of the G7 and to continue strict sanctions against Russia and strong support for Ukraine. They also confirmed that they are seriously concerned about Russia's nuclear threats, which are absolutely unacceptable, and that Russia should never use nuclear weapons under any circumstances.
- (2) The two leaders concurred that North Korea's ballistic missile launches which are unprecedented both in their frequency and in their manner are absolutely unacceptable, and confirmed that they will continue to work closely together toward the complete denuclearization of North Korea in accordance with UN Security Council resolutions. They also confirmed that they will continue to cooperate in dealing with North Korea, including in addressing to illegal ship-to-ship transfers and the abduction issue.
- (3) The two leaders strongly opposed unilateral attempts to change the status quo by force in the East and South China Seas, and confirmed to continue close coordination in addressing various issues related to China.

5. The two leaders also had a candid discussion on the CPTPP and concurred on the importance of maintaining the high standards of the agreement as well as to continue to work closely together. The two leaders also concurred to strengthen cooperation in economic areas including energy and food, as well as in the areas of development finance and economic security including responses to economic coercion.

6. In addition, Prime Minister Kishida, under Japan's G7 Presidency this year, expressed his determination to lead efforts to address the various challenges facing the international community, and explained to Prime Minister Trudeau the priorities of Japan's G7 Presidency. Prime Minister Trudeau expressed his full support for the success of the G7 Hiroshima Summit, and the two leaders concurred to continue to work closely together toward the success of the G7 Hiroshima Summit.
   Prime Minister Kishida stated that, at the G7 Hiroshima Summit, he would like to demonstrate the vision and determination by the G7 to firmly reject any unilateral attempts to change the status quo by force or the threat or use of nuclear weapons, and to uphold the international order based on the rule of law. Prime Minister Kishida and Prime Minister Trudeau also concurred that it is important for the G7 to work together in such areas as world economy including energy and food security, nuclear disarmament and non-proliferation, economic security, and global issues including climate change, health, and development.

https://pm.gc.ca/en/news/readouts/2023/01/12/prime-minister-justin-trudeau-meets-prime-minister-japan-kishida-fumio

Prime Minister Justin Trudeau meets with Prime Minister of Japan Kishida Fumio

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January 12, 2023
Ottawa, Ontario

Today, Prime Minister Justin Trudeau met with the Prime Minister of Japan, Kishida Fumio. The leaders reaffirmed the strength of Canada and Japan's strategic partnership as well as their shared commitment to a free, open, and inclusive Indo-Pacific region. The leaders committed to continue working closely to grow our economies, create good jobs in both countries, strengthen the rules-based international system, and improve regional security, including through Canada's recently announced Indo-Pacific Strategy and Japan's National Security Strategy.

The leaders discussed strengthening bilateral trade, investment, and innovation, and reinforcing supply chain resilience and economic security to create good middle-class jobs and new opportunities for our businesses. They talked about expanding cooperation in areas such as agriculture and agri-food, energy, critical minerals, and emerging technologies. They also discussed their shared commitment to maintain and build on the Comprehensive and Progressive Agreement for Trans-Pacific Partnership's (CPTPP) high standards, which facilitate growth and job creation for both countries.

They announced a planned incoming mission to Canada in early spring of 2023 welcoming Japanese companies seeking new partners and investment opportunities in Canada related to zero-emission vehicles and batteries. They also announced Canada's plan to undertake a Team Canada trade mission to Japan in October as part of Canada's Indo-Pacific Strategy.

The prime ministers discussed Japan's priorities for its upcoming G7 Presidency and the importance of continued G7 coordination to uphold the rules-based international system, in light of new and emerging global challenges. They will maintain close cooperation between G7 members to denounce Russia's unjustifiable and illegal aggression against Ukraine, and to protect Ukraine's sovereignty and territorial integrity. Prime Minister Trudeau raised the importance of maintaining work on the G7's Gender Equality Advisory Council.

The leaders shared concerns about the wider global impacts of Russia's military aggression against Ukraine, notably for the Global South, with shortages and rising prices of food, fuel, and fertilizer. They committed to working together, including with G7 partners, to find practical ways to mitigate these impacts, particularly for the most vulnerable people, and to address their significant implications for the Indo-Pacific region. Prime Minister Trudeau also raised the importance of G7 members engaging on issues around the world, including anti-regime protests in Iran and the humanitarian and security crisis in Haiti.

Prime Minister Kishida shared details of Japan's new National Security Strategy. The two leaders discussed their concerns about China's actions in the region and agreed on the importance of a coordinated approach to security in the Indo-Pacific. They talked about their deep concern with the threat of North Korea's nuclear weapons and ballistic missile programs and reiterated their support for a complete, verified, and irreversible dismantlement of North Korea's nuclear weapons. The prime ministers reaffirmed their commitment to the multinational effort to help monitor United Nations sanctions against North Korea, to which Canada is contributing through Operation NEON.

The prime ministers also hosted Canadian and Japanese business leaders for a luncheon, to share their vision for a stronger trade, investment, and innovation partnership. They highlighted the growing and exciting business potential between the two countries.

Prime Minister Trudeau and Prime Minister Kishida agreed to remain in close contact as Japan prepares to host the G7 Summit in Hiroshima, in May 2023.

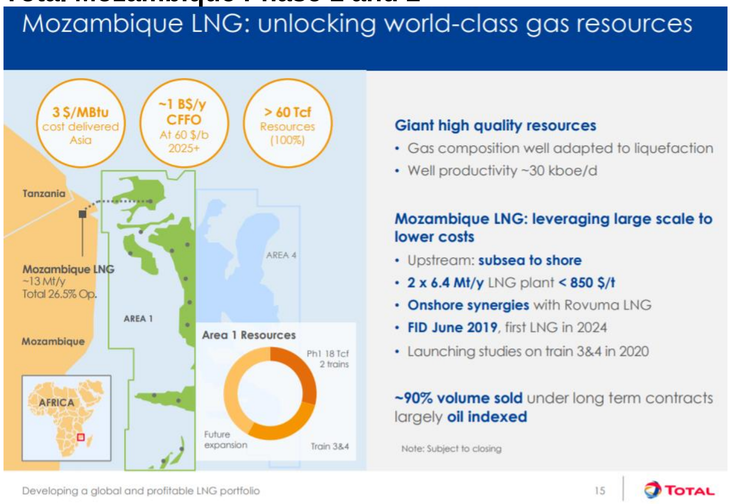
Multiple Brownfield LNG FIDs Now Needed To Fill New LNG Supply Gap From Mozambique Chaos? How About LNG Canada Phase 2?

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



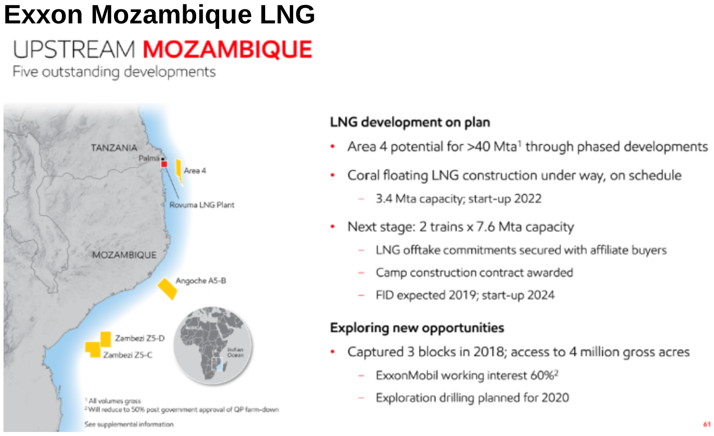
Source: Total Investor Day September 24, 2019

Total's Mozambique force majeure is no surprise, especially the need to the restoration of security and stability "in a sustained manner". 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".

Does anyone really think Total will risk another quick 2-3 month restart or even in 2021? 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.

Mozambique's security issues pushes back 5.0 bcf/d of new LNG supply at least a couple years. The global LNG issue is that 5 bcf/d of new Mozambique LNG supply (apart from the Eni Coral FLNG of 0.45 bcf/d) won't start up in 2024 and continuing thru the 2020s. And we believe all LNG forecasts included this 5.0 bcf/d to be in service in the 2020s as Mozambique had been considered the best positioned LNG supply to access Asia after Australia and Papua New Guinea. (i) Eni Coral Sul (Rovuma Basin) FLNG of 0.45 bcf/d planned in service in 2022. [LINK] This is an offshore floating LNG vessel that is still expected to be in service in 2022. (ii) Total Phase 1 to add 1.7 bcf/d with an in service originally planned for 2024. We expect the in service data to be pushed back to at least 2026 assuming Total gives a development restart approval in Dec 2021. In theory, this would only be a 1 year loss of time. However, Total has let services go, the project will be idle for 9 months, it isn't clear if the need to get people out quickly let them do a complete put the project on hold, and how many people will be on site maintaining the status of the development during the force majeure. Also what new procedures and safety will be put in place for a restart. These all mean there will be added time needed to get the project back to where it was when force majeure was declared ie. why we think a 12 month time delay will be more like an 18 month project delay. (iii) Exxon's Rozuma Phase 1 LNG will add 2.0 bcf/d and, pre-Covid, was expected to be in service in 2025. We believe the delays related to security and safety at Total are also going to impact Exxon. We find it highly unlikely the Exxon board would take a different security and safety decision than Total. Pre-pandemic, Exxon's March 6, 2019 Investor Day noted their operated Mozambique Rovuma LNG Phase 1 was to be 2 trains each with 1.0 bcf/d capacity for total initial capacity of 2.0 bf/d with FID expected in 2019 and first LNG deliveries in 2024. The 2019 FID expectation was later pushed to be expected just before the March 2020 investor day. But the pandemic hit, and on March 21, 2020, we tweeted [LINK] on the Reuters story "*Exclusive: Coronavirus, gas slump put brakes on Exxon's giant Mozambique LNG plan"* [LINK] that noted Exxon was expected to delay the Rovuma FID. There was no timeline, but the expectation was that FID would now be in 2022 (3 years later than original timeline0 and that would push first LNG likely to 2027. (iv) Total Phase 2 was to add 1.3 bcf/d. There was no firm in service date but it was expected to follow closely behind Phase 1 to maintain services. That would have put it originally in the 2026/2027 period. But if Phase 1 is pushed back 2 years, so will Phase 2 so more likely 2028/2029.. (v) Total Phase 1 + 2 and Exxon Rozuma Phase 1 total 5.0 bcf/d and would have been (and still are) in all LNG supply forecasts for the 2020s. (vi) We aren't certain if the LNG supply forecasts include Exxon Rozuma Phase 2 ,which would be an additional 2.0 bcf/d on top of the 5.0 bcf/d noted above. Exxon Rozuma has always been expected to be at least 2 Phases. This has been the plan since the Anadarko days given the 85 tcf size of the resource on Exxon's Area 4. There was no firm in service data for Phase 2, but it was expected they would also closely follow Phase 1 to maintain services. We expect that original timeline would have been 2026/2027 and that would not be pushed back to 2029/2030. (vii) It doesn't matter if its only 5 bcf/ of Mozambique that is delayed 2 to 3 years, it will cause a bigger LNG supply gap and sooner. The issue for LNG markets is this is taking projects that are in development effectively out of the queue for some period.

Exxon Mozambique LNG



Source: Exxon Investor Day March 6, 2019

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

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

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

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

<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

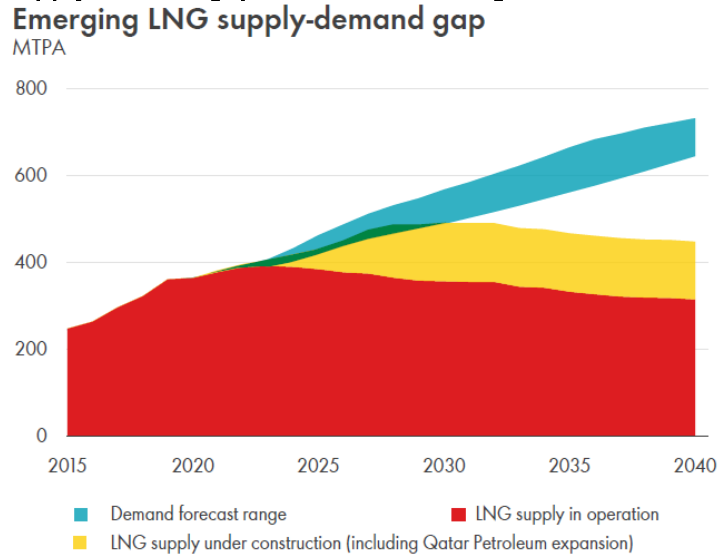
Source: IEA Tracking Clean Energy Progress, June 2020

<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

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

And does this bigger, nearer supply gap force LNG players to look at what brownfield LNG projects they could advance? A greenfield LNG project would likely take at least until 2027 to be in operations. Its why we believe the Mozambique delays will effectively force major LNG players to look to see if there are brownfield LNG projects they should look to advance. Prior to the just passed winter, no one would think Shell or other major LNG players would be considering any new LNG FIDs in 2021. All the big companies are in capital reduction mode and debt reduction mode. But Brent oil is now solidly over $60 and LNG prices hit record levels in Jan and the world's economic and oil and gas demand outlook are increasing with vaccinations. And we are starting to see companies move to increasing capex with the higher cash flows. We would not expect any major LNG players to move to FID right away. But we see them watching to see if 2021 plays out to still support this increasing LNG supply gap. And unless new mutations prevent vaccinations from returning the world to normal, we suspect that major LNG players, like other oil and gas companies, will be looking to increase capex as they approve 2022 budgets. The outlook for the future has changed dramatically in the last 5 months. The question facing Shell and others, should they look to FID new LNG brownfield projects in the face of an increasing LNG supply gap that is going to hit faster and harder than expected a few months ago. We expect these decisions to be looked at before the end of 2021. LNG prices will be stronger, but we expect the limiting cap in Asia will be that thermal coal will be used to mitigate some LNG price pressure.

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

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

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

Posted 11am on July 14, 2021

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

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

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

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

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

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

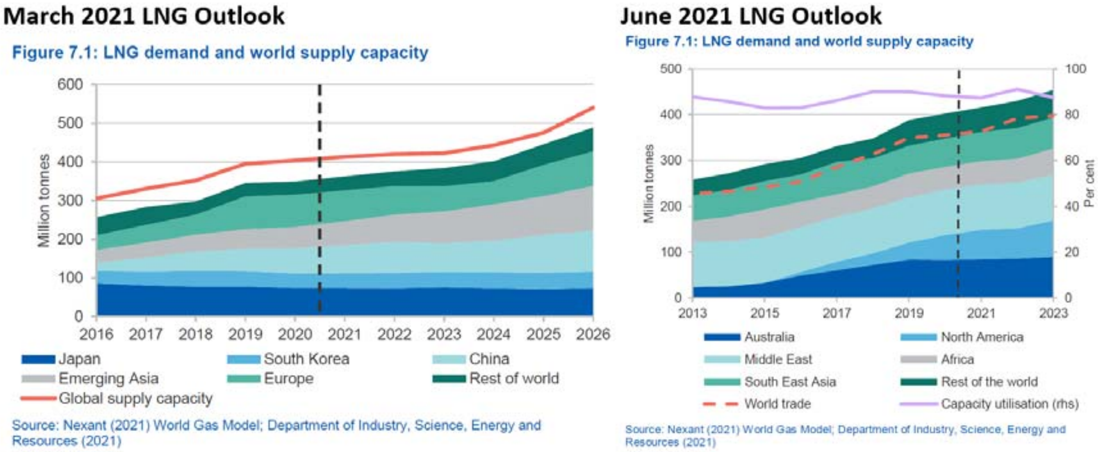
Common theme - new LNG supply is being delayed ie. [Total] Mozambique. Don't forget need capacity>demand due to normal maintenance, etc. Positive for LNG." (ii) Chevron's Gorgon. A big LNG story in H2/20 was the emergence of weld quality issues in the propane heat exchangers at Train 2, which required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

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

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

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

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

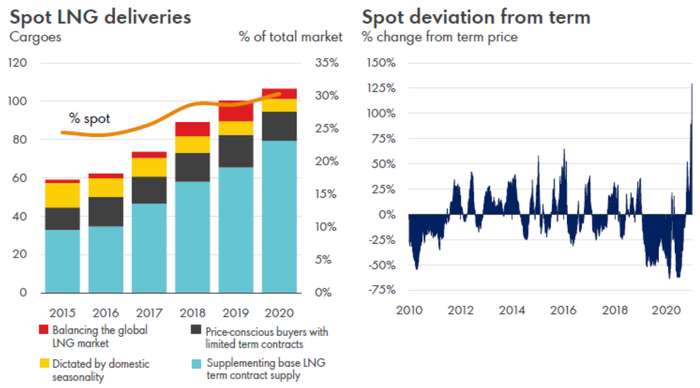


Source: Australia Resources and Energy Quarterly

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

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

Spot LNG deliveries and Spot deviation from term price



Source: Shell LNG Outlook 2021 on Feb 25, 2021

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

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

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

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

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

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

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

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

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

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

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

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

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

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

https://www.defenseone.com/threats/2023/01/navy-secretary-warns-if-defense-industry-cant-boost-production-arming-both-ukraine-and-us-may-become-challenging/381722/

US Navy Secretary Carlos Del Toro speaks during the United States Naval Academy 2022 Graduation Ceremony at the Navy-Marine Corps Memorial Stadium in Annapolis, Maryland, on May 27, 2022. MANDEL NGAN / AFP) (PHOTO BY MANDEL NGAN/AFP VIA GETTY IMAGES

Navy Secretary Warns: If Defense Industry Can't Boost Production, Arming Both Ukraine and the US May Become 'Challenging'

Carlos Del Toro's comments come as an admiral accuses weapons makers of using the pandemic as an excuse for not delivering arms on time.

BY MARCUS WEISGERBER

GLOBAL BUSINESS EDITOR
JANUARY 11, 2023

If weapons makers can't boost production in the next six to 12 months, the United States may find it "challenging" to continue arming itself and helping Ukraine, the Navy secretary said Wednesday.

Carlos Del Toro was speaking to a group of reporters on the sidelines of a Surface Navy Association conference in Arlington, Virginia, just days after the Biden administration announced it would send armored fighting vehicles to Ukraine. Some Republicans are pushing for the U.S. to stop giving weapons to Kyiv.

The secretary was asked to respond to comments made at the conference by Adm. Daryl Caudle, commander of U.S. Fleet Forces Command. Caudle, the reporter said, worried that "the Navy might get to the point where it has to make the decision whether it needs to arm itself or arm Ukraine, and has the Navy gotten to that point yet?"

Del Toro replied, "With regards to deliveries of weapons systems for the fight in Ukraine…Yeah, that's always a concern for us. And we monitor that very, very closely. I wouldn't say we're quite there yet, but if the conflict does go on for another six months, for another year, it certainly continues to stress the supply chain in ways that are challenging."

The Navy secretary said that Deputy Defense Secretary Kathleen Hicks has been working "very closely with [the defense] industry, to motivate them to find out what their challenges or obstacles are to be able to increase their own production rates."

“It's obvious that you know, these companies have a substantial pipeline for the future,” Del Toro said. “They now need to invest in their workforce, as well as the capital investments that they have to make within their own companies to get their production rates up.”

Most U.S. weapons sent to Ukraine are coming from Army, not Navy stockpiles. Still, U.S. officials recently announced they would start sending Sea Sparrow missiles to Ukraine. Last year, Denmark gave Ukraine U.S.-made Harpoon missiles.

Speaking earlier at the SNA conference, Caudle said that the timeliness of weapons deliveries have real implications both for the Ukrainian and U.S. militaries.

“I'm not...talking about what it’s doing to me, I'm talking about of course, we're going to help a country—deliver the stuff we need—so they can win that conflict against Russia and it's not going to destroy and set me back into the dark ages,” he said.

Over the past three years, companies have blamed weapons production delays on the supply chain issues and worker shortages stemming from the COVID-19 pandemic.

Still, Caudle accused defense companies of using the pandemic as an excuse for missing weapons delivery deadlines.

“I’m not as forgiving of the defense industrial base. I’m just not,” he said. “I am not forgiving of the fact that you’re not delivering the ordnance we need. All this stuff about COVID this, parts, supply chain this, I just don’t really care. We’ve all got tough jobs.”

Caudle specifically mentioned torpedoes and Standard Missile-6 interceptors being late. Deliveries of the SM-6, which are made by Raytheon Technologies, have been slowed, in part, due to problems getting the rocket motors from Aerojet Rocketdyne, a key supplier.

“We’re talking about war fighting and nation security and going against a competitor here and a potential adversary that is like nothing we’ve ever seen and we keep dilly dallying around with these deliveries,” the admiral said. “I don't see good accountability and I don't get to see good return on investment from the government [side], I really don't.”

Oil price outlook – Snapshot: January 9, 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 as middle distillate cracks weakened.
	Crude stocks	↓	• In the week ending December 30, land crude-oil storage levels in BloombergNEF's tracked regions (the US, ARA and Japan) grew 1.1% to 476.5 million barrels (m bbl). The stockpile **deficit** against the five-year average (2015-19) **narrowed from 30.0m bbl to 18.5m bbl**. • Including global floating crude stockpiles from the same week, total crude oil inventories increased by 2.7% to 645.2m bbl, while the stockpile **deficit of 3.1m bbl flipped to a surplus to 26.4m bbl.**
	Product stocks	↑	• In the week ending December 30, gasoline and light distillate stockpiles in BNEF's tracked regions (the US, ARA, Singapore, Japan and Fujairah) dropped by 0.5% week-on-week to 266.5m bbl, with the stockpile **deficit** against the three-year average (2017-19) **widening from 10.5m bbl to 20.0m bbl**. Gasoil and middle distillate stockpiles in BNEF's tracked regions were up 0.4% to 154.6m bbl, with the stockpile **deficit** against the three-year average **widening from 18.7m bbl to 26.6m bbl**. • Oil product stockpiles in tracked regions fell by 0.6% to 956.4m bbl, with the stockpile **deficit** against the three-year seasonal average **widening from 15.9m bbl to 32.1 m bbl**. Altogether, crude and product stockpiles increased by 0.7% to 1,601.7m bbl, with the stockpile **deficit narrowing from 19.0m bbl to 5.7m bbl.**
	Demand indicators	↔	• In the week to January 16, global jet fuel demand from commercial passenger flights is set to rise by 2.2% to 5.54 million barrels per day. Jet fuel consumption by international passenger flight departures is on course to rise 18,300 barrels per day (or +0.6%) week-on-week, while consumption by domestic passenger flight departures will surge by 99,400 barrels per day (or +4.5%). In the week to January 7, flight departures in the Eurocontrol area rose to 93.4% of the equivalent week in 2019, up from 85.6% last week. The four-week moving average also inched higher to 90.6%, from 88.5%. Meanwhile, in the same week, US passenger throughput rose to 104.0% of the average week in 2019, up from 92.6% last week. The four-week moving average rose to 96.0%, from 93.7%. • In the week to January 4, TomTom's peak congestion data showed strong declines in Europe (-12.0%), Asia Pacific excluding mainland China (-18.8%) and North America (-2.6%). The weakness in congestion levels is largely driven by the holiday season. In the week to January 8, road congestion in China's 15 key cities surged by 21.6 percentage points to 115.6% 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 14.4% higher than January 2022 levels. • Weather in several cities across Western Europe and East Asia turned warmer over the past week.
Financial	**Macro indicators**	↓	• The dollar index averaged 104.4 in the week to January 6 and was 0.4% higher than the week before. The Global Manufacturing PMI fell for the seventh straight month to 48.6 in December, from 48.8 in November.
	Hedge fund positioning	↓	• In the week to January 3, Managed Money net positioning in the oil complex was down by 11.7m bbl (or -2.6%) week-on-week to 433.8m bbl, and stood at the tenth percentile of the past five years.
	Options and volatility	↔	• There was a notable increase in open interest for front month Brent calls, and as well as a drop in open interest for front month Brent puts. Brent and WTI 1M volatility skews fell slightly over the past week.
Outlook	**Weekly call**	↔	• BNEF is neutral on oil prices for the week ahead, with Brent Mar-23 trading at $80.88/bbl and WTI Feb-23 trading at $76.09/bbl at the time of writing. • In the week to January 8, the seven-day moving average of road congestion in China's key 15 cities (weighted by vehicle registration count) saw yet another strong weekly growth, and on a month-to-date basis stood 14.4% higher than January 2022 levels. Congestion levels in all of the fifteen cities seem to have bottomed. Of all 99 cities tracked by BNEF, 89 cities registered growth in road congestion, with the mean congestion level growing by 19.1 percentage points to 91.8% of January 2021 levels. • Outside of mainland China, road congestion levels saw another week of strong declines due to the holiday season. The US four-week average motor gasoline and distillate fuel supplied declined in the week to December 30, inching further from their respective 2017-2021 seasonal averages. • The four-week average (or 28-day MA) flight departures in the Eurocontrol area against the equivalent week in 2019 rose to the highest level since March 17, 2020. • Oil inventories saw a net bearish move in the week ending December 30, as the widening surplus of crude stockpiles outweighed the growing oil product stockpile deficit. • Whether China is able to sustain the momentum in its demand recovery is likely to be the key driver of oil prices in the weeks ahead.

