Energy Tidbits

Saudi Aramco CEO Warns “Strained” Global Spare Oil Capacity is <2 mmb/d and “Declining Fast”

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Short-Term Energy Outlook

Forecast highlights

Global liquid fuels

- The August *Short-Term Energy Outlook* (STEO) is subject to heightened uncertainty resulting from Russia's full-scale invasion of Ukraine, how sanctions affect Russia's oil production, the production decisions of OPEC+, the rate at which U.S. oil and natural gas production rises, and other contributing factors. Less robust economic activity in our forecast could result in lower-than-forecast energy consumption.

- We forecast the spot price of Brent crude oil will average $105 per barrel (b) in 2022 and $95/b in 2023.

- U.S. crude oil production in our forecast averages 11.9 million barrels per day (b/d) in 2022 and 12.7 million b/d in 2023, which would set a record for most U.S. crude oil production in a year. The current record is 12.3 million b/d, set in 2019.

- We estimate that 98.8 million b/d of petroleum and liquid fuels was consumed globally in July 2022, an increase of 0.9 million b/d from July 2021. We forecast that global consumption of petroleum and liquid fuels will average 99.4 million b/d for all of 2022, which is a 2.1 million b/d increase from 2021. We forecast that global consumption of petroleum and liquid fuels will increase by another 2.1 million b/d in 2023 to average 101.5 million b/d.

- The U.S. retail price for regular grade gasoline averaged $4.56 per gallon (gal) in July, and the average retail diesel price was $5.49/gal. We expect retail gasoline prices to average $4.29/gal in the third quarter of 2022 (3Q22) and fall to an average of $3.78/gal in 4Q22. Retail diesel prices in our forecast average $5.02/gal in 3Q22 and $4.39/gal in 4Q22.

- U.S. refineries average 93% utilization in 3Q22 in our forecast, as a result of high wholesale product margins. Elevated prices for gasoline and diesel reflect refining margins for those products that are at or near record highs amid low inventory levels.

Natural gas

- In July, the Henry Hub spot price averaged $7.28 per million British thermal units (MMBtu), down from $7.70/MMBtu in June and $8.14/MMBtu in May. Average natural gas prices fell over the last two months primarily because of additional supply in the domestic market following the shutdown of the Freeport LNG export terminal on June 8. However, prices increased by almost 50%, from $5.73/MMBtu on July 1 to $8.37/MMBtu on July 29, because of continued high demand for natural gas from the electric power sector. We expect the Henry Hub price to average $7.54/MMBtu in the second half of 2022 and then fall to an average of $5.10/MMBtu in 2023 amid rising natural gas production.

- U.S. natural gas inventories ended July at 2.5 trillion cubic feet (Tcf), which was 12% below the 2017–2021 average. We forecast that natural gas inventories will end the 2022 injection season (end of October) at close to 3.5 Tcf, which would be 6% below the five-year average.

- We forecast that U.S. LNG exports will average 10.0 Bcf/d in 3Q22 and 11.2 Bcf/d for all of 2022, a 14% increase from 2021. This increase is the result of additional U.S. LNG export capacity that has come online and Freeport LNG resuming operations sooner than we had initially expected. In the first half of 2022, the United States became the largest LNG exporter in the world. We forecast LNG exports will average 12.7 Bcf/d in 2023.

- U.S. consumption of natural gas in our forecast averages 85.2 Bcf/d in 2022, up 3% from 2021. Consumption in the electric power sector continues to increase as a result of limited switching from natural gas-fired generators to coal-fired generators for power generation, despite elevated natural gas prices. In addition, rising U.S. natural gas consumption reflects increased consumption in the residential and commercial sectors as a result of colder temperatures on average in 2022 than in 2021. We forecast that natural gas consumption will average 83.8 Bcf/d in 2023, about 1.3 Bcf/d (2%) lower than in 2022.

- We forecast U.S. dry natural gas production to average 97.1 Bcf/d in August and 96.6 Bcf/d during all of 2022, which would be 3.0 Bcf/d (3%) more than in 2021. We expect dry natural gas production to average 100.0 Bcf/d in 2023.

Electricity, coal, renewables, and emissions

- We expect U.S. sales of electricity to ultimate customers to increase in the forecast by 2.5% in 2022, mostly because of rising economic activity but also because of hot summer weather in much of the country. Forecast U.S. sales of electricity decline by 0.3% in 2023.

- The largest increases in U.S. electricity generation in our forecast come from renewable energy sources, mostly solar and wind. We expect renewable sources will provide 22% of U.S. generation in 2022 and 24% in 2023, up from 20% in 2021.

- We forecast the U.S. residential electricity price will average 14.6 cents per kilowatthour (kWh) in 2022, up 6.1% from 2021. Higher retail electricity prices largely reflect an increase in wholesale power prices driven by rising natural gas prices. Annual average wholesale prices for 2022 range from an average of $62 per megawatthour (MWh) in Florida to $95/MWh in the ISO New England and New York ISO markets.

- The U.S. electric power sector added 13 gigawatts (GW) of utility-scale solar photovoltaic (PV) capacity in 2021. Solar capacity additions in the forecast period total 20 GW for 2022 and 24 GW for 2023, and they represent an addition of 31 billion kWh of electric power generation in 2022 and 41 billion kWh in 2023.

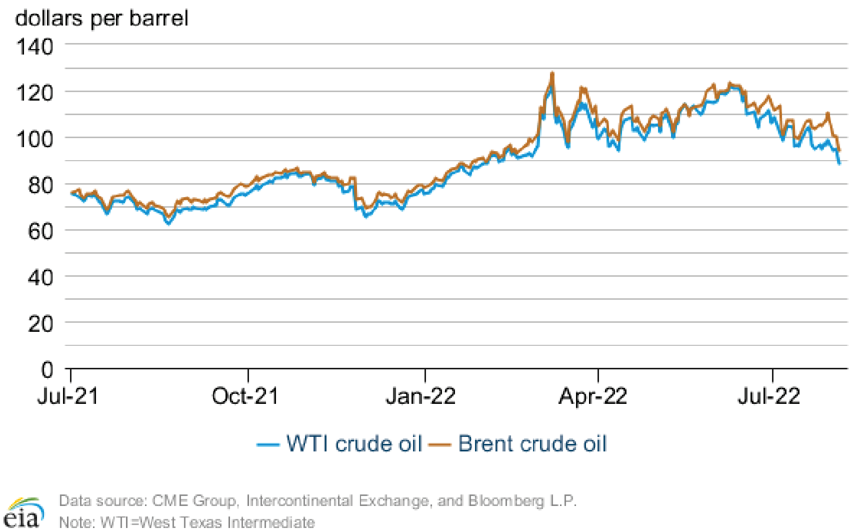
- U.S. coal production is forecast to increase by 21 million short tons (MMst) to 599 MMst in 2022 and to 601 MMst in 2023. We expect coal consumption to be slightly lower in 2022 at 541 MMst, relative to 546 MMst in 2021. This forecast decline is a result of constraints on coal generation and mine shutdowns as well as coal transportation limitations. As coal plant shutdowns continue and natural gas prices fall, coal consumption is expected to decline by 9% to 493 MMst in 2023. Coal exports increase from 85 MMst in 2021 to 87 MMst in 2022 and to 98 MMst in 2023.

Petroleum and Natural Gas Markets Review

Crude oil

Prices: The front-month futures price for Brent crude oil settled at $94.12 per barrel (b) on August 4, a decrease of $17.51/b from the July 1 price of $111.63/b. The front-month futures price for West Texas Intermediate (WTI) crude oil for delivery at Cushing, Oklahoma, decreased by $19.89/b during the same period, settling at $88.54/b on August 4 **(Figure 1)**.

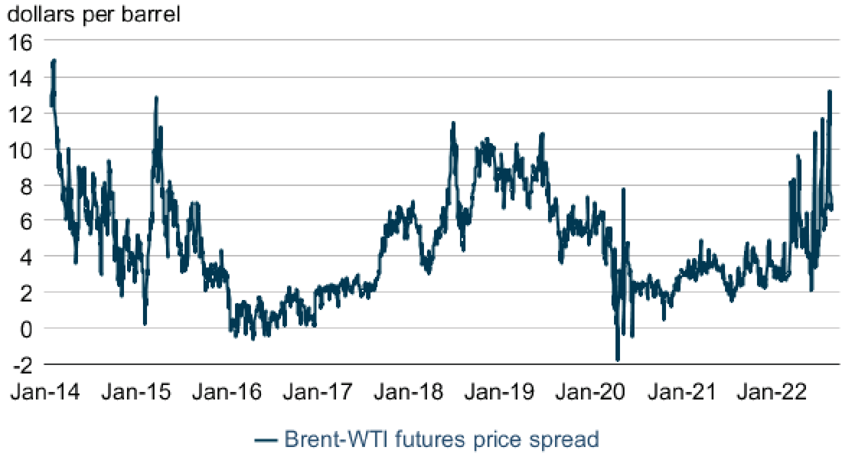
Figure 1. Crude oil front-month futures prices



Data source: CME Group, Intercontinental Exchange, and Bloomberg L.P.
Note: WTI=West Texas Intermediate

Crude oil prices generally decreased in July, and the price of WTI decreased by more than Brent. The price spread between Brent and WTI increased to a high of $13.26/b on July 29, the highest price spread since January 14, 2014 **(Figure 2)**. This wide Brent-WTI spread, which reflects supply and demand dynamics in Northwest Europe, has come down in the first few trading days of August but remains high.

Figure 2. Brent–WTI futures price spread

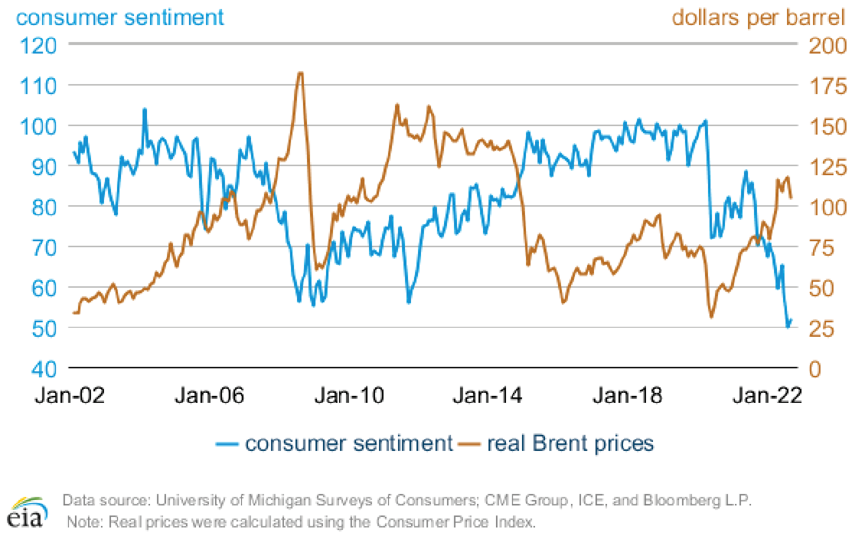


Data source: Intercontinental Exchange, as compiled by Bloomberg L.P.
Note: WTI=West Texas Intermediate

Russia's full-scale invasion of Ukraine has resulted in shifting trade patterns, leaving Europe to find substitutes for Russia's oil. This change has driven up the price of Brent contracts to a level high enough to reduce Asia's imports of Brent crude oil and to retain more oil in Europe. The Brent-WTI spread has also increased enough to attract more imports of crude oil from the United States into Europe. From March through July, the Brent-WTI spread averaged $6.05/b, an almost $2.50/b increase from the first two months of the year. We forecast the Brent-WTI spread will average $6/b in 2023, up $2/b from the July STEO. This high spread will keep exports from Europe to Asia subdued and encourage higher imports from the United States, both of which will likely be necessary as the EU reduces crude oil imports from Russia by 90% by the end of the year.

Although supply disruptions have kept crude oil prices around $100/b, crude oil prices have come down slightly in July as concerns of slower economic growth or a recession become more prevalent. These concerns are reflected in the University of Michigan's survey of consumer sentiment, which recorded its lowest reading on record in June, with data going back to November 1952 **(Figure 3)**. Likewise, consumer sentiment in the Euro Area has decreased, reaching record lows in July.

Figure 3. Consumer sentiment and real Brent crude oil prices

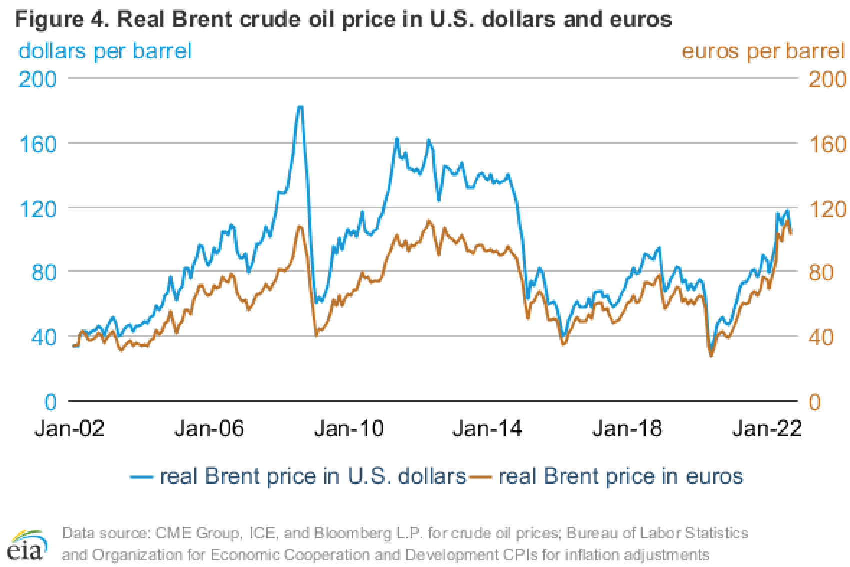


Consumer sentiment has been decreasing as inflation continues to be strong, borrowing costs increase with higher interest rates, and economic growth shows signs of slowing. Data points reflecting these trends include:

- The Bureau of Labor Statistics' Consumer Price Index in June showed year-over-year inflation of 9.1%, its fastest rate since 1981.
- Inflationary concerns have led to the Federal Reserve increasing interest rates, which increases borrowing costs and could also be affecting consumer sentiment.
- As prices have risen, U.S. manufacturing, as measured by the manufacturing Purchasing Manager Index (PMI), decreased in July to its lowest levels since July 2020.
- The Bureau of Economic Analysis's gross domestic product report released in July showed U.S. real gross domestic product contracting by an estimated 0.9% in 2Q22, making it the second consecutive quarter of economic contraction.