BloombergNEF

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
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	
October 19	↔	↓	↔	↓	↑	↔	↓	Brent-Dec: 90.28 WTI-Dec: 82.78	
October 4	↔	↔	↑	↔	↓	↓	↔	Brent-Dec: 90.71 WTI-Nov: 85.26	
September 27	↔	↓	↓	↓	↓	↓	↔	Brent-Dec: 94.06 WTI-Nov: 87.83	
September 6	↓	↑	↔	↓	↔	↑	↓	Brent-Nov: 101.00 WTI-Oct: 95.40	

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

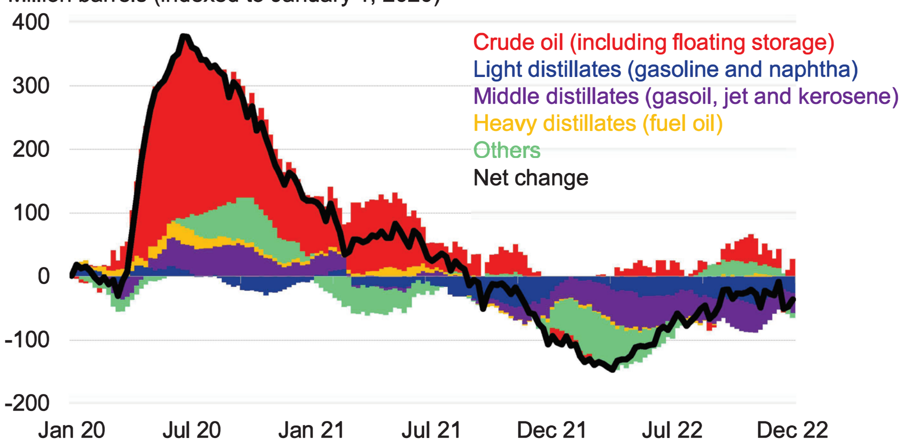
BloombergNEF

Weekly oil inventories

Oil inventories rose by 0.7% over the past week

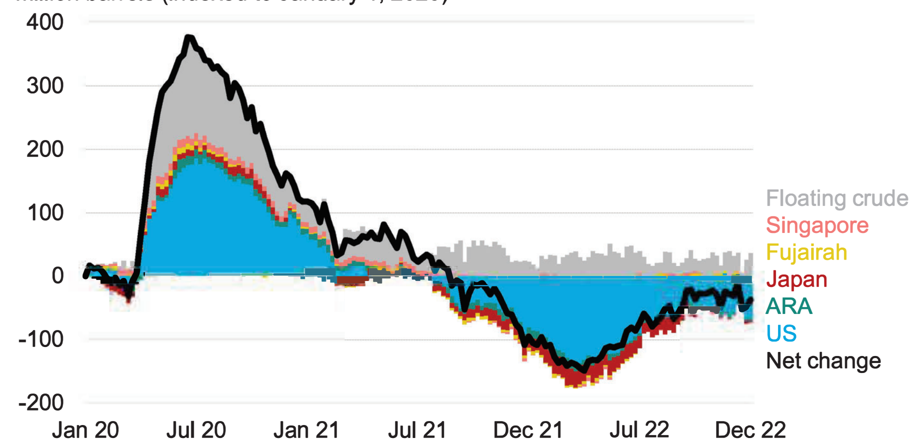
Weekly oil inventories by type

Million barrels (indexed to January 1, 2020)



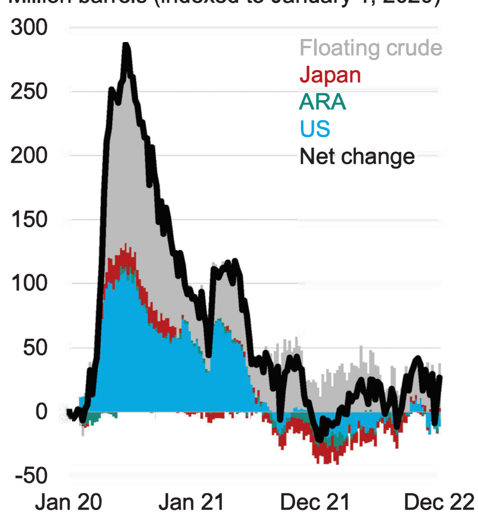
Weekly oil inventories by region

Million barrels (indexed to January 1, 2020)



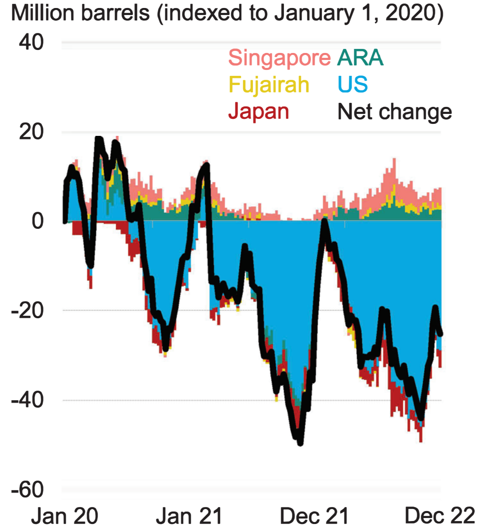
Crude inventories

Million barrels (indexed to January 1, 2020)



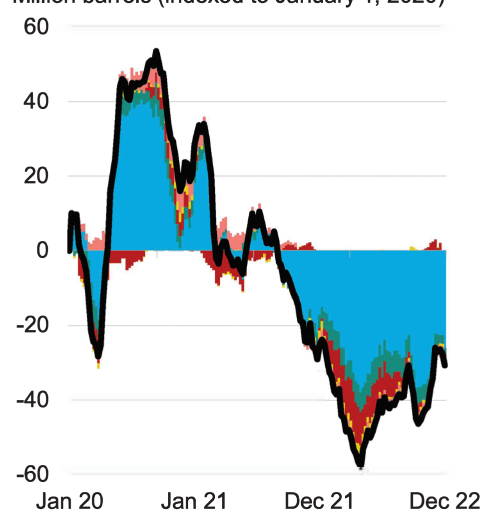
Light distillate inventories

Million barrels (indexed to January 1, 2020)



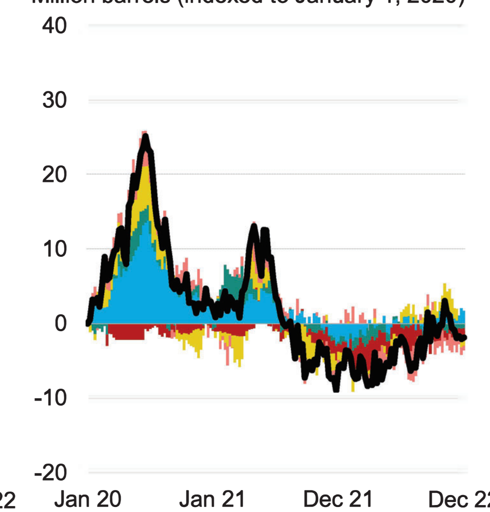
Middle distillate inventories

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 **December 30, 2022**.*

Fundamentals | Financial

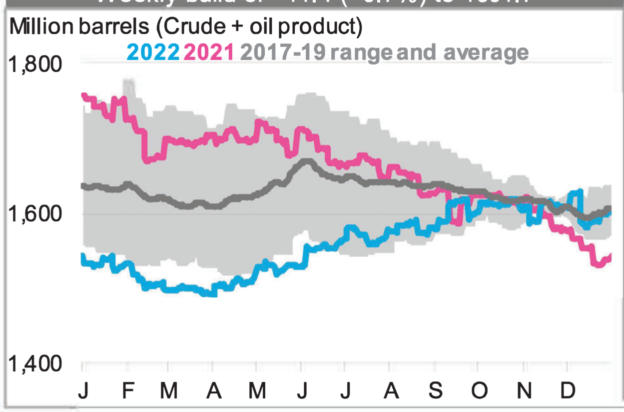
Aggregated oil stockpiles

Bearish: Stockpile deficit narrowed from 19.0m bbl to 5.7m bbl

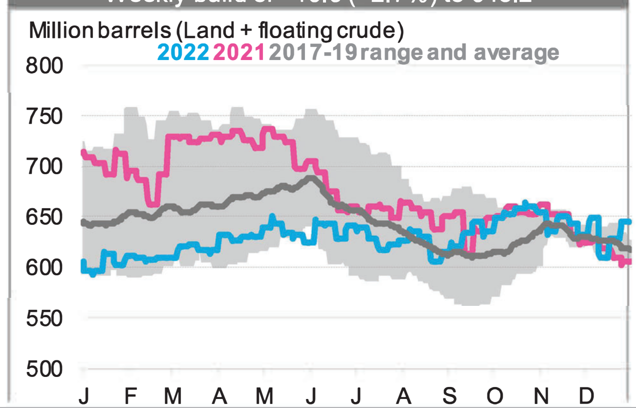
- Charts below use the **2017-19** (three-year) seasonal stockpiles. All calculations are recalibrated to measure against their respective three-year seasonal averages, so the values below may differ from the previous slides.
- Land crude inventories include the US, ARA, Japan and Shandong Teapots. Floating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

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

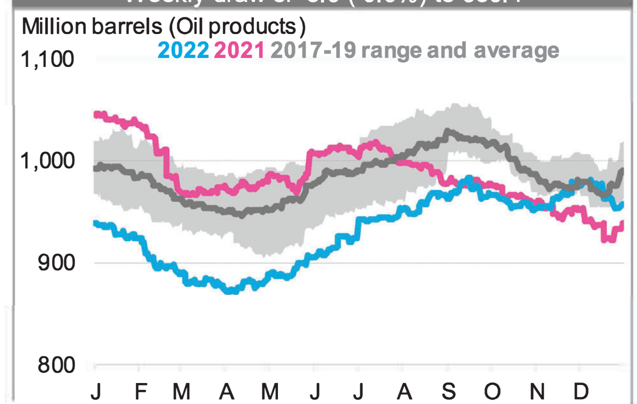
Weekly build of +11.4 (+0.7%) to 1601.7



Weekly build of +16.9 (+2.7%) to 645.2

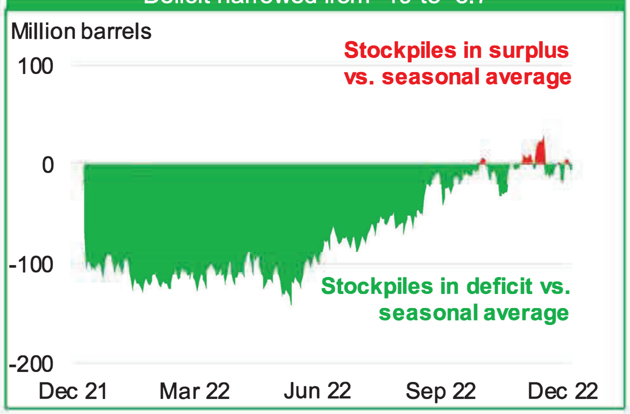


Weekly draw of -5.6 (-0.6%) to 956.4

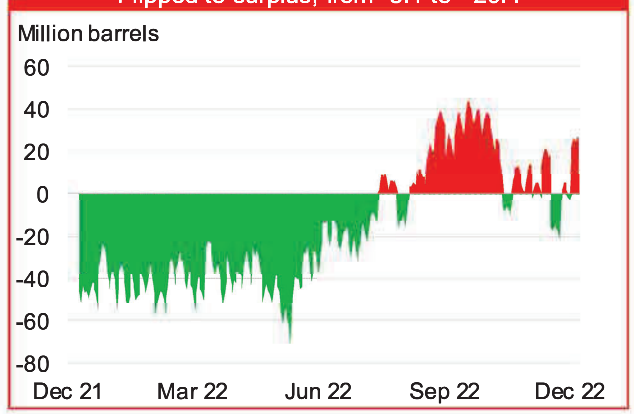


Charts below subtract current stockpiles by the 2017-19 (three-year) seasonal average

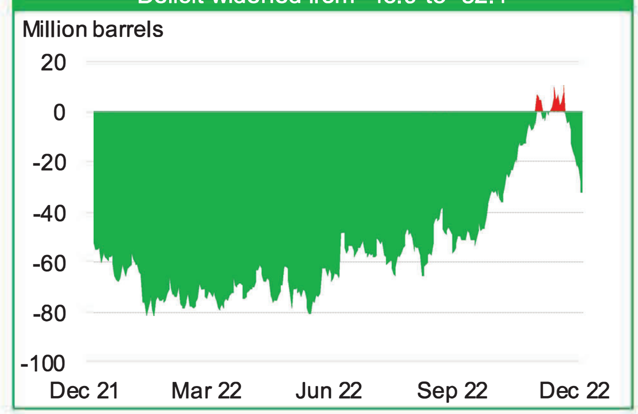
Deficit narrowed from -19 to -5.7



Flipped to surplus, from -3.1 to +26.4



Deficit widened from -15.9 to -32.1



Source: BloombergNEF, US EIA, PJK, IE Singapore, FEDCom/Platts, PAJ ,Vortexa, Genscape. Note: As of the ***week ending December 30, 2022.***

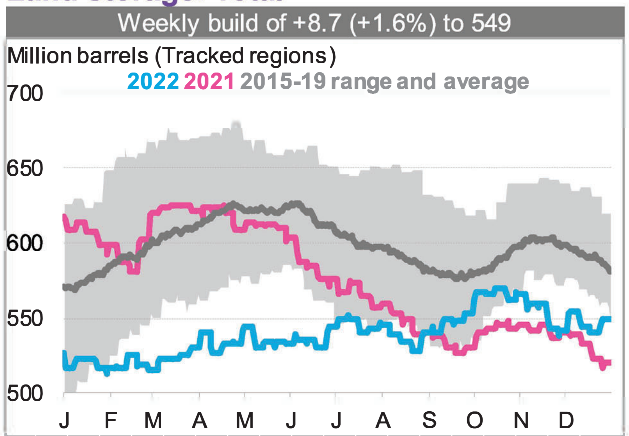
Fundamentals Financial

Crude stocks: Land

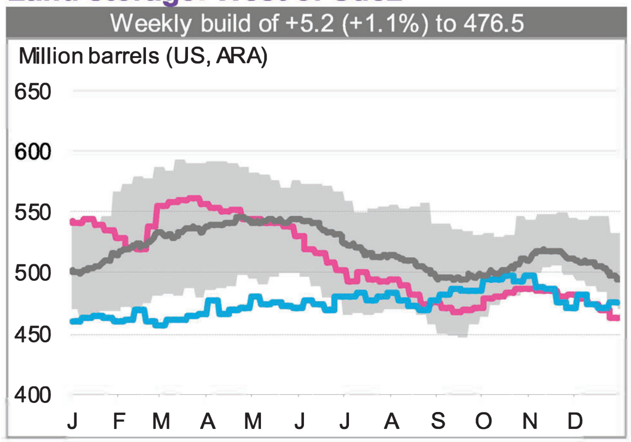
Bearish: Stockpile deficit narrowed from 47.8m bbl to 32.5m bbl

- 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.

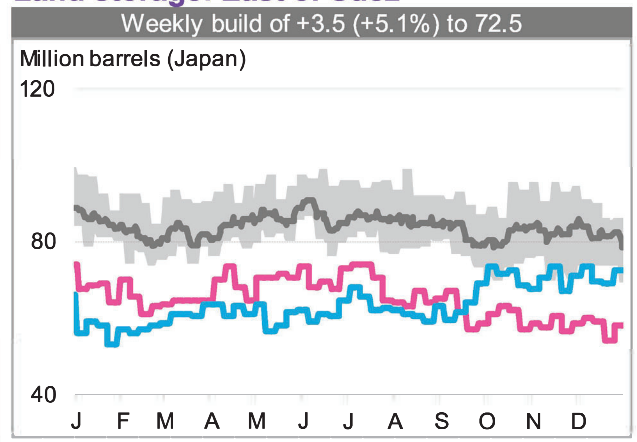
Land storage: Total



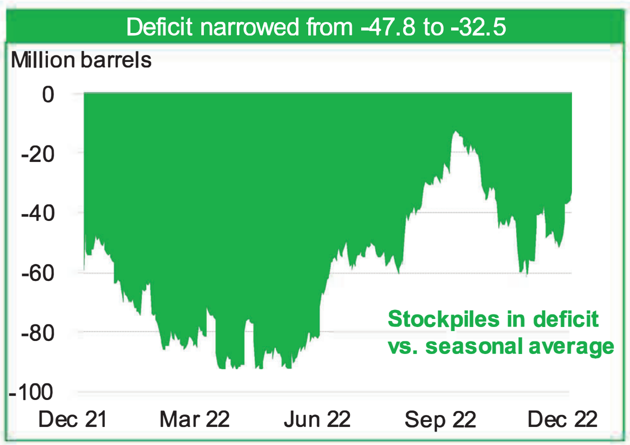
Land storage: West of Suez

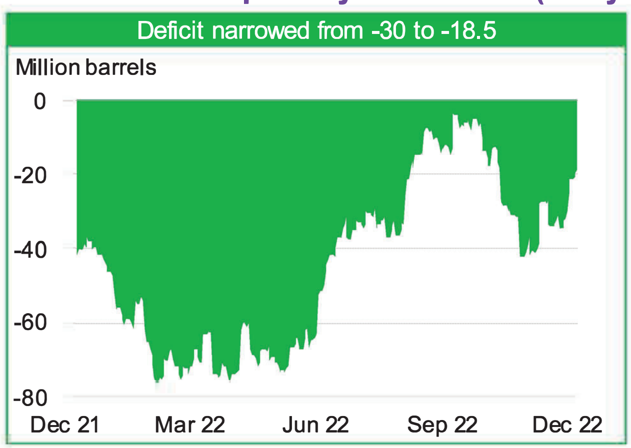


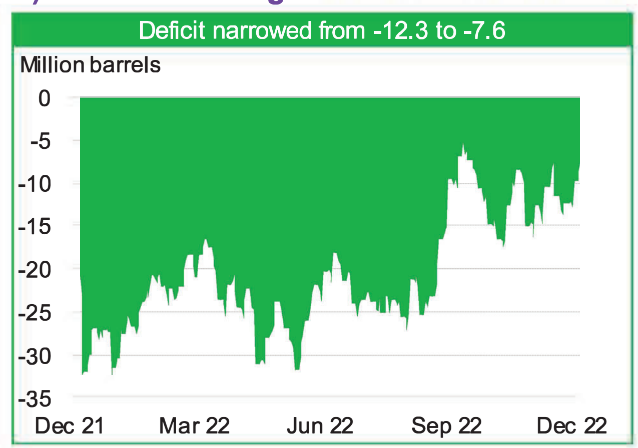
Land storage: East of Suez



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







*Source: BloombergNEF, US EIA, Genscape, PAJ. Note: As of the **week ending December 30, 2022.***

Fundamentals Financial

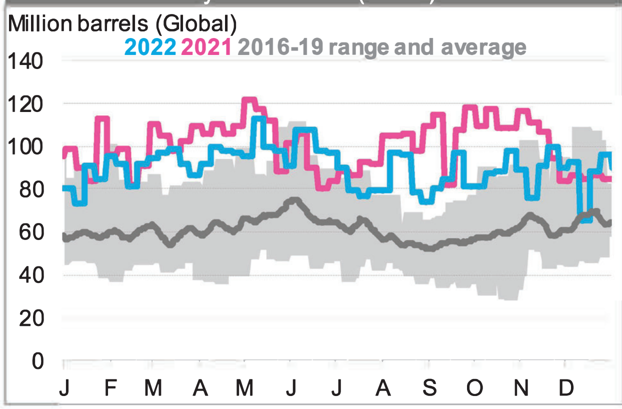
Crude stocks: Floating

Neutral: Stockpile surplus widened from 31.8m bbl to 32.1m 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 (ie, the week before the latest data shown below).

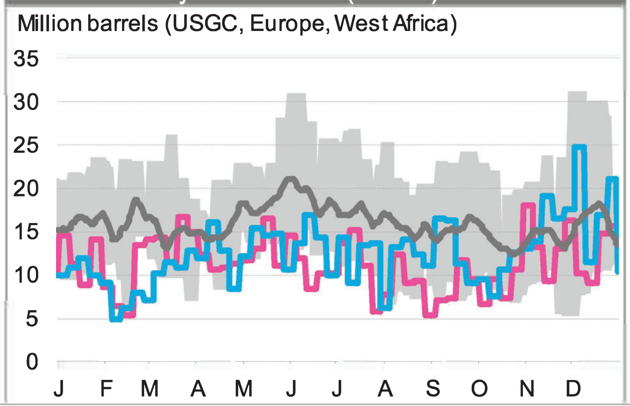
Floating storage: Total

Weekly draw of -6.2 (-6.5%) to 90



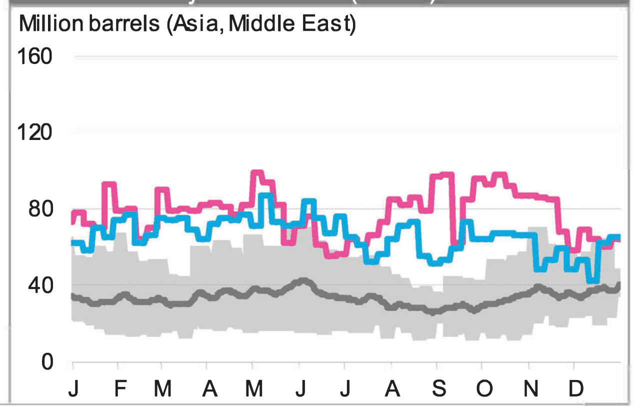
Floating storage: West of Suez

Weekly draw of -10.6 (-50.3%) to 10.4



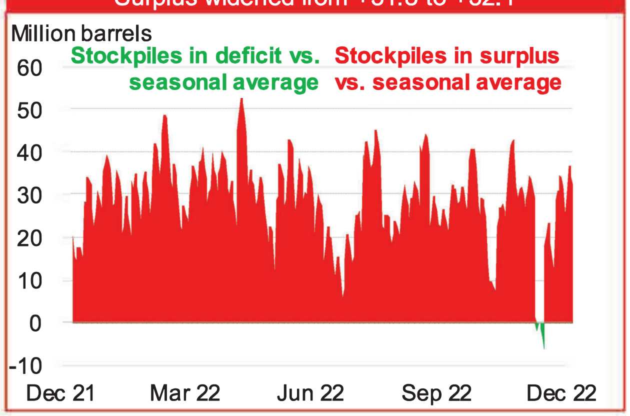
Floating storage: East of Suez

Weekly build of +0.3 (+0.4%) to 64.8

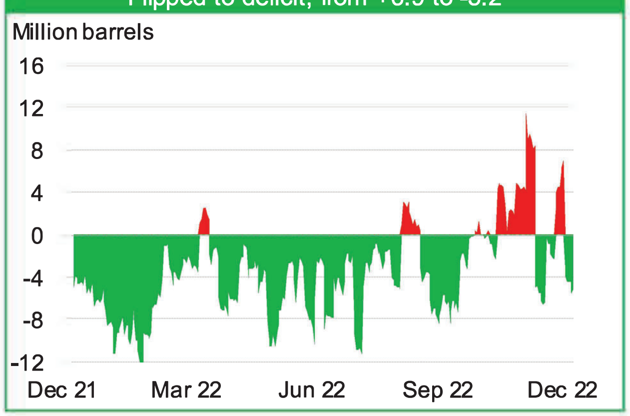


Charts below subtract current stockpiles by the 2016-19 (four-year) seasonal average

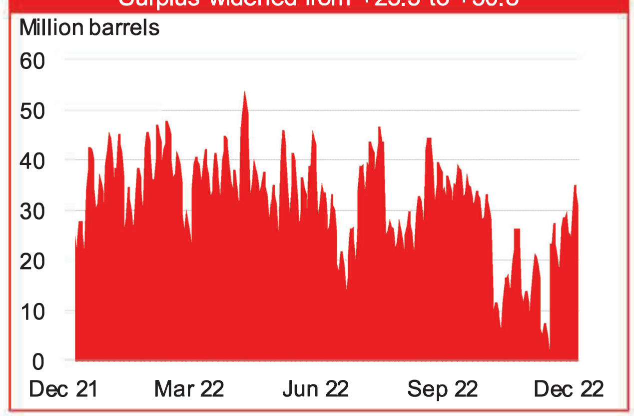
Surplus widened from +31.8 to +32.1



Flipped to deficit, from +6.9 to -5.2



Surplus widened from +25.5 to +30.8



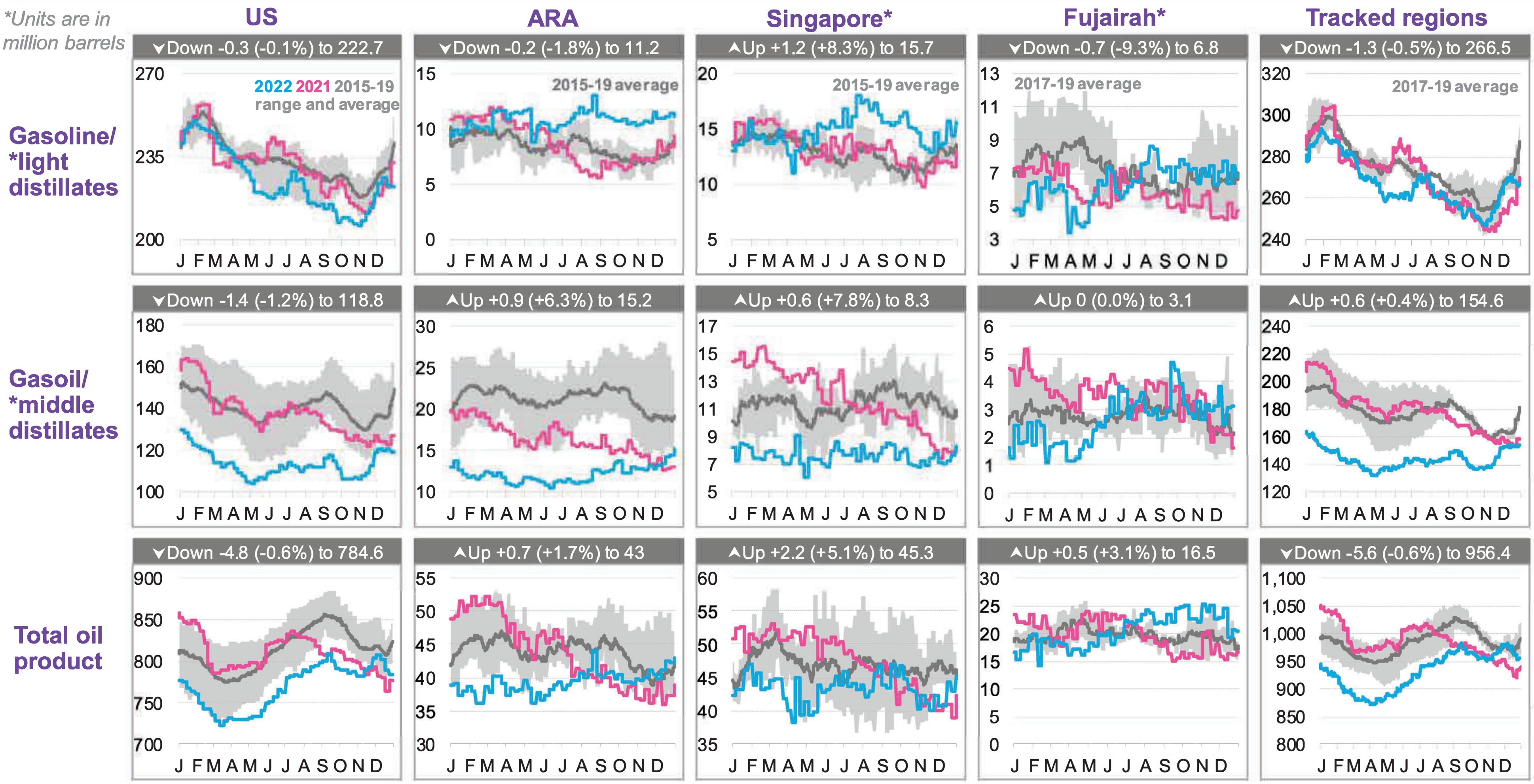
Source: BloombergNEF, Vortexa. Note: As of the ***week ending January 6, 2023****. *Data from Vortexa are revised frequently, so the data in this report might change week-to-week.*

Fundamentals | Financial

Product stocks: Current versus seasonal average

Bullish: Oil product stockpiles in tracked regions fell by 0.6% over the past week

- Chart legend are as follows: 2022, 2021 and the 2015-19 range and average. For Fujairah and tracked regions, the **2017-19 (three-year) seasonal range** is shown. Tracked regions include US, ARA, Singapore, Japan and Fujairah

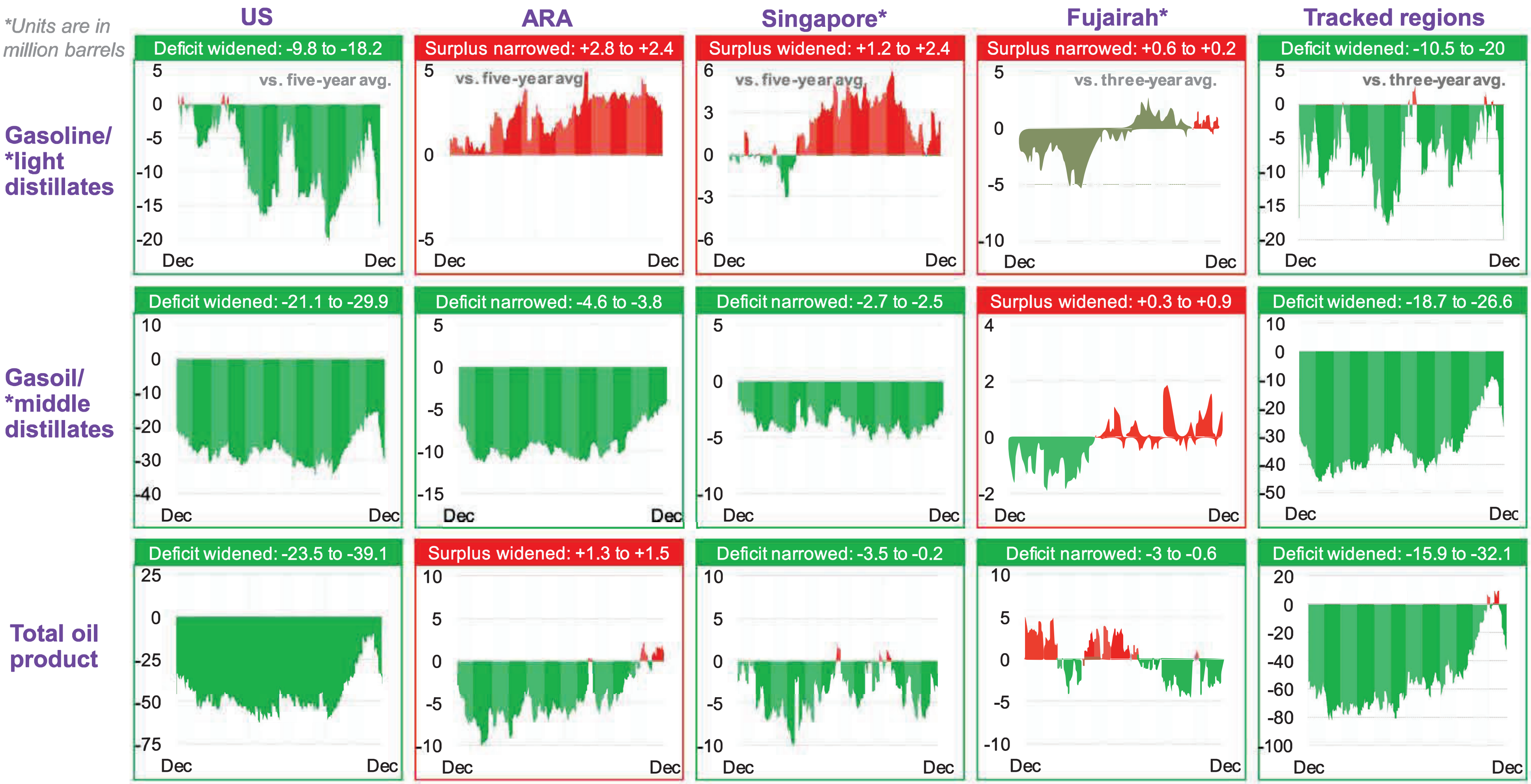


Source: BloombergNEF, US EIA, PJK, IE Singapore, FEDCom/Platts, PAJ. Note: As of the ***week ending December 30, 2022.***

Product stocks: Current versus seasonal average

Bullish: Oil product stockpile deficit widened from 15.9m bbl to 32.1m bbl

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



Source: BloombergNEF, US EIA, PJK, IE Singapore, FEDCom/Platts, PAJ. Note: As of the ***week ending December 30, 2022.***

Jan 13, 2023 06:14:08

OIL DEMAND MONITOR: China Stirs as Curbs Ditched; India Climbing

Global outlook remains unclear as economy faces headwinds
US demand trajectory clouded by impact of December big freeze

By John Deane

(Bloomberg) -- China's Covid upsurge is a wildcard that complicates the process of charting a precise course for global oil demand in the coming year – but there are early signals that consumption may be set to pick up.