Consumer sentiment has often declined in response to high crude oil prices. This trend likely reflects the effects of higher crude oil prices on consumer budgets. Higher crude oil prices lead directly to increased costs for fuel that consumers purchase for transportation. Additionally, rising crude oil prices can create inflationary pressures throughout the economy by raising input costs of goods. Because inflation has been affecting consumers' budgets for an extended time now, it is likely that some consumers have begun to make lifestyle adjustments that are reducing petroleum product consumption in the third quarter, which we have reflected as reductions in our forecast.

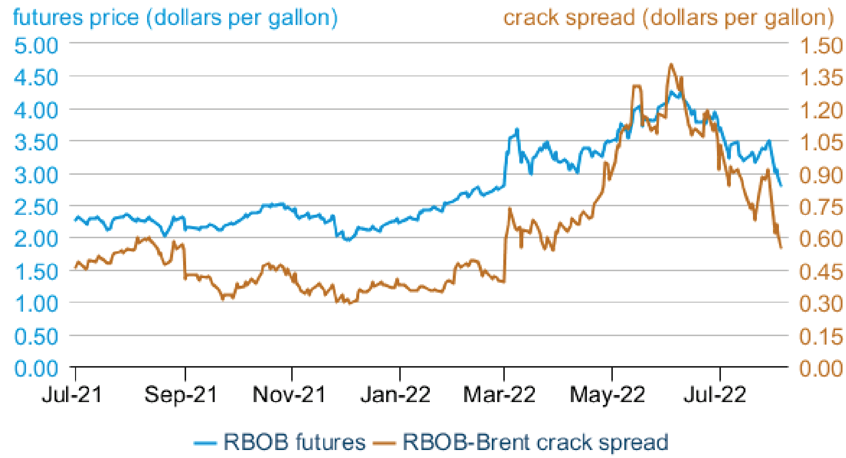
Price of Brent crude oil in U.S. dollars and euros: As U.S. interest rates rise and concerns of a recession increase, demand for U.S. dollars has increased, strengthening its value relative to other currencies. For countries using a currency other than the U.S. dollar, a strengthening dollar could make the imported cost of a barrel of crude oil more expensive. For example, recently the dollar has been trading close to the euro for the first time since 2002. Whereas the inflation-adjusted price of a barrel of crude oil in U.S. dollars is not as high as the levels seen from 2011–2014 or in 2008, the real price of a barrel of crude oil in euros has surpassed those highs **(Figure 4)**. The relatively higher prices have further contributed to slowing growth in petroleum and other liquids consumption in the second half of 2022 (2H22).



Petroleum products

Gasoline prices: The front-month futures price of RBOB (the petroleum component of gasoline used in many parts of the country) settled at $2.79 per gallon (gal) on August 4, down 89 cents/gal from July 1 **(Figure 5)**. The RBOB-Brent crack spread (the difference between the price of RBOB and the price of Brent crude oil) settled at $0.55/gal on August 4, down 48 cents/gal during the same period.

Figure 5. Historical RBOB front-month futures prices and crack spreads



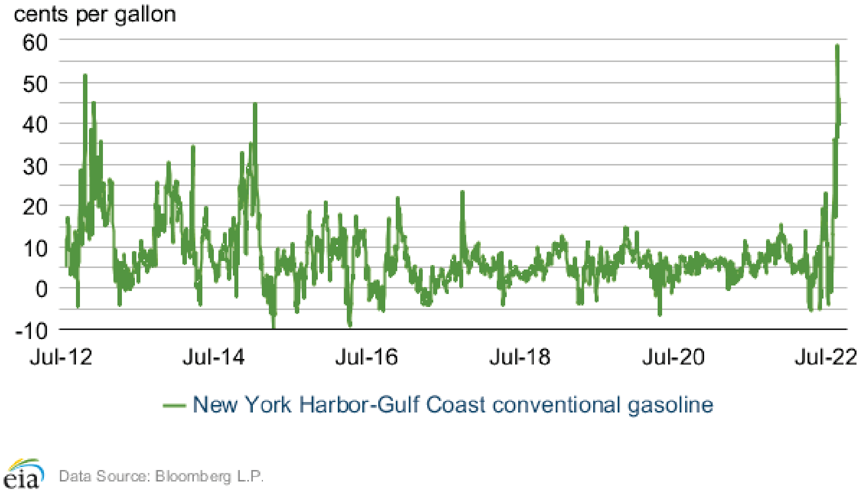
Data source: CME Group and Bloomberg L.P.
Note: RBOB is the petroleum component of gasoline used in many parts of the country.

Lower crude oil prices and a narrowing gasoline crack spread both contributed to an overall decrease in RBOB prices in July. The monthly average RBOB price in July was $3.34/gal, a decrease of 65 cents/gal compared with June. Just over half of this decrease was in the gasoline crack spread, which decreased to a monthly average of 85 cents/gal, down 34 cents/gal compared with June. The gasoline crack spread has remained below $1/gal since July 1.

Gasoline inventories in the United States increased by 7.8 million barrels in July compared with June. Increased gasoline production as a result of high refinery utilization has filled inventories amid relatively lower gasoline demand compared with 2021. We estimate that refinery utilization and gasoline production will rise in August before decreasing in September, in line with normal seasonal trends for fall maintenance. We estimate that less gasoline demand in the fall and winter will partially offset lower refinery production during the fall maintenance season, though this will lead to normal seasonal draws on inventories until November. From September through the end of 2022, we expect end-of-month motor gasoline inventories to be within 10 million barrels of the five-year average. As inventories grow closer to typical seasonal levels, we expect monthly average gasoline prices to continue decreasing. However, unexpected reductions in refinery operations because of unplanned outages—particularly those related to hurricanes on the Gulf Coast—as well as potential increases in driving activity in response to lower retail gasoline prices both present upside risks to gasoline prices and crack spreads.

New York Harbor-Gulf Coast price differential: The price differential for conventional gasoline between the New York Harbor and U.S. Gulf Coast spot markets increased substantially in July. On July 29, the price spread widened to 59 cents/gal, the widest spread in real terms since September 2012 **(Figure 6)**. The average price spread in July was 27 cents/gal, the widest monthly average price spread in real terms since 2014.

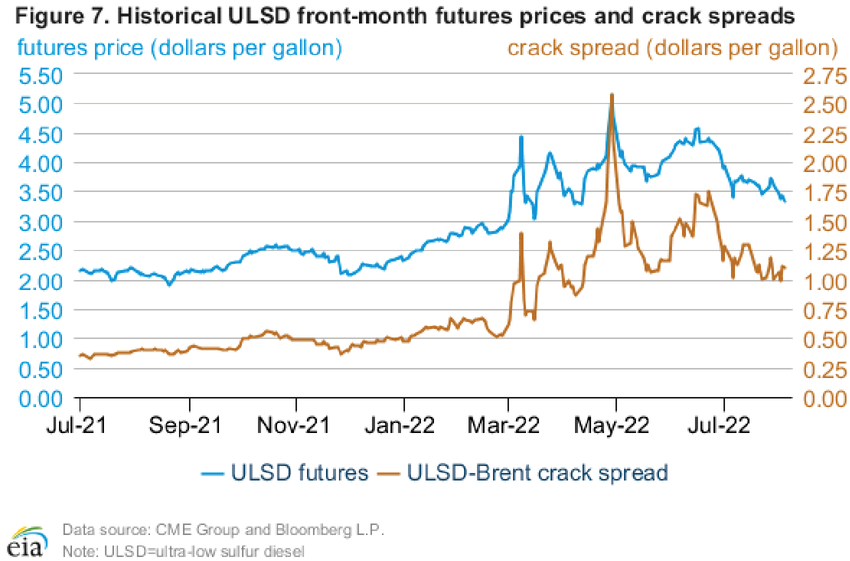
Figure 6. New York Harbor-Gulf Coast conventional gasoline spot price differentials



The wide price spread reflects substantially lower gasoline inventories at New York Harbor and along the East Coast than on the Gulf Coast. East Coast weekly motor gasoline inventories have averaged 21% less than the five-year average since May. In contrast, Gulf Coast weekly motor gasoline inventories have averaged slightly more than the five-year average since May. East Coast refineries produce a relatively small share of the overall volume of gasoline that is consumed in the region. The East Coast has historically imported gasoline from Europe and Canada and received transfers from the U.S. Gulf Coast to meet its consumption needs. Lower gasoline inventories along the East Coast reflect the impact of not only reduced imports of gasoline from Europe but also the closure of what had been the East Coast's largest refinery in 2019, as well as the closure of the export-oriented Canadian Come-by-Chance refinery in 2020. With these lost sources of supply, Gulf Coast refiners have increased refinery utilization and gasoline production in response to the high prices, but logistical capacity constraints limit the volume of gasoline that can be moved to East Coast markets, accounting for the wide regional discrepancy in inventory levels.

Trade press reports have suggested that line space along the Colonial Pipeline (the largest petroleum product pipeline connecting the Gulf Coast to the East Coast), which is traded on secondary markets, was pricing at its highest premium to the pipeline's tariff rate since 2015. Gasoline that cannot be moved along the Colonial Pipeline or the smaller Products SE Pipeline must instead be moved from the Gulf Coast to the East Coast by rail or Jones Act compliant tanker. The current level of the regional price spread suggests that even capacity on more expensive modes of transit between the Gulf Coast to the East Coast, such as rail or tanker, are being used to their current capacity. Increased tanker traffic, more available space on rail lines, or even increased long distance trucking traffic to certain regions may become temporarily viable at current price spreads if market participants believe the price spreads will last long enough to justify the diversion of resources.

__Ultra-low sulfur diesel prices:__ The front-month futures price for ultra-low sulfur diesel (ULSD) for delivery in New York Harbor settled at $3.34/gal on August 4, a 60 cents/gal decrease from July 1 **(Figure 7)**. The ULSD-Brent crack spread (the difference between the price of ULSD and the price of Brent crude oil) decreased 18 cents/gal during the same period and settled at $1.10/gal on August 4.

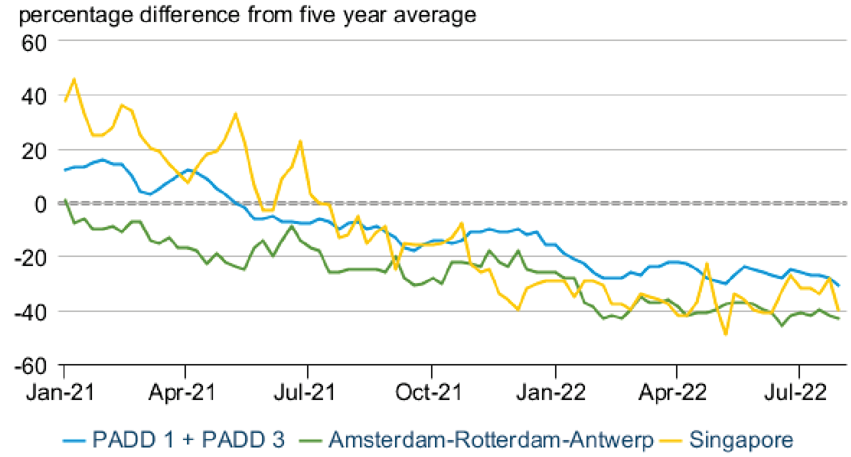


ULSD prices and crack spreads decreased this month to levels not seen since early April, as concerns about a potential recession weighed on the economic outlook. Compared with June, July ULSD prices were 15% lower, and crack spreads were 24% narrower, marking the first decline in ULSD prices since the beginning of the year. However, ULSD prices in July were still 71% higher than in July 2021, and ULSD crack spreads for July were three times wider than in July 2021.

Declining crude oil prices and less domestic consumption of distillate contributed to lower distillate prices. We estimate distillate consumption decreased by 0.2 million b/d (4%) from June to 3.7 million b/d in July. Consumption typically declines in July as stocks rebuild to prepare for higher demand during the fall harvest season and winter heating season. However, we estimate U.S. distillate inventories decreased 1.8 million barrels (2%) in July to reach 109 million barrels, or 26% below the five-year average. We estimate U.S. distillate production averaged 5.1 million b/d in July, slightly below June, which had seen the most production since December 2019. Strong global distillate demand continues to support higher production and, with lower domestic consumption, higher-than-average exports in July. We forecast production will remain above 2021 levels through the rest of the year.

__International distillate inventories:__ Western sanctions against Russia's petroleum product exports following its full-scale invasion of Ukraine in February have been a major driver of global distillate prices this year. Even before the sanctions, however, distillate inventories at all three major trading hubs (New York Harbor, Amsterdam-Rotterdam-Antwerp, and Singapore) started the year below their respective five-year averages **(Figure 8)**. U.S. distillate inventories increased to record highs in 2020 when the COVID-19 pandemic resulted in historically low consumption of petroleum products. As demand returned, inventory drawdowns began in the United States and followed overseas by the beginning of 2021. As of July 29, 2022, combined distillate inventories in the East Coast and the Gulf Coast (PADD 1 and PADD 3) were 31% below the five-year average, and inventories at Amsterdam-Rotterdam-Antwerp and Singapore were around 40% below their five-year averages. In addition to sanctions on Russia's exports, reduced refinery capacity in the United States and lower quotas for exports from China contributed to distillate inventory draws. Low inventories globally have put sustained upward pressure on distillate prices. We forecast higher-than-average domestic distillate production will begin contributing to building inventories in August with overall domestic stocks reaching 119 million barrels, or 17% short of the five-year average, by the end of this year.

Figure 8. International distillate inventories

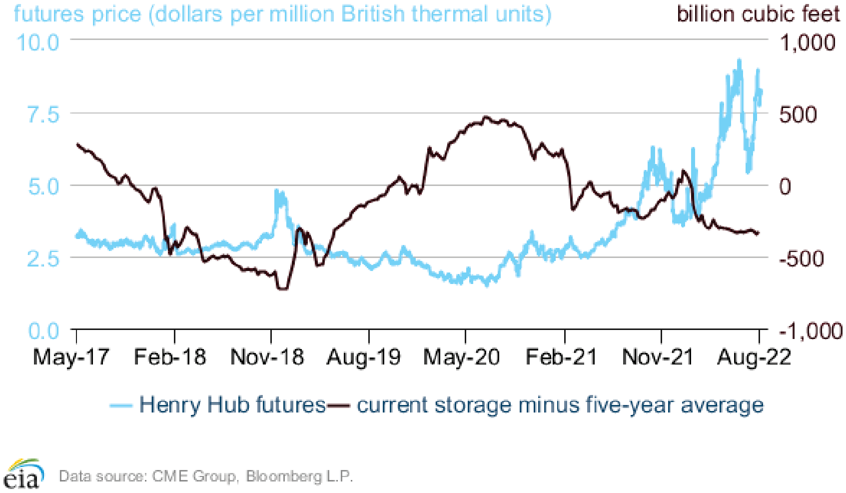


Data source: EIA, *Weekly Petroleum Status Report*, and CME Group as compiled by Bloomberg L.P.

Natural gas

Prices: The front-month natural gas futures contract for delivery at the Henry Hub settled at $8.12 per million British thermal units (MMBtu) on August 4, up $2.39/MMBtu from July 1, 2022 **(Figure 9)**. The average price for front-month natural gas futures contracts in July was $7.19/MMBtu, down 41 cents/MMBtu from June's average of $7.60/MMBtu when the front-month natural gas futures price topped $9.00/MMBtu on two days.

Figure 9. U.S. natural gas front-month futures prices and current storage deviation from five-year average

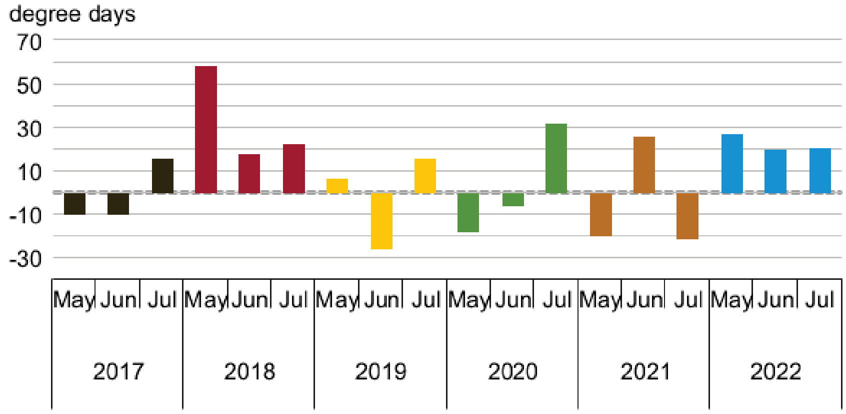


Natural gas injections into storage in June were 2% higher than the five-year (2017–2021) average. That trend reversed in July as 10% less natural gas was injected into storage than the five-year average. We estimate that storage inventories ended July at 2,493 billion cubic feet (Bcf), 12% less than the five-year average level.

The front-month Henry Hub futures price fell from $9.29/MMBtu on June 7, the day before the outage at Freeport LNG, to $5.42/MMBtu on June 30, likely because of market anticipation that the decrease in natural gas available for export would lead to an increase in natural gas supply available in the U.S. market. With more natural gas supply available, market participants may have anticipated more natural gas injections into storage. However, higher-than-normal temperatures in July increased consumption of natural gas for electric power generation to meet air-conditioning demand. We estimate that an average of 41.8 billion cubic feet per day (Bcf/d) of natural gas was consumed in the electric power sector during July, 2.2 Bcf/d more than the five-year average and 5.0 Bcf/d more than in June. At the same time, we estimate that dry natural gas production averaged 96.4 Bcf/d in July, down 0.6 Bcf/d from June.

Summer space cooling: During May, June, and July, the United States experienced 800 cumulative cooling degree days (CDD), or 69 (9%) more than the prior 10-year (2011–2020) average **(Figure 10),** and the most CDDs for this time period since 2018. Higher-than-normal temperatures led to more consumption of natural gas for electric power generation to meet air-conditioning demand. We estimate that natural gas consumption in the electric power sector averaged 36.2 Bcf/d from May through July, 2.1 Bcf/d more than the same time period in 2021 and 3.4 Bcf/d more than the five-year average. The strong demand has led to lower-than-average injections into natural gas storage for three of the four months so far during this injection season (April–October) and has contributed to the deficit in the storage inventory compared with the five-year average. The sustained lower-than-average storage inventories have put upward pressure on the Henry Hub spot natural gas price.

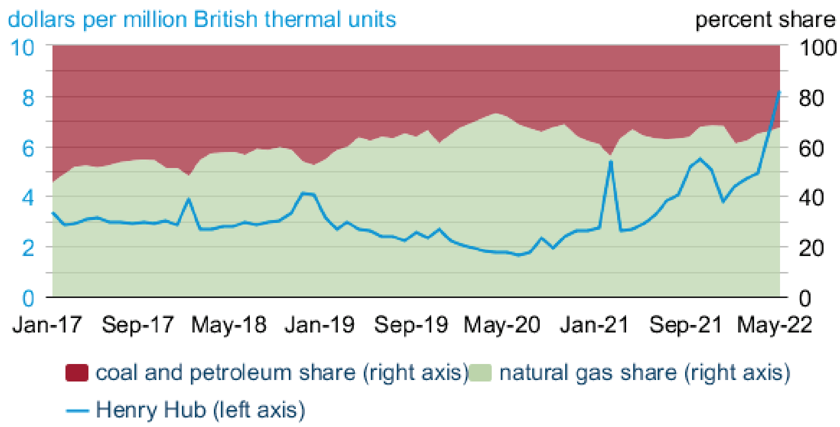
Figure 10. May–July cooling degree days deviation from 10-year average



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

Natural gas share of electricity generation: In recent years, the electric power sector substituted natural gas-fired generation with coal-fired generation when natural gas prices rose. However, in recent months, coal power plants have responded less to price than in the past, most likely as a result of continued coal capacity retirements, constraints in fuel delivery to coal plants, and lower-than-average stocks at coal plants. Additionally, growth in electricity generation capacity from renewable sources is limiting the dispatch of both coal and natural gas. The Henry Hub spot natural gas price has remained elevated since the beginning of the year, but natural gas has maintained a more than 60% share of fossil-fuel sourced electricity generation **(Figure 11)**. The Henry Hub spot price increased $3.76/MMBtu from January to May, but the natural gas share of fossil-fuel sourced electricity generation also increased from 60% in January to 67% in May despite the higher fuel cost.

Figure 11. Shares of fossil-fuel electricity generation in the United States and Henry Hub spot price



Data source: U.S. Energy Information Administration, Short-Term Energy Outlook
Note: Fossil-fuel=natural gas, petroleum liquids, petroleum coke, and coal

Notable forecast changes

- This STEO incorporates our changed forecast for the Brent and WTI crude oil price spread. Changes to sources of Europe's crude oil imports following Russia's full-scale invasion of Ukraine and the EU's subsequent petroleum import ban have contributed to redirections in oil trade flows. European countries are importing more crude oil from the United States and exporting less crude oil to countries in Asia, contributing to the development of a crude oil import price premium in Europe. As a result, we anticipate this trend will maintain a wider price spread between Brent and WTI crude oil of $6/b in 2023, which is $2/b wider than in the July STEO.

- Natural gas prices have risen in recent weeks in response to the sooner-than-expected re-opening of the Freeport LNG export terminal and ongoing hot weather. As a result, we have increased our forecast for natural gas prices. We now forecast that the Henry Hub price will average $7.54/MMBtu during the second half of 2022 compared with a forecast of $5.97/MMBtu in the last STEO. We have also raised our forecast average price for 2023 from $4.76/MMBtu to $5.10/MMBtu.

- We have revised our modeling of electricity supply to better reflect regional differences in fuel costs. This change, along with a higher forecast natural gas price, has contributed to some significant increases in our forecast for wholesale electricity prices, particularly in the Northeast. In the current STEO, we forecast winter wholesale prices in ISO New England will average $176 per megawatthour (MWh) between December and February compared with $57/MWh in the previous STEO. The large increase in forecast prices reflects updates to our assumption about that region's natural gas costs for this winter. We also raised our forecast electricity prices in Texas's ERCOT market.

- You can find more information in the detailed table of forecast changes.

This report was prepared by the U.S. Energy Information Administration (EIA), the statistical and analytical agency within the U.S. Department of Energy. By law, EIA's data, analyses, and forecasts are independent of approval by any other officer or employee of the U.S. Government. The views in this report therefore should not be construed as representing those of the U.S. Department of Energy or other federal agencies.

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

U.S. Energy Information Administration | Short-Term Energy Outlook - August 2022

	2021				2022				2023				Year		
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	2021	2022	2023
Production (million barrels per day) (a)															
OECD	30.21	30.79	31.11	32.22	31.66	32.13	32.84	33.56	33.82	33.93	34.12	34.70	31.09	32.55	34.14
U.S. (50 States)	17.74	19.11	19.00	19.90	19.44	20.18	20.55	21.05	21.11	21.26	21.55	21.97	18.94	20.31	21.48
Canada	5.62	5.37	5.49	5.68	5.66	5.71	5.74	5.85	5.92	5.88	5.90	5.91	5.54	5.74	5.90
Mexico	1.93	1.95	1.90	1.92	1.91	1.89	1.89	1.86	1.90	1.87	1.83	1.79	1.92	1.89	1.85
Other OECD	4.92	4.37	4.73	4.71	4.65	4.34	4.66	4.79	4.88	4.92	4.84	5.02	4.68	4.61	4.91
Non-OECD	62.58	63.99	65.62	66.13	67.21	66.98	68.38	67.68	66.91	67.33	67.52	67.01	64.59	67.57	67.19
OPEC	30.34	30.88	32.28	33.10	33.75	33.77	34.11	34.23	34.58	34.53	34.53	34.51	31.66	33.97	34.54
Crude Oil Portion	25.08	25.49	26.84	27.67	28.19	28.34	28.63	28.71	29.02	29.10	29.05	28.99	26.28	28.47	29.04
Other Liquids (b)	5.26	5.39	5.44	5.44	5.56	5.43	5.48	5.52	5.56	5.43	5.48	5.52	5.38	5.50	5.50
Eurasia	13.42	13.66	13.63	14.27	14.39	13.43	13.92	13.48	12.66	12.33	12.27	12.27	13.75	13.80	12.38
China	4.99	5.03	5.01	4.93	5.18	5.19	5.14	5.18	5.22	5.25	5.24	5.28	4.99	5.17	5.25
Other Non-OECD	13.82	14.42	14.70	13.82	13.90	14.59	15.21	14.78	14.45	15.22	15.48	14.94	14.19	14.62	15.03
Total World Production	92.79	94.79	96.73	98.35	98.87	99.11	101.21	101.24	100.72	101.26	101.64	101.71	95.68	100.12	101.33
Non-OPEC Production	62.45	63.91	64.45	65.24	65.13	65.34	67.10	67.01	66.14	66.73	67.11	67.19	64.02	66.15	66.80
Consumption (million barrels per day) (c)															
OECD	42.45	44.08	45.82	46.81	45.89	45.05	45.78	46.61	46.14	45.65	46.33	46.70	44.81	45.83	46.21
U.S. (50 States)	18.45	20.03	20.21	20.41	20.22	20.06	20.21	20.85	20.35	20.74	20.86	21.03	19.78	20.34	20.75
U.S. Territories	0.21	0.19	0.19	0.20	0.22	0.20	0.20	0.22	0.22	0.20	0.21	0.22	0.20	0.21	0.21
Canada	2.26	2.24	2.50	2.40	2.33	2.36	2.48	2.48	2.44	2.39	2.49	2.47	2.35	2.41	2.45
Europe	11.91	12.62	13.83	13.89	13.08	13.35	13.67	13.36	13.13	13.15	13.55	13.32	13.07	13.37	13.29
Japan	3.73	3.08	3.18	3.67	3.73	3.11	3.21	3.53	3.77	3.11	3.14	3.44	3.42	3.39	3.36
Other OECD	5.89	5.92	5.90	6.23	6.30	5.97	6.01	6.18	6.23	6.06	6.09	6.23	5.99	6.12	6.15
Non-OECD	51.78	52.21	52.53	53.64	53.13	53.31	53.78	54.16	55.23	55.66	55.30	54.94	52.54	53.60	55.28
Eurasia	4.66	4.73	5.09	4.95	4.48	4.33	4.69	4.62	4.28	4.43	4.75	4.66	4.86	4.53	4.53
Europe	0.74	0.74	0.74	0.76	0.75	0.75	0.76	0.76	0.75	0.77	0.77	0.77	0.75	0.76	0.76
China	15.27	15.48	14.99	15.33	15.25	15.24	15.24	15.78	16.52	16.41	15.78	15.70	15.27	15.38	16.10
Other Asia	13.43	12.98	12.84	13.69	13.82	13.79	13.49	13.91	14.48	14.45	13.87	14.17	13.23	13.75	14.24
Other Non-OECD	17.68	18.27	18.87	18.91	18.83	19.19	19.61	19.09	19.21	19.59	20.13	19.64	18.44	19.18	19.64
Total World Consumption	94.23	96.29	98.36	100.45	99.02	98.36	99.56	100.76	101.37	101.30	101.63	101.64	97.35	99.43	101.49
Total Crude Oil and Other Liquids Inventory Net Withdrawals (million barrels per day)															
U.S. (50 States)	0.47	0.51	0.37	0.77	0.75	0.38	0.45	0.64	-0.01	-0.44	-0.11	0.40	0.53	0.56	-0.04
Other OECD	0.87	0.15	0.97	0.67	-0.23	-0.36	-0.68	-0.36	0.21	0.15	0.03	-0.15	0.66	-0.41	0.06
Other Stock Draws and Balance	0.11	0.84	0.28	0.66	-0.38	-0.77	-1.42	-0.76	0.45	0.33	0.07	-0.32	0.47	-0.84	0.13
Total Stock Draw	1.44	1.50	1.62	2.10	0.15	-0.75	-1.65	-0.47	0.65	0.04	-0.01	-0.06	1.67	-0.69	0.15
End-of-period Commercial Crude Oil and Other Liquids Inventories (million barrels)															
U.S. Commercial Inventory	1,302	1,271	1,241	1,194	1,154	1,193	1,240	1,218	1,223	1,271	1,283	1,257	1,194	1,218	1,257
OECD Commercial Inventory	2,908	2,864	2,745	2,636	2,616	2,688	2,798	2,810	2,795	2,829	2,839	2,826	2,636	2,810	2,826