The world's biggest oil importer has seen road traffic levels rise, with congestion intensifying across a range of the nation's biggest cities, according to calculations by BloombergNEF based on Baidu data. And a jump in demand for jet fuel looks on the cards as citizens make the most of the recent relaxation of travel curbs and embark on Lunar New Year celebrations.

Combined domestic and international airline seat capacity for Northeast Asia – which includes China – now trails the equivalent period of 2019 by only 7.6%, according to OAG data. That compares with more than 30% in early November.

"With restrictions in China being eased, capacity data for Northeast Asia shows a 10.2% jump week-over-week," the travel data provider said in its latest report. Still, a tendency to cut schedule flights at short notice and logistical issues may constrain the pace of aviation's recovery in the short-term.

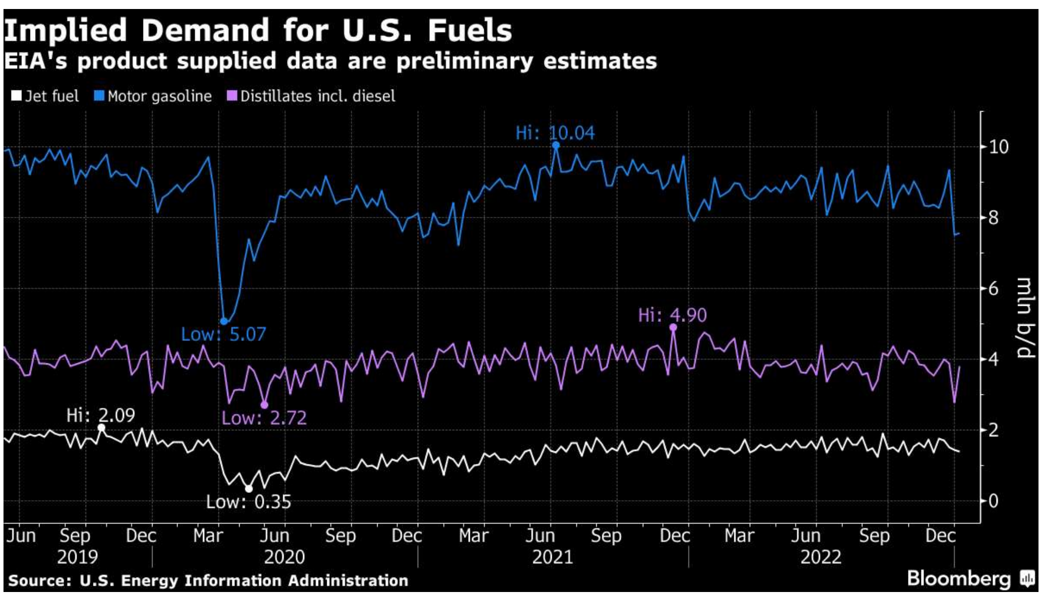
Read More: Covid Pivot Sets Up China Oil Demand for Record This Year

Elsewhere, fuel consumption in India jumped to a multimonth high in December, with demand for diesel and gasoline higher on both a month-on-month and year-on-year basis, according to preliminary data.

Still, among 13 major world cities regularly tracked each Monday morning in this monitor only four – London, Rome, Paris and Berlin – showed congestion above typical 2019 levels, according to data from navigation technology company TomTom NV.

Against a backdrop of stuttering global economic activity, China by itself "will struggle to propel oil prices back into triple digits," PVM Oil Associates analyst Stephen Brennock said in a note. "The prospect of a price rally over the coming months hinges on more than China's reopening, a fact that those who have put all their eggs in the Chinese basket would do well to appreciate."

In the US, weekly Energy Information Administration weekly data was again skewed by the impact of last month's freezing weather, though the report showed a rebound in refinery utilization rates as fuelmakers restarted, following the cold spell. Runs should continue to rise as more refineries come back online.



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	-4.4	+0.3	-7.1	-13	-8.4	w	Jan. 6	7.56m b/d	EIA
Distillates product supplied	US	+1.9	+5.9	+13	+29	+1.4	w	Jan. 6	3.82m b/d	EIA
Jet fuel product supplied	US	-12	-4.2	-13	-22	-20	w	Jan. 6	1.41m b/d	EIA
Total oil products supplied	US	-15	-10	-9	-11	-12	w	Jan. 6	17.63m 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		+7.5	+41	-26	-23	m	Week to Jan. 1	5,338 liters/d	BEIS
Diesel avg sales per station	UK		-0.3	+14	-50	-43	m	Week to Jan. 1	5,243 liters/d	BEIS
Total road fuels sales per station	UK		+3.5	+27	-40	-35	m	Week to Jan. 1	10,581 liters/d	BEIS
Total Products	India		+3.1			+4	m	December	19.6m tons	PPAC (prelim.)
Gasoline	India		+5.9			+4.3	m	December	2.98m tons	PPAC
Diesel	India		+6.5			+0.2	m	December	7.78m tons	PPAC
LPG	India		+3.9			+4.4	m	December	2.58m tons	PPAC
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		-1.2			-3.2	m	November	4.04m m3	UFIP
Gasoline	France		+8				m	November	n/a	UFIP
Road diesel	France		-4.2				m	November	n/a	UFIP
Jet fuel	France		+21		-13	-13	m	November	550k m3	UFIP
All petroleum products	France		-0.8			-4.6	m	November	4.526m 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		+6.2	+26	+4.4	-6.9	m	November	85.7k tons	ENSE
Diesel	Portugal		-2	+5.9	-4.1	-3.8	m	November	393.9k tons	ENSE
Jet fuel	Portugal		+9	+201	+2.9	-20	m	November	114.9k 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	Jan 9	Jan 2	Dec 26	Dec 19	Dec 12	Dec 5	Nov 28	Nov 21	Nov 14	Nov 7	Oct 31	Oct 24
		(for Jan. 9)							Congestion mins added to 1 hr trip at 8am* local time						
Congestion	Tokyo	-76	-76	9	6	38	38	38	41	37	47	37	37	34	39
Congestion	Taipei	-3	-26	34	5	35	35	46	37	37	34	34	35	45	35
Congestion	Jakarta	-9	+16	35	11	10	19	31	34	34	31	33	40	35	36
Congestion	Mumbai	-54	+6	22	18	10	17	21	22	20	23	23	19	21	2
Congestion	New York	-13	-17	27	1	1	26	32	30	30	32	33	35	26	37
Congestion	Los Angeles	-5	-2	34	2	2	19	34	33	28	21	36	35	29	35
Congestion	London	+16	+7	44	1	1	20	41	40	47	40	45	57	38	22
Congestion	Rome	+33	+24	65	7	0	50	52	48	47	49	50	58	8	51
Congestion	Madrid	-37	-45	22	3	1	29	40	8	28	26	29	26	2	35
Congestion	Paris	+9	+1	49	14	7	30	48	58	49	51	49	49	8	33
Congestion	Berlin	+5	+18	35	10	1	22	30	32	27	35	30	31	19	26
Congestion	Mexico City	-32	+133	34	5	4	17	14	37	35	0	29	45	34	40
Congestion	Sao Paulo	-60	-47	17	6	7	22	33	30	22	35	10	34	40	33

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

* 9am statistics are used for Mumbai. All other cities use 8am

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 Jan. 9 vs Dec. 12. Holidays in many parts of the world on Dec. 26 and Jan. 2 depressed traffic volumes on those days

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	+8.3	+28	-1.8	+6.5	-0.2	+14	d	Jan. 10	176,102	Flightradar24
Commercial flights	Worldwide	+17	+52	-7.6	-1.8	+2.6	+2.1	d	Jan. 10	104,481	Flightradar24
Seat capacity per week	Worldwide	+23	+74	-10	-7.2		-1	w	Jan. 9 week	95.9m seats	OAG
Air traffic (flights)	Europe				-13	-6.6	-8.6	d	Jan. 10	20,835	Eurocontrol
Air passenger traffic per month	China		-41	-72	-76	-21		m	November 2022	12.6m	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	-5.9%	unch	-17%	-9.1%	Jan. 6	14.65m b/d	EIA
Utilization	US	-4.3	+2.1	-12	-8.1	Jan. 6	84.1%	EIA
Utilization	US Gulf	-5.4	+1.4	-13	-10	Jan. 6	84.3%	EIA
Utilization	US East	+2	+22	+1.1	-2.4	Jan. 6	89%	EIA
Utilization	US Midwest	-8.5	-2.7	-12	-6.7	Jan. 6	84.8%	EIA
Utilization (indep. refs)	Shandong, China	-2.1	-14	-0.1	-4	Jan. 13	63.3 %	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.

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--With assistance from Julian Lee, Stephen Voss and Debjit Chakraborty.

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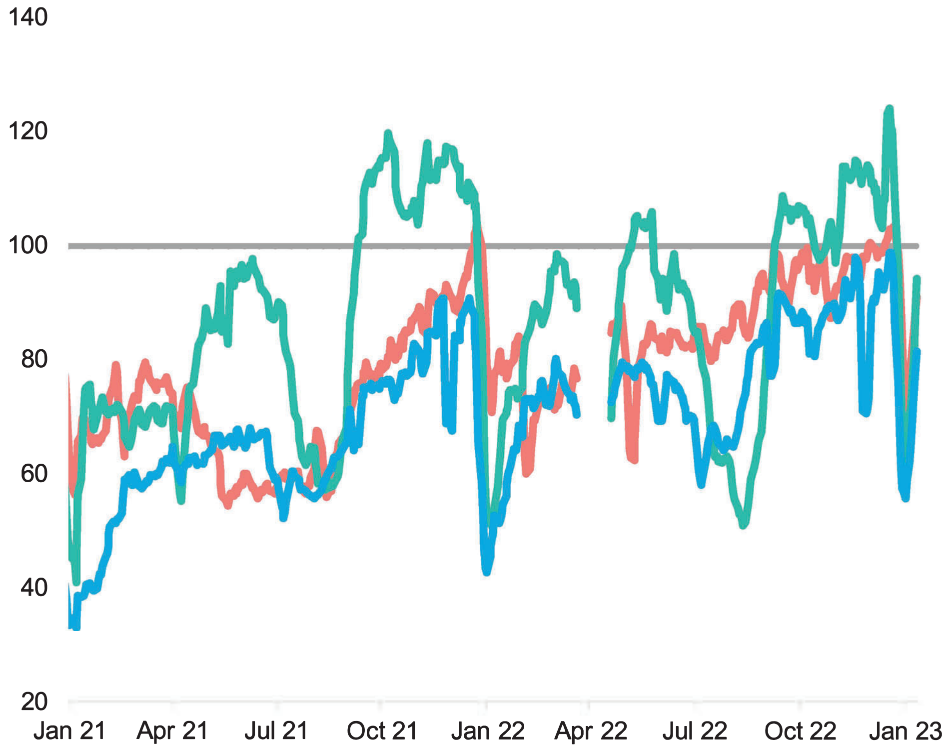
TomTom Baidu

Comparing the two mobility indicators

Traffic levels rebound across the world as holiday season ends

TomTom congestion index

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

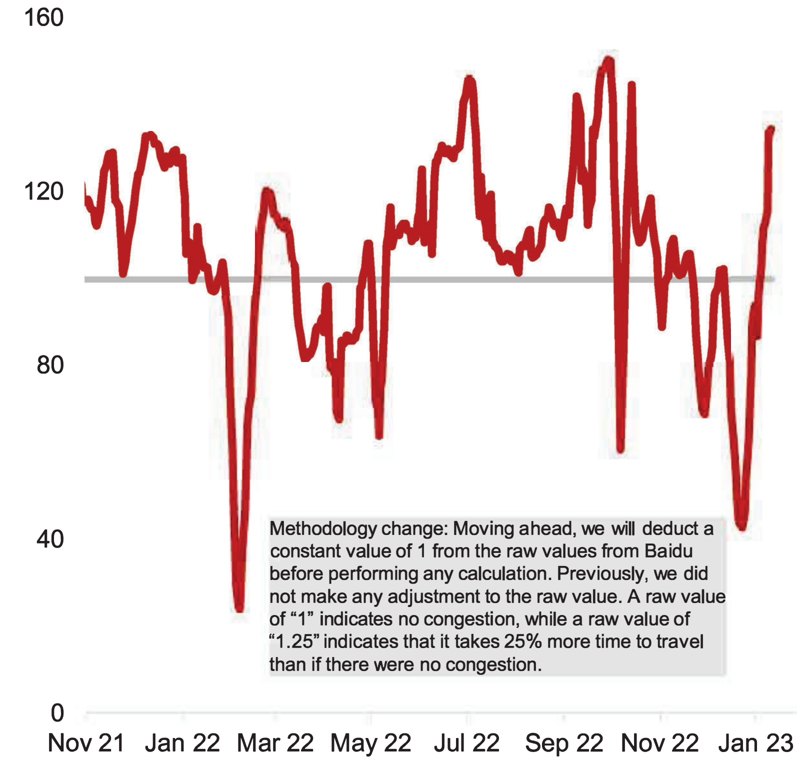


	Latest	Week Δ	Four-week Δ
Europe	**94.3**	27.2 (+40.6%)	-14.7 (-13.5%)
Asia Pacific	**90.9**	18.1 (+24.8%)	-10.1 (-10.0%)
North America	**81.4**	20.9 (+34.5%)	-15.1 (-15.7%)

*Source: TomTom road congestion data, BloombergNEF. Note: **Asia Pacific excludes China. Data updated to January 11, 2023.** Δ = change.*

China-15 (Baidu) congestion index

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



	Latest	Week Δ	Four-week Δ
China-15	**134.38**	32.02 (+31.28%)	47.49 (+54.65%)

*Source: BloombergNEF, calculated from Baidu data. Note: Data updated to **January 11, 2023**. Δ = change.*

TomTom Baidu

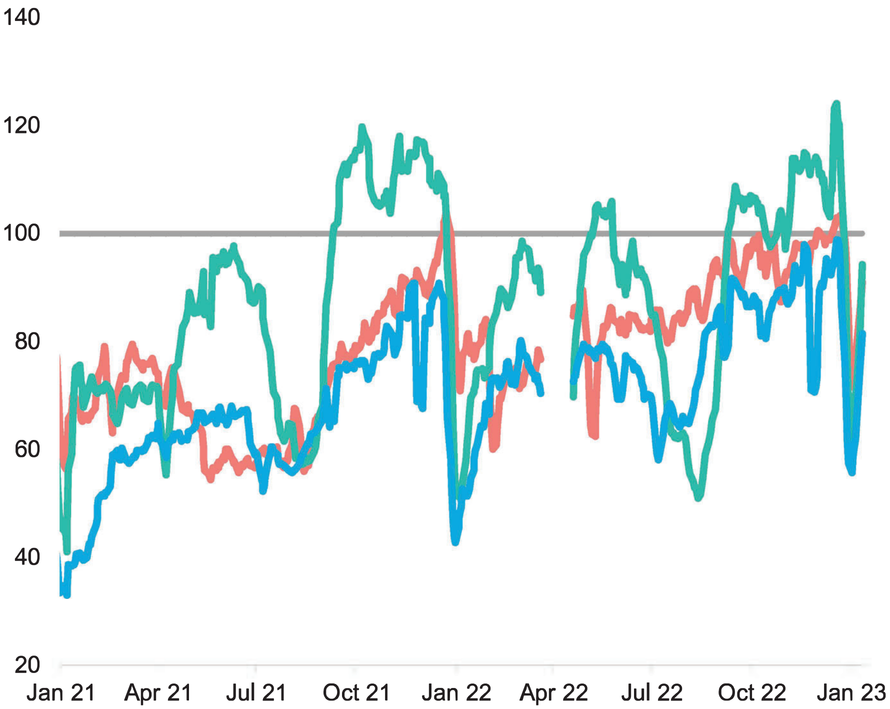
Apple Mobility reports were discontinued on April 14, 2022. We have resumed updating TomTom congestion data, which was previously updated to March 16.

TomTom congestion index

Traffic ramps up but remains below 2019 levels

Regional road-congestion index

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



	Latest	Week Δ	Four-week Δ
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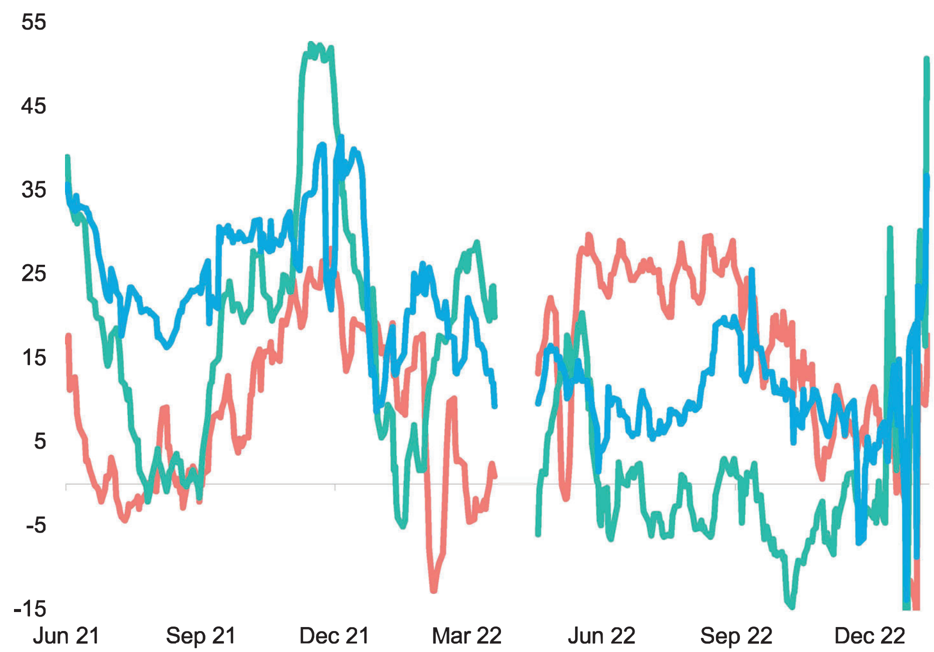
North America	**81.4**	20.9 (+34.5%)	-15.1 (-15.7%)

Index point change versus the previous year

Percentage point change vs the year before (seven-day moving average)



Index point Δ vs year before	Index point Δ vs year before (last week)
+36.89	+14.32
+12.60	-3.86
+29.89	+14.89

*Source: TomTom Traffic Index, BloombergNEF. Note: **Asia Pacific excludes China. Data updated to January 11, 2023,** with weekly addition from December 21, 2022. Index point change versus the previous year is obtained by averaging the latest weekly values. Δ = change.*

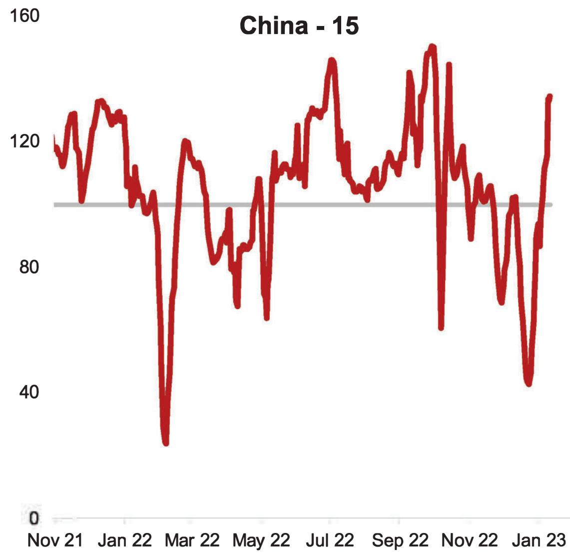
BloombergNEF

China (Baidu) congestion index

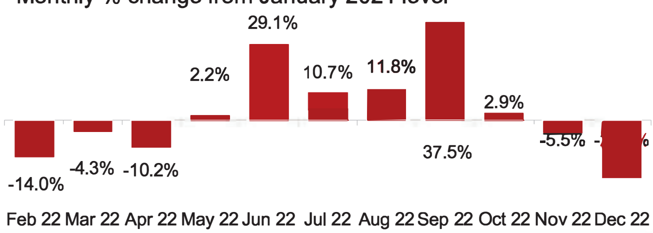
Major urban hubs see record surge in congestion levels

China congestion index (calculated from Baidu data)

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



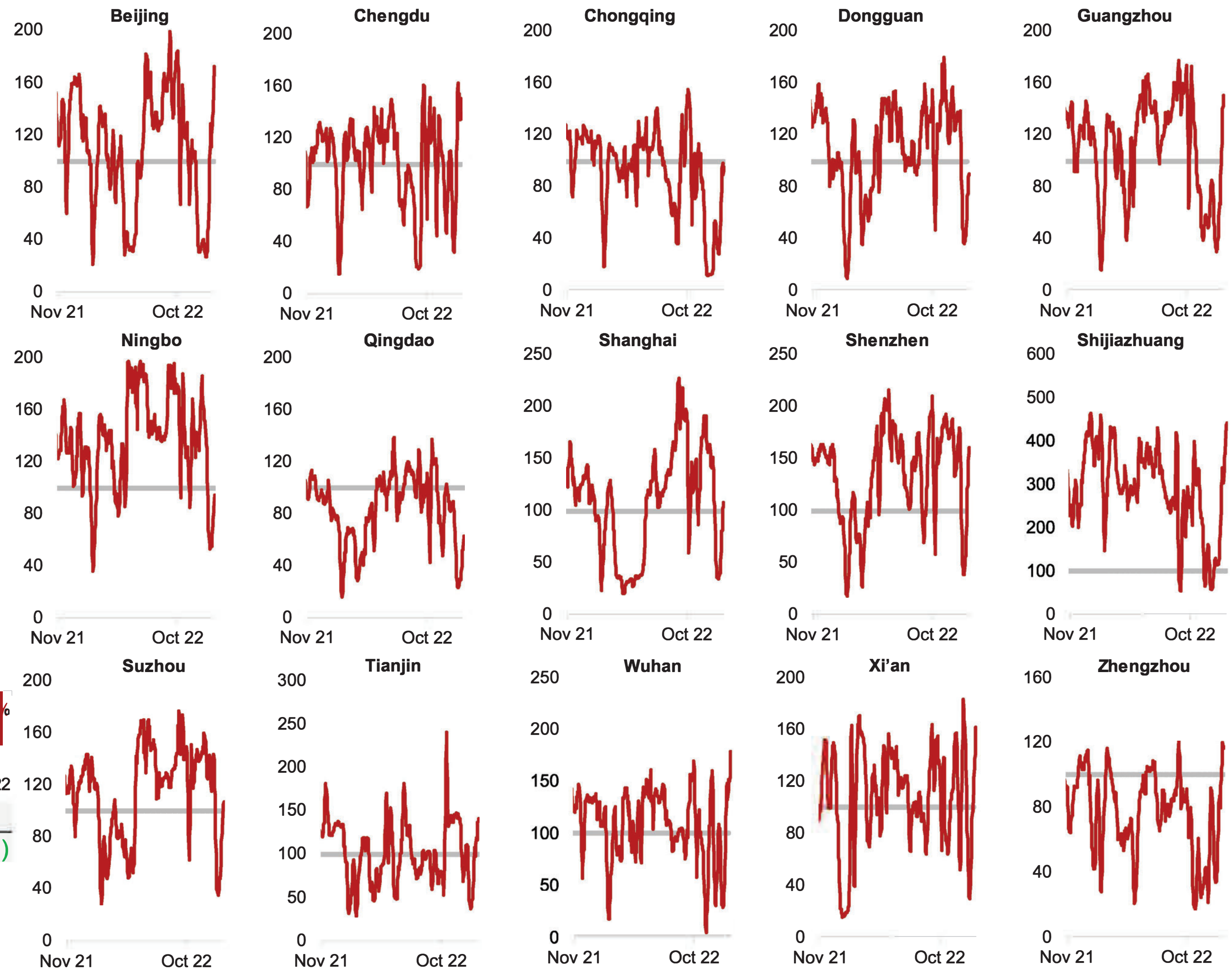
Monthly % change from January 2021 level



	Latest	Week Δ	Four-week Δ
China - 15	134.38	32.02 (+31.28%)	47.49 (+54.65%)

Road traffic in China in the week ending January 11 was up 32.02 percentage points to 134.38 of January 2021 levels.

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



Source: BloombergNEF, calculated from Baidu's data. Note: ***Data updated to January 11, 2023****. City-level charts display the 15 cities with the highest number of vehicle registrations (excluding two- and three-wheelers). The China-15 congestion level is calculated by taking the weighted average of the congestion levels in the 15 cities and their vehicle registration numbers. Δ = change.*

TomTom | Baidu

China’s city-level data (Baidu)

- China’s city-level congestion data is shown below. Data is available in the accompanying Excel sheet.
- Congestion levels are compared against January 2021 levels. An index value below 100 indicates a decrease from January 2021 levels.
- Sparklines reflect the weekly congestion indices dating back to August 2021.

		January 2021 = 100	Weekly point Δ	Weekly percent Δ
Baoding	保定	148.15	23.86	19.20%
Beijing	北京	172.16	44.09	34.43%
Cangzhou	沧州	127.78	25.50	24.93%
Changchun	长春	144.43	46.23	47.08%
Changsha	长沙	98.89	30.60	44.81%
Changzhou	常州	111.07	18.36	19.81%
Chengdu	成都	135.00	-19.11	-12.40%
Chongqing	重庆	121.71	26.76	28.18%
Dali	大理	120.14	32.33	36.83%
Dalian	大连	152.47	56.96	59.63%
Datong	大同	103.87	22.43	27.54%
Dezhou	德州	75.14	8.22	12.28%
Dongguan	东莞	89.65	32.65	57.29%
Foshan	佛山	83.08	26.23	46.14%
Fuzhou	福州	108.60	54.76	101.71%
Ganzhou	赣州	127.93	19.61	18.10%
Guangzhou	广州	150.31	61.52	69.28%
Guilin	桂林	72.07	12.14	20.25%
Guiyang	贵阳	50.75	11.44	29.09%
Haikou	海口	68.08	34.21	101.01%
Handan	邯郸	151.92	32.60	27.32%
Hangzhou	杭州	121.91	43.60	55.68%
Harbin	哈尔滨	121.14	13.74	12.80%
Hefei	合肥	86.97	19.55	28.99%
Hengshui	衡水	76.95	18.12	30.80%
Hengyang	衡阳	86.71	13.83	18.98%
Huai'an	淮安	102.60	31.28	43.87%
Huhhot	呼和浩特	102.91	26.67	34.99%
Huizhou	惠州	88.25	29.91	51.27%
Huzhou	湖州	79.78	28.07	54.28%
Jiangmen	江门	101.93	36.94	56.83%
Jiaxing	嘉兴	48.13	8.99	22.95%
Jinan	济南	103.98	36.60	54.31%
Jinhua	金华	97.38	12.58	14.84%
Jining	济宁	84.13	25.83	44.31%

		January 2021 = 100	Weekly point Δ	Weekly percent Δ
Kunming	昆明	85.39	2.16	2.59%
Langfang	廊坊	110.93	11.22	11.25%
Lanzhou	兰州	173.60	40.90	30.82%
Lasa	拉萨	129.53	11.65	9.89%
Leshan	乐山	71.67	-0.79	-1.10%
Lianyungang	连云港	82.77	27.47	49.67%
Linyi	临沂	79.33	32.96	71.08%
Liuzhou	柳州	71.58	11.67	19.49%
Luoyang	洛阳	113.77	12.10	11.90%
Maoming	茂名	79.97	27.99	53.84%
Mianyang	绵阳	90.81	14.17	18.49%
Nanchang	南昌	82.88	9.17	12.43%
Nanchong	南充	125.16	7.35	6.24%
Nanjing	南京	115.30	40.27	53.67%
Nanning	南宁	102.11	22.02	27.49%
Nantong	南通	99.07	42.32	74.56%
Nanyang	南阳	117.68	27.76	30.87%
Ningbo	宁波	92.42	20.58	28.64%
Qingdao	青岛	63.21	23.51	59.21%
Qingyuan	清远	98.93	39.20	65.63%
Qinhuangdao	秦皇岛	127.99	29.58	30.06%
Quanzhou	泉州	50.38	12.53	33.10%
Sanya	三亚	133.88	39.82	42.33%
Shanghai	上海	107.58	47.27	78.37%
Shantou	汕头	63.40	18.12	40.03%
Shaoguan	韶关	74.78	14.53	24.12%
Shaoxing	绍兴	37.54	-1.21	-3.14%
Shenyang	沈阳	180.18	62.04	52.52%
Shenzhen	深圳	161.04	72.48	81.85%
Shijiazhuang	石家庄	440.94	88.17	24.99%
Suzhou	苏州	106.61	37.43	54.10%
Tai'an	泰安	91.49	17.43	23.53%
Taiyuan	太原	151.32	45.30	42.73%
Taizhou	台州	75.00	15.50	26.05%
Tangshan	唐山	124.34	15.28	14.01%

		January 2021 = 100	Weekly point Δ	Weekly percent Δ
Tianjin	天津	140.47	30.14	27.32%
Urumqi	乌鲁木齐	118.22	32.71	38.25%
Weifang	潍坊	80.43	17.66	28.13%
Wenzhou	温州	68.08	11.12	19.53%
Wuhan	武汉	177.93	31.85	21.80%
Wuxi	无锡	108.00	40.51	60.02%
Xiamen	厦门	73.67	26.03	54.64%
Xi'an	西安	158.14	34.72	28.13%
Xianyang	咸阳	148.26	97.06	189.59%
Xingtai	邢台	191.57	8.02	4.37%
Xining	西宁	103.28	21.18	25.80%
Xinxiang	新乡	101.41	3.79	3.89%
Xuzhou	徐州	59.53	13.71	29.93%
Yancheng	盐城	90.72	31.36	52.83%
Yangquan	阳泉	123.16	23.46	23.52%
Yangzhou	扬州	60.34	21.15	53.96%
Yantai	烟台	77.87	30.04	62.83%
Yibin	宜宾	106.45	33.81	46.54%
Yinchuan	银川	88.33	21.92	33.00%
Yunfu	云浮	66.49	22.36	50.65%
Zhangjiakou	张家口	127.88	16.28	14.59%
Zhangzhou	漳州	81.96	17.71	27.57%
Zhanjiang	湛江	103.80	51.72	99.32%
Zhaoqing	肇庆	102.36	38.57	60.45%
Zhengzhou	郑州	117.26	23.87	25.56%
Zhenjiang	镇江	37.55	14.39	62.13%
Zhongshan	中山	126.62	11.69	10.18%
Zhuhai	珠海	91.56	39.56	76.06%
Zibo	淄博	65.02	18.38	39.41%

Source: BloombergNEF, calculated from Baidu data. Note: ***Data updated to January 11, 2023.*** *Δ = change.*

https://www.iata.org/en/pressroom/2023-releases/2023-01-09-02/

Press Release No: 65

Date: 9 January 2023

Passenger Recovery Continues in November

Geneva - The International Air Transport Association (IATA) announced that the air travel recovery continued through November 2022.