(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 August 4, 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 - August 2022

	2021				2022				2023				Year		
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	2021	2022	2023
Supply (million barrels per day)															
Crude Oil Supply															
Domestic Production (a)	**10.82**	**11.34**	**11.18**	**11.66**	**11.46**	**11.69**	*12.01*	*12.28*	*12.39*	*12.50*	*12.82*	*13.10*	**11.25**	*11.86*	*12.70*
Alaska	**0.46**	**0.44**	**0.41**	**0.44**	**0.45**	**0.44**	*0.44*	*0.45*	*0.44*	*0.41*	*0.43*	*0.44*	**0.44**	*0.44*	*0.43*
Federal Gulf of Mexico (b)	**1.83**	**1.80**	**1.49**	**1.71**	**1.67**	**1.69**	*1.73*	*1.81*	*1.86*	*1.83*	*1.74*	*1.74*	**1.71**	*1.72*	*1.79*
Lower 48 States (excl GOM)	**8.54**	**9.10**	**9.29**	**9.50**	**9.34**	**9.56**	*9.84*	*10.03*	*10.09*	*10.27*	*10.65*	*10.92*	**9.11**	*9.69*	*10.48*
Crude Oil Net Imports (c)	**2.87**	**2.96**	**3.60**	**3.09**	**3.00**	**2.92**	*3.04*	*3.23*	*3.16*	*3.52*	*3.13*	*2.19*	**3.13**	*3.05*	*3.00*
SPR Net Withdrawals	**0.00**	**0.18**	**0.04**	**0.26**	**0.31**	**0.81**	*0.96*	*0.41*	*0.04*	*0.09*	*0.03*	*0.11*	**0.12**	*0.63*	*0.07*
Commercial Inventory Net Withdrawals	**-0.18**	**0.59**	**0.30**	**-0.01**	**0.08**	**-0.10**	*-0.05*	*-0.13*	*-0.39*	*0.08*	*0.20*	*-0.07*	**0.18**	*-0.05*	*-0.04*
Crude Oil Adjustment (d)	**0.30**	**0.57**	**0.49**	**0.51**	**0.71**	**0.73**	*0.33*	*0.16*	*0.22*	*0.22*	*0.23*	*0.16*	**0.47**	*0.48*	*0.21*
Total Crude Oil Input to Refineries	**13.81**	**15.65**	**15.60**	**15.51**	**15.56**	**16.06**	*16.29*	*15.96*	*15.42*	*16.40*	*16.40*	*15.50*	**15.15**	*15.97*	*15.93*
Other Supply															
Refinery Processing Gain	**0.84**	**0.97**	**0.97**	**1.04**	**0.95**	**1.07**	*1.06*	*1.06*	*1.03*	*1.00*	*1.00*	*0.99*	**0.95**	*1.04*	*1.01*
Natural Gas Plant Liquids Production	**4.86**	**5.46**	**5.52**	**5.74**	**5.61**	**6.00**	*6.07*	*6.26*	*6.28*	*6.31*	*6.30*	*6.40*	**5.40**	*5.99*	*6.32*
Renewables and Oxygenate Production (e)	**1.03**	**1.13**	**1.10**	**1.24**	**1.19**	**1.20**	*1.20*	*1.24*	*1.20*	*1.22*	*1.21*	*1.27*	**1.12**	*1.21*	*1.23*
Fuel Ethanol Production	**0.90**	**0.99**	**0.96**	**1.06**	**1.02**	**1.01**	*1.01*	*1.02*	*0.99*	*1.00*	*0.99*	*1.02*	**0.98**	*1.02*	*1.00*
Petroleum Products Adjustment (f)	**0.19**	**0.22**	**0.22**	**0.23**	**0.22**	**0.23**	*0.22*	*0.22*	*0.21*	*0.22*	*0.22*	*0.22*	**0.22**	*0.22*	*0.21*
Product Net Imports (c)	**-2.94**	**-3.13**	**-3.24**	**-3.86**	**-3.74**	**-4.16**	*-4.16*	*-4.25*	*-4.13*	*-3.82*	*-3.94*	*-3.70*	**-3.29**	*-4.08*	*-3.90*
Hydrocarbon Gas Liquids	**-2.02**	**-2.23**	**-2.16**	**-2.19**	**-2.14**	**-2.23**	*-2.34*	*-2.48*	*-2.55*	*-2.51*	*-2.59*	*-2.58*	**-2.15**	*-2.30*	*-2.56*
Unfinished Oils	**0.14**	**0.25**	**0.22**	**0.08**	**0.09**	**0.27**	*0.37*	*0.22*	*0.19*	*0.25*	*0.37*	*0.21*	**0.17**	*0.24*	*0.25*
Other HC/Oxygenates	**-0.08**	**-0.04**	**-0.03**	**-0.06**	**-0.09**	**-0.10**	*-0.05*	*-0.03*	*-0.04*	*-0.04*	*-0.03*	*-0.02*	**-0.05**	*-0.07*	*-0.03*
Motor Gasoline Blend Comp.	**0.55**	**0.79**	**0.66**	**0.40**	**0.40**	**0.59**	*0.46*	*0.19*	*0.37*	*0.63*	*0.38*	*0.43*	**0.60**	*0.41*	*0.45*
Finished Motor Gasoline	**-0.66**	**-0.66**	**-0.68**	**-0.85**	**-0.76**	**-0.77**	*-0.77*	*-0.65*	*-0.73*	*-0.67*	*-0.69*	*-0.67*	**-0.71**	*-0.74*	*-0.69*
Jet Fuel	**0.03**	**0.09**	**0.09**	**0.00**	**-0.04**	**-0.08**	*-0.03*	*-0.03*	*-0.09*	*0.03*	*0.05*	*0.06*	**0.05**	*-0.04*	*0.01*
Distillate Fuel Oil	**-0.49**	**-0.90**	**-0.94**	**-0.89**	**-0.81**	**-1.19**	*-1.20*	*-1.01*	*-0.77*	*-1.10*	*-1.03*	*-0.88*	**-0.80**	*-1.05*	*-0.95*
Residual Fuel Oil	**0.08**	**0.05**	**0.08**	**0.16**	**0.14**	**0.11**	*0.10*	*0.14*	*0.03*	*0.07*	*0.04*	*0.14*	**0.09**	*0.12*	*0.07*
Other Oils (g)	**-0.49**	**-0.49**	**-0.50**	**-0.50**	**-0.54**	**-0.75**	*-0.70*	*-0.60*	*-0.54*	*-0.48*	*-0.43*	*-0.38*	**-0.49**	*-0.65*	*-0.46*
Product Inventory Net Withdrawals	**0.65**	**-0.26**	**0.03**	**0.52**	**0.37**	**-0.33**	*-0.46*	*0.36*	*0.34*	*-0.61*	*-0.33*	*0.35*	**0.23**	*-0.02*	*-0.06*
Total Supply	**18.43**	**20.03**	**20.21**	**20.41**	**20.16**	**20.06**	*20.21*	*20.85*	*20.35*	*20.74*	*20.86*	*21.03*	**19.78**	*20.32*	*20.75*
Consumption (million barrels per day)															
Hydrocarbon Gas Liquids	**3.40**	**3.33**	**3.31**	**3.60**	**3.87**	**3.40**	*3.49*	*3.97*	*4.04*	*3.59*	*3.51*	*3.94*	**3.41**	*3.68*	*3.77*
Other HC/Oxygenates	**0.11**	**0.13**	**0.11**	**0.16**	**0.13**	**0.17**	*0.18*	*0.24*	*0.23*	*0.22*	*0.21*	*0.27*	**0.13**	*0.18*	*0.23*
Unfinished Oils	**0.05**	**0.03**	**-0.05**	**-0.01**	**0.13**	**0.03**	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	**0.00**	*0.04*	*0.00*
Motor Gasoline	**8.00**	**9.07**	**9.13**	**8.96**	**8.47**	**8.95**	*8.91*	*8.97*	*8.56*	*9.09*	*9.12*	*8.95*	**8.80**	*8.83*	*8.93*
Fuel Ethanol blended into Motor Gasoline	**0.82**	**0.93**	**0.94**	**0.95**	**0.87**	**0.93**	*0.92*	*0.93*	*0.88*	*0.94*	*0.93*	*0.94*	**0.91**	*0.91*	*0.92*
Jet Fuel	**1.13**	**1.34**	**1.52**	**1.49**	**1.45**	**1.58**	*1.56*	*1.53*	*1.44*	*1.59*	*1.63*	*1.60*	**1.37**	*1.53*	*1.57*
Distillate Fuel Oil	**3.97**	**3.93**	**3.87**	**4.00**	**4.14**	**3.84**	*3.80*	*3.98*	*4.05*	*3.91*	*3.89*	*3.98*	**3.94**	*3.94*	*3.96*
Residual Fuel Oil	**0.26**	**0.25**	**0.33**	**0.41**	**0.38**	**0.33**	*0.34*	*0.34*	*0.30*	*0.31*	*0.32*	*0.34*	**0.31**	*0.35*	*0.32*
Other Oils (g)	**1.53**	**1.95**	**1.98**	**1.81**	**1.65**	**1.76**	*1.93*	*1.82*	*1.73*	*2.03*	*2.18*	*1.96*	**1.82**	*1.79*	*1.97*
Total Consumption	**18.45**	**20.03**	**20.21**	**20.41**	**20.22**	**20.06**	*20.21*	*20.85*	*20.35*	*20.74*	*20.86*	*21.03*	**19.78**	*20.34*	*20.75*
Total Petroleum and Other Liquids Net Imports	**-0.07**	**-0.16**	**0.35**	**-0.77**	**-0.74**	**-1.24**	*-1.12*	*-1.01*	*-0.97*	*-0.31*	*-0.81*	*-1.51*	**-0.16**	*-1.03*	*-0.90*
End-of-period Inventories (million barrels)															
Commercial Inventory															
Crude Oil (excluding SPR)	**501.9**	**448.0**	**420.4**	**421.4**	**414.4**	**423.8**	*428.2*	*440.1*	*475.6*	*468.2*	*450.1*	*456.1*	**421.4**	*440.1*	*456.1*
Hydrocarbon Gas Liquids	**168.6**	**195.8**	**225.6**	**188.4**	**142.0**	**199.0**	*241.5*	*194.7*	*155.4*	*206.6*	*248.0*	*205.7*	**188.4**	*194.7*	*205.7*
Unfinished Oils	**93.3**	**93.0**	**90.2**	**80.3**	**87.9**	**88.0**	*88.3*	*82.6*	*92.2*	*89.7*	*89.0*	*82.2*	**80.3**	*82.6*	*82.2*
Other HC/Oxygenates	**29.1**	**27.5**	**25.4**	**28.6**	**34.1**	**30.4**	*30.4*	*30.7*	*32.8*	*31.5*	*31.3*	*31.5*	**28.6**	*30.7*	*31.5*
Total Motor Gasoline	**237.6**	**237.2**	**227.0**	**232.2**	**238.5**	**219.1**	*221.0*	*235.5*	*233.7*	*236.2*	*227.4*	*241.5*	**232.2**	*235.5*	*241.5*
Finished Motor Gasoline	**20.3**	**18.6**	**18.5**	**17.7**	**17.3**	**17.6**	*19.9*	*24.0*	*21.3*	*22.9*	*24.0*	*26.8*	**17.7**	*24.0*	*26.8*
Motor Gasoline Blend Comp.	**217.4**	**218.6**	**208.5**	**214.5**	**221.2**	**201.5**	*201.1*	*211.5*	*212.4*	*213.4*	*203.4*	*214.8*	**214.5**	*211.5*	*214.8*
Jet Fuel	**39.0**	**44.7**	**42.0**	**35.8**	**35.6**	**39.9**	*43.1*	*39.9*	*39.2*	*40.0*	*42.5*	*39.3*	**35.8**	*39.9*	*39.3*
Distillate Fuel Oil	**145.5**	**140.1**	**131.7**	**129.9**	**114.6**	**111.1**	*114.8*	*118.5*	*108.1*	*113.4*	*120.4*	*122.7*	**129.9**	*118.5*	*122.7*
Residual Fuel Oil	**30.9**	**31.1**	**28.0**	**25.4**	**27.9**	**28.4**	*28.3*	*30.3*	*30.2*	*31.1*	*29.6*	*31.1*	**25.4**	*30.3*	*31.1*
Other Oils (g)	**55.8**	**54.1**	**50.5**	**51.8**	**58.5**	**52.8**	*44.1*	*46.1*	*55.7*	*54.0*	*45.0*	*46.6*	**51.8**	*46.1*	*46.6*
Total Commercial Inventory	**1301.7**	**1271.5**	**1240.7**	**1193.8**	**1153.6**	**1192.6**	*1239.8*	*1218.4*	*1222.9*	*1270.6*	*1283.3*	*1256.8*	**1193.8**	*1218.4*	*1256.8*
Crude Oil in SPR	**637.8**	**621.3**	**617.8**	**593.7**	**566.1**	**492.0**	*403.3*	*365.5*	*361.7*	*353.9*	*351.3*	*340.8*	**593.7**	*365.5*	*340.8*

(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 August 4, 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 - August 2022

	2021				2022				2023				Year		
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	2021	2022	2023
Supply (billion cubic feet per day)															
Total Marketed Production	**97.65**	**101.12**	**101.89**	**104.86**	**102.77**	**105.21**	*105.66*	*106.83*	*107.60*	*108.99*	*109.41*	*109.40*	**101.40**	*105.13*	*108.86*
Alaska	**1.02**	**0.95**	**0.90**	**1.02**	**1.06**	**0.97**	*0.79*	*0.90*	*0.93*	*0.80*	*0.76*	*0.89*	**0.97**	*0.93*	*0.85*
Federal GOM (a)	**2.26**	**2.25**	**1.82**	**2.11**	**2.04**	**2.11**	*2.14*	*2.11*	*2.13*	*2.05*	*1.92*	*1.88*	**2.11**	*2.10*	*2.00*
Lower 48 States (excl GOM)	**94.37**	**97.92**	**99.17**	**101.73**	**99.67**	**102.14**	*102.74*	*103.82*	*104.54*	*106.14*	*106.73*	*106.63*	**98.32**	*102.10*	*106.02*
Total Dry Gas Production	**90.59**	**93.15**	**93.86**	**96.52**	**94.60**	**96.61**	*97.02*	*98.09*	*98.90*	*100.13*	*100.52*	*100.51*	**93.55**	*96.59*	*100.02*
LNG Gross Imports	**0.15**	**0.02**	**0.03**	**0.04**	**0.15**	**0.07**	*0.18*	*0.20*	*0.32*	*0.18*	*0.18*	*0.20*	**0.06**	*0.15*	*0.22*
LNG Gross Exports	**9.27**	**9.81**	**9.60**	**10.32**	**11.50**	**10.84**	*9.95*	*12.35*	*12.92*	*12.61*	*12.31*	*12.88*	**9.76**	*11.16*	*12.68*
Pipeline Gross Imports	**8.68**	**6.81**	**7.24**	**7.82**	**8.92**	**7.56**	*6.51*	*6.72*	*7.78*	*6.47*	*6.32*	*6.50*	**7.63**	*7.42*	*6.76*
Pipeline Gross Exports	**8.31**	**8.66**	**8.50**	**8.40**	**8.43**	**8.57**	*9.29*	*9.23*	*9.13*	*9.03*	*9.34*	*9.24*	**8.47**	*8.88*	*9.18*
Supplemental Gaseous Fuels	**0.17**	**0.15**	**0.15**	**0.17**	**0.19**	**0.17**	*0.17*	*0.17*	*0.17*	*0.17*	*0.17*	*0.17*	**0.16**	*0.17*	*0.17*
Net Inventory Withdrawals	**17.18**	**-9.12**	**-7.87**	**1.03**	**20.14**	**-10.26**	*-8.75*	*2.75*	*14.80*	*-12.69*	*-9.00*	*3.78*	**0.24**	*0.90*	*-0.83*
Total Supply	**99.18**	**72.53**	**75.31**	**86.86**	**104.07**	**74.74**	*75.89*	*86.36*	*99.91*	*72.62*	*76.55*	*89.04*	**83.42**	*85.19*	*84.48*
Balancing Item (b)	**0.26**	**-0.58**	**-0.21**	**-1.23**	**0.24**	**0.16**	*-1.09*	*0.57*	*-0.57*	*-0.63*	*-0.74*	*-0.60*	**-0.45**	*-0.03*	*-0.64*
Total Primary Supply	**99.44**	**71.95**	**75.10**	**85.62**	**104.30**	**74.90**	*74.81*	*86.93*	*99.34*	*71.99*	*75.80*	*88.44*	**82.97**	*85.16*	*83.84*
Consumption (billion cubic feet per day)															
Residential	**25.67**	**7.50**	**3.62**	**14.43**	**26.09**	**7.81**	*3.42*	*16.66*	*24.59*	*7.77*	*3.86*	*16.68*	**12.75**	*13.44*	*13.18*
Commercial	**14.87**	**6.23**	**4.68**	**10.08**	**15.62**	**6.64**	*4.45*	*10.33*	*15.18*	*7.06*	*4.85*	*10.47*	**8.94**	*9.23*	*9.37*
Industrial	**23.81**	**21.46**	**21.14**	**23.44**	**25.23**	**21.96**	*20.97*	*23.25*	*22.37*	*20.33*	*21.25*	*24.30*	**22.46**	*22.84*	*22.07*
Electric Power (c)	**26.79**	**29.20**	**37.94**	**29.47**	**28.65**	**30.63**	*38.09*	*28.32*	*28.36*	*28.86*	*37.72*	*28.44*	**30.88**	*31.44*	*30.86*
Lease and Plant Fuel	**4.87**	**5.04**	**5.08**	**5.23**	**5.12**	**5.24**	*5.27*	*5.33*	*5.36*	*5.43*	*5.45*	*5.45*	**5.05**	*5.24*	*5.43*
Pipeline and Distribution Use	**3.29**	**2.38**	**2.48**	**2.83**	**3.45**	**2.47**	*2.47*	*2.90*	*3.33*	*2.38*	*2.51*	*2.95*	**2.74**	*2.82*	*2.79*
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	**99.44**	**71.95**	**75.10**	**85.62**	**104.30**	**74.90**	*74.81*	*86.93*	*99.34*	*71.99*	*75.80*	*88.44*	**82.97**	*85.16*	*83.84*
End-of-period Inventories (billion cubic feet)															
Working Gas Inventory	**1,801**	**2,585**	**3,306**	**3,210**	**1,401**	**2,328**	*3,132*	*2,879*	*1,547*	*2,702*	*3,530*	*3,182*	**3,210**	*2,879*	*3,182*
East Region (d)	**313**	**515**	**804**	**766**	**242**	**479**	*775*	*665*	*250*	*596*	*894*	*759*	**766**	*665*	*759*
Midwest Region (d)	**395**	**630**	**966**	**887**	**296**	**558**	*918*	*807*	*345*	*652*	*1,000*	*853*	**887**	*807*	*853*
South Central Region (d)	**760**	**993**	**1,053**	**1,143**	**587**	**889**	*965*	*984*	*685*	*1,029*	*1,108*	*1,092*	**1,143**	*984*	*1,092*
Mountain Region (d)	**113**	**175**	**205**	**171**	**90**	**137**	*169*	*151*	*86*	*134*	*201*	*182*	**171**	*151*	*182*
Pacific Region (d)	**197**	**246**	**248**	**218**	**165**	**239**	*280*	*246*	*155*	*264*	*301*	*270*	**218**	*246*	*270*
Alaska	**23**	**27**	**30**	**25**	**21**	**24**	*26*	*26*	*26*	*26*	*26*	*26*	**25**	*26*	*26*

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

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

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

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

\- = no data available

LNG: liquefied natural gas.

Notes: EIA completed modeling and analysis for this report on August 4, 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://rbnenergy.com/keep-this-party-going-the-expansion-of-permian-gas-infrastructure-is-far-from-over

Keep This Party Going - The Expansion Of Permian Gas Infrastructure Is Far From Over

Tuesday, 08/09/2022

Published by: Housley Carr

The build-out of natural gas processing plants in the Permian continues unabated. In just the past few days, four of the largest midstream players in the U.S.'s premier hydrocarbon production area have unveiled plans for a combined 1.3 Bcf/d of new processing capacity, most of it in the gassier Delaware Basin portion of the crude-oil-focused play. And that's on top of the 11.7 Bcf/d of processing that's already been added in the Permian over the past four-and-a-half years — and the 2.6 Bcf/d of soon-to-be-finished projects announced previously. That's quite a run, and still more processing plants may be in the cards — if midstreamers build more takeaway-pipeline capacity. In today's RBN blog, we discuss recent processing-plant and pipeline developments in West Texas and southeastern New Mexico.

Production of dry natural gas in the Permian is now averaging 15.5 Bcf/d — an amazing thing, really, when you consider that (1) at the start of 2018, the region was producing less than 7 Bcf/d, and (2) the focus of production in the Permian is crude oil, whereas associated gas (natgas and NGLs) has until recently been a byproduct of sorts that producers and their midstream cohorts need to deal with as they continue to expand their activities. Handling all that raw gas has required the development of scores (yes, scores!) of gas processing plants and a number of new or expanded natural gas and NGL pipelines. And oil-focused producers have been willing to pony up for processing because the last thing they want is for their oil production to be stymied because their gas didn't flow. The infrastructure build-out continued without letup during the COVID era, as we chronicled in our ... Ready for It? blog series, One Step Ahead and, most recently, More, More, More. (And don't forget, we track everything related to Permian gas markets in RBN's weekly NATGAS Permian report.)

In a related vein, we've also been monitoring the ongoing consolidation and rationalization of gas gathering and processing assets in the Permian, and written blogs about the merger of Altus Midstream and BCP Raptor Holdco LP (the corporate parent of EagleClaw Midstream) into a new entity called Kinetik Holdings; Enterprise Products Partners' purchase of Navitas Midstream, a leading gas gatherer/processor in the Midland Basin; and (just last month) Targa Resources' acquisition of Lucid Energy Group from Riverstone Holdings and Goldman Sachs Asset Management for $3.55 billion in cash.

When Enterprise announced the Navitas deal in January 2022, there was talk that the company was planning at sixth gas processing plant at Navitas's centralized, 1-Bcf/d processing complex near the border of Midland and Glasscock counties in West Texas. Plans for that 300-MMcf/d "Plant 6" have since been announced (it will come online in the second quarter of 2023), and Enterprise announced August 3 that, thanks to continued production growth in the area, it now plans to build another 300-MMcf/d facility — Plant 7 — at the same location (yellow-striped dot to right in Figure 1). Operation of Plant 7 is slated to begin in the first quarter of 2024. Enterprise also announced last week that it will construct Mentone III, a 300-MMcf/d processing plant, at its Mentone complex in Loving County, TX (in the Delaware Basin; yellow-striped dot to left). The facility also is expected to begin operating in the first quarter of 2024. Mentone I, a 200-MMcf/d plant, came online in late 2018 and the 300-MMcf/d Mentone II plant — now under construction — is scheduled to start up in the fourth quarter of this year.

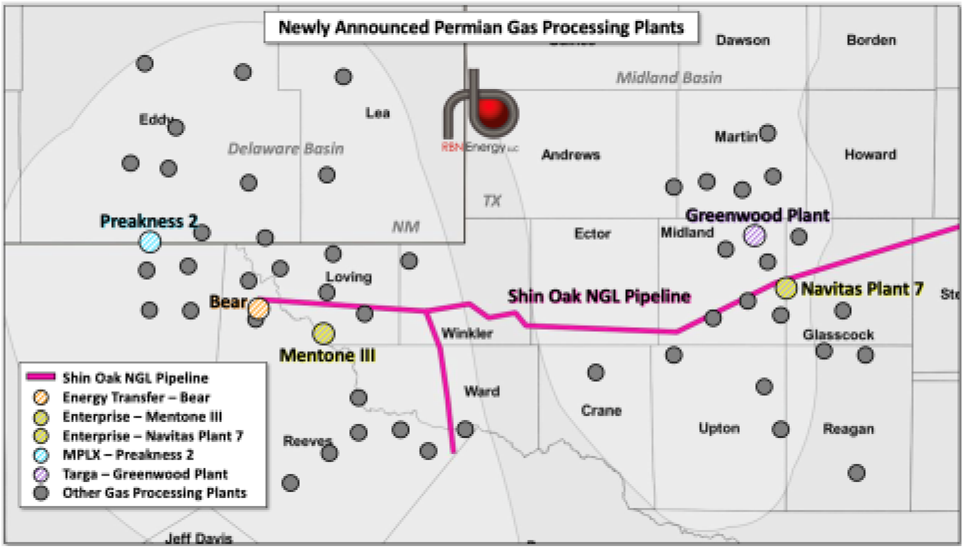


Figure 1. Newly Announced Permian Gas Processing Plants. Source: RBN

When all its announced processing projects are up and running in about a year and a half, Enterprise will have 2.2 Bcf/d of processing capacity in the Delaware and 1.6 Bcf/d in the Midland, as well as the ability to extract a total of more than 520 Mb/d of mixed NGLs from those processing plants (300 Mb/d-plus in the Delaware and 220 Mb/d-plus in the Midland). The ongoing run-up in Permian NGL volumes is spurring the need for more NGL takeaway capacity, as evidenced by Enterprise's announcement (also on August 3) that it plans to expand the capacity of the 550-Mb/d Shin Oak NGL Pipeline (hot-pink line in Figure 1) by up to 275 Mb/d by mid-2024. Shin Oak, which runs from West Texas to the NGL storage and fractionation hub in Mont Belvieu, TX, is co-owned by Enterprise, with a 67% stake, and Kinetik (the recently merged Altus and EagleClaw — see above), with 33%.