Total traffic in November 2022 (measured in revenue passenger kilometers or RPKs) rose 41.3% compared to November 2021. Globally, traffic is now at 75.3% of November 2019 levels.
International traffic rose 85.2% versus November 2021. The Asia-Pacific continued to report the strongest year-over-year results with all regions showing improvement compared to the prior year. November 2022 international RPKs reached 73.7% of November 2019 levels.
Domestic traffic for November 2022 was up 3.4% compared to November 2021 with travel restrictions in China continuing to dampen the global result. Total November 2022 domestic traffic was at 77.7% of the November 2019 level.

"Traffic results in November reinforce that consumers are thoroughly enjoying the freedom to travel. Unfortunately, the reactions to China's reopening of international travel in January reminds us that many governments are still playing science politics when it comes to COVID-19 and travel. Epidemiologists, the European Centre for Disease Prevention and Control and others have said that the reintroduction of testing for travelers from China can do little to contain a virus that is already present around the world. And China's objections to these policy measures are compromised by their own pre-departure testing requirements for people traveling to China. Governments should focus on using available tools to manage COVID-19 effectively—including improved therapeutics and vaccinations—rather than repeating policies that have failed time and again over the last three years," said Willie Walsh, IATA's Director General.

AIR PASSENGER MARKET DETAIL- NOVEMBER 2022	WORLD SHARE[1]	RPK	ASK	PLF(%-PT)[2]	PLF (LEVEL)[3]
Total Market	**100%**	**41.3%**	**23.8%**	**10.0%**	**80.8%**
Africa	1.9%	84.5%	51.7%	13.3%	74.8%
Asia Pacific	27.5%	68.4%	31.3%	17.0%	77.0%
Europe	25.0%	37.0%	19.6%	10.6%	83.8%
Latin America	6.5%	27.8%	27.6%	0.2%	82.0%
Middle East	6.6%	77.9%	41.3%	15.9%	77.5%
North America	32.6%	19.6%	13.3%	4.4%	83.2%

1) % of industry RPKs in 2021 2) Year-on-year change in load factor 3) Load Factor Level

International Passenger Markets

Asia-Pacific airlines had a 373.9% rise in November traffic compared to November 2021, which was the strongest year-over-year rate among the regions. Capacity rose 159.2% and the load factor was up 35.9 percentage points to 79.2%.

European carriers' November traffic climbed 45.3% versus November 2021. Capacity increased 25.1%, and load factor moved up 11.6 percentage points to 83.6%, highest among the regions.

Middle Eastern airlines saw an 84.6% traffic rise in November compared to November 2021. November capacity increased 45.4% versus the year-ago period, and load factor climbed 16.5 percentage points to 77.7%.

North American carriers experienced a 69.9% traffic rise in November versus the 2021 period. Capacity increased 45.5%, and load factor climbed 11.6 percentage points to 81.0%.

Latin American airlines' November traffic rose 59.2% compared to the same month in 2021. November capacity climbed 55.6% and load factor increased 1.9 percentage points to 82.9%.

African airlines had an 83.5% rise in November RPKs versus a year ago. November 2022 capacity was up 48.4% and load factor climbed 14.2 percentage points to 74.3%, the lowest among regions.

Domestic Passenger Markets

NOVEMBER 2022 (% YEAR-ON-YEAR)	WORLD SHARE[1]	RPK	ASK	PLF (%-PT)[2]	PLF (LEVEL)[3]
Domestic	62.3%	3.4%	-3.1%	5.1%	80.7%
Domestic Australia	0.8%	190.0%	90.5%	29.0%	84.4%
Domestic Brazil	1.9%	5.1%	7.0%	-1.4%	80.9%
Domestic China P.R.	17.8%	-38.8%	-41.6%	-2.9%	64.0%
Domestic India	2.1%	11.1%	0.5%	8.4%	87.9%
Domestic Japan	1.1%	37.3%	17.7%	10.8%	75.5%
Domestic US	25.6%	5.0%	2.2%	2.3%	84.0%

1) % of industry RPKs in 2021 2) Year-on-year change in load factor 3) Load Factor Level

Brazil's domestic RPKs rose 5.1% in November compared to November 2021 and are now at 96.2% of 2019 levels.

US domestic traffic climbed 5.0% in November compared to November 2021, pushing it to 99% of the November 2019 level.

NOVEMBER 2022(% CH VS THE SAME MONTH IN 2019)	WORLD SHARE[1]	RPK	ASK	PLF (%-PT)[2]	PLF (LEVEL)[3]
TOTAL MARKET	**100.0%**	**-24.7%**	**-24.6%**	**-0.1%**	**80.8%**
International	37.7%	-26.3%	-28.9%	0.7%	80.9%
Domestic	62.3%	-22.3%	-20.8%	-1.5%	80.7%

1) % of industry RPKs in 2021 2) Change in load factor vs same month in 2019 3) Load Factor Level

https://www.iata.org/en/pressroom/2023-releases/2023-01-09-01/

Date: 9 January 2023

Air Cargo Demand Softens in November

Geneva - The International Air Transport Association (IATA) released data for November 2022 global air cargo markets showing that demand softened as economic headwinds persist.

Global demand, measured in cargo tonne-kilometers (CTKs*), fell 13.7% compared to November 2021 (-14.2% for international operations).

Capacity (measured in available cargo tonne-kilometers, ACTK) was 1.9% below November 2021. This was the second year-on-year contraction following the first last month (in October) since April 2022. International cargo capacity decreased 0.1% compared to November 2021.

Compared to pre-COVID-19 levels (November 2019), there was a smaller contraction in overall demand (-10.1%), while capacity was down 8.8%.

Several factors in the operating environment should be noted:

- Global new export orders, a leading indicator of cargo demand, were stable in October. For major economies, new export orders are shrinking except in Germany, the US, and South Korea, where they grew.
- Global goods trade expanded by 3.3% in October. Given the softening in air cargo demand, this suggests that maritime cargo was the primary beneficiary.
- The US dollar has appreciated sharply, adding cost pressure as many costs are denominated in US dollars. This includes jet fuel, which is already at elevated levels.
- The Consumer Price Index for G7 countries decreased from 7.8% in October to 7.4% in November, the largest month-on-month decline in 2022. Inflation in producer (input) prices reduced to 12.7% in November, its lowest level so far in 2022.

"Air cargo performance softened in November, the traditional peak season. Resilience in the face of economic uncertainties is demonstrated with demand being relatively stable on a month-to-month basis. But market signals are mixed. November presented several indicators with upside potential: oil prices stabilized, inflation slowed and there was a slight expansion in goods traded globally. But shrinking export orders globally and China's rising COVID cases are cause for careful monitoring," said Willie Walsh, IATA's Director General.

AIR CARGO MARKET IN DETAIL - NOVEMBER 2022	WORLD SHARE[1]	CTK	ACTK	CLF(%-PT)[2]	CLF(LEVEL)[3]
Total Market	***100.0%***	**-13.7%**	**-1.9%**	**-6.7%**	**49.1%**
Africa	*1.9%*	-6.3%	-11.4%	2.5%	45.8%
Asia Pacific	*32.6%*	-18.6%	-4.5%	-9.5%	54.5%
Europe	*22.8%*	-16.5%	-6.6%	-6.8%	56.9%
Latin America	*2.2%*	2.8%	19.9%	-6.4%	38.2%
Middle East	*13.4%*	-14.7%	2.1%	-9.3%	47.5%
North America	27.2%	-6.6%	0.3%	-3.1%	41.9%

1) % of industry CTKs in 2021 2) Year-on-year change in load factor 3) Load Factor Level

November Regional Performance

Asia-Pacific airlines saw their air cargo volumes decrease by 18.6% in November 2022 compared to the same month in 2021. This was the worst performance of all regions and a decline in performance compared to October (-14.7%). Airlines in the region continue to be impacted by lower levels of trade and manufacturing activity and disruptions in supply chains due to China's rising COVID cases. Available capacity in the region decreased by 4.5% compared to 2021.

North American carriers posted a 6.6% decrease in cargo volumes in November 2022 compared to the same month in 2021. This was an improvement in performance compared to October (-8.6%). Capacity increased 0.3% compared to November 2021.

European carriers saw a 16.5% decrease in cargo volumes in November 2022 compared to the same month in 2021. This was an improvement in performance compared to October (-18.8%), thanks to the stronger new export orders in Germany. Airlines in the region continue to be most affected by the war in Ukraine. High inflation levels, most notably in Türkiye, also affected volumes. Capacity decreased 6.6% in November 2022 compared to November 2021.

Middle Eastern carriers experienced a 14.7% year-on-year decrease in cargo volumes in November 2022. This was a marginal improvement to the previous month (-15.0%). Cargo volumes to/from Europe impacted the region's performance, registering a 16.3% year-on-year decline in November. Capacity increased 2.1% compared to November 2021.

Latin American carriers reported a 2.8% increase in cargo volumes in November 2022 compared to November 2021. This was the strongest performance of all regions, and a significant improvement in performance compared to October (-1.4%). Capacity in November was up 2.8% compared to the same month in 2021.

African airlines saw cargo volumes decrease by 6.3% in November 2022 compared to November 2021. This was an improvement in performance compared to the previous month (-8.3%). Capacity was 11.4% below November 2021 levels.

> View November Air Cargo Market Analysis (pdf)

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Notes for Editors:

- * Please note that as of January 2020 onwards, we have clarified the terminology of the Industry and Regional series from 'Freight' to 'Cargo', the corresponding metrics being FTK (changed to 'CTK'), AFTK (changed to 'ACTK'), and FLF (changed to 'CLF'), in order to reflect that the series have been consisting of Cargo (Freight plus Mail) rather than Freight only. The data series themselves have not been changed.

- IATA (International Air Transport Association) represents some 300 airlines comprising 83% of global air traffic.
- You can follow us at twitter.com/iata for announcements, policy positions, and other useful industry information.

- Explanation of measurement terms:
  - CTK: cargo tonne-kilometers measures actual cargo traffic
  - ACTK: available cargo tonne-kilometers measures available total cargo capacity
  - CLF: cargo load factor is % of ACTKs used

- IATA statistics cover international and domestic scheduled air cargo for IATA member and non-member airlines.
- Total cargo traffic market share by region of carriers in terms of CTK is: Asia-Pacific 32.6%, Europe 22.8%, North America 27.2%, Middle East 13.4%, Latin America 2.2%, and Africa 1.9%.

https://www.gov.scot/news/delivering-a-fair-and-secure-zero-carbon-energy-system/

News

Delivering a fair and secure zero carbon energy system

Published **10 January 2023 16:15**

Energy, Business, industry and innovation, Environment and climate change

Strategy to deliver a just transition for the energy sector published.

A route map to secure Scotland's fastest possible fair and just transition away from fossil fuels has been published.

The draft 'Energy Strategy and Just Transition Plan' sets out a plan for Scotland's renewables revolution to be accelerated as North Sea basin resources decline.

This would result in a net jobs gain across the energy production sector, with the potential to increase renewable energy exports and reduce exposure to future global energy market fluctuations.

Key policy proposals published for consultation include:

- substantially increasing the current level of 13.4 Gigawatts (GW) of renewable electricity generation capacity, with an additional 20 GW by 2030, which could produce the equivalent of nearly 50% of current demand
- an ambition for 5 GW of renewable and low-carbon hydrogen power by 2030, and 25 GW by 2045
- increasing contributions of solar, hydro power and marine energy to the energy mix
- generation of surplus electricity enabling export of electricity and renewable hydrogen to support decarbonisation across Europe
- setting out final policy positions on fossil fuel energy, including consulting on a presumption against new exploration for North Sea oil and gas
- accelerated decarbonisation of domestic industry, transport and heat in buildings
- increasing access to affordable energy by urging the UK Government to take stronger, more targeted action for fair energy market reform
- maximising household, business and community benefit from energy projects, including through shared ownership of renewables

Published as part of the draft Energy Strategy is a Just Transition Plan for the energy sector. This details the support being provided to grow Scotland's highly skilled energy workforce, increase jobs in energy generation and the supply chain, while enabling communities and businesses, particularly in the North East, to prosper.

Analysis shows the number of low carbon production jobs is estimated to rise from 19,000 in 2019 to 77,000 by 2050 as the result of a just energy transition, meaning there will be more jobs in energy production in 2050 than there are now.

The Strategy also sets out recommended actions for the UK Government to take in reserved policy areas, including powers relating to energy security, market mechanisms, network investment and market regulation. Scottish Ministers have invited the UK Government to join an Energy Transition delivery group to drive forward the vision set out in the Strategy.

Net Zero & Energy Secretary Michel Matheson said:

"Scotland is an energy rich nation, with significant renewable energy resource, a highly-skilled workforce and innovative businesses across a globally renowned supply chain.

"The renewables revolution is global, as all countries seek to address concerns about climate change, and Scotland is at the forefront of this transition.

"At a time of unprecedented uncertainty in our energy sector, accelerating the transition towards becoming a renewables powerhouse makes sense for a number of reasons – particularly to helping to mitigate against future global market volatility and the high energy prices which are making life so difficult for so many people across Scotland. For example, onshore wind is one of the most affordable forms of energy.

"While we do not hold all the powers to address these issues at source, this Strategy sets out how we can achieve an energy transition that ensures we have sufficient, secure and affordable energy to meet our needs, support Scotland's economic growth and capitalise on future sustainable export opportunities."

Just Transition Minister Richard Lochhead said:

"The oil and gas industry has made a vast contribution to Scotland's economy and its workers are some of the most highly-skilled in the world. But Scotland's oil and gas basin is now a mature resource.

"A just transition to a net zero energy system will secure alternative employment and economic opportunities for those already working in the industry and will provide new green jobs in Scotland for future generations. Embracing this change will ensure we avoid repeating the damage done by the deindustrialisation of central belt communities in the 1980s.

"There is a bright future for a revitalised North Sea energy sector focussed on renewables."

Background

The draft Energy Strategy and Just Transition Plan is available on the Scottish Government website.

A consultation on the Strategy and Plan will run until Tuesday 4th April 2023.

The Scottish Energy Statistics Hub provides key energy data relating to Scotland's energy demand and generation.

Read the Cabinet Secretary for Net Zero, Energy and Transport's full statement to the Scottish Parliament on Tuesday 10 January 2023.

Ministerial Foreword

The evidence has never been stronger on the need for transformation of our energy system. We are publishing this draft Energy Strategy and Just Transition Plan at a time of unprecedented uncertainty and change in global and national energy systems. The imperative is clear: in this decisive decade, we must deliver an energy system that meets the challenge of becoming a net zero nation by 2045, supplies safe and secure energy for all, generates economic opportunities, and builds a just transition.

The current uncertainty in our energy sector, with global market volatility and high energy prices, is impacting Scotland's people, communities and businesses. This energy crisis has demonstrated how vulnerable our energy system is to international price shocks, as well as laying bare the need for structural reform of our energy system to ensure affordability for consumers. Whilst the Scottish Government does not have the powers to intervene in the energy markets to address these issues at source, we are taking action wherever we can to support those impacted through these difficult months. The delivery of this draft Energy Strategy and Just Transition Plan will reduce energy costs in the long term and reduce the likelihood of future energy cost crises.

It is also clear that as part of our response to the climate crisis we must reduce our dependence on oil and gas, and that Scotland is well positioned to do so in a way that ensures we have sufficient, secure and affordable energy to meet our needs, to support economic growth and to capture sustainable export opportunities. Unlimited extraction of fossil fuels is not consistent with our climate obligations. However, irrespective of the climate imperative, as an already established mature basin in gradual decline, planning for a just transition to our net zero energy system and securing alternative employment and economic opportunities for workers is essential if Scotland is to avoid repeating the damage done by the deindustrialisation of central belt communities in the 1980s, and to fully capitalise on our potential as a location for low carbon and renewable energy expertise.

For all these reasons, this draft Strategy and Plan supports the fastest possible just transition for the oil and gas sector in order to secure a bright future for a revitalised North Sea energy sector focused on renewables. This draft Strategy sets out policy positions on oil and gas, both offshore and onshore, and provides an opportunity for the public to give their views.

Scotland is at the forefront of the clean energy transition and Scotland's green jobs revolution is underway.

This draft Strategy sets out key ambitions for Scotland's energy future including:

- More than 20 GW of additional renewable electricity on- and offshore by 2030.
- An ambition for hydrogen to provide 5 GW or the equivalent of 15% of Scotland's current energy needs by 2030 and 25 GW of hydrogen production capacity by 2045.
- Increased contributions from solar, hydro and marine energy to our energy mix.
- Accelerated decarbonisation of domestic industry, transport and heat.
- Establishment of a national public energy agency – Heat and Energy Efficiency Scotland.
- By 2030, the need for new petrol and diesel cars and vans phased out and car kilometres reduced by 20%.
- Generation of surplus electricity, enabling export of electricity and renewable hydrogen to support decarbonisation across Europe.
- Energy security through development of our own resources and additional energy storage.
- A just transition by maintaining or increasing employment in Scotland's energy production sector against a decline in North Sea production.
- Maximising the use of Scottish manufactured components in the energy transition, ensuring high-value technology and innovation.

Through accessing global markets, Scotland can realise vast growth opportunities, including exporting our skills and knowledge in offshore energy and decommissioning. Fully realising these opportunities will require co-operation and action at a UK-level to facilitate smooth international trade, particularly in light of Brexit.

Recent global events have shown us how interconnected energy markets around the world are. To ensure we deliver climate-friendly, affordable and secure energy supplies here in Scotland, we must look to collaborate with others, particularly our neighbours around the North Sea, in creating mutual energy security and shared strategic advantage. The North Sea has the potential to be 'the battery for Europe' – we will look to work with others on how to realise this potential, and how best to create shared and mutually reinforcing systems and infrastructure.

This is also our first draft Just Transition Plan. Our draft Plan proposes a vision for a just energy transition that benefits communities and workers across Scotland, provides high-quality jobs and economic benefit, delivers affordability, and protects our environment and our energy security. This draft Plan is the result of collaboration between people from all parts of Scotland and all walks of life. We have highlighted how workers, businesses, communities and consumers have shaped this draft through our early co-design and set out the next steps in that process.

We will also show how this energy transition can lead to growth in employment in the sector through the development of new industries.

This draft Strategy and Plan presents the actions being taken by the Scottish Government under the current constitutional settlement. We have highlighted the key policy levers and decisions that are currently held by the UK Government and where, because of the reservation of powers to the UK Government, action is required by UK Ministers and regulators alongside that of the Scottish Government.

To ensure we succeed in delivering the level of ambition in this strategy within the current constitutional settlement, we need to work together with the UK Government. We invite the UK Government to work with us through establishment of an Energy Transition taskforce, to deliver tangible action to drive the energy transition.

Michael Matheson MSP

Cabinet Secretary for Net Zero, Energy and Transport

Richard Lochhead MSP

Minister for Just Transition, Fair Work and Employment

Contents

Executive Summary

To realise our climate change ambitions, we need to transform the way Scotland generates, transports and uses energy. We must seize the huge opportunity this presents and deliver maximum benefits to Scotland's people, workers, communities and economy from our vast renewable energy resource. This draft Energy Strategy and Just Transition Plan sets out the scale of that opportunity and provides clarity on how Scotland will prepare for a Just Energy Transition.

Our vision is that by 2045 Scotland will have a flourishing, climate friendly energy system that delivers affordable, resilient and clean energy supplies for Scotland's households, communities and business. This will deliver maximum benefit for Scotland, enabling us to achieve our wider climate and environmental ambitions, drive the development of a wellbeing economy and deliver a just transition for our workers, businesses, communities and regions.

In order to deliver that vision, this strategy sets out clear policy positions and a route map of actions with a focus out to 2030 that the Scottish Government will take and the changes that the UK Government must deliver.

The research underpinning that vision shows that if successful we can deliver a net zero energy system for Scotland that also delivers a net gain in employment in Scotland's energy production sector.

Preparing for a Just Transition: Scotland's first draft Just Transition Plan

To secure a just transition that benefits all of Scotland's communities, we must take steps to ensure that our national, regional and local energy economies are thriving, and that the Strategy and Plan delivers for all parts of Scotland.

We are committed to increasing access to affordable energy. We will continue to do all we can to support households and businesses, and to prioritise those in or at risk of fuel poverty. We urge the UK Government to reform the energy market to permanently break the link between the price of electricity and the cost of gas to help realise the benefits of the low costs of renewable electricity.

We are committed to maximising community benefits from, and ownership of, energy projects, and providing regional and local opportunities to participate in our net zero energy future. We are encouraging developers to offer community benefits and shared ownership opportunities to communities as standard on all new renewable energy projects, including repowering and extensions to existing projects.

For areas of Scotland with traditionally higher dependence on fossil fuel related economic activity, such as the North East, Grangemouth and Shetland, the transition will involve shifting investment and employment to renewable sectors such as wind and marine energy.

Maximising opportunities for growing net zero energy sectors and businesses, driving investment and increasing trade opportunities will be critical to delivering a just transition. Through government investment in the net zero energy economy and by providing a stable policy environment and clear market signals, our aim is to attract increased levels of private and inward investment into Scotland's energy sector. Boosting our skills base and domestic supply chain will support the creation of vital jobs across the economy.

We are already investing almost £5 billion in the net zero energy economy in Scotland over this parliamentary term, prioritising those projects that align with our vision as set out in this draft Strategy and Plan. Our capital investment is primarily focussed on the demand sectors of heat, transport and industry. Under the current constitutional settlement, the Scottish Government is unable to invest in many parts of the UK's liberalised energy markets. We will continue to use our capital funds to support those least able to pay, to maximise economic opportunities for communities across Scotland and to promote environmental protection.

Expanding our energy generation sector

We are taking action to transform and expand Scotland's energy generation sector. Scotland's rich renewables endowment means we can not only generate enough cheap green electricity to power Scotland's economy, but also export electricity to our neighbours, supporting jobs here in Scotland and the decarbonisation ambitions of our partners.

We are setting an ambition for more than 20 GW of additional low-cost renewable electricity generation capacity by 2030, including 12 GW of onshore wind, and we are consulting on setting a further offshore deployment ambition, and a new ambition for solar, wave and tidal deployment. Scotland already has 13.4 GW of renewable electricity generation capacity. An additional 20 GW of renewable generation will more than double our existing renewable generation capacity by 2030 generating enough power each year to power the equivalent of every home Scotland for over 7 years.[1] That is the equivalent of 48% of Scotlands current total energy demand.[2]

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[1] Calculations based on 10 GW offshore and 10 GW onshore operating at load factors of 51% and 37% (taken from BEIS Electricity Generation Cost Report 2020) to produce 77TWh of electricity. Assumes a home consumes 3,880kWh/year and an EV consumes 2,345kWh/year (sources: Energy Consumption in the UK, and EV Database)

[2] Calculations based on 10 GW offshore and 10 GW onshore operating at load factors of 51% and 37% (taken from BEIS Electricity Generation Cost Report 2020) to produce 77TWh of

There are tremendous opportunities ready to be seized over the coming years as our renewables capabilities and wider supply chains grow. As one of the cheapest forms of electricity, offshore wind has a vital role to play in decarbonising our energy demand and securing a just transition to net zero. Subject to planning and consenting decisions and finding a route to market, we have a current reported potential pipeline (subject to change) of over 38 GW of offshore wind projects. When projects which are awaiting construction, under construction or already operational are added to this, the total potential capacity reaches over 40 GW – the equivalent to produce enough electricity annually to power every home in Scotland for 17 years or every home in the UK for over a year and a half.

We have set a renewable and low-carbon hydrogen production ambition of 5 GW by 2030 - equivalent to a sixth of Scotland's energy needs by 2030 - and an ambition for 25 GW by 2045. Hydrogen is an emerging sector perfectly placed to support a just transition for existing oil and gas workforces and we have set out plans to rapidly grow Scotland's hydrogen economy.

Hydro power has the potential to play a significantly greater role in the energy transition and we are urging the UK Government to act now to ensure the clean energy and storage capability of Scotland's hydro resource can be realised by instituting appropriate market mechanisms. We are also clear that the UK Government plays a critical role in delivering carbon capture, utilisation and storage (CCUS) in Scotland, as we do not hold the necessary legislative and regulatory levers. UK Government certainty and support, including access to BEIS business models, is essential to accelerate the Scottish Cluster project. The development of CCUS infrastructure in Scotland's industrial clusters in Grangemouth and the North East could ensure a just transition for important domestic industries, protecting jobs and utilising existing skills.

We are taking action across all sectors of the economy to reduce our reliance on fossil fuels. The Scottish Government is clear that unlimited extraction of fossil fuels is not consistent with our climate obligations. Neither is it a solution to the energy price crisis people across Scotland are facing. We want to see the fastest possible just transition for the oil and gas sector.
We have finalised our position of no support for unconventional oil and gas in Scotland. We are finalising our policy positions on onshore conventional oil and gas, and coal extraction, as part of this Strategy and Plan. We have also updated our position on offshore oil and gas and are consulting on it.
The Scottish Government has devolved powers over onshore oil and gas (both conventional and unconventional), but powers over offshore oil and gas are reserved to the UK Government. These positions can be found in Chapter 3.

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electricity. Assumes a home consumes 3,880kWh/year and an EV consumes 2,345kWh/year (sources: Energy Consumption in the UK, and EV Database)

We do not support the building of new nuclear power plants, which due to the high costs of nuclear[3], as well as taking decades to build, will do nothing to address the urgent imperative of driving down energy prices.

Changing the way we use energy

We must change the way we use energy – reducing demand across our heat and transport sectors and replacing fossil fuel demand with zero carbon technologies. Low cost, renewable electricity will be critical for decarbonising our energy use, along with significant volumes of renewable and low-carbon hydrogen in harder-to-decarbonise sectors.

We are taking action so that by 2030 the vast majority of the 170,000 off-gas homes that currently use high emissions oil, LPG and solid fuels, as well as at least 1 million homes currently using mains gas, convert to zero emissions heating. We are also reducing emissions from our non-domestic buildings.

We are bringing forward a Heat in Buildings Bill which will outline proposals for regulating for energy efficiency and zero direct emissions heat in Scotland's homes and buildings.

Recognising the pace at which we must act to decarbonise heat in our homes and buildings Heat and Energy Efficiency Scotland - our National Public Energy Agency - will play an important role in co-ordinating this huge transition and help to ensure it is a just and fair one.

We have committed to reduce car kilometres by 20% by 2030 and to help people on lower incomes and in remote rural and island communities to switch to zero emissions vehicles through our consumer focussed incentive schemes. We are developing a Just Transition Plan for transport that delivers for people, places and communities across Scotland.

While we expect oil and gas to remain a component of Scotland's energy system while it transitions to a zero carbon system, particularly in industrial energy usage, we are clear that overall use of fossil fuels across heating and transport sectors must decline and that alternative technology and energy solutions are available.

We will continue to support industry to work towards 43%[4] decarbonisation by 2032, through match funding for industrial energy efficiency and decarbonisation, including through the Scottish Industrial Energy Transformation Fund and the Low Carbon Manufacturing Challenge Fund.

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[3] For example, £92.50 per megawatt hour for Hinkley C compared to £37.65 per megawatt hour for offshore wind

[4] From 2018 levels

To drive essential CCUS deployment, we will continue to work with the North East CCUS industry led alliance to support the delivery of the CCUS industry in Scotland; support the Scottish Cluster through the UK Government's cluster sequencing process; continue to build the evidence base to underpin this; and explore the international opportunities afforded by Scotland's vast CO_2 storage assets, alongside a prioritisation of domestic hard to abate emissions. We will also continue to work with the UK Government, Welsh Government and Northern Ireland Executive to align the UK Emissions Trading Scheme with our net zero targets; ensuring a strong carbon price to incentivise business investment in decarbonisation.

We are providing a suite of support and advice services, such as the Farm Advisory Service, to help farmers and crofters reduce their energy demand and decarbonise energy use, as well as highlighting the range of ways farmers and land managers can participate in the net zero energy economy.