Targa announced July 29 that it has closed on its acquisition of Lucid Energy, which had been the largest privately held gas processor in the Permian, with seven processing plants (combined capacity of almost 1.2 Bcf/d) at three sites in the northern Delaware Basin in southeastern New Mexico. Targa is now finishing up construction of a 230-MMcf/d processing plant (Red Hills VI) at what had been Lucid's Red Hills complex in Lea County, NM — that facility is slated to start up within the next few weeks. Targa also is building a pair of 275-MMcf/d plants in Midland County (Legacy I and II), the first of which will also begin operating in a few weeks (with the second to follow in the second quarter of 2023). But that's not all. Targa on August 4 announced plans for yet another 275-MMcf/d processing plant, this one at a new site in the Midland Basin near Greenwood, TX (purple-striped dot in Figure 1), that is scheduled to come online in the fourth quarter of next year. And, in a sort-of-related move, Targa plans to build a 120-Mb/d fractionation plant in Mont Belvieu that will start up in the second quarter of 2024 and be known as Train 9.

Plans for two other Permian processing plants — both in the Delaware Basin in West Texas — were also unveiled over the past few days. On August 2, MPLX announced that it will build a second 200-MMcf/d facility at its Preakness complex in Culberson County; Preakness 2 (blue-striped dot in Figure 1) will come online in the second half of 2024. (MPLX also is building the 200-MMcf/d Torñado II plant in Loving County, which will be up and running in the second half of this year.) Then, on August 3, Energy Transfer announced that it plans to begin operating its newly announced Bear facility — a 200-MMcf/d processing plant near Orla (orange-striped dot in Figure 1) — in the second quarter of 2023. (Energy Transfer also is building the 200-MMcf/d Grey Wolf plant at a yet-to-be-identified site in the Delaware; it will start up by the end of this year.)

As we said in our Life in the Fast Lane blog in May, with natural gas production rising, the Permian may be headed for another round of serious pipeline constraints. And (as if you needed to be reminded), a shortfall in gas takeaway capacity in the Permian could limit crude oil production growth there. Figure 2 shows NATGAS Permian's forecast for dry gas production in the Permian (blue-shaded area) as well as effective takeaway capacity out of the region (green line), along with arrows pointing out past and planned takeaway capacity additions.

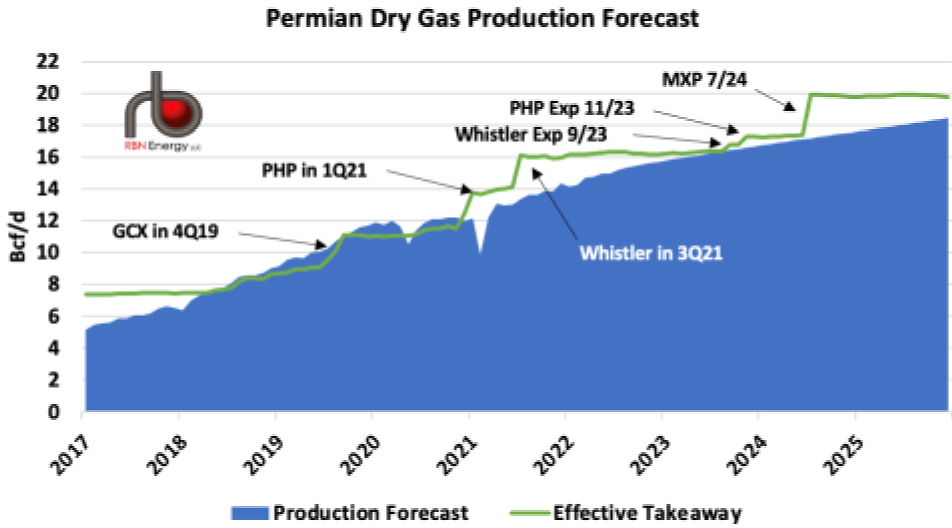


Figure 2. Permian Dry Gas Production and Takeaway Capacity. Source: NATGAS Permian

As you can see, the additions of the 2-Bcf/d Permian Highway Pipeline (PHP) in the first quarter of 2021 and the 2-Bcf/d Whistler Pipeline in the third quarter of last year gave Permian producers some breathing room, but the takeaway situation is likely to tighten considerably over the next year or so until the 500-MMcf/d Whistler Expansion project comes online in September 2023 and the 650-MMcf/d PHP Expansion follows that in November 2023. Permian production growth through the mid-2020s will depend on the timely mid-2024 completion of the 2.5-Bcf/d Matterhorn Express Pipeline (MXP), which will run from the Waha hub to the Katy (TX) area near Houston and which is being co-developed by WhiteWater Midstream, EnLink Midstream, MPLX and (Permian producer) Devon Energy.

The degree of takeaway constraints over the longer term will depend on how quickly production grows. The forecast shown in Figure 2 is a middle-of-the-road one, and if production growth ends up being more robust the Permian could be in for another rough patch.

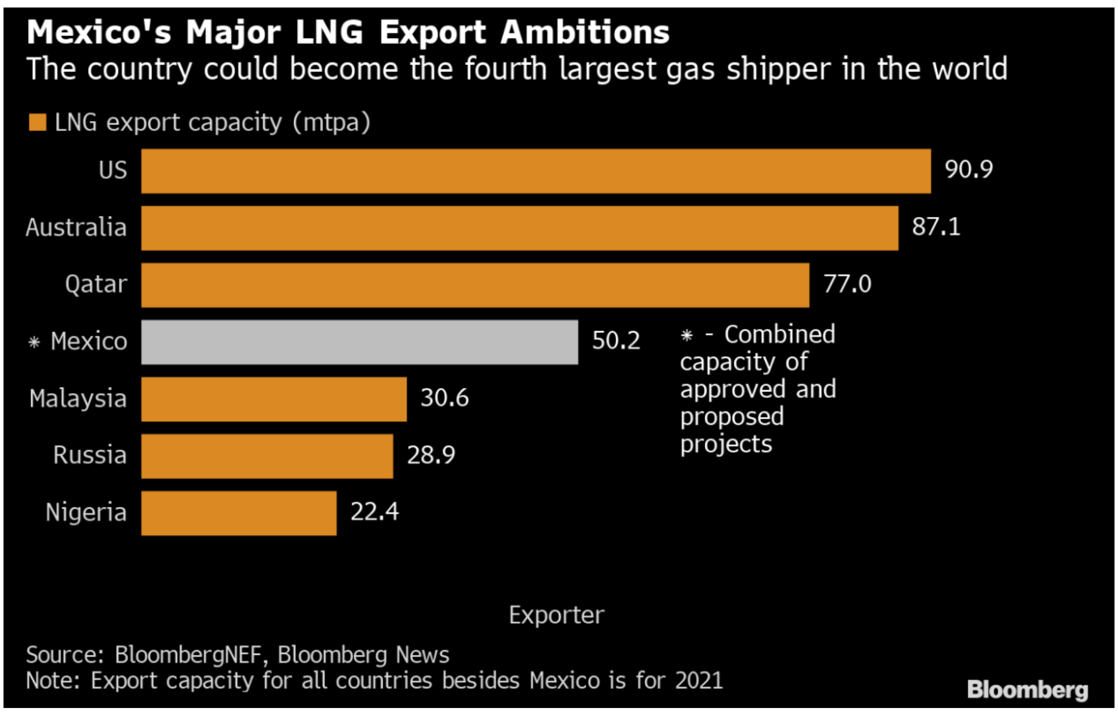
The music for “Keep This Party Going” was written by Keith Strickland and the lyrics by Fred Schneider, Kate Pierson and Cindy Wilson. The song appears as the 11th tune on the B-52s’ seventh studio album, *Funplex*. The song celebrates having fun and partying, with an outro section that name-drops many cities, guaranteeing that concert fans will go nuts when the city the band is playing in is mentioned. Personnel on the record were: Fred Schneider (vocals, cowbell), Kate Pierson (vocals), Cindy Wilson (vocals), Keith Strickland (guitars, programming), Tracy Wormworth (bass), Sterling Campbell (drums), and Pete Davis (keyboards, programming).

Funplex was recorded between September 2006 and November 2007 and produced by Steve Osborne. Released in March 2008, the album went to #11 on the Billboard 200 Albums chart. It was the band's first studio album of new material since *Good Stuff,* released in 1992. Three different covers were offered on the *Funplex* CD in the Digipak format, and some autographed copies were offered at Newbury Comics and FYE stores. Target offered limited quantities of a double CD of the album, including a disc of a live concert at the Roxy in Los Angeles. Two singles were released from the LP.

The B-52s are an American new wave dance band formed in Athens, GA, in 1976 by Fred Schneider, Kate Pierson, Cindy Wilson, Ricky Wilson and Keith Strickland. After guitarist Ricky Wilson's death in October 1985, drummer Keith Strickland switched to guitar duties in the band. The band combined 1950s and '60s pop and rock with dance beats and a fascination for low-brow art and trash culture. They have released seven studio albums, six compilation albums, three live albums, one EP and 27 singles. The B-52s start their farewell tour at the end of August. It runs to mid-November, ending with a final concert where it all began in their hometown of Athens.

Mexico Plans to Become an Export Hub With US-Drilled Natural Gas
2022-08-12 09:00:46.883 GMT

By Sergio Chapa
(Bloomberg) -- Mexico — which imports nearly all of the natural gas it burns — has laid out a somewhat surprising mission: to become one of the world's top exporters of the fuel, and fast.
Although natural gas exports from Mexico are today non-existent, seeing as it produces too little of the power-plant fuel to supply even its own domestic needs, the country's physical proximity to booming US reserves positions it well to supply American gas to hungry buyers in Europe and Asia. With US shale in mind, a total of eight liquified natural gas export projects have been proposed south of the border boasting annual combined capacity of 50.2 million tons. Some of the operations aim to come online as soon as next year.
If they're all completed, the Latin American newcomer would join a very small club of nations that ship abroad the superchilled fuel — commonly called LNG — clocking in at No. 4 behind only the US, Australia and Qatar. And unlike those other three export heavyweights, Mexico would mostly be shipping out gas that it imported in the first place.



Mexico's big plans to enter the export market come at a time when natural gas demand is soaring globally. Gas was already gaining in popularity versus dirtier fossil fuels like coal due to its comparatively lower carbon footprint when the war in Ukraine propelled demand to an entirely new level. Forty-four markets imported LNG last year, almost twice as many as a decade ago, the International Group of Liquefied Natural Gas

Importers said, and the world has been racing to boost both import and export capacity in the months since. Asia has been the destination for nearly half of US LNG cargoes over the past two years, though Europe's efforts to diversify away from Moscow means buyers in all regions are competing for a limited supply of the fuel.

"Mexico is set to become an exporter of US-produced natural gas and this is mostly driven by market dynamics that are taking place globally — especially those in Asia — not precisely due to Mexico's policies," said Adrian Duhalt, a scholar at the Baker Institute's Center for the United States and Mexico at Rice University.

To be sure, there's no guarantee all the proposed projects will be built, or that they'll be constructed on time. Some of them will still need last-mile pipeline connections, too.

But the main gas pipeline capacity they'll need to operate is already there. US gas can be shipped in via more than a dozen cross-border pipelines built during former President Enrique Peña-Nieto's single term in office between 2012 and 2018. Those conduits cost billions of dollars and have a combined capacity of nearly 14 billion cubic feet a day, federal figures show. So far this year, Mexico has imported an average of 6.7 billion cubic feet per day from the US, meaning the lines could move more than double the current volumes. That's on top of the roughly 2.6 billion cubic feet of natural gas per day Mexico produces.

Mexico's current president, Andres Manuel Lopez Obrador, was a vocal critic of his predecessor's policies, including the cross-border pipeline projects, which required Mexico to sign long-term take-or-pay contracts that forced it to pay for full capacity whether it was being used or not. That imported gas was supposed to supply Mexico's internal needs, but after more than a dozen natural gas power plants got derailed before they were built, Mexico found itself paying for a lot of spare pipeline capacity it wasn't using.

Early in his term, AMLO, as the current president is known, negotiated a deal with three pipeline operators to save the nation $4.5 billion. His administration has also pledged to build more in-country pipelines to get sufficient fuel to demand centers in central and southern Mexico that still face occasional natural gas shortages due to infrastructure issues.

The rest of the imported gas would go toward making Mexico an export hub.

It's certainly well positioned: Six of the eight LNG projects proposed in Mexico are along the Pacific Coast where cargoes can be shipped to destinations in Asia without having to go through the Panama Canal. With the exception of one offshore project in Veracruz, all of the gas for the plants would come from the US via cross-border pipelines.

Mexico's government didn't reply to requests for comment.

LNG Export Projects in Mexico
One project is under construction and more are on the drawing board

Project	Location	Status	Production Capacity (mtpa)	Daily Nat Gas Use (bcf/d)
Energia Costa Azul (Phase I)	Baja California	Under Construction	3.3	0.4
Energia Costa Azul (Phase II)	Baja California	Proposed	12.4	2.0
Mexico Pacific Limited	Sonora	Proposed	14.1	1.9
Vista Pacifico LNG	Sinaloa	Proposed	4.0	0.5
Salina Cruz LNG	Oaxaca	Proposed	3.0	0.4
Amigo LNG	Sonora	Proposed	7.8	1.0
Altamira FLNG	Tamaulipas	Proposed	4.2	0.6
Lakach FLNG	Veracruz	Proposed	1.4	0.2
Total			50.2	7.0

Source: Bloomberg

Bloomberg

So far, the only one under construction is the first phase of the Sempra Energy-owned Energia Costa Azul export terminal along the Pacific Coast in the Mexican state of Baja California.
The other projects are still on the drawing board but have seen momentum in the months following Russia's invasion of Ukraine.
New York-based LNG company New Fortress Energy Inc. signed a pair of deals in July to develop offshore LNG export projects off the coasts of Tamaulipas and Veracruz that could potentially supply Europe. Mexico's-state owned Federal Electricity Commission said the same month that it's looking to develop LNG export terminals in the states of Sinaloa and Oaxaca in a tie-up with Sempra. Once approval and permitting go through, most LNG projects can begin exports in roughly four years.
So if the gas getting shipped out of Mexico will be produced in the US, why not just ship it from American ports?
Blame opposition at the local and state levels. Several of the proposed projects in Mexico moved forward only after Canadian pipeline operator Pembina Pipeline Corp. canceled its proposed Jordan Cove LNG export terminal in Oregon due to heavy pushback in the US.
"This speaks more about how difficult it is to build export terminals in California and Oregon that developers are trying to set up projects in Mexico," Duhalt said.