Creating the conditions for a net zero energy system

By 2030, our energy system will be in the midst of a major transformation, integrating new ways of producing, transporting and using energy. Our energy supplies need to be secure, reliable and affordable for people and businesses across Scotland. This draft Strategy and Plan sets out how we are working with the UK Government on key areas of energy security, network investment and market regulation to ensure we have the infrastructure and market design that will enable the transformation of Scotland's energy system in line with our vision. Our energy infrastructure must also be resilient to the impacts of climate change in Scotland.

Working with the UK Government

Many of the key decision-making powers in energy sit with the UK Government, with responsibility for making or changing legislation and regulations reserved under the Scotland Act. Critical areas where the UK Government must take action to secure the full benefits of the energy transition for Scotland's people and businesses include:

- electricity market reform;
- support for carbon capture and storage;
- action on energy affordability;
- reforms to consenting of offshore wind and regulation of the offshore marine environment; and
- the development of new market mechanisms to support clean energy technology deployment.

We have set out in Chapter 7 the key issues where actions by the UK Government and UK regulatory bodies are required to meet the ambition outlined in this strategy. We will invite the UK Government and those relevant bodies to join us as part of an Energy Transition delivery group to drive this strategy forward, identify and remove barriers, harness the opportunities and track progress in delivering a net zero energy system for Scotland.

Summary of policies set out in this draft Strategy and Plan	
	A Just Transition
	We are setting out actions in this Strategy and Plan to ensure that • People have access to affordable clean energy. • Communities and places can participate and benefit in the net zero energy transition. • We have a supportive policy environment, maximising the impact of government expenditure and attracting private investment. • Scotland is home to a multi-skilled energy workforce, boosting our domestic supply chain and manufacturing capabilities. • Scotland's net zero energy system is continuously innovative and competitive in domestic and international markets.
Community benefits and shared ownership	We have set an ambition for 2 GW of community owned energy by 2030. We will encourage developers to offer community benefit and shared ownership opportunities as standard on all new renewable energy projects – including repowering and extensions to existing projects. We are currently updating our Good Practice Principles for Community Benefit from Offshore Renewable Energy Developments, and will consult on new draft guidance in 2023. We will engage with the UK Government to consider mechanisms for maximising opportunities for community benefit and shared ownership for renewable energy developments.
	Energy supplies – Scaling up renewable energy
Offshore Wind	The Offshore Wind Policy Statement, published in 2020, set out our ambition to achieve 8-11 GW of offshore wind in Scottish waters by 2030. This consultation seeks views on whether the Scottish Government should set an increased ambition for offshore wind deployment, and what the level of ambition should be, by 2030 and 2045. The draft Strategy and Plan also acknowledges that the major expansion of offshore wind will impact marine biodiversity and other users of the sea, and describes the action we are taking to balance those impacts.
Onshore Wind	In the Onshore Wind Policy Statement, published in December 2022, we set an ambition for a further 12 GW of onshore wind by 2030, increasing from 8.78 GW as of June 2022 to 20 GW by 2030, more than double our existing capacity. Our draft Strategy and Plan restates our ambition and provides clear positions on community benefit and shared ownership,

	including how communities can benefit from repowering of existing sites. The Onshore Wind Policy Statement sets out how we will work with industry to deliver an Onshore Wind Sector Deal in 2023, to ensure we maximise deployment and the economic opportunities that flow from it.
Marine	The draft marine vision consults on a new ambition for marine deployment and presents the opportunities for the sector, and potential actions to enable the continued growth of both wave and tidal energy. This will support the delivery of a secure and low carbon energy system and a new industrial opportunity for Scotland.
Solar	We will support the sector to minimise barriers to deployment, aiming to maximise the contribution solar can make to a just, inclusive transition to net zero. We are keen to see the number of solar installations offering community benefits increase and continue to encourage the sector to consider what packages of community benefit it can offer communities local to developments, in line with our Good Practice Principles.[5]
Hydro power	Hydro power has the potential to play a significantly greater role in the energy transition – both at small-scale in co-operation with local communities as part of a diverse resilient energy supply in remote parts of Scotland, and at larger scale, providing flexibility services to the grid and helping to ensure a continued resilient and secure electricity supply. We urge the UK Government to provide appropriate market mechanisms for hydro power to ensure the full potential of this sector is realised.
Hydrogen	The Hydrogen Action Plan and this draft both reaffirm policy support for hydrogen, and our strong ambitions for Scotland's hydrogen economy. They highlight our intention to capture the supply chain and infrastructure benefits to the Scottish economy from taking a leading role in hydrogen production. Previous ambitions on hydrogen production have not changed: • 5 GW installed renewable and low-carbon hydrogen production capacity in Scotland by 2030 • 25 GW installed renewable and low-carbon hydrogen production capacity in Scotland by 2045
Energy supplies - Reducing our reliance on fossil fuels	
Fossil fuel electricity generation	We are opposed to the continued use of unabated fossil fuels to generate electricity. The deployment of CCUS for the Scottish Cluster must demonstrate decarbonisation at pace and cannot be used to justify unsustainable levels of fossil fuel extraction or impede Scotland's just transition to net zero.
Oil and Gas – Offshore	This draft sets out our support for the fastest possible just transition for the sector and consults on the principles on which decisions for future extraction would be based.

[5] Community benefits from onshore renewable energy developments

	The UK Government has introduced a checkpoint to ensure any future licensing is compatible with the UK's climate objectives before a licensing round is offered. In line with advice from the Climate Change Committee (CCC)[6] Scottish Government policy is that climate compatibility checkpoints for oil and gas licensing should extend beyond new licensing rounds to cover fields that are consented but not yet in production. Further, we consider that any checkpoint should also include an assessment of the proposed production's contribution to international climate commitments. Whilst licensing is reserved to the UK Government, the Scottish Government is consulting on whether, in order to support the fastest possible and most effective just transition, there should be a presumption against new exploration for oil and gas.
Oil and Gas - Onshore	The draft reaffirms our preferred policy position of no support for the exploration or development of onshore conventional oil and gas in Scotland and position of no support for unconventional oil and gas.
Coal	The draft reaffirms our preferred policy position of no support for coal extraction in Scotland.
Nuclear	The draft reiterates our firm position on traditional nuclear energy, that we do not support the building of new nuclear power plants under current technologies.
Energy demand for heat, transport, industry and agriculture	
Heat in Buildings	This draft reaffirms our ambitions to decarbonise 1 million homes by 2030, and to reduce emissions from our non-domestic buildings and invest over £1.8 billion in decarbonising homes and buildings, through Heat and Energy Efficiency Scotland - our national energy agency.
Transport	This draft reaffirms our ambitions to reduce car kilometres by 20% and sets out the significant investment in sector decarbonisation.
Industry	The draft sets out how we will continue to support industrial energy efficiency and decarbonisation including low carbon manufacturing over the course of this parliament and sets out our work to deliver a Just Transition Plan for Grangemouth.
CCUS	The Scottish Government remains supportive of CCUS as part of the energy transition. In particular it remains committed to supporting the delivery of the Scottish Cluster. However, we agree that any strategy for deployment of these technologies must enable decarbonisation at pace and cannot be used to justify unsustainable levels of fossil fuel extraction or impede Scotland's just transition to net zero.
Agriculture	This draft sets out how we are building our evidence base through research on opportunities for the sector to decarbonise their energy usage and our continued support through a suite of advice programmes.

[6] Letter: Climate Compatibility of New Oil and Gas Fields - Climate Change Committee

This consultation document

This draft Strategy and Plan presents the vision for Scotland's future decarbonised energy system and the actions we and others need to take to deliver it.

It sets a vision to 2045, and a route map of ambitions and actions that, coupled with detailed sectoral plans and the forthcoming Climate Change Plan, will guide decision-making and policy support over the course of this decade to 2030. The Strategy and Plan provides policy certainty for consumers, businesses and investors and sets a clear direction for the future of Scotland's oil and gas sector.

Chapter 1 describes our vision for this energy system transition, with a focus on the interim milestones we must achieve by 2030.

Chapters 2-5 set out how we will prepare for a just transition and the action we will take to achieve the vision. This includes proposals for how we can secure maximum social and economic benefit from the transition for Scotland, working with business and investors to attract additional capital and inward investment to support our net zero ambitions and export potential.

Chapter 6 sets out a consolidated route map of actions, and **Chapter 7** describes the changes needed at UK level to realise the vision.

Throughout the document, you will find boxes that set out the positive impacts that the energy transition will deliver for Climate and the Environment (green boxes), for our Economy (orange boxes), and for Scotland's Communities and Regions (blue boxes). This draft Strategy and Plan describes the actions we and partners - including industry, the wider public sector and the UK Government - must take to achieve those positive outcomes.

This consultation provides an opportunity for communities, workers, citizens and businesses to engage in the process of co-designing Scotland's energy transition. In consulting on this draft vision and route map, our purpose is to:

1. seek views on our vision and the actions we are taking to transition to an affordable, resilient and clean energy system; and
2. understand how we secure the maximum social and economic benefits from the energy transition for Scotland.

You will find **consultation questions in Annex B**, along with information on how to respond to this consultation. We invite you to respond to these questions by 4 April 2023. We will use the consultation responses received, and the continuing engagement we will be carrying out, to further develop the Strategy and Plan, before a final version is published in late 2023.

Ola Borten Moe is Minister of Research and Higher Education since 2021. Previously, he also served as Minister of Petroleum and Energy from 2011 to 2013.

https://www.facebook.com/SPolabortenmoe/posts/pfbid02FhTrNJAApZa6m392J41EgiRbFzG6ffgq12n3JAwqYQVL3cR7p9ztixMQjR1wG6qXl

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Ola Borten Moe
January 6 ·

Det er stadig mer åpenbart at vi alt for lenge har oppført som om det er ubegrenset tilgang på fornybar og rimelig strøm i Norge. Faktum er enkelt og greit at det er mangel på energi i kraftsystemene våre. Svært høye priser og frykt for forsyningssikkerheten dokumenterer dette. Vi må derfor selvsagt få et langt mer realistisk forhold til hva vi bruker energi på. Og vi må få et bevist forhold til enkle faktorer som ressurseffektivitet og virkningsgrad. Hydrogen er sikkert bra til mye, men faktum er at det er et høyeksplosivt lagringsmedium med store energitap i begge ender av prosessen. Om du bruker 100 kwh strøm til å produsere hydrogen vil du sitte igjen med en energimengde i hydrogen tilsvarende 50 kwh. Halvparten av energien er med andre ord tapt. Om du videre skal bruke dette hydrogenet i en brenselscelle taper du ytterligere 50%. Om du kjører det i en turbin for å produsere strøm taper du 70%. Med andre ord får du en utnyttelsesgrad i en bil på ca 25% eller 25 kwh av de opprinnelige 100 kwh pga energitap i prosessene. I en enkel turbin er tapet enda større. Denne strømmen/energien kunne alternativt blitt brukt direkte all den tid den tas fra nettet i Norge med en utnyttelsesgrad til for eksempel oppvarming, produksjon eller transport på 90-100%! Om Statkraft sammen med NEL lykkes med å etablere 2 gw elektrolyse av hydrogen i Norge tilsvarer det en energimengde på ca 17,5 twh, eller om lag 12-13% av all kraftproduksjon i Norge. Med 75% energitap er det 14 twh, eller 10% av all norsk kraftproduksjon rett i dass. Det er etter mitt skjønn lysår unna å være forsvarlig eller fornuftig. Vi trenger all den energien vi har og får til langt mer fornuftige ting enn å fyre for kråka.

Stat

STATKRAFT.NO
Nel og Statkraft legger grunnlaget for en verdikjede for grønt hydrogen i Norge
Hydrogenteknologiselskapet Nel og Europas største leverandør av fornybar energi, Statkraft, signerte nylig en kontrakt for leveranse av 40 MW elektrolysørutstyr og vil dermed samarbeide om å skape en sterk verdikjede...

505 — 161 comments 108 shares

Google Translate of Moe's above Facebook posting

It is increasingly obvious that for far too long we have acted as if there is unlimited access to renewable and affordable electricity in Norway. The fact is plain and simple that there is a lack of energy in our power systems. Very high prices and fears about security of supply document this. We must therefore of course have a far more realistic relationship with what we use energy for. And we must have a proven relationship with simple factors such as resource efficiency and effectiveness. Hydrogen is certainly good for many things, but the fact is that it is a highly explosive storage medium with large energy losses at both ends of the process. If you use 100 kwh of electricity to produce hydrogen, you will be left with an amount of energy in hydrogen corresponding to 50 kwh. In other words, half of the energy is lost. If you are going to use this hydrogen in a fuel cell, you lose a further 50%. If you run it in a turbine to produce electricity, you lose 70%. In other words, you get a utilization rate in a car of about 25% or 25 kwh of the original 100 kwh due to energy loss in the processes. In a simple turbine, the loss is even greater. Alternatively, this current/energy could have been used directly all the time it is taken from the grid in Norway with a utilization rate for, for example, heating, production or transport of 90-100%! If Statkraft together with NEL succeeds in establishing 2 gw electrolysis of hydrogen in Norway, this corresponds to an energy quantity of approximately 17.5 twh, or approximately 12-13% of all power production in Norway. With a 75% energy loss, that's 14 twh, or 10% of all Norwegian power production right there. It is, in my opinion, light years away from being justifiable or reasonable. We need all the energy we have and can do for far more sensible things than fighting for the crow.

Google Translate of Statkraft's press release [LINK] linked in Moe Facebook posting

NEWS 2023

NEL AND STATKRAFT LAY THE FOUNDATION FOR A VALUE CHAIN FOR GREEN HYDROGEN IN NORWAY

Nel and Statkraft are laying the foundations for a value chain for green hydrogen in Norway

06 JAN., 2023

The hydrogen technology company Nel and Europe's largest supplier of renewable energy, Statkraft, recently signed a contract for the delivery of 40 MW electrolyser equipment and will thus work together to create a strong value chain for the production of green hydrogen in Norway.

Press releases

- We are determined to contribute to making Norway a leading producer of green hydrogen and establish an ecosystem of equipment suppliers, including the production of electrolysers, say Nels CEO Håkon Volldal and CEO of Statkraft, Christian Rynning-Tønnesen.

The announcement came in connection with German Vice-Chancellor Robert Habeck's visit to Nel's fully automatic electrolyser factory on Herøya. Industry Minister Jan Christian Vestre also joined the delegation together with his colleague, Energy and Energy Minister Terje Lien Aasland. The ministers are enthusiastic about the two companies' plans for a value chain for green hydrogen in Norway.

- It is gratifying that leading Norwegian players such as Nel and Statkraft are planning value chains for green hydrogen in Norway. This is an important step in the right direction to achieve our ambitions to build a coherent value chain for hydrogen and facilitate the production of hydrogen with no or low emissions to cover the national demand for hydrogen, says Oil and Energy Minister Terje Aasland .

From left: Habeck, Volldal, Rynning-Tønnesen, Aasland and Vestre Statkraft has recently signed a contract for the supply of 40 MW electrolyser equipment from Nel. The electrolysers will be manufactured at Nel's factory on Herøya and used for the production of green hydrogen in some of Statkraft's many hydrogen projects. As Europe's largest supplier of renewable energy, Statkraft has ambitions to reach an annual development rate of 4 GW of new power production and to have 2 GW of renewable hydrogen production in place by 2030. In Norway, Statkraft will strengthen its investment in developing new renewable power production and flexibility in hydropower and wind power both on- and offshore.

- The contract with Nel is the first important step towards realizing our ambitions of 2 GW of green hydrogen and securing production capacity for several of our hydrogen projects, says Rynning-Tønnesen. Volldal is very happy to have Statkraft on its customer list.

- Statkraft is Europe's largest supplier of renewable energy and a well-reputed and highly knowledgeable renewable company with an ambitious growth agenda, and we are very proud that they have chosen us as a supplier of green hydrogen technology, says Volldal.

- With this and other orders, Nel strengthens its position as a leading supplier and exporter of hydrogen equipment, which is crucial for the green shift in Europe and internationally, and for the development of new green jobs in Norway, says Volldal.

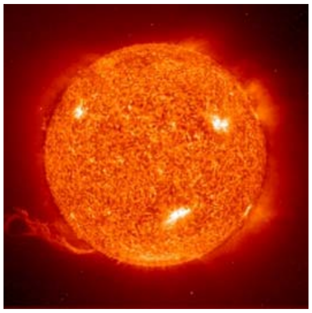
https://www.eia.gov/energyexplained/hydrogen/#:~:text=Hydrogen%20is%20an%20energy%20carrier&text=Hydrogen%2C%20like%20electricity%2C%20is%20an,source%20of%20energy%20or%20fuel.

Independent Statistics & Analysis
U.S. Energy Information Administration

Hydrogen explained
What is hydrogen?

Hydrogen is the simplest element. Each atom of hydrogen has only one proton. Hydrogen is also the most abundant element in the universe. Stars such as the sun consist mostly of hydrogen. The sun is essentially a giant ball of hydrogen and helium gases.

Hydrogen occurs naturally on earth only in compound form with other elements in liquids, gases, or solids. Hydrogen combined with oxygen is water (H_2O). Hydrogen combined with carbon forms different compounds—or hydrocarbons—found in natural gas, coal, and petroleum.



The sun is essentially a giant ball of hydrogen gas undergoing fusion into helium gas. This process causes the sun to produce vast amounts of energy.

Source: NASA (public domain)
?

Hydrogen is the lightest element. Hydrogen is a gas at normal temperature and pressure, but hydrogen condenses to a liquid at minus 423 degrees Fahrenheit (minus 253 degrees Celsius).

Hydrogen is an energy carrier

Energy carriers allow the transport of energy in a usable form from one place to another. Hydrogen, like electricity, is an energy carrier that must be produced from another substance. Hydrogen can be produced—separated—from a variety of sources including water, fossil fuels, or biomass and used as a source of energy or fuel. Hydrogen has the highest energy content of any common fuel by weight (about three times more than gasoline), but it has the lowest energy content by volume (about four times less than gasoline).

It takes more energy to produce hydrogen (by separating it from other elements in molecules) than hydrogen provides when it is converted to useful energy. However, hydrogen is useful as an energy source/fuel because it has a high energy content per unit of weight, which is why it is used as a rocket fuel and in fuel cells to produce electricity on some spacecraft. Hydrogen is not widely used as a fuel now, but it has the potential for greater use in the future.

Last updated: January 20, 2022

https://www.whitehouse.gov/ceq/news-updates/2023/01/06/biden-harris-administration-releases-new-guidance-to-disclose-climate-impacts-in-environmental-reviews/
JANUARY 06, 2023

Biden-Harris Administration Releases New Guidance to Disclose Climate Impacts in Environmental Reviews

The White House Council on Environmental Quality (CEQ) today released updated Guidance on Consideration of Greenhouse Gas Emissions and Climate Change to help Federal agencies better assess and disclose climate impacts as they conduct environmental reviews, delivering more certainty and efficiency in the permitting process for clean energy and other infrastructure projects. This step, directed by Executive Order 13990, Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis, advances President Biden's commitment to restore science in Federal decision making, fight climate change, and build resilient infrastructure.

As Federal agencies review and build new infrastructure and clean energy projects, including those funded through the Bipartisan Infrastructure Law and Inflation Reduction Act, the updated guidance will improve sustainability while keeping environmental reviews focused and efficient. The guidance – which CEQ is issuing as interim guidance and is available for public comment – provides more clarity and predictability for conducting reviews, including highlighting existing tools and best practices.

The updated guidance also improves transparency in the reporting of greenhouse gas emissions, including the appropriate use of the social cost of greenhouse gases to disclose climate impacts, provides specific recommendations for renewable and low greenhouse gas projects to keep reviews focused, and makes projects more climate-smart and resilient while helping reach President Biden's goal to achieve net-zero emissions by 2050.

"Disclosing and reducing emissions will ensure we're building sustainable, resilient infrastructure for the 21st century and beyond," said CEQ Chair Brenda Mallory. "These updated guidelines will provide greater certainty and predictability for green infrastructure projects, help grow our clean energy economy, and help fulfill President Biden's climate and infrastructure goals."

The new guidance builds on the final "Phase 1" National Environmental Policy Act (NEPA) rule issued in April 2022, which restored clarity to key provisions of the NEPA regulations. It also builds on the Biden-Harris Administration's Permitting Action Plan, which outlines the Administration's strategy for ensuring that Federal environmental reviews and permitting processes are effective, efficient, and transparent, guided by the best available science to promote positive environmental and community outcomes, and shaped by early and meaningful public engagement.

The guidance replaces 2016 emissions guidance that was withdrawn by the previous Administration. CEQ's new climate change guidance recommends that agencies account for greenhouse gas (GHG) emissions in NEPA reviews. It provides Federal agencies a common approach for assessing their proposed actions, while recognizing each agency's unique circumstances and authorities. Specifically, the guidance:

- Updates the 2016 guidance consistent with developments in climate science, caselaw, and the urgency of the climate crisis;

- Emphasizes a "rule of reason" that the depth of analysis should be proportional to a project's impacts and clarifies that projects that will reduce GHG emissions, such as certain renewable and low GHG projects, can have less detailed GHG emissions analysis;

- Clarifies best practices for analyzing climate change effects, including by clarifying the need to quantify indirect emissions, which will help projects avoid legal setbacks and provide transparency to help drive climate-smart decisions;

- Recommends best practices for communicating and providing context for climate impacts, such as by noting relevant climate action commitments and goals and using the social cost of GHGs to generate monetary estimates of climate impacts;

- Recommends that agencies mitigate GHG emissions to the greatest extent possible;

- Advances environmental justice by encouraging agencies to meaningfully engage with affected communities and incorporate environmental justice considerations into climate-related analysis; and,

- Supports broad scale or programmatic approaches that can make later reviews more efficient.

CEQ's Guidance on Consideration of Greenhouse Gas Emissions and Climate Change is available for public comment through March 10, 2023.

Excerpts

period, and successive reports shall be due annually on the same date thereafter. Without limitation, Peloton acknowledges and agrees that failure to make such timely and accurate reports as required by this Agreement and Order may constitute a violation of Section 19(a)(3) of the CPSA and may subject the Firm to enforcement under section 22 of the CPSA.

36. Notwithstanding and in addition to the above, Peloton shall promptly provide written documentation of any changes or modifications to its compliance program or internal controls and procedures, including the effective dates of the changes or modifications thereto. Peloton shall cooperate fully and truthfully with staff and shall make available all non-privileged information and materials and personnel deemed necessary by staff to evaluate Peloton's

construed against any party, for that reason, in any subsequent dispute.

44. The Agreement may not be waived, amended, modified, or otherwise altered, except as in accordance with the provisions of 16 CFR 1118.20(h). The Agreement may be executed in counterparts.

45. If any provision of the Agreement or the Order is held to be illegal, invalid, or unenforceable under present or future laws effective during the terms of the Agreement and the Order, such provision shall be fully severable. The balance of the Agreement and the Order shall remain in full force and effect, unless the Commission and Peloton agree in writing that severing the provision materially affects the purpose of the Agreement and the Order.

Secretary, U.S. Consumer Product Safety Commission.

[FR Doc. 2023–00146 Filed 1–6–23; 8:45 am]

BILLING CODE 6355–01–P

COUNCIL ON ENVIRONMENTAL QUALITY

[CEQ–2022–0005]

RIN 0331–AA06

National Environmental Policy Act Guidance on Consideration of Greenhouse Gas Emissions and Climate Change

AGENCY: Council on Environmental Quality.

ACTION: Notice of interim guidance; request for comments.

technical sophistication, data availability, and GHG source profiles. Agencies should use tools that reflect the best available science and data. These tools can provide GHG emissions estimates, including emissions from fossil fuel combustion and carbon sequestration [57] for many of the sources and sinks potentially affected by proposed resource management actions.[58] When considering which tools to employ, it is important to consider the proposed action's temporal scale and the availability of input data.[59] Furthermore, agencies should seek to obtain the information needed to quantify GHG emissions, including by requesting or requiring information held by project applicants or by conducting modeling when relevant.

In the rare instance when an agency determines that tools, methodologies, or data inputs are not reasonably available to quantify GHG emissions associated with a specific action, the agency should explain why such an analysis cannot be done, and should seek to present a reasonable estimated range of quantitative emissions for the proposed action and alternatives. Where tools are available for some aspects of the analysis but not others, agencies should use all reasonably available tools and describe any relevant limitations. Agencies are encouraged to identify and communicate any data or tool gaps that they encounter to CEQ.

If an agency determines that it cannot provide even a reasonable range of potential GHG emissions, the agency should provide a qualitative analysis and its rationale for determining that a quantitative analysis is not possible. A qualitative analysis may include sector-specific descriptions of the GHG emissions from the category of Federal agency action that is the subject of the NEPA analysis, but should seek to provide additional context for potential resulting emissions.

Agencies should be guided by the rule of reason, as well as their expertise and experience, in conducting analysis commensurate with the quantity of projected GHG emissions and using GHG quantification tools suitable for the proposed action.[60] The rule of reason and the concept of proportionality caution against providing an in-depth analysis of emissions regardless of the insignificance of the quantity of GHG emissions that the proposed action would cause. For example, some proposed actions may involve net GHG emission reductions or no net GHG increase, such as certain infrastructure or renewable energy projects. For such actions, agencies should generally quantify projected GHG emission reductions, but may apply the rule of reason when determining the appropriate depth of analysis such that precision regarding emission reduction benefits does not come at the expense of efficient and accessible analysis. Absent exceptional circumstances, the relative minor and short-term GHG emissions associated with construction of certain renewable energy projects, such as utility-scale solar and offshore wind, should not warrant a detailed analysis of lifetime GHG emissions. As a second example, actions with only small GHG emissions may be able to rely on less detailed emissions estimates.

B. Disclosing and Providing Context for a Proposed Action's GHG Emissions and Climate Effects

In addition to quantifying emissions as described in Section IV(A), agencies should disclose and provide context for GHG emissions and climate effects to help decision makers and the public understand proposed actions' potential GHG emissions and climate change effects. To disclose effects and provide additional context for proposed actions' emissions once GHG emissions have been estimated, agencies should use the following best practices, as relevant:

(1) In most circumstances, once agencies have quantified GHG emissions, they should apply the best available estimates of the SC–GHG [61] to the incremental metric tons of each individual type of GHG emissions [62] expected from a proposed action and its alternatives.[63] SC–GHG estimates allow monetization (presented in U.S. dollars) of the climate change effects from the marginal or incremental emission of GHG emissions, including carbon dioxide, methane, and nitrous oxide.[64] These 3 GHGs represent more than 97 percent of U.S. GHG emissions.[65] The SC–GHG provides an appropriate and valuable metric that gives decision makers and the public useful information and context about a proposed action's climate effects even if no other costs or benefits are monetized, because metric tons of GHGs can be difficult to understand and assess the significance of in the abstract.[66] The SC–GHG translates metric tons of emissions into the familiar unit of dollars, allows for comparisons to other monetized values, and estimates the damages associated with GHG emissions over time and associated with different GHG pollutants.[67] The SC–GHG also can

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[60] *See* 40 CFR 1502.2(b) (environmental impact statements shall discuss impacts in proportion to their significance); 40 CFR 1502.15 (data and analyses in a statement shall be commensurate with the importance of the impact).

[61] The SC–GHG estimates provide an aggregated monetary measure (in U.S. dollars) of the future stream of damages associated with an incremental metric ton of emissions and associated physical damages (*e.g.*, temperature increase, sea-level rise,

Order 13990 (Feb. 2021), *https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf*. The Technical Support Document notes that estimates of the SC–GHG have been used in NEPA analysis.

[62] Note that applying the specific social cost of each individual GHG to the quantifications of that GHG is more accurate than transforming the gases into CO_2-equivalents and then multiplying the CO_2-equivalents by the social cost of CO_2. *See* IWG SC–GHG, U.S. Gov't, *Addendum to Technical Support Document on Social Cost of Carbon for Regulatory Impact Analysis under Executive Order 12866: Application of the Methodology to Estimate the Social Cost of Methane and the Social Cost of Nitrous Oxide*, 2 (Aug. 2016), *https://www.epa.gov/sites/default/files/2016-12/documents/addendum_to_sc-ghg_tsd_august_2016.pdf*.

[63] *See* IWG SC–GHG, *Technical Support Document*, *supra* note 61. Agencies should typically apply the best available estimates of the SC–GHG to the incremental metric tons of GHG emissions expected from a proposed action and its alternatives. In uncommon circumstances, an agency may choose not to do so if doing so would be confusing, there are no available estimates for the GHG at issue, or, consistent with the concept of proportionality, an agency does not produce a quantitative estimate of GHG emissions because the emissions at issue are *de minimis*.

[64] Estimates of SC–HFCs have been developed and are available for use in NEPA analysis. *See, e.g.*, EPA, Regulatory Impact Analysis for Phasing Down Production and Consumption of Hydrofluorocarbons (HFCs) (June 2022), *https://www.epa.gov/system/files/documents/2022-07/*

the risks from or resilience to climate change inherent in a proposed action and its design.

Agencies must consider a range of reasonable alternatives, as well as reasonable mitigation measures if not already included in the proposed action or alternatives, consistent with the level of NEPA review (*e.g.*, EA or EIS) and the purpose and need for the proposed action.[76] Agencies should leverage the early phases of their existing planning processes to help identify potential alternatives to address an action's anticipated environmental effects. When analyzing alternatives, agencies should compare the anticipated levels of GHG emissions from each alternative—including the no action alternative—and mitigation to provide information to the public and enable the decision maker to make an informed choice. To help provide clarity, agencies should consider presenting charts, tables, or figures, as appropriate, to compare GHG emissions and climate effects across alternatives.

Neither NEPA, the CEQ Regulations, or this guidance require the decision maker to select the alternative with the lowest net GHG emissions or climate costs or the greatest net climate benefits. However, and in line with the urgency of the climate crisis, agencies should use the information provided through the NEPA process to help inform decisions that align with climate change commitments and goals. For instance, agencies should evaluate reasonable alternatives that may have lower GHG emissions, which could include technically and economically feasible clean energy alternatives to proposed fossil fuel-related projects, and consider mitigation measures to reduce GHG emissions to the greatest extent possible.

Where relevant—such as for proposed actions that will generate substantial GHG emissions—agencies should identify the alternative with the lowest net GHG emissions or the greatest net climate benefits among the alternatives they assess. And, as described throughout this guidance, they should use the NEPA process to make informed decisions grounded in science that are transparent with respect to how Federal actions will help meet climate change goals and commitments, or alternately, detract from them.

D. Baseline for Considering Environmental Effects

A NEPA review must identify the area affected by a proposed action (*i.e.*, the affected environment).[77] Identification of the affected environment includes identifying and describing reasonably foreseeable environmental trends, including climate change effects. The NEPA review also must identify the current and projected future state of the affected environment without the proposed action (*i.e.*, the no action alternative), which serves as the baseline for considering the effects of the proposed action and its reasonable alternatives.[78] For an estimate of GHG emissions from the proposed action to have meaningful context, an accurate estimate of GHG emissions without the proposed action should be included in a NEPA review. The temporal bounds for the analysis are determined by the projected initiation of the action and the expected life of the proposed action and its effects.[79] It is noteworthy that the impacts of GHGs can be very long-lasting.[80]

E. Direct and Indirect Effects

NEPA requires agencies to consider the reasonably foreseeable direct and indirect effects of their proposed actions and reasonable alternatives (as well as the no-action alternative).[81] The term "direct effects" refers to reasonably foreseeable effects that are caused by the action and occur at the same time and place.[82] The term "indirect effects" refers to effects that are caused by the action and are later in time or farther removed in distance, but are still reasonably foreseeable.[83] Indirect effects generally include reasonably foreseeable emissions related to a proposed action that are upstream or downstream of the activity resulting from the proposed action.[84] For example, where the proposed action involves fossil fuel extraction, direct emissions typically include GHGs emitted during the process of exploring for and extracting the fossil fuel. The reasonably foreseeable indirect effects of such an action likely would include effects associated with the processing, refining, transporting, and end-use of the fossil fuel being extracted, including combustion of the resource to produce energy. Indirect emissions[85] are often reasonably foreseeable since quantifiable connections frequently exist between a proposed activity that involves use or conveyance of a commodity or resource, and changes relating to the production or consumption of that resource.[86]

As discussed in Section IV(A), agencies generally should quantify all reasonably foreseeable emissions associated with a proposed action and reasonable alternatives (as well as the no-action alternative). Quantification should include the reasonably foreseeable direct and indirect GHG emissions of their proposed actions. Agencies also should disclose the information and any assumptions used in the analysis and explain any uncertainty.[87] In assessing a proposed action's, and reasonable alternatives', reasonably foreseeable direct and indirect GHG emissions, the agency should use the best available information.[88] As with any NEPA review, the rule of reason should guide the agency's analysis and the level of

[76] *See* 42 U.S.C. 4332(2)(C), 4332(2)(E), and 40 CFR 1502.14(e), 1501.5(c)(2). The purpose and need for action usually reflects both the extent of the agency's statutory authority and its policies.

[77] *See* 40 CFR 1502.15 (providing that environmental impact statements shall succinctly describe the environmental impacts on the area(s) to be affected or created by the alternatives under consideration).

[78] *See, e.g.*, CEQ, Memorandum to Agencies: Forty Most Asked Questions Concerning CEQ's NEPA Regulations, Question 3, "No-Action Alternative" (1986) ("This analysis provides a benchmark, enabling decisionmakers to compare the magnitude of environmental effects of the action alternatives").

[79] CEQ, *Considering Cumulative Effects Under the National Environmental Policy Act* (1997), *https://ceq.doe.gov/publications/cumulative_effects.html*. Agencies also should consider proposed actions pursuant to E.O. 13653, *Preparing the United States for the Impacts of Climate Change*, 78 FR 66817 (Nov. 6, 2013), which considers how capital investments will be affected by a changing climate over time.

[80] Elevated concentrations of carbon dioxide will persist in the atmosphere for hundreds or thousands of years, so the earth will continue to warm in the coming decades. The warmer it gets, the greater the risk for more severe changes to the climate and the earth's system. EPA, *Impacts of Climate Change, https://www.epa.gov/climatechange-science/impacts-climate-change* (last updated Aug. 19, 2022); EPA, *Understanding Global Warming Potentials, https://www.epa.gov/ghgemissions/understanding-global-warming-potentials* (last updated May 5, 2022).

[81] 42 U.S.C. 4332(2)(C)(i); 40 CFR 1508.1(g).

[82] 40 CFR 1508.1(g)(1).

[83] 40 CFR 1508.1(g)(2); *see also Birckhead* v. *Fed. Energy Regul. Comm'n*, 925 F.3d 510, 516 (D.C. Cir. 2019).

[84] These indirect emissions are sometimes referred to as "upstream" or "downstream emissions," described in relation to where in the causal chain they fall relative to the proposed action.

[85] As used in this guidance, "indirect emissions" refers to emissions that are indirect effects of the proposed action.

[86] For example, natural gas pipeline infrastructure creates the economic conditions for additional natural gas production and consumption, including both domestically and internationally, which produce indirect (both upstream and downstream) GHG emissions that contribute to climate change.

[87] *See* 40 CFR 1502.21.

[88] For example, agencies may consider consulting information available from the U.S. Energy Information Administration, the International Energy Agency, the Federal Energy Management Program, or the Department of Energy. *See, e.g.*, U.S. Energy Info. Admin., Annual Energy Outlook 2022 (Mar. 3, 2022), *https://www.eia.gov/outlooks/aeo/*; International Energy Agency (IEA), *Net Zero by 2050*, (May 2021), *https://www.iea.org/reports/net-zero-by-2050*.

Contents

$2.5 billion

Total investment planned by Hanwha Q Cells in the US

8.4GW

Hanwha's planned US module assembly capacity after expansion

1 – 4 years

Estimated payback period for US solar factories only through subsidies

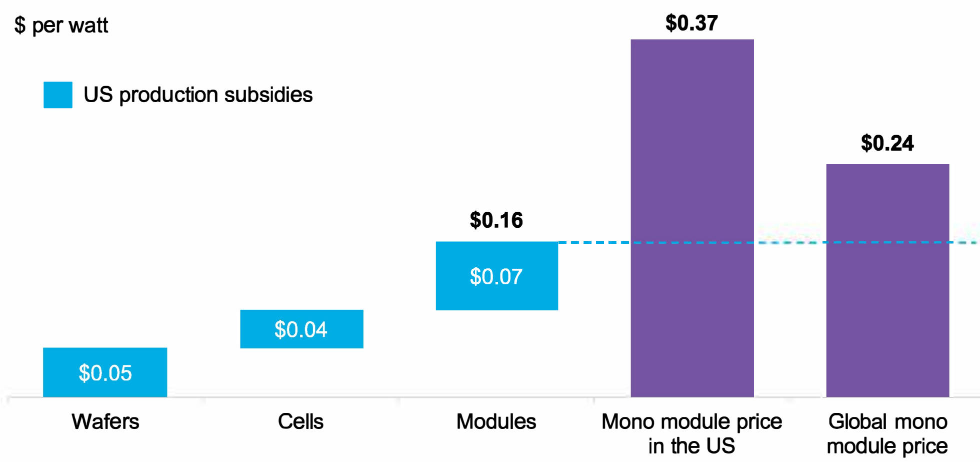
Hanwha's Plan to Make It the Largest US Solar Manufacturer

Hanwha Solutions will invest $2.5 billion in US solar manufacturing, building a new components factory in Georgia with the capacity to produce 3.3 gigawatts (GW) a year of ingots, wafers, cells, and modules and expanding an existing module plant's volume by 3.4GW a year.

The $2.3 billion capex for the integrated factory is higher than BNEF's estimates for US plants, and we estimate it would cost less than $600 million in China. The big difference is likely to be in the land and building costs, and in importing manufacturing equipment.

Hanwha expects to receive about $875 million in annual tax credits under the US production-linked incentive in the Inflation Reduction Act (IRA), or $0.16 per watt from the integrated factory. The total subsidies amount to two-thirds of the selling price of modules made in China, which is currently $0.24 in markets without import restrictions, and almost half of the US price of $0.37.

Figure 1: US solar production subsidies compared with US, China module prices



Source: BloombergNEF. Note: Refers to average module prices recorded on January 4, 2023.

The company would recover the $2.5 billion investment in the new 6.7GW of annual capacity in just over three years from the subsidies and could earn about $2.5 billion a year in module sales at current prices, if the plants operated at full capacity. The IRA makes US solar manufacturing very lucrative despite the country's difficult business environment, and this will not be the last announcement of major capacity building.

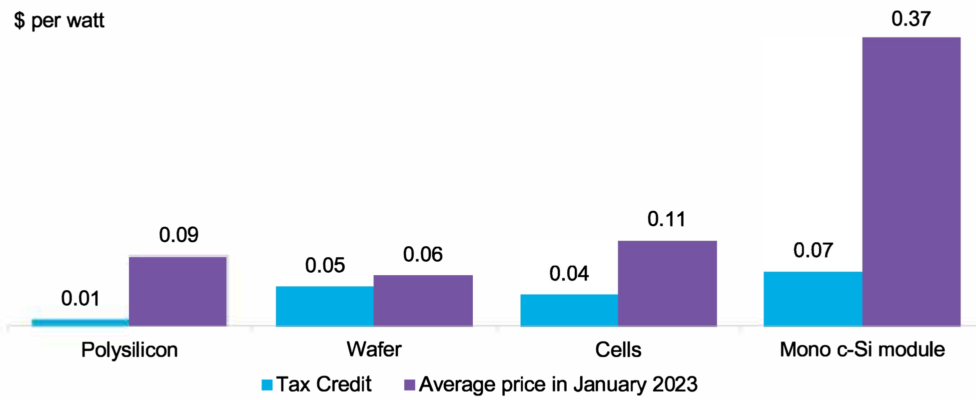
BNEF estimates that the initial capex of new module factories in the US would pay itself back just from subsidies in one to four years assuming full utilization and the selling price of the modules covers the operating cost of making them.

Upfront costs are lower for expansions of existing factories compared with the construction of brand-new plants. Vertically integrated facilities, such as the one planned by Hanwha, would take longer to get full pay back only from subsidies than just module assembly plants. But this new

Pol Lezcano
plezcano1@bloomberg.net

factory would receive subsidies to cover roughly 30-35% of integrated module production costs, assuming it costs $0.45-0.50 to make in the US.

Figure 2: Tax credits for US solar factories and average January 2023 component prices

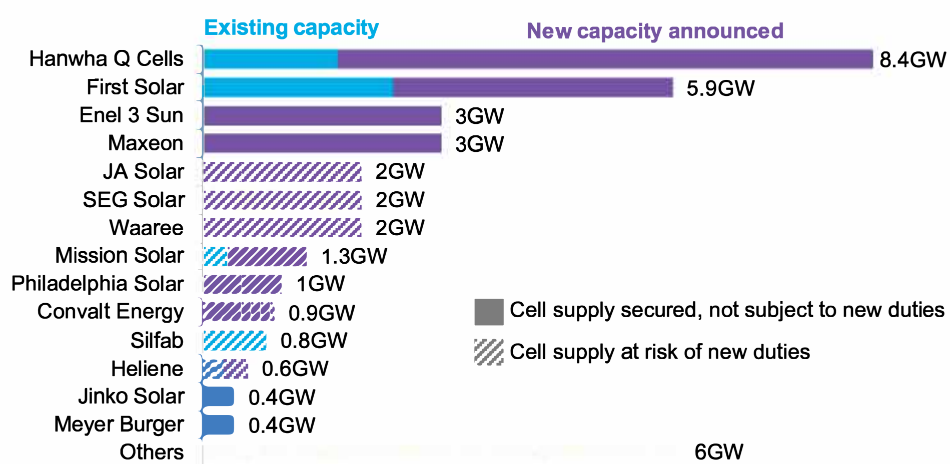


Source: BloombergNEF. Note: Conversion factor of 2.72g/W used to convert polysilicon from metric tons to watts. Conversion factor of 7.72W/piece used for wafers.

When completed, Hanwha will have a total 8.4GW of module capacity in the US and will overtake First Solar as the biggest US manufacturer. First Solar plans to have almost 6GW of annual thin-film module capacity in the coming years, up from its current 2.4GW. JA Solar, one of the biggest solar makers globally, just announced a new 2GW factory too, its first investment in the US.

New prohibitively high US duties on cells from Southeast Asia are expected to go into effect starting December 2024. The tariffs could make it difficult for over 18GW of yearly planned module factories in the US to source high-quality cells tariff-free. Other firms, such as First Solar, Hanwha Q Cells or Maxeon, will likely be exempted from the tariffs by the US Department of Commerce or plan to make their own cells in the US.

Figure 3: Existing and announced US annual module manufacturing capacity (GW/year)



Source: BloombergNEF. Note: Some of the companies plan to make their own cells or will not be subject to existing and new US duties on cells.

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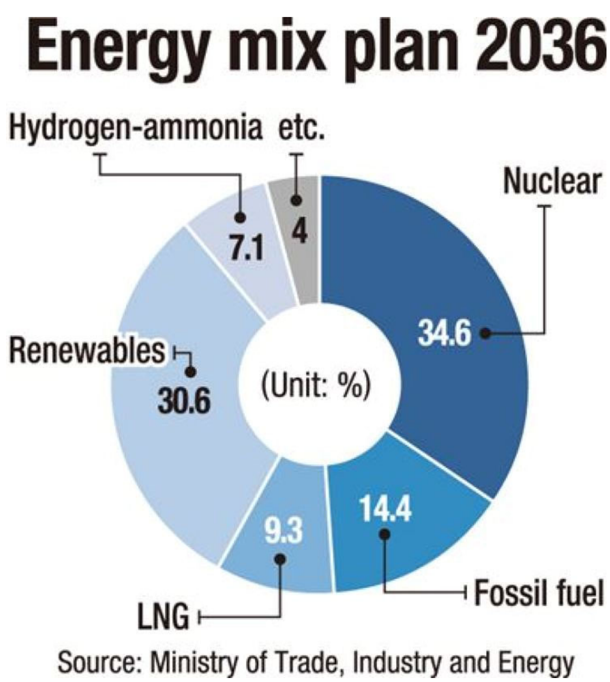
Korea to boost share of nuclear power to 34.6% of energy mix by 2036

Posted : 2023-01-12 16:21

Updated : 2023-01-12 16:27



Gov't also plans to raise reliance on renewables to 30.6% from current 6.2%

By Lee Kyung-min

Korea will increase the proportion of nuclear power to over 30 percent of the country's total energy mix by 2036, while the share of renewable energy will rise to 20 percent, the government said Thursday. The proportion of fossil fuel and liquefied natural gas (LNG) will be drastically reduced to below 15 percent and 10 percent, respectively.

The Ministry of Trade, Industry and Energy said the proportion of nuclear energy will be raised to 34.6 percent by 2036, up from 23.4 percent in 2018. The proportion of renewables will rise to 30.6 percent, up from 6.2 percent during the same period.

The plan is the final version of the new energy directives under the Yoon Suk Yeol administration announced in July, when he reiterated the need to place greater emphasis on nuclear energy as not only a power source but an export growth driver. The set of policies have since undergone reviews by relevant ministries, public hearings and parliamentary standing committees. They have also been subject to environmental impact studies.

The proportions of fossil fuel and LNG will fall to 14.4 percent and 9.3 percent in 2036, down from 41.9 percent and 26.8 percent in 2018, respectively.

Carbon neutrality

"Korea will rely more on nuclear power generation and renewables instead of fossil fuel and LNG," the ministry said. "The balanced energy mix will advance the effective use of renewables to better achieve carbon neutrality."

Korea will need energy generation facilities with a maximum capacity of 143.9 gigawatts (GW), in order to help guarantee a stable supply of 118.0 GW needed by the entire country by 2036.

The renewable energy portfolio will be reoriented to reduce the current heavy reliance on solar energy and instead raise the proportion of wind power.

The facility capacity ratio of solar energy to wind energy will come to 66 to 34 in 2036, a revision from 92 to 8 in 2021.

The new energy drive will seek ways to overhaul the current unified and outdated power trading system.

In the first half of this year, the government will establish a new power market that accurately prices each energy source based on individual characteristics. Also reflected will be the differing needs and interests of power generators and suppliers.

The new market will be able to meet the real-time needs of energy users, enabled by the abolishment of the current 24-hour delay between orders and receipts of power sources that are traded.

The trading interval will be shortened to 15 minutes, a reduction from a one-hour interval to better meet fluctuations in market demand.

Also to be revised is the method of setting the system marginal price (SMP), which is the wholesale price Korea Electric Power Corp. (KEPCO) pays to power generators to buy electricity.

The new market will also allow the trading of backup power sources.

The government will foster trading or renewable energy sources under a Power Purchase Agreement (PPA), which is a long-term contract whereby a business agrees to buy electricity directly from a renewable energy vendor.

https://angusreid.org/canada-energy-nuclear-power-oil-and-gas-wind-solar/

As support for nuclear energy increases, two-in-five say they'd be comfortable with a plant within 50 km

Three-in-five Canadians want further development of nuclear power in the country

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January 11, 2023 – As the world pushes towards net-zero emissions targets, and away from the war-influenced roller coaster of fossil fuel prices, many countries – including Canada – are putting the nuclear option back on the table.

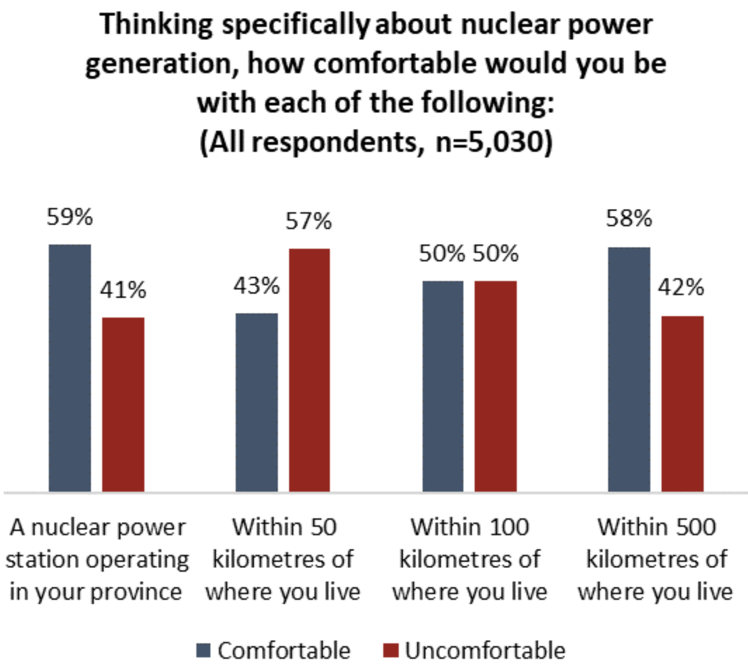
Touted as a low greenhouse gas emission energy source, and a way to insulate against the volatile prices of fossil fuels, nuclear power has returned to vogue following a year of oil price shocks.

New data from the non-profit Angus Reid Institute finds increasing support from Canadians for nuclear power. In June 2021, half (51%) of Canadians said they would like to see further development of nuclear power generation. Now approaching three-in-five (57%) say the same.

Over a decade ago, in the wake of the 2011 Fukushima nuclear disaster, there was a global move away from nuclear power. Quebec decommissioned its only nuclear power plant in 2012, while Ontario in 2020 had planned a phase out at its Pickering plant, which has since been delayed.

Proximity is a key consideration with Fukushima and the 1986 Chernobyl catastrophe in recent memory. The latter irradiated a more than 4,000 square kilometre area around the plant still closed for the most part to human activity. However, two-in-five (43%) Canadians say they would be comfortable with a nuclear power plant operating within 50 kilometres of where they live. That proportion increases when Canadians consider a plant operating within 500 kilometres of their home (58%) or within their province (59%).

Further, the data indicate strong support among Canadians for increasing development of solar (81%) and wind power (74%). Support for the continued development of crude oil is muted nationally (50%), but higher in regions where it represents a significant economic pillar – Alberta (75%), Saskatchewan (72%) and Newfoundland and Labrador (72%).



More Key Findings:

- Among the energy sources surveyed, Canadians are least supportive of the expanded use of hydraulic fracturing, also known as fracking (31%), and coal mining (19%).
- Quebec is the only province in which a majority (56%) oppose the expansion of nuclear power. Quebecers (70%), alongside Newfoundlanders and Labradorians (63%), say they are uncomfortable with a nuclear power plant in their province at a majority level.
- At least two-thirds of men of all ages believe Canada should expand nuclear power as an energy source. Women are divided over the increased use of nuclear power (43% support, 38% oppose).
- More than four-in-five (86%) past Conservative voters support the expansion of the use of oil and gas in Canada. One-third (32%) of those who voted Liberal in 2021, and one-quarter (23%) of those who voted NDP, say the same.

About ARI
*The **Angus Reid Institute (ARI)** was founded in October 2014 by pollster and sociologist, Dr. Angus Reid. ARI is a national, not-for-profit, non-partisan public opinion research foundation established to advance education by commissioning, conducting and disseminating to the public accessible and impartial statistical data, research and policy analysis on economics, political science, philanthropy, public administration, domestic and international affairs and other socio-economic issues of importance to Canada and its world.*
Because its small population precludes drawing discrete samples over multiple waves, data on Prince Edward Island is not released.

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- **Support high for further development of renewables, lower for fossil fuels**
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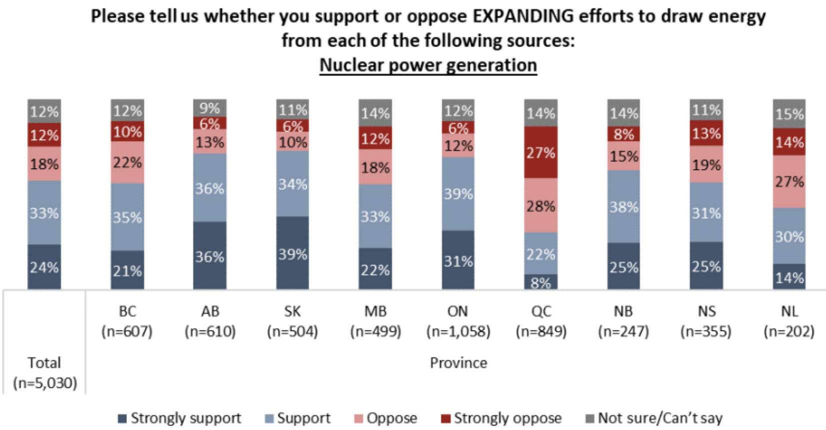
Part One: Nuclear power in Canada

Nuclear power generation has been part of Canada's electricity mix since the early 1960s. There are currently four nuclear power plants operating in two Canadian provinces – three in Ontario and one in New Brunswick. The Canada Energy Regulator estimates the four nuclear stations generate 15 per cent of the country's electricity.

The global energy crisis brought on by Russia's invasion of Ukraine increased interest in nuclear power. Nuclear power is also seen as "critical" to meeting global net zero emissions targets by the administration of U.S. President Joe Biden and the International Energy Agency. Last year, the Canadian government agreed, announcing $1 billion in funding for small modular nuclear reactors. However, there are significant concerns with Canada's aging nuclear power plants. All of Canada's nuclear reactors were built between the 1960s and 1990s, more than half of which have aged beyond their designed 30-year operating lifetime. There are also persistent concerns over the storage of nuclear waste, which must be isolated for hundreds of years. Canada has generated 2.5 million cubic metres of radioactive waste from its history of nuclear power production, 99 per cent of which is graded as having "low-level" radioactivity. Currently, nuclear waste is stored at seven locations in Manitoba, Ontario, Quebec, and New Brunswick, mostly near active or former nuclear reactors.

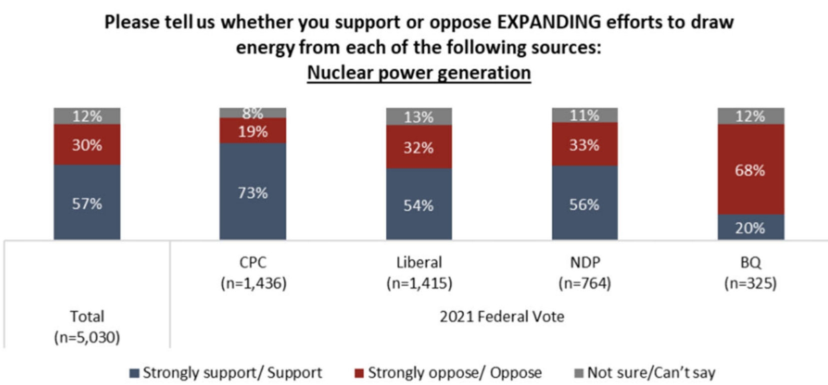
Three-in-five Canadians support expanding nuclear power generation

Approaching twice as many Canadians support the expansion of nuclear power in the country (57%) as oppose it (30%). Support for further nuclear power generation is high in two provinces that currently have nuclear power plants operating, Ontario (70%) and New Brunswick (63%). Those two provinces have begun exploring smaller so-called "modular nuclear reactors", alongside Saskatchewan (73%) and Alberta (71%), where support for more nuclear power is also high. Opposition to the further development of nuclear power is highest in Quebec (56%), which decommissioned its only nuclear power plant in 2012.

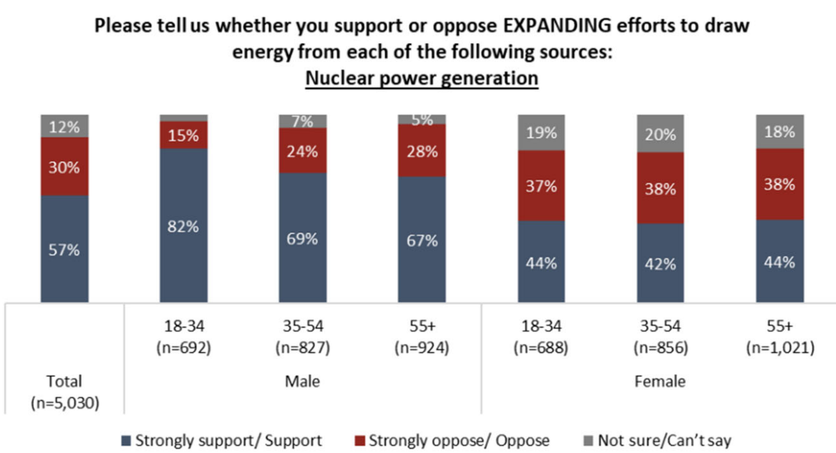


Because its small population precludes drawing discrete samples over multiple waves, data on Prince Edward Island is not released.

Past Conservative voters are more supportive of further development of nuclear energy (73%) than those who voted Liberal (54%) or NDP (56%). Still, more than half of those who voted for those two parties in 2021 believe nuclear power should be expanded in Canada:



Men, and especially those aged 18- to 34-years old, are much more supportive of Canada increasing its use of nuclear power than women. Women of all ages are divided over the prospect of increasing nuclear power generation than not. This gender divide over nuclear power support has been seen in public opinion [dating back to the 1970s](#).

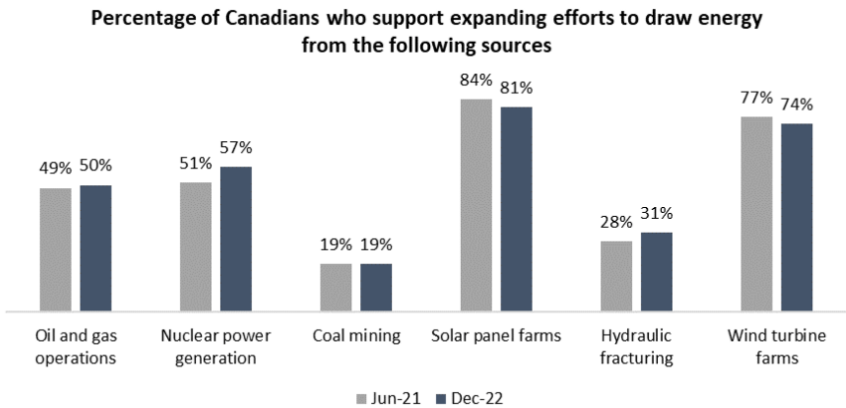


Desire to expand nuclear increased in last year

2022 saw a resurgence in appreciation for the potential of nuclear power, after a period of decline for the industry brought on by the Fukushima nuclear disaster in 2011. That year a tsunami caused a nuclear accident at Japan's Fukushima nuclear power plant. In the aftermath, several countries, including Japan and Germany, began scaling back their nuclear power generation. Ontario, too, had planned to phase out its Pickering plant, though it has since delayed that plan.