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https://www.centrica.com/media-centre/news/2022/centrica-signs-lng-heads-of-agreement-with-delfin/
09 August 2022

Centrica signs LNG Heads of Agreement with Delfin

Centrica and Delfin Midstream Inc. today announced the signing of a Heads of Agreement to purchase 1.0 million tonnes per annum (MTPA) of Liquefied Natural Gas ("LNG") for 15-years on a Free on Board ("FOB") basis at the Delfin Deepwater Port, located 40 nautical miles off the coast of Louisiana.

This agreement provides Delfin with another key foundation customer which will facilitate a Final Investment Decision (FID) for the first floating LNG export facility in the United States by the end of this year, with operations expected to commence in 2026.

"We are very pleased to enter into this agreement with Centrica and continue to rapidly advance Delfin's position as a leading source of reliable low-cost energy from the safety of the US at compelling prices. Market demand for long-term LNG continues to be strong and buying activity from Europe and various other geographies has accelerated over the past few months. As a modular project that can make FID in 3.5 MTPA increments, this agreement materially advances our first vessel's path towards FID later this year"

Dudley Poston, CEO of Delfin

Against a challenging geopolitical and macroeconomic environment Centrica has been working to bolster the UK and Ireland's energy security both now and over the longer term. Last month Centrica signed an additional £4bn supply agreement with Equinor to supply 4.5 million UK homes through to 2025, and this £7bn agreement with Delfin, which starts in 2026, will underpin the expansion of US LNG export capacity, an increasingly important source of stable, reliable future gas supply.

"Natural gas has now been recognised as an essential transition fuel on the path to net zero just at the point geopolitical uncertainty is impacting the global gas market. Additional US gas export capacity will help increase UK, European and global energy security, reflecting the increasing importance of LNG in the global gas supply chain. I'm delighted to sign this Heads of Agreement with Delfin as we continue to deliver our new strategy, growing Centrica's LNG portfolio and ensuring that we increase our access to a diversified range of reliable gas supplies for our customers."

Chris O'Shea, Centrica Group Chief Executive

"A key component of our Energy Security Strategy is that natural gas is a key transition fuel on the road to clean, affordable, home-grown energy. From renewables to nuclear, we have ambitious plans for greater energy independence, but we are also realistic about our energy needs now and in the years ahead. That means we need to secure more diverse and reliable sources of natural gas from friends, allies and strategic partners. Today’s deal between Centrica and Delfin is positive news for the UK, helping to ensure our diversity of supply from reliable sources - like our friends in the United States - for many years to come."

Kwasi Kwarteng MP, UK Secretary of State for Business and Energy

- Centrica Press Office

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NOTES

About Delfin

Delfin is a leading LNG export infrastructure development company utilizing low-cost Floating LNG technology solutions. Delfin is the parent company of Delfin LNG LLC (“Delfin LNG”) and Avocet LNG LLC. Delfin LNG is a brownfield Deepwater Port requiring minimal additional infrastructure investment to support up to four FLNG Vessels producing up to 13 million tonnes of LNG per annum. Delfin purchased the UTOS pipeline, the largest natural gas pipeline in the Gulf of Mexico. Delfin LNG received a positive Record of Decision from MARAD and approval from the Department of Energy for long-term exports of LNG to countries that do not have a Free Trade Agreement with the United States. Further information is available at www.delfinmidstream.com.

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

Posted Wednesday April 28, 2021. 9:00 MT

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

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

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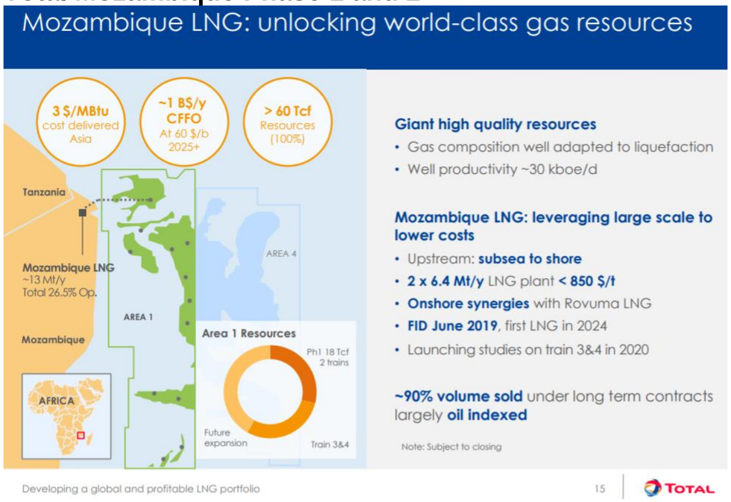
Total Mozambique Phase 1 and 2



Source: Total Investor Day September 24, 2019

<u>Total's Mozambique force majeure is no surprise, especially the need to the restoration of security and stability "in a sustained manner"</u>. Yesterday, Total announced [LINK] "*Considering the evolution of the security".* No one should be surprised by the force majeure or the sustained manner caveat. SAF Group posts a weekly Energy Tidbits research memo [LINK], wherein we have, in multiple weekly memos, that Total had shut down development in December for 3 months due to the violent and security risks. It restarted development on Wed March 24, violence/attacks immediately resumed for 3 consecutive days, and then Total suspended development on Sat March 27. Local violence/attacks shut development down in Dec, the situation gets settled enough for Total to restart in March, only to be shut down 3 days thereafter. No one should be surprised especially with Total's need to see security and stability "in a sustained manner".

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

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

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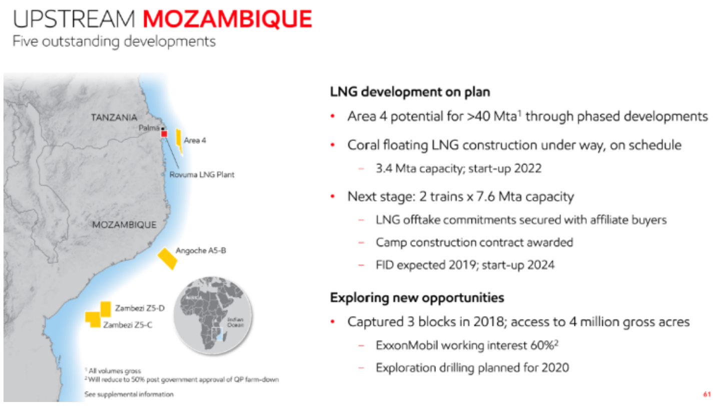
continuing thru the 2020s. And we believe all LNG forecasts included this 5.0 bcf/d to be in service in the 2020s as Mozambique had been considered the best positioned LNG supply to access Asia after Australia and Papua New Guinea. (i) Eni Coral Sul (Rovuma Basin) FLNG of 0.45 bcf/d planned in service 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

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[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

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

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

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

Source: IEA

On Track More Efforts Needed Not on Track

Source: IEA Tracking Clean Energy Progress, June 2020

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

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

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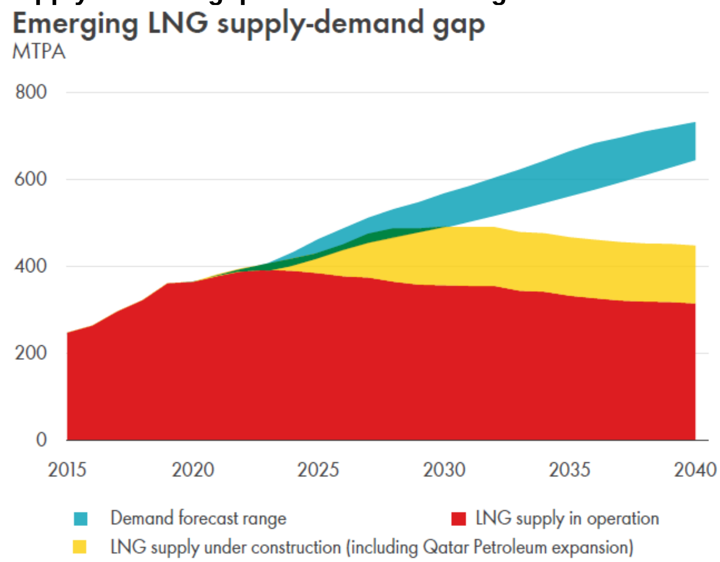
would have reflected some delay, perhaps 1 year, at Mozambique but would be surprised if they put a 2-3 year delay in for the 5 bcf/d from Total Phase 1 +2 and Exxon Rozuma Phase 1. Compared to their LNG Outlook 2020, it looks like there was no change for their estimate of global natural gas demand growth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

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



Source: Shell LNG Outlook 2021, Feb 25, 2021

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

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

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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.

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

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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

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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.*

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

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

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

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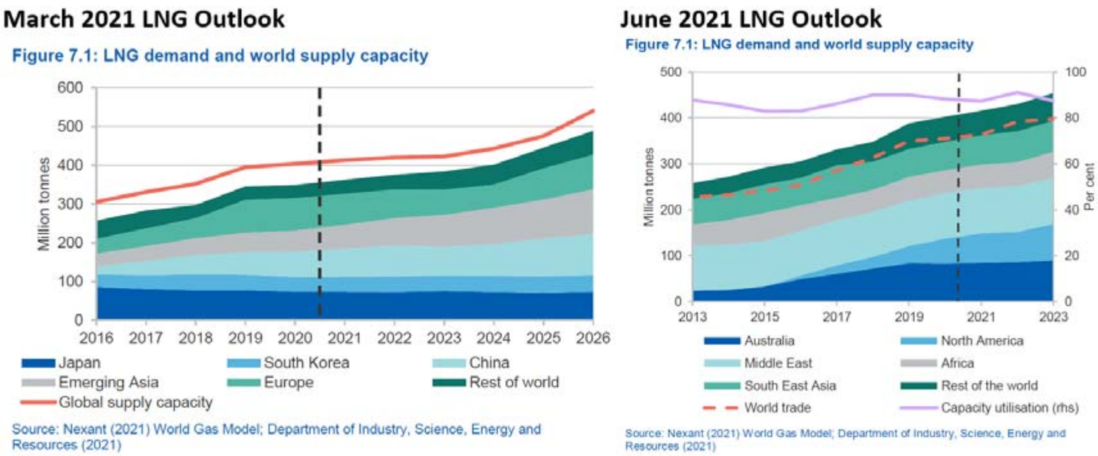
demand that we highlight later in the blog. They didn't say anything else specific on Mozambique but, surely they have to also be delaying the follow on Total Phase 2 of 1.3 bcf/d and Exxon Rozuma Phase 1 of 2.0 bcf/d.

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."*

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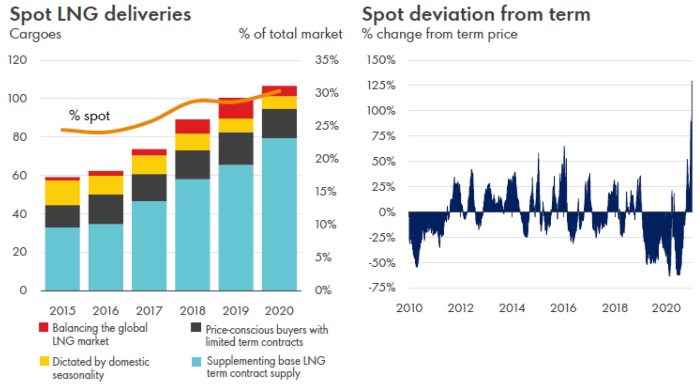
Spot LNG deliveries and Spot deviation from term price



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.

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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%*

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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.

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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.

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Offshore Alliance

August 2 at 10:17 PM ·

Earlier today, Shell HR confirmed that they ripped off the Prelude FLNG workforce by taking twice as much as what they were lawfully allowed to deduct, from members' July pay packets, for the June PIA stoppages. Of course it was just an accident....

Shell's wage theft of members does not end there as the Offshore Alliance believe that Shell's pro-rata deduction of the Offshore Allowance and Commuting Allowance is unlawful.

Our lawyers are currently reviewing Shell's actions with a view to prosecuting them in the Federal Court. It has the stench of Coercion and Adverse Action about it.

Shell management have now advised our Prelude members that they are digging in for the long haul and will be preparing for the Prelude to be shut down for months.

Shell have now missed 6 offtakes and $960 million of revenue.

A shutdown until Xmas will cost Shell an additional $5.5 Billion of gas revenue - not to mention the deferral of the Turnaround by 10 months.

Shell's HR and Operations team responsible for the Prelude EBA debacle must feel very proud of their efforts.

There is a growing number of Shell's management team who are privately seething about the pig-headed and irrational actions of the Shell managers responsible for not sorting out the Prelude EBA, and for the 54 days of Protected Industrial Action.

Heads will roll once the dust settles (if not before), and plenty of them. No HR or Operations manager gets to burn $1 Billion of revenue without consequence.

The Offshore Alliance has a simple message for Shell. We will go one day longer and one day stronger.

Offshore Alliance

August 2 at 2:00 PM ·

Whilst Europe is heading for “fuel poverty” and a deep freeze and the East Coast of Australia runs out of gas, Shell’s Prelude FLNG management have locked themselves into a bargaining dispute that has cost Shell close to $1 Billion in lost gas production.

Shell are now telling our Prelude FLNG members that the Turnaround planned to commence in 28 days’ time is “unlikely to go ahead” and will be cancelled if the Prelude FLNG dispute isn’t resolved within 7 days.

The Turnaround crew will now have to source other work because there is not much chance of the PIA ending within 7 days.

There is even less chance that mediation by a private mediator without PIA will resolve the dispute whilst Shell refuse to negotiate or agree to job security, pay levels and the involvement of the FWC in resolving disciplinary matters.