An oil price shock in 2022 brought on by Russia's invasion of Ukraine has made some countries delay or reconsider their nuclear phaseouts. With many countries setting net zero emissions goals, there is significant appeal in nuclear power as a low emission energy source.

With all this in the background, Canadian support for nuclear power expansion has grown by six points (51% to 57%) in the last 18 months. Meanwhile, support for the increase of supply of other sources such as oil and gas, coal, solar, and wind is stable:

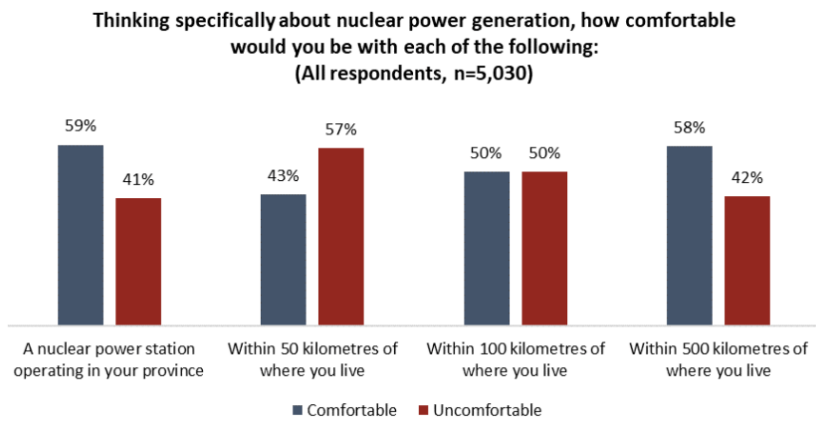


How close is too close?

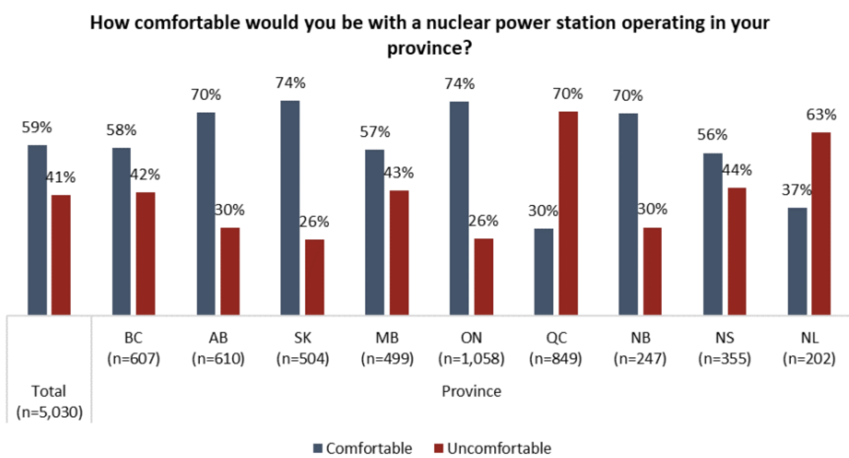
In the history of nuclear power generation, only two events have been designated a "major accident" by the International Nuclear Event Scale: the 1986 Chernobyl disaster and the 2011 Fukushima disaster. Two North American disasters – an accident in Chalk River, Ont. in 1952 and the partial meltdown at Three Mile Island in 1979 – are rated lower on the scale.

The disaster at Chernobyl required an initial evacuation of around 30 kilometres from the centre of the power plant, while the disaster at Fukushima required a smaller evacuation of 20 kilometres. Both disasters spawned exclusion zones that persist to this day, though the one around Chernobyl is much larger in size – 4,143 square kilometres – than the one around Fukushima – 207 square kilometres. Chernobyl killed 30 people initially and 60 of radiation induced cancer. A UN report on Chernobyl in 2005, which has been contested, estimated 4,000 people died in the years since due to disaster-related illnesses. There has only been one casualty due to radiation from the Fukushima disaster, but more than 2,000 people died as a result of the evacuation.

The potential for nuclear disaster means proximity is an important consideration when it comes to nuclear power plants. While there is much less appetite for Canadians for a nuclear power plant to be operating closer to their home than farther away, two-in-five (43%) say they would be comfortable with one operating within 50 kilometres of where they live. That number rises to three-in-five (58%) for a nuclear power plant operating within 500 kilometres. Overall, the majority (59%) say they would be comfortable with a power plant operating in their province:



In the two provinces where nuclear power plants currently operate – Ontario and New Brunswick – residents are much more comfortable (74% Ontario, 70% New Brunswick) than not (26%, 30% respectively). Majorities of Albertans (70%) and Saskatchewanians (74%), too, say they would be comfortable with a nuclear power plant in their province. Only in Quebec (70%) and Newfoundland and Labrador (63%) do majorities of residents say they would be uneasy with nuclear power generation happening in their province:



Because its small population precludes drawing discrete samples over multiple waves, data on Prince Edward Island is not released.

Part Two: Oil and gas, and the green alternatives

In 2021, the federal government passed a law to commit to achieving net-zero greenhouse gas emissions by 2050. The road map to reaching that goal includes reducing emissions by 40 to 45 per cent from 2005 levels by 2030.

Electricity generation was the sixth largest source of greenhouse gas emissions in Canada in 2020, although there have already been significant reductions in emissions in that sector since the turn of the century. According to the government, greenhouse gases from combustion-based electricity generation have declined by 52 per cent between 2005 and 2020. This is attributed in a large part due to the decline in the use of coal across the country, and increase in the use of renewables.

Renewable sources currently represent 18.9 per cent of Canada's total energy supply, meaning non-renewable, and emissions-intensive energy, still plays a significant role.

Support high for further development of renewables, lower for fossil fuels

There are high levels of support among Canadians for the expansion of solar (81%), and wind (74%) power generation. For both, support is higher among women than men.

There is less support overall for further development of fossil fuels. Traditional oil and gas receive the most support, with half of Canadians (50%) on board with expansion of that energy source. There is less enthusiasm for hydraulic fracturing (31%) – also known as fracking – and coal mining (19%). For all three fossil fuel sources, men are more interested in seeing their expansion than women:

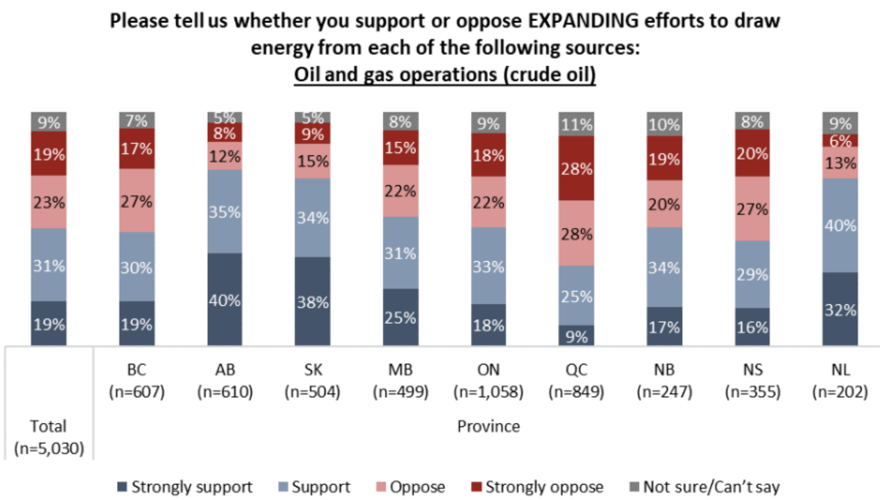
Support for expanding each energy source in Canada							
	Total (n=5,030)	Male			Female		
		18-34 (n=692)	35-54 (n=827)	55+ (n=924)	18-34 (n=688)	35-54 (n=856)	55+ (n=1,021)
Solar panel farms	81%	78%	76%	78%	83%	83%	86%
Wind turbine farms	74%	76%	69%	68%	80%	76%	77%
Nuclear power generation	57%	82%	69%	67%	44%	42%	44%
Oil and gas operations	50%	53%	64%	65%	24%	44%	47%
Hydraulic fracturing	31%	46%	43%	38%	21%	26%	18%
Coal mining	19%	28%	25%	20%	13%	17%	12%

There is also more enthusiasm for an increase in the use of fossil fuel from past Conservative voters than those who voted for other parties in the 2021 election. Those who voted Liberal, NDP and Bloc Québécois are much more supportive of renewable sources than those who voted Conservative, though notably a majority of past CPC voters support the expansion of solar (65%) and half (53%) the expansion of wind:

Support for expanding each energy source in Canada					
	Total (n=5,030)	2021 Federal Vote			
		CPC (n=1,436)	Liberal (n=1,415)	NDP (n=764)	BQ (n=325)
Solar panel farms	81%	65%	94%	96%	90%
Wind turbine farms	74%	53%	89%	93%	90%
Nuclear power generation	57%	73%	54%	56%	20%
Oil and gas operations	50%	86%	32%	23%	26%
Hydraulic fracturing	31%	59%	15%	10%	21%
Coal mining	19%	36%	7%	7%	4%

Regional divide evident in support for expansion of oil and gas

The extraction of oil and gas represents significant pillars in the economies of Alberta, Saskatchewan and Newfoundland and Labrador. In those three provinces, enthusiasm for the expansion of oil and gas is much higher than elsewhere in the country. Those in Quebec (55%) are the most likely to oppose more energy being drawn from oil and gas. Opinion is much more divided elsewhere in the country:



Because its small population precludes drawing discrete samples over multiple waves, data on Prince Edward Island is not released.

Survey Methodology:

The Angus Reid Institute conducted an online survey from Nov. 28 to Dec. 3, 2022 among a representative randomized sample of 5,030 Canadian adults who are members of Angus Reid Forum. For comparison purposes only, a probability sample of this size would carry a margin of error of +/- 1 percentage points, 19 times out of 20. Discrepancies in or between totals are due to rounding. The survey was self-commissioned and paid for by ARI.

For detailed results by age, gender, region, education, and other demographics, click here.

To read the full report, including detailed tables and methodology, click here.

To read the questionnaire in English and French, click here.

Image – Jason Paris/Flickr

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https://www.ntsb.gov/Advocacy/Activities/Pages/Homendy-20230111.aspx

Keynote to Transportation Research Board

THE HONORABLE JENNIFER HOMENDY

CHAIR, NATIONAL TRANSPORTATION SAFETY BOARD

REMARKS AS PREPARED FOR DELIVERY BEFORE THE TRANSPORTATION RESEARCH BOARD

JANUARY 11, 2023, 102ND ANNUAL MEETING

WASHINGTON, DC

June 10, 1999: Bellingham, Washington.

A hazardous liquid pipeline ruptures and releases over 200,000 gallons of gasoline into a creek that flows through Whatcom Falls Park.

About 90 minutes later, the gas ignites and burns 1 ½ miles along the creek. The massive fireball sends a plume of smoke 30,000 feet in the air, which is visible from Vancouver, Canada.

Three children are killed.

One teenager, who's flyfishing, is overcome by fumes, loses consciousness, and drowns.

Two other children survive the initial blast but suffer second- and third-degree burns over 90% of their bodies and die the next day.

They're just 10 years old.

Fast forward to January 6, 2005: Graniteville, South Carolina.

The crew of a freight train traveling 47 miles per hour encounters a misaligned switch that diverts them from the main line onto an industrial track leading to a textile mill, where their train hits an unoccupied, parked train.

The collision derails both locomotives and 16 of the 43 freight cars on their train, including three tank cars containing chlorine, one of which breaches, releasing chlorine gas.

One tank car might not seem like a lot, but the volume of a cloud of chlorine gas is 450 times greater than the volume of the liquid released.

The locomotive engineer, who's just 28 years old, six employees of the textile mill, a truckdriver at the mill, and one local resident die of chlorine gas inhalation within minutes of exposure.

Over 500 people suffering from respiratory difficulties are taken to local hospitals. Over 5,000 others are evacuated.

The locomotive engineer, whose parents I came to know, survives the collision but walks about 100 yards and lays down, hoping to shield himself from the toxic cloud.

Unfortunately, chlorine gas is 2 ½ times heavier than air, so it settles to the ground, where the locomotive engineer is laying. He dies.

One more.

Labor Day 2019. It's 3 a.m. onboard the *Conception*, a dive boat anchored about a mile off the coast of Santa Barbara, California.

Thirty-three passengers and one crewmember are below deck in the bunkroom asleep when a fire erupts right above them.

The bunkroom has two exits: the main exit up a set of stairs and a difficult-to-locate emergency escape hatch. Unfortunately, both lead to the same location: directly into the path of the fire.

The *Conception* burns to the waterline. Just after daybreak, the vessel sinks, taking 34 souls along with it.

It remains the deadliest marine accident in recent U.S. history.

When I was asked to deliver this keynote address, I considered talking about safety challenges and opportunities in aviation, commercial space, maritime, pipelines, rail and transit, and on our roadways — an area I have a tremendous passion for.

I considered talking about some of our safety recommendations, from mandating SMS — safety management systems — to improving fishing vessel safety, to requiring collision avoidance and V2X in all vehicles, to protecting all road users through a Safe System Approach — all of which are on our Most Wanted List.

I considered talking about our recent research on turbulence, which is aimed at preventing injuries to flight attendants and passengers. Or the safety risks of lithium-ion battery fires in electric vehicles.

I want to take a second and mention that I'm concerned about the increased risk of severe injury and death for all road users from heavier curb weights and increasing size, power, and performance of vehicles on our roads, including electric vehicles.

A GMC Hummer EV weighs over 9,000 pounds, up from about 6,000 pounds. Its gross vehicle weight rating is a staggering 10,550 pounds. The battery pack alone weighs over 2,900 pounds — about the weight of a Honda Civic.

The Ford F-150 Lightning is between 2,000 and 3,000 pounds heavier than the non-electric version. The Mustang Mach-E, Volvo XC40 EV, and RAV4 EV are all roughly 33% heavier. That has a significant impact on safety for all road users.

Now I want to be clear: I'm inspired by the Administration's commitment to phasing out carbon emissions. We do have a climate crisis that needs to be addressed. The U.S. transportation sector accounts for the largest portion of U.S. greenhouse gas emissions, and I firmly believe it is a human right to breathe clean air.

But we have to be careful that we aren't also creating unintended consequences: more death on our roads. Safety, especially when it comes to new transportation policies and new technologies, cannot be overlooked. *Ever*.

As I look across this room, I see so many friends and colleagues and people I look forward to meeting: state DOTs, federal agencies, associations, and researchers. All of you are safety champions. Thank you for your work!

Speaking of safety champions, I'd like to thank Nat Ford for inviting me and for an extraordinary year leading TRB. I'd also like to welcome incoming Chair Shawn Wilson and add my congratulations to the award winners on stage here with me; we're all safer for your efforts — thank you!

I'd like to thank Victoria, Neil, and the entire TRB team for the incredible work you do.

And, of course, I want to acknowledge my colleagues from the NTSB here in the room or watching virtually. I'm so proud to work with each of you.

What I want to focus on today is why we're here — and it's not the receptions that follow transportation camp!

What I want to focus on today is why we do what we do at the NTSB and why I'm so passionate…we're so passionate…about safety.

Their names are Liam, Wade, and Stephen: the three children killed in the Bellingham pipeline rupture.

Their names are Chris, Steven, Tony, Allen, John, "Rusty," Willie Charles, Joseph, and Willie Lee — the victims of the Graniteville train collision.

And their names are J.P., Patricia, Neal, Marybeth, Charlie, Kendra, Raymond, Justin, Lisa, Kristy, Yuko, Vaidehi, Adrian, Andrew, Yulia, Dan, Allie, Jang, Sunil, Carrie, Kristian, Kaustubh, Sanjeeri, Steve, Diana, Tia, Berenice, Evan, Angela, Michael, Fernisa, Nicole, Ted, and Wei — all of whom perished on the Conception.

There are so many others whose names don't make headlines — including those hurt by decisions made decades ago — decisions guided by systemic racism, poverty, inequality, and sexism.

That includes sexual harassment, especially in transportation. Seventy-one percent of women in aviation experience sexual harassment at work. That has an impact on performance and safety.

We're fighting for the nine people who died two Januarys ago in Avenal, California, in a horrific crash that could've been prevented with speed limiters and in-vehicle alcohol detection technology — two things the NTSB has been calling for for years. Seven of the victims were children. The oldest was 15 and the youngest was just 6 years old.

We're fighting for the seven people who died — including a 10-year-old — in a 2019 air tour helicopter accident in Kekaha, Hawaii.

Sightseeing flights, helicopter air tours, hot air balloon rides, and similar experiences are not held to the same safety standards as other commercial flights.

I'm pleased that, today, the FAA proposed extending SMS requirements to charter, commuter, air tour operators, and aircraft manufacturers — all of which are longstanding NTSB recommendations. That's a great first step!

We're fighting for the 43,000 people who die annually on our roads and the millions more who are injured. Not just drivers, but all road users. No matter their race, ethnicity, ability, income, or where they live. No matter whether they're walking, biking, rolling, or driving.

That is who the NTSB is fighting for…who we're all fighting for.

And let's not forget what we're fighting for: zero in every mode of transportation.

Plenty of people think zero deaths is an unrealistic goal.

I remember one op-ed called zero a "pipedream" when Secretary Buttigieg embraced the goal last year — the first U.S. Secretary of Transportation to do that. It was brave.

What about you? Who thinks we'll never see a day with zero transportation deaths?

Every time I ask that question, no one wants to put their hand up. I understand.

Then think about a good goal. Should we aim to cut transportation deaths by 25%? How about 50%? By when?

Keep that goal in mind.

Now, let me ask you: what's an acceptable number of transportation deaths for YOUR family?

Zero just became real, didn't it?

There's no acceptable amount of injury or death when it's OUR colleague. OUR best friend. OUR partner. OUR parent. OUR son. OUR daughter.

When we say zero is impossible, there's an unspoken caveat: as long as "*my*" *people are safe.*

When anyone plans for more deaths, calling them projections, it says there's an "acceptable" number of lives lost.

It says some death is OK.

It says some people don't count.

That's the message we send to the grieving parents of Liam, Stephen, and Wade.

To Chris's parents.

To the 34 Conception families.

Hear me: it's NOT acceptable. Not a single life lost. Zero has to be just as real for them as it is for us.

We must care about the safety of strangers: people we will never meet.

Because it's the *right* thing to do.

It's what drives everyone at the NTSB and many of you.

Getting to zero isn't easy. You all know that.

What I'm about to say might surprise you: to take on a challenge as big as zero and succeed, we need more than smarts.

Don't get me wrong; we need your research to inform new policies, new systems, new regulations, new laws — especially when we have so much advancement in new technology. And we need safety champions to bring it all to life.

We need everyone in this fight.

That's the power of TRB and everyone here: you have incredible power to help get us to zero.

But we also need something else — something less tangible.

We need to be fearless: unafraid to open our hearts to the preventable pain of transportation disasters and to fearlessly pursue solutions.

Fearless in refusing to take "no" for an answer.

Fearless in having the political will to do the hard things, say the hard things.

Fearless in the conference rooms and boardrooms where we work. In our communities and in our personal lives.

Fearless.

That's why I told you stories — true stories — not statistics.

That's why I talked to you today about people I'm fighting for…we're fighting for.

Here's one last story. It's a familiar one.

In 1961, President John F. Kennedy challenged the nation to land a man on the moon and return him safely to the earth. His deadline? By the end of the decade — just 8 ½ years to make the impossible *possible*.

You all know what happened next.

We did put a man on the moon — two, in fact! — and days later, we safely returned them to earth.

Since then, a dozen Americans have walked on the lunar surface. This number will soon climb when the first woman and the first person of color join their ranks, courtesy of the Artemis missions!

JFK's moon shot began not with facts, but with a *feeling*.

A powerful feeling that we could do more than dream of reaching new heights — we could achieve it.

Brilliant minds — like all of you here — fought day in, day out, to make it happen.

People like you fearlessly pursued the greatest feat of human ingenuity ever undertaken at the time.

The feelers.

The fighters.

The fearless.

These are the people who do the impossible. Who always have throughout human history, and who *always* will.

These are the people we need right now, in this moment.

Because zero is our moon shot.

That's what we're fighting for.

In the year ahead, I challenge you: be a feeler.

Feel for Liam, Stephen, and Wade — three kids who just wanted to go fishing or play at the park.

Feel for Chris and the eight other people who died in a toxic cloud caused by a rail disaster.

Feel for the 34 people who set sail on a scuba trip…34 people who never made it back home.

Let it fuel you as you fight for safety.

Fight for their bereaved families.

Fight for all the grieving families who've lost someone they love to a transportation disaster.

Fight so your family is never one of them.

Most of all, be fearless.

Fearlessly pursue zero as your only goal, in every mode of transportation.

Zero at sea and on our waterways.

Zero on passenger rail and freight rail.

Zero on our transit systems.

Zero on our streets and sidewalks.

Zero in our bike lanes and bus lanes.

Zero along every inch of pipeline running under your feet and mine.

Zero in our skies and in our airspace.

Zero under the stars of outer space.

The feelers. The fighters. The fearless.

That's you.

You are the leaders we need right now — this very instant.

Leaders who feel it in their bones: *safety is my calling, not just a career*.

I come from the labor movement, and we have a saying: mourn the dead and fight like hell for the living. We need leaders who fight like hell, not for the safety of "their" people, but of ALL people.

Leaders who recruit their heart and soul to this fight, in addition to their intellect.

Leaders who are fearlessly vulnerable.

Leaders who never forget what we're fighting for…*who* we're fighting for.

If you do all that...you *will* achieve the "rejuvenation" this meeting calls for. You will get us to zero.

When it gets hard — and it will — look to the people next to you for strength.

And you can always, always look to the NTSB. I promise you this: we will never, ever give up.

Until there's no longer a need for our safety recommendations.

Until there's no longer a need for the NTSB.

Until we have a safe transportation system for *all*.

Until there's zero.

Thank you.

https://ark-invest.com/wrights-law/#:~:text=Pioneered%20by%20Theodore%20Wright%20in%201936%2C%20Wright%E2%80%99s%20Law,produced%2C%20costs%20will%20fall%20by%20a%20constant%20percentage.

ARK Invest> What Is Wright's Law

The Learning Curve Or The Cumulative Average Model

What is Wright's Law?

Pioneered by Theodore Wright in 1936, Wright's Law aims to provide a reliable framework for forecasting cost declines as a function of cumulative production. Specifically, it states that for every cumulative doubling of units produced, costs will fall by a constant percentage.

Theodore Paul Wright

(May 25, 1895 – August 21, 1970)

Theodore Paul Wright, also known as T. P. Wright, was a U.S. aeronautical engineer and educator. His career spanned numerous positions, including Naval Aircraft Inspector, Executive Engineer at the Curtiss Aeroplane Company, Chief Engineer of the Curtiss-Wright Corporation. He was a member of the National Defense Advisory Committee under President Franklin D. Roosevelt, Assistant Chief of the Aircraft Section in the Office of Production Management, Chairman of the Joint Aircraft Committee, Director of the Aircraft Resources Control Office and a member of the War Production Board.

While studying airplane manufacturing, Wright determined that for every doubling of airplane production the labor requirement was reduced by 10-15%. In 1936, he detailed his full findings in the paper "Factors Affecting the Costs of Airplanes." Now known as "Wright's Law", or experience curve effects, the paper described that "we learn by doing" and that the cost of each unit produced decreases as a function of the cumulative number of units produced.

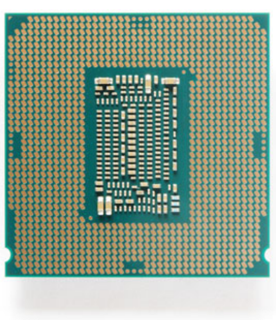
With his extensive knowledge, Wright played a key role in expanding U.S. aircraft production, especially in developing essential statistical tools that provided accurate information on industrial capacity and measured worker efficiency.

Wright’s Law Formula

Y = cumulative average time (or cost) per unit
X = cumulative number of units produced
a = time (or cost) required to produce 1st unit
b = slope of the function

$$Y = aX^{b}$$

What about Moore’s Law?



What is the difference between Wright’s Law and Moore’s Law?

Moore’s Law – named after Gordon Moore for his work in 1965 – focuses on cost as a function of time. Specifically, it states that the number of transistors on a chip would double every two years. Wright’s Law on the other hand forecasts cost as a function of units produced.

Measured over the decade to 2015, ARK found that a price forecast based on Wright’s Law was 40% more accurate than one based on Moore’s Law.

Read More

Example

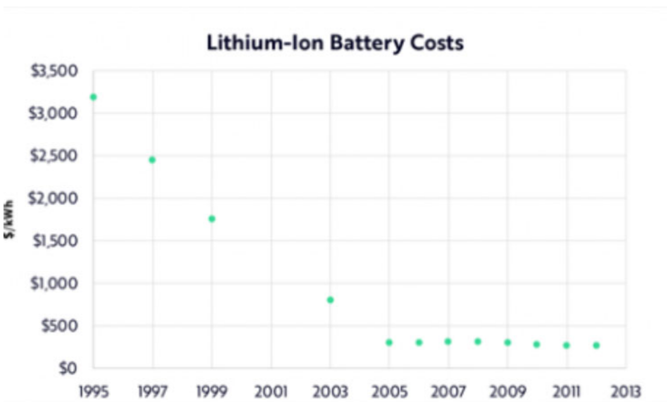
A Real-Life Use Case For Wright's Law

Lithium-ion batteries offer a good case study highlighting the benefit of using Wright's Law over Moore's Law.

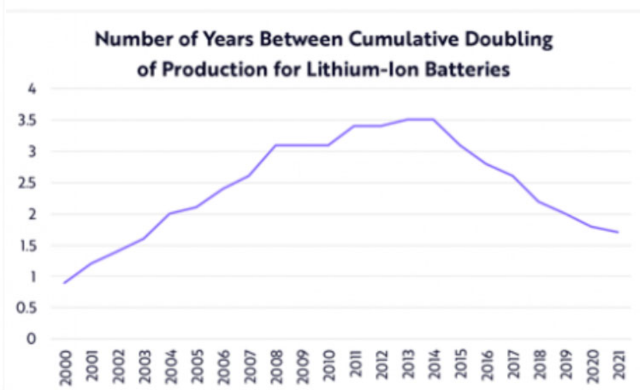
Based on Moore's Law and as shown in the chart, most analysts would conclude that lithium-ion batteries matured by 2005. After two decades of declining roughly 10% on average per year, lithium ion battery costs flattened out.

However, those 10% declines pushed the unit-cost of lithium-ion batteries across a critical threshold, enabling the production of electric vehicles at scale. One 200+ mile range electric vehicle has as much battery power as 5,000 iPhones, so if just 1% of auto sales were to convert from gas powered to electric, they would more than double the demand for batteries relative to those required for smartphones globally. Recognizing that batteries were about to hit this tipping point, analysts could have forecasted that the time required for the cumulative doubling of production would drop precipitously and that the decline in costs would reaccelerate, as shown in the following charts.

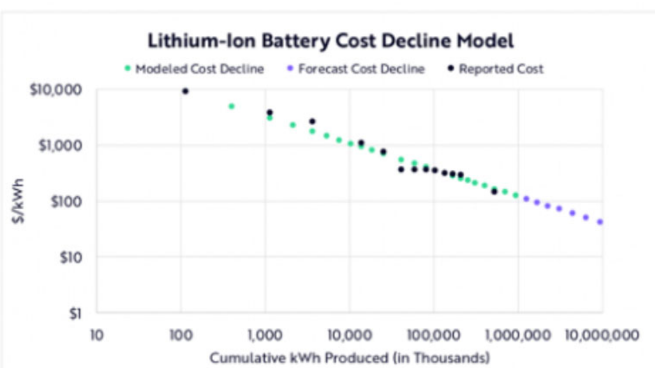
The decline in prices has opened up new segments of the auto market to lithium-ion batteries which, in turn, is pushing them toward an even larger market, utility-scale energy storage.



Source: ARK Investment Management LLC, 2018; IEA, Bloomberg New Energy Finance, Avicenne Energy



Source: ARK Investment Management LLC, 2018; IEA, Bloomberg New Energy Finance, Avicenne Energy



Source: ARK Investment Management LLC, 2018; IEA, Bloomberg New Energy Finance, Avicenne Energy

SAF Group created transcript of comments by COP28 President Designate Dr. Sultan Al Jaber (Group CEO of Abu Dhabi National Oil Company, ADNOC) at Atlantic Council Global Energy Forum on Sat Jan 14, 2023. Video clips at
https://twitter.com/saudTalreyami/status/1614186676129259522
https://twitter.com/UAE_Forsan/status/1614162092948623360

Items in "italics" are SAF Group created transcript

"*Yet we must be honest with ourselves about how much progress we have actually achieved and how much further and faster we truly need to go"*

"We are way off track when it comes to the key Paris goal of holding global temperatures down to 1.5 degrees and the hard reality is that in order to achieve this goal, global emissions must fall 43% by 2030. To add to that challenge, we must decrease emissions at a time of continued economic uncertainty, heightened geopolitical tensions, and increasing pressure on energy security"

"We will pursue global consensus"

"We will work very closely with the UNFCC to move from ambition to real action. We will mobilize the private sector and all other sectors to deliver greater, more meaningful impact"

"We can only succeed if we have an open and constructive dialogue. Let us together create a paradigm shift for tangible progress"

"I urge all parties to help make COP28 a COP of concrete outcomes and practical solutions"

"Where together we can ensure sustainable development for this generation and all generations to come"

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

https://www.ft.com/content/6abb5562-59a0-49a7-8cc0-8fb48e5d6fe9

Fed will not become a 'climate policymaker', says Jay Powell

Colby Smith in Washington and Delphine Strauss in London

Jay Powell has said the Federal Reserve will not become a "climate policymaker", as he mounted a full-throated defence of the US central bank's independence from political influence.

In a speech delivered on Tuesday, the Fed chair said the central bank must steer clear of issues outside its congressionally mandated purview and instead maintain a narrow focus on keeping consumer prices stable, fostering a healthy labour market and ensuring the safety of the country's banking system.

"It is essential that we stick to our statutory goals and authorities, and that we resist the temptation to broaden our scope to address other important social issues of the day," he said at a conference hosted by Sweden's central bank.

"Without explicit congressional legislation, it would be inappropriate for us to use our monetary policy or supervisory tools to promote a greener economy or to achieve other climate-based goals."

He added: "We are not, and will not be, a 'climate policymaker'."

Republican lawmakers have accused the Fed of overreaching its mandate by pledging to consider climate-related financial risks, an area in which Powell on Tuesday said the central bank had "narrow, but important, responsibilities" tied to bank supervision.

"The public reasonably expects supervisors to require that banks understand, and appropriately manage, their material risks, including the financial risks of climate change," he added.

In a panel that followed the remarks, Mervyn King, a former governor of the Bank of England, said central bank independence was a "great responsibility and it cannot be misused by trying to creep into areas, which have not been explicitly delegated by the appropriate political process".

"I worry that people, in the great enthusiasm for doing good, are actually putting at risk central bank independence," he said of climate-related issues. Republican senators last year blocked the appointment of Sarah Bloom Raskin, president Joe Biden's pick to lead bank oversight at the Fed, after taking issue with her calls for regulators to more proactively address financial risks related to climate change.

Several other major central banks have advocated for expanding their remit to include policing of climate risks. Mark Carney, another former governor of the BoE, has been the leading supporter of such a shift.

Powell on Tuesday said central bank independence was particularly important if the Fed was to succeed in its battle to tame inflation, which is still running at multi-decade highs.

"Restoring price stability when inflation is high can require measures that are not popular in the short term as we raise interest rates to slow the economy," he said. "The absence of direct political control over our decisions allows us to take these necessary measures without considering short-term political factors."

Since March, the Fed has raised its benchmark rate from near-zero to just under 4.5 per cent and plans to further squeeze the economy this year. In separate remarks on Tuesday, Fed governor Michelle Bowman said the central bank still has "a lot more work to do" in terms of tightening. She added that the size of the forthcoming rate increases and the eventual stopping point will depend on the data.

"I will be looking for compelling signs that inflation has peaked and for more consistent indications that inflation is on a downward path," she said at the event hosted by the Florida Bankers Association.

Democratic lawmakers have called on the central bank to back off of its tightening plans, warning of unnecessary economic pain and excessive job losses.

"The tools that we have work and I think there's nothing wrong with our mandates," Powell told the panel.

Speaking at the same event in Stockholm, European Central Bank executive board member Isabel Schnabel said monetary policymakers should press ahead with interest rate rises to fight inflation despite the risk that higher borrowing costs could derail global environmental efforts.

“The green transition would not thrive in a high-inflation environment. Price stability is a precondition for the sustainable transformation of our economy,” Schnabel said at the event in Stockholm on Tuesday.

Schnabel’s view aligns with the consensus among central bankers that it is up to governments to drive the transition to cleaner energy, while monetary policymakers should focus on their core task of fighting inflation. She pointed to a “persistent build-up of underlying price pressures” despite the unexpectedly sharp fall in headline eurozone inflation as energy prices subsided.

But Schnabel said the ECB needed to act faster to bring its own investments and lending operations in line with the objectives of the Paris agreement and achieve carbon neutrality by 2050.

The ECB had aimed to make its holdings of corporate bonds more climate-friendly by putting more weight on climate-related criteria when it made new purchases. However because it has stopped increasing its net bond holdings, this policy has “lost much of its punch”, Schnabel added.

Dan Tsubouchi @Energy_Tidbits · Jan 9

china speeding to herd immunity.
@AmChamSh Eric Zheng just now. no official stats but in Shanghai, based on anecdotal evidence at least 70% of people have already got the Covid infection.
set up for sustained #Oil demand recovery on Q2.
thx @business
#OOTT

2,308 3 13

Dan Tsubouchi @Energy_Tidbits · Jan 10

1/2. ICYMI. Biden boost to #Wind #Solar, big hit to #Oil #NatGas permitting

"relative minor and short-term GHG emissions associated with CONSTRUCTION of certain renewable energy projects" = less detailed emissions est. Plus no need to incl emissions to get critical metals.
#OOTT

3,635 1 5 8

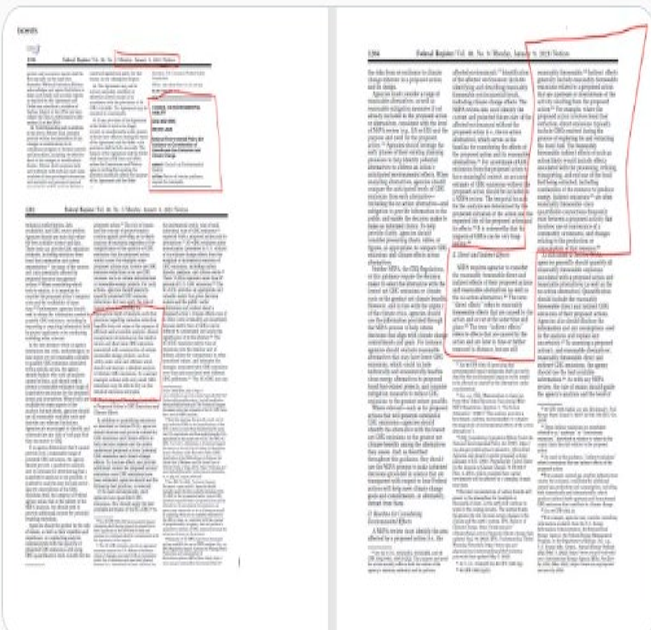
Show this thread

Dan Tsubouchi @Energy_Tidbits · Jan 10

2/2. But #Oil #NatGas infra must include foreseeable direct & Indirect effects ie. explore, production, processing, transportation, etc. Plus incl est $ impact of social cost.

Will any major new #Oil #NatGas infra get permitted or just drawn out for a long time?

#OOTT



1,796 · 1 · 2 · 3

Dan Tsubouchi @Energy_Tidbits · Jan 10

Peak #Oil demand is still years away.

Good reminder #Oil consumption/demand growth may be modest in the 1.4b OECD countries, but can't hold back the 6.4b non-OECD countries from growing economies and petroleum products consumption at stronger rates.

Thx @EIAgov.

#OOTT

> **EIA** @EIAgov · Jan 10
>
> Why would oil prices decline if petroleum consumption increases?
>
> Check out #STEO Between the Lines, a new feature of our monthly forecasts.
>
> ➡️eia.gov/outlooks/steo/...⬅️
>
> Show this thread

4,686 2 5 26

Dan Tsubouchi @Energy_Tidbits · Jan 10

WOW! wonder what brought this on? "it would be inappropriate for us to use our monetary policy or supervisory tools for example to promote a greener economy or achieve other climate based goals. we are not and will not be a climate policymaker @federalreserve chair Powell. #OOTT

23K 7 16 76

Dan Tsubouchi @Energy_Tidbits · Jan 11

Breaking. @SullyCNBC just said FAA grounds all flights nationwide. wonder what cause this computer outage. #OOTT

2,626 1 3 7

Dan Tsubouchi @Energy_Tidbits · Jan 11

good news, domestic departures restarting

however, the chaos will just be starting with pilot max times and other follow on problems

hope the best for people trying to fly today!

> The FAA ✈️ @FAANews · Jan 11
>
> Update 4: The FAA is making progress in restoring its Notice to Air Missions system following an overnight outage. Departures are resuming at @EWRairport and @ATLairport due to air traffic congestion in those areas. We expect departures to resume at other airports at 9 a.m. ET.
>
> Show this thread

1,041 1

Dan Tsubouchi @Energy_Tidbits · Jan 11

For those not near their laptop, @EIAgov released #Oil #Gasoline #Distillates inventory as of Jan 6. Table below compares EIA data vs @business expectations as of 4:30am MT and vs @APIenergy yesterday. Prior to release, WTI was $76.39. #OOTT

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

cts Inventory Jan 8: EIA, Bloomberg Survey Expectations, Al		
rrels)	EIA	Expectations
	18.96	-2.00
	4.11	0.75
	-1.07	-1.17
	22.00	-2.42

s commercial so builds in impact of 0.8 mmb draw from SPR for Ja

ided in the oil data, Cushing had a build of 2.51 mmb for Jan 6 wee

A, Bloomberg

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

943 · 1

Dan Tsubouchi @Energy_Tidbits · Jan 11

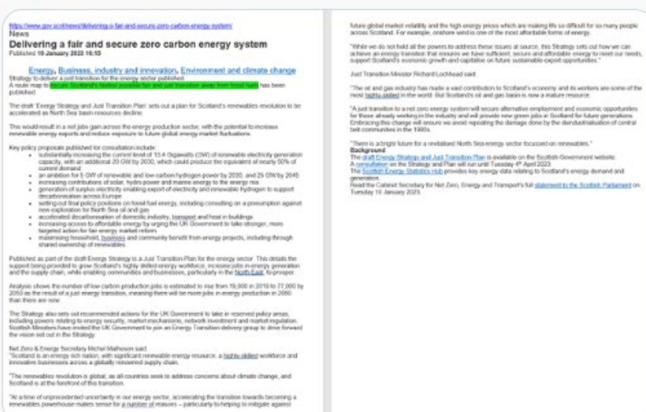
Is this the #energytransition?

Peak #Oil #NatGas demand still years away.

Western #Oil #NatGas exporters CAN, US, now Scotland 👎 prioritize reducing #FossilFuels production.

KSA,UAE, Qatar say Thank You!

#OOTT



News

Delivering a fair and secure zero carbon energy system

Energy, Business, industry and innovation, Environment and climate change

2,483 · 7 · 16

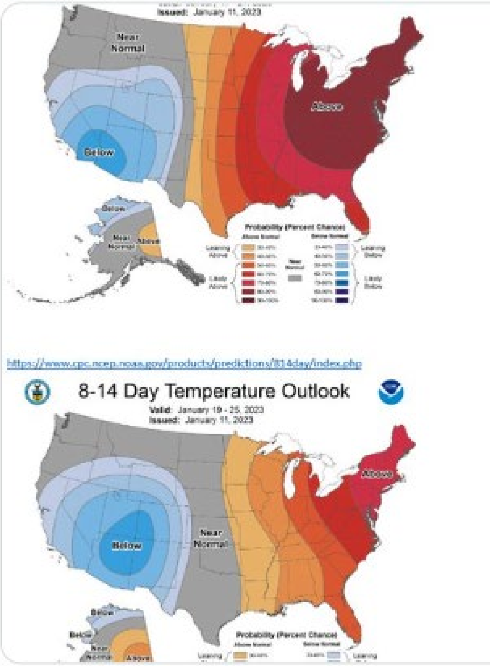
Dan Tsubouchi @Energy_Tidbits · Jan 11

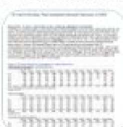
Continued negative tone to HH #NatGas prices.

@NOAA updated fcast still calls for warmer than normal temps in east half of US thru at least Jan 25.

Never a positive if Jan is warm. See 👇 Jan 8 tweet, shows Jan is normally peak winter temperature driven demand period.

#OOTT



> **Dan Tsubouchi** @Energy_Tidbits · Jan 8
>
> 
>
> See 👇 excerpt from SAF Group Jan 8, 2023 Energy Tidbits memo on the table with data showing the huge swings in residential/commercial #NatGas consumption in hot vs cold winters. #OOTT twitter.com/Energy_Tidbits...

2,314 · 1 · 2 · 6

Dan Tsubouchi @Energy_Tidbits · Jan 13

🇯🇵 #Kishida "agreed to strengthen cooperation.. incl LNG Canada"

#Trudeau evaded when asked if 🇨🇦 looking at easing regulatory hurdles so #LNGCanada Phase 2 expansion of #LNGCanada can get approved?

let's hope he just didn't want to give Blueberry River FN more leverage?

#OOTT

> Dan Tsubouchi @Energy_Tidbits · Jan 12
>
> 
>
> What's going on BC? 45 days since you were "very close" to agreement with Blueberry River First Nations!
>
> Hurting NE BC 2023 drilling.
>
> ...

2,262 · 1 · 5

Dan Tsubouchi @Energy_Tidbits · Jan 13

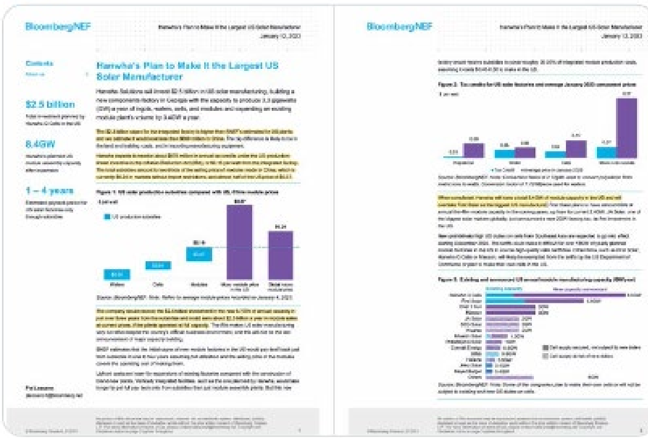
ICYMI.

#Hanwha to invest $2.5b for new #solar components factory in Georgia.

Why? #InflationReductionAct to provide ~$875 million in annual tax credits ie. recover $2.5b in ~3 yrs just from the tax credits. That's huge risk reduction!

Thx @BloombergNEF Pol Lezcano.

#OOTT



1,474 3 7

Dan Tsubouchi @Energy_Tidbits · Jan 13

OOPS, too late!

"careful that we aren't also creating unintended consequences: more death on our roads"

"increased risk of severe injury & death for all road users from heavier curb weights & increasing size ..." from EV trucks & cars warns @NTSB chair @JenniferHomendy

#OOTT

Excerpt from https://www.ntsb.gov/Advocacy/Activities/Pages/Homendy-20230111.aspx

Keynote to Transportation Research Board

THE HONORABLE JENNIFER HOMENDY

CHAIR, NATIONAL TRANSPORTATION SAFETY BOARD

REMARKS AS PREPARED FOR DELIVERY BEFORE THE TRANSPORTATION RESEARCH BOARD

JANUARY 11, 2023, 102ND ANNUAL MEETING

I want to take a second and mention that I'm concerned about the increased risk of severe injury and death for all road users from heavier curb weights and increasing size, power, and performance of vehicles on our roads, including electric vehicles.

A GMC Hummer EV weighs over 9,000 pounds, up from about 6,000 pounds. Its gross vehicle weight rating is a staggering 10,550 pounds. The battery pack alone weighs over 2,900 pounds — about the weight of a Honda Civic.

The Ford F-150 Lightning is between 2,000 and 3,000 pounds heavier than the non-electric version. The Mustang Mach-E, Volvo XC40 EV, and RAV4 EV are all roughly 33% heavier. That has a significant impact on safety for all road users.

Now I want to be clear: I'm inspired by the Administration's commitment to phasing out carbon emissions. We do have a climate crisis that needs to be addressed. The U.S. transportation sector accounts for the largest portion of U.S. greenhouse gas emissions, and I firmly believe it is a human right to breathe clean air.

But we have to be careful that we aren't also creating unintended consequences: more death on our roads. Safety, especially when it comes to new transportation policies and new technologies, cannot be overlooked. *Ever.*

3,060 · 6 · 11

Dan Tsubouchi @Energy_Tidbits · Jan 14

Hmm!

Will Greens be satisfied if @SultanAhmedalj8 #COP28 delivers "tangible progress" and "practical solutions" to Paris 1.5C goal amidst "increasing pressure on energy security"?

Or prefer another aspirational COP that sees world falling further behind Paris 1.5C goal?

#OOTT

SAF Group created transcript of comments by COP28 President Designate Dr. Sultan Al Jaber (Group CEO of Abu Dhabi National Oil Company, ADNOC) at Atlantic Council Global Energy Forum on Sat Jan 14, 2023. Video clips at
https://twitter.com/saudTalreyami/status/1614186676129259522
https://twitter.com/UAE_Forsan/status/1614162092948623360

Items in "italics" are SAF Group created transcript

"Yet we must be honest with ourselves about how much progress we have actually achieved and how much further and faster we truly need to go"

"We are way off track when it comes to the key Paris goal of holding global temperatures down to 1.5 degrees and the hard reality is that in order to achieve this goal, global emissions must fall 43% by 2030. To add to that challenge, we must decrease emissions at a time of continued economic uncertainty, heightened geopolitical tensions, and increasing pressure on energy security"

"We will pursue global consensus"

"We will work very closely with the UNFCC to move from ambition to real action. We will mobilize the private sector and all other sectors to deliver greater, more meaningful impact"

"We can only succeed if we have an open and constructive dialogue. Let us together create a paradigm shift for tangible progress"

"I urge all parties to help make COP28 a COP of concrete outcomes and practical solutions"

"Where together we can ensure sustainable development for this generation and all generations to come"

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

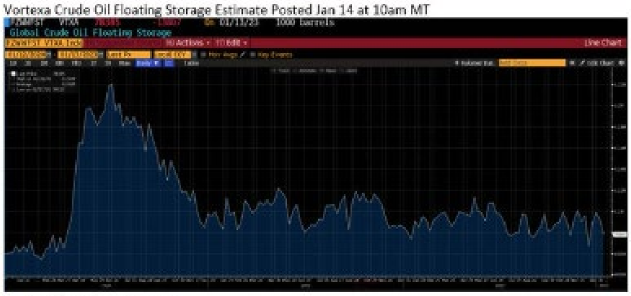
1,180 1

Dan Tsubouchi @Energy_Tidbits · 22h

SAF

#Vortexa crude #Oil floating storage at 01/13 est 78.39 mmb, -13.8 mmb WoW vs revised up by +5.47 mmb 01/06 of 92.19 mmb. Last several weeks average 87.5 mmb (was 89.3 mmb). Thx @Vortexa @business. #OOTT

Vortexa Crude Oil Floating Storage Estimate Posted Jan 14 at 10am MT



Source: Bloomberg, Vortexa

Posted Jan 14, 10am MT

FZWWFST VTXA Inde

01/12/2020 - 01/13/2023

	Date	Last Px
Fr	01/13/2023	78385
Fr	01/06/2023	92192
Fr	12/30/2022	99136
Fr	12/23/2022	89209
Fr	12/16/2022	67245
Fr	12/09/2022	95973
Fr	12/02/2022	90272
Fr	11/25/2022	100.872k
Fr	11/18/2022	92509
Fr	11/11/2022	77508
Fr	11/04/2022	90999

Jan 7, 10am MT

FZWWFST VTXA Inde

01/05/2020 - 01/06/2023

	Date	Last Px
Fr	01/06/2023	86473
Fr	12/30/2022	98010
Fr	12/23/2022	88620
Fr	12/16/2022	65993
Fr	12/09/2022	94265
Fr	12/02/2022	90887
Fr	11/25/2022	100.867k
Fr	11/18/2022	92113
Fr	11/11/2022	76062
Fr	11/04/2022	89658
Fr	10/28/2022	98148

Dec 31, 10am MT

FZWWFST VTXA Inde

12/29/2019 - 12/30/2022

	Date	Last Px
Fr	12/30/2022	93489
Fr	12/23/2022	88734
Fr	12/16/2022	66097
Fr	12/09/2022	93469
Fr	12/02/2022	90319
Fr	11/25/2022	101.508k
Fr	11/18/2022	92871
Fr	11/11/2022	76732
Fr	11/04/2022	90004
Fr	10/28/2022	98051
Fr	10/21/2022	87631

Source: Bloomberg, Vortexa

4,025 1 4 16

Dan Tsubouchi @Energy_Tidbits · 18h

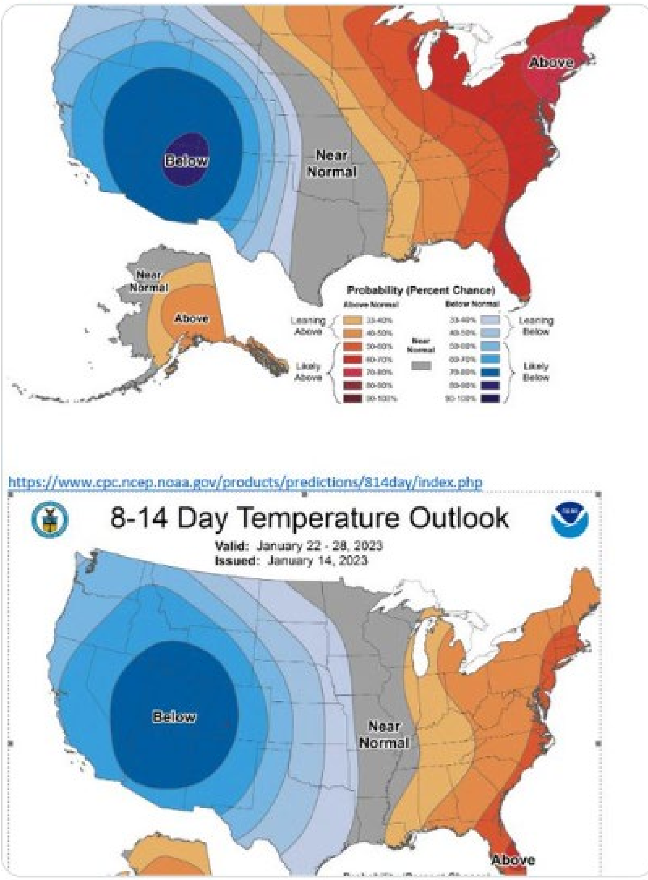
HH #NatGas -24% in Jan to ~$3.40 driven by very warm temps across most of US in Jan

Finally, seeing a forecast for more normal to below normal temps for more of US to end Jan.

May not drive HH #NatGas higher, but hopefully at least supports a floor.

Thx @NOAA.

#OOTT



2,121 1 1 11

Dan Tsubouchi @Energy_Tidbits · 2h

"#Hydrogen, like #Electricity, is an energy carrier that must be produced from another substance" ie. #NatGas.

Hydrogen is the big push for #EnergyTransition, but note 👇 Jan 21, 2022 @EIAgov Hydrogen explained that hydrogen, like electricity, is an energy carrier.

#OOTT

> **Dan Tsubouchi** @Energy_Tidbits · Jan 21, 2022
>
> "takes more energy to produce #hydrogen (by separating it from other elements in molecules) than hydogren provides when it is converted to useful energy" "an energy carrier that must be produced from another substance". nice to see @EIAgov give facts not fiction. #OOTT #NatGas

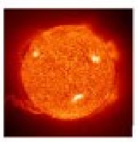
https://www.eia.gov/energyexplained/hydrogen/#:~:text=Hydrogen%20is%20an%20energy%20carrier&text=Hydrogen%2C%20like%20electricity%2C%20is%20an,source%20of%20energy%20or%20fuel.

eia Independent Statistics & Analysis U.S. Energy Information Administration

Hydrogen explained
What is hydrogen?

Hydrogen is the simplest element. Each atom of hydrogen has only one proton. Hydrogen is also the most abundant element in the universe. Stars such as the sun consist mostly of hydrogen. The sun is essentially a giant ball of hydrogen and helium gases.

Hydrogen occurs naturally on earth only in compound form with other elements in liquids, gases, or solids. Hydrogen combined with oxygen is water (H_2O). Hydrogen combined with carbon forms different compounds—or hydrocarbons—found in natural gas, coal, and petroleum.



The sun is essentially a giant ball of hydrogen gas undergoing fusion into helium gas. This process causes the sun to produce vast amounts of energy.

Source: NASA (public domain)

Hydrogen is the lightest element. Hydrogen is a gas at normal temperature and pressure, but hydrogen condenses to a liquid at minus 423 degrees Fahrenheit (minus 253 degrees Celsius).

Hydrogen is an energy carrier

Energy carriers allow the transport of energy in a usable form from one place to another. Hydrogen, like electricity, is an energy carrier that must be produced from another substance. Hydrogen can be produced—separated—from a variety of sources including water, fossil fuels, or biomass and used as a source of energy or fuel. Hydrogen has the highest energy content of any common fuel by weight (about three times more than gasoline), but it has the lowest energy content by volume (about four times less than gasoline).

It takes more energy to produce hydrogen (by separating it from other elements in molecules) than hydrogen provides when it is converted to useful energy. However, hydrogen is useful as an energy source/fuel because it has a high energy content per unit of weight, which is why it is used as a rocket fuel and in fuel cells to produce electricity on some spacecraft. Hydrogen is not widely used as a fuel now, but it has the potential for greater use in the future.

Last updated: January 20, 2022

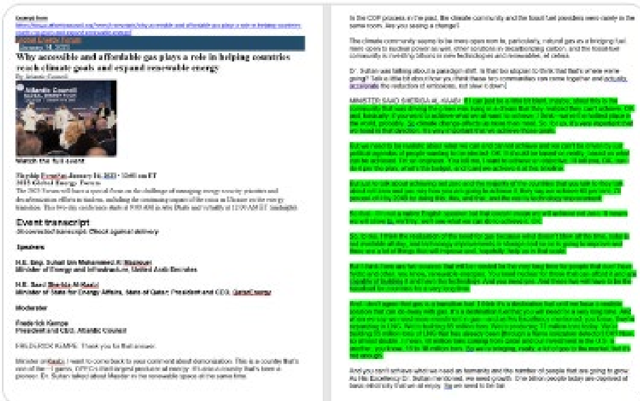
1,577 1

Dan Tsubouchi @Energy_Tidbits · 1h

#NetZero reality check.

"If I can just be a little bit blunt, maybe, about this is the community that was driving the green was living in a dream that they realized they can't achieve". Also #NatGss is a destination fuel. @qatarenergy CEO.

Thx @FredKempe @AtlanticCouncil
#OOTT



728 · 4

Dan Tsubouchi @Energy_Tidbits · 1h

Will Russia pipeline #NatGas ever flow again to Germany? @qatarenergy CEO thinks so. not to pre invasion levels but enough to be big relief to EU market and stabilize #NatGas prices.

Thx @FredKempe @AtlanticCouncil

#OOTT #LNG

1,003 · 2

SAF

Dan Tsubouchi @Energy_Tidbits · 18m ···

Inmate escaping or crazyman?

See 👇 Norway cabinet minister Moe 01/08 posting.

Hydrogen has large energy losses at both ends of the process, "in my opinion, light years away from being justifiable or reasonable".

Energy will be $$$$ in the #EnergyTransition.

#OOTT #NatGas

Ola Borten Moe is Minister of Research and Higher Education since 2021. Previously, he also served as Minister of Petroleum and Energy from 2011 to 2013.

https://www.facebook.com/SPolabortenmoe/posts/pfbid02FhTrNJAApZa6m392J41EgiRbFzG8ffgq12n3JAwgYQVL3cR7p9rtxMQjR1wG6qXl

Ola Borten Moe

January 6 ·

STATKRAFT.NO

Nel og Statkraft legger grunnlaget for en verdikjede for grønt hydrogen i Norge

161 comments 188 shares

Google Translate of Moe's above Facebook posting

It is increasingly obvious that for far too long we have acted as if there is unlimited access to renewable and affordable electricity in Norway. The fact is plain and simple that there is a lack of energy in our power systems. Very high prices and fears about security of supply document this. We must therefore of course have a far more realistic relationship with what we use energy for. And we must have a proven relationship with simple factors such as resource efficiency and effectiveness. Hydrogen is certainly good for many things, but the fact is that it is a highly explosive storage medium with large energy losses at both ends of the process. If you use 100 kwh of electricity to produce hydrogen, you will be left with an amount of energy in hydrogen corresponding to 50 kwh. In other words, half of the energy is lost. If you are going to use this hydrogen in a fuel cell, you lose a further 50%. If you run it in a turbine to produce electricity, you lose 70%. In other words, you get a utilization rate in a car of about 25% or 25 kwh of the original 100 kwh due to energy loss in the processes. In a simple turbine, the loss is even greater. Alternatively, this current/energy could have been used directly all the time it is taken from the grid in Norway with a utilization rate for, for example, heating, production or transport of 90-100%! If Statkraft together with NEL succeeds in establishing 2 gw electrolysis of hydrogen in Norway, this corresponds to an energy quantity of approximately 17.5 twh, or approximately 12-13% of all power production in Norway. With a 75% energy loss, that's 14 twh, or 10% of all Norwegian power production right there. It is, in my opinion, light years away from being justifiable or reasonable. We need all the energy we have and can do for far more sensible things than fighting for the crow.

372 · 1 · 3