Shells inability to complete the scheduled Turnaround may put Shell’s License to Operate at risk, unless NOPSEMA give Shell the green light to gamble with the health and safety of Prelude workers.

Shell reckon they've already struck a deal with the Regulator to continue on without doing the much needed Turnaround.

Once again, NOPSEMA appear to be folding to the demands of big oil and gas companies.

Shell are refusing to bargain for an Enterprise Agreement because they claim their management team are too busy dealing with PIA.

That is clearly bullshit, as the only thing Shell's management team are doing is counting the lost production and profit resulting from their failure to agree to job security provisions which prevent them from outsourcing the jobs of the Prelude crew to low-wage labour hire contractors.

Shell's claim that we are seeking a guarantee of 20 years work for members on the Prelude FLNG shows how little they understand our bargaining claims.

They will never understand our bargaining claims if they don't get back to the bargaining table.

All the while, Europe is ratcheting up the rationing of gas, and Australia's East Coast is facing significant under-supply issues heading into next year.

Shell's handling of the Prelude FLNG EBA is diabolical and the management team responsible for this mess will inevitably be sacked and sent to purgatory. It's simply a matter of when.

August 8, 2022
https://www.facebook.com/Offshore-Alliance-524335271311416/photos/

Offshore Alliance
7 hrs ·

On Thursday 4th August, Shell filed a S.425 application in the Fair Work Commission seeking an urgent Hearing in the FWC for Orders which would have suspended all of the Protected Industrial Action which impact Turnaround activities.

Between Friday morning and 7.00PM last night, the FWC mediated the bargaining negotiations and were successful in assisting the parties reduce the number of outstanding bargaining claims from 7 to 3.

Shell however have not yet agreed to job security provision which will prevent them outsourcing the jobs of Shell Prelude employees to low-wage labour hire contractors.

With a self-imposed deadline of wanting negotiations finalised on Sunday evening, Shell asked the FWC to Hear its application to suspend all Protected Industrial Action on the Prelude which impacted Turnaround activities.

Shell did not specify which of our particular actions would 'impact' the Turnaround.

The Fair Work Commission have this morning dismissed Shell's S.425 application and Protected Industrial Action on the Prelude continues into its 58th day.

This is a massive win by the Offshore Alliance and ETU lawyers. We have a top-notch in-house and external legal staff and won't be intimidated by the big-end-of-town law firms.

Shell would have been better bargaining than going down their failed path of litigation. Once again, their industrial strategy has hit a brick wall.

The Offshore Alliance remains willing to meet with Shell to try and settle the remaining bargaining claims.

The failure of Shell to resolve relatively simple bargaining claims is a damming reflection on their local HR management and operations personnel who have been in charge of the Prelude EBA negotiations.

The recalcitrance and intransigence of Shell has now cost the company over $1.1 Billion in lost hydrocarbon production and revenue.

Their actions are illogical and they are massively out of step with the industry in regard to their industrial conduct.

Shell's Prelude Asset Manager Peter Norman has now advised members that Shell have decided to cancel the Turnaround and will re-schedule it to sometime in 2023.

The Union will be sending NOPSEMA correspondence about Shell's latest announcement.

Shell's blind bargaining ideology has come at a price which makes no sense to key stakeholders.

$1.1 Billion tipped down the drain to avoid securing the jobs of Prelude workers? This is an obscenity.

It's time for Shell's national and/or international management to step in and sort out the mess created by the local Prelude HR and Operations management personnel.

https://www.facebook.com/pages/category/Labor-Union/Offshore-Alliance-524335271311416/

Offshore Alliance

August 10 at 2:00 PM ·

Shell Prelude Asset Manager Peter Norman needs to explain to the Shell Board how INPEX exported 52 more LNG cargoes than Shell's Prelude FLNG in the first 6 months of 2022. The difference between the 8.9MT capacity at INPEX and the 3.64MT capacity on Prelude does not explain Shell's offtake performance. Especially when the recent INPEX Turnaround is factored in.

INPEX sorted out an EBA with the Offshore Alliance earlier this year with zero impact on offtakes or production.

Shell on the other hand have dragged negotiations on for over 18 months and haven't completed an offtake since July 08 2022. Not to mention the brakes being put on production in June.

Rather than resolving our outstanding bargaining claims and resolving the cost-neutral job security claims, Shell have preferred to wage war on their Prelude workforce.

Shell's global management team need to take over the Prelude bargaining negotiations, which have been the most ideologically driven and inept bargaining dispute in corporate history.

What company is willing to burn over $1 billion in lost production and cancel a major turnaround because they want the “flexibility” of outsourcing direct-hire jobs to low-wage labour hire contractors?

Google Translate of Kommersant report https://www.kommersant.ru/doc/5503226
10.08.2022, 00:41

Arctic LNG-2 to be powered from water

Turkish floating station can provide energy for NOVATEK's project

According to Kommersant, NOVATEK figured out how to solve the problem of supplying the first line of the Arctic LNG-2. To do this, the company will order a floating power plant with a capacity of about 300-400 MW, powered by gas piston engines, from the Turkish Karpowership. Such a decision was required due to the fact that the American Baker Hughes refused to supply the gas turbines needed to liquefy the gas and power the lines. According to analysts, the choice of the Turkish company looks justified and has no alternative.

NOVATEK will order a floating power plant to supply the first line of the Arctic LNG-2 plant under construction from the Turkish Karpowership, according to Kommersant sources familiar with the situation. Gas reciprocating engines will be installed on the barge, the capacity of the floating thermal power plant will be 300-400 MW, Kommersant's interlocutors find it difficult to name the timing of its construction. Probably, the same energy supply option will be adopted for the second and third lines of the LNG plant, Kommersant's interlocutors believe.

Karpowership (owned by Karadeniz Energy Group) is one of the world's largest operators of floating power plants, the company mainly supplies its vessels to countries experiencing severe energy shortages. The company's fleet of about 4 GW operates in eight countries in Africa, Cuba, the Middle East and Indonesia. NOVATEK and Karpowership did not respond to Kommersant's request.

As part of Arctic LNG-2, NOVATEK plans to build three lines for the production of LNG with a capacity of 6.6 million tons per year each, the launch of the first is scheduled for 2023, the second - for 2024, the third - for 2025. LNG lines for the Arctic LNG-2 plant are being built at the shipyard in Murmansk on gravity bases, which will then be transported by sea to the Gulf of Ob to the installation site at the Utrenny terminal, next to the Utrenny field on Gydan.

As Kommersant wrote on June 16, NOVATEK faced a number of technical difficulties after the American Baker Hughes (BH) refused to supply contracted equipment for the LNG plant - LM9000 gas turbines. It should be noted that the supply of gas turbines to the Russian Federation is not directly prohibited by the EU and US sanctions, although the fifth package of EU sanctions, introduced on April 8, prohibits the supply of key gas liquefaction equipment to the Russian Federation. BH was to supply about 20 LM9000 turbines up to 75 MW, based on the engine for the Boeing 777, for three Arctic LNG-2 lines.

For the first line, BH was supposed to supply seven machines (some for the LNG process, some for power supply), but, according to Kommersant, it shipped only four of them, which will be used in the LNG process. At the same time, Kommersant's interlocutors emphasize that the LM9000 machine is advanced in its lineup and rather difficult to maintain, without the support of the manufacturer and in the absence of supplies of spare parts, problems with its service may arise.

It is not yet clear what equipment NOVATEK will choose for the LNG process on the second and third lines of Arctic LNG-2 to replace the BH turbines. The head of NOVATEK, Leonid Mikhelson, said at SPIEF 2022 that the most important critical equipment for LNG production is the turbine. “Now we are looking, redesigning to replace the turbine with an electric drive. The most difficult issue is the turbine. We have 115 MW at Power Machines, but it is industrial. There is no 70–80 MW turbine. Electric drives were discussed with two or three manufacturers who together will make an electric drive. It will take a couple of years. Accordingly, to provide energy, it will be necessary to build a power plant for 400 MW per line, ”he said (quote from Interfax). Mr. Mikhelson clarified that for the first line of Arctic LNG-2, the issue of replacing the turbine with an electric drive is not worth it,

Independent energy expert Yuri Melnikov notes that Karpowership specializes in the field of floating thermal power plants, so the choice looks reasonable and uncontested - there are no analogues available in the world. According to him, electricity from a floating power plant will be more expensive than from a stationary one, and the performance of the LM9000 in terms of efficiency in this project is unattainable, but with the long-term restriction of BH's business in Russia, there are no alternatives.

Tatyana Dyatel

https://tass.com/economy/1484407
25 JUL, 03:58

Nord Stream deliveries will reach technically possible limits after installing turbine

On July 9, Canada decided to return the repaired Siemens turbine after numerous requests from Germany

MOSCOW, July 25. /TASS/. Gas deliveries through the Nord Stream pipeline will reach technologically possible limits after the turbine returned from repairs is installed, Russian presidential spokesman Dmitry Peskov told reporters on Monday.

"Of course, the turbine will be installed. We know that there are still issues with other units, which Siemens is also aware of. But, of course, the turbine will be installed after all formalities are completed. And deliveries will continue to the extent that is technologically possible," he replied when asked if Gazprom will now be able to install a turbine and increase gas supplies to Europe.

Due to the late return of Siemens gas turbines after repairs due to Canadian sanctions against Russia, the gas pipeline has been operating at only 40% of its maximum capacity since mid-June.

After numerous requests from Germany, Canada decided to return the repaired Siemens turbine on July 9. According to the European Commission, Canada's return of the Nord Stream turbine does not violate EU sanctions on Russia because they do not relate to gas transit equipment.

Russian President Vladimir Putin said that if the Nord Stream turbine is not returned to Russia, only 30 mln cubic meters of gas per day can be delivered along the pipeline instead of the current 60 mln cubic meters.

https://tass.com/economy/1484405
25 JUL, 03:49

Russia is not interested in completely stopping gas deliveries to Europe — Kremlin

At the same time, Dmitry Peskov noted that "if Europe continues on its path of totally reckless imposition of restrictions and sanctions that hit it, then the situation will be different"

MOSCOW, July 25. /TASS/. Russia is not interested in a complete cessation of gas supplies to European countries, since Moscow largely guarantees the energy security of the EU, Russian presidential spokesman Dmitry Peskov told reporters on Monday.

"Russia is not interested in this," he said, commenting on the statement of European Commission President Ursula von der Leyen that in the face of reduced gas supplies from Russia, Europe should prepare for its complete cessation.

"Russia is a responsible gas supplier, and regardless of what anyone says in the European Commission, in European capitals, in the United States, Russia was, is, and will continue to be the country that largely guarantees Europe's energy security," Peskov added.

On the other hand, Peskov noted, "If Europe continues on its path of totally reckless imposition of restrictions and sanctions that hit it, then the situation will be different." "But Russia is not interested in this," he assured

https://www.kommersant.ru/doc/5412128
06/16/2022, 00:50

Baker Hughes terminates service agreements for LNG projects in Russia

According to Kommersant's information, the American Baker Hughes stops servicing all Russian LNG projects. In particular, the company is withdrawing service engineers from Gazprom's Sakhalin-2 and NOVATEK's Yamal LNG projects, as well as design engineers from NOVATEK's Arctic LNG-2 under construction. Simultaneously, Baker Hughes will stop shipping for the latest equipment project, including gas turbines. The timing of the completion of the construction of the first line of the Arctic LNG-2 directly depends on these deliveries.

The American Baker Hughes recalls its engineers for the maintenance of key technological equipment (gas turbines and compressors) from the Yamal LNG projects of NOVATEK and Sakhalin-2 of Gazprom, project engineers from the Arctic LNG-2 project of NOVATEK under construction, and also stops all shipments of equipment for LNG projects in Russia. This was reported to Kommersant by sources among the Russian counterparties of the company. According to them, in fact, this calls into question the further operation and commissioning of foreign equipment, and also makes it impossible to supply spare parts for its repairs.

The American company is terminating the agreements, despite the fact that there are no direct sanctions restrictions on the service and supply of gas turbines in the Russian Federation (the conclusion of new contracts is prohibited), and Gazprom and NOVATEK are not under direct US or EU sanctions.

Completion of the construction of the first Arctic LNG-2 line for 6.6 million tons is now directly dependent on the supply of Baker Hughes LM9000 gas turbines.

In total, seven turbines are to be delivered to the first line (part for the LNG production process, part for power generation), but, according to Kommersant, only half of the machines have been shipped to NOVATEK so far. There is, in fact, nothing to replace this equipment now: analogues are not produced in the Russian Federation, and LNG production lines have already been designed for the LM9000.

NOVATEK did not respond to Kommersant's request about a possible delay in commissioning the first Arctic LNG-2 line and the number of vehicles received. Sakhalin-2 (Gazprom has 50% + 1 share) has signed a long-term service contract for the maintenance of four Frame 7EA turbines (used in the process, power - 90 MW) and five Frame 5 turbines (25 MW, for power generation).). The project company Sakhalin Energy did not respond to Kommersant's request.

The head of NOVATEK, Leonid Mikhelson, said on May 19 that the company still maintains plans to launch the first line of Arctic LNG-2 in 2023. To do this, a floating platform from Murmansk to the waters of the Gulf of Ob should be sent to navigation in 2022, which will last until about the end of August. “There are big difficulties today with the imposition of sanctions, and not only the sanctions for the products and services themselves, there are many logistical difficulties ... We manage to overcome these difficulties so far, and so far we have not changed plans for the timing of the introduction,” Mr. Mikhelson explained.

As part of Arctic LNG-2, NOVATEK planned to build three lines for the production of LNG with a capacity of 6.6 million tons per year each, the launch of the second line was planned for 2024, the third - for 2025. At the same time, the head of TotalEnergies Patrick Pouyanne (the company has 10% in the project) reported that the first Arctic LNG-2 platform is 98% ready and has a high chance of completion, but “there may be some tricky moments”, because some of the equipment is still not delivered in the Russian Federation (quote from Bloomberg).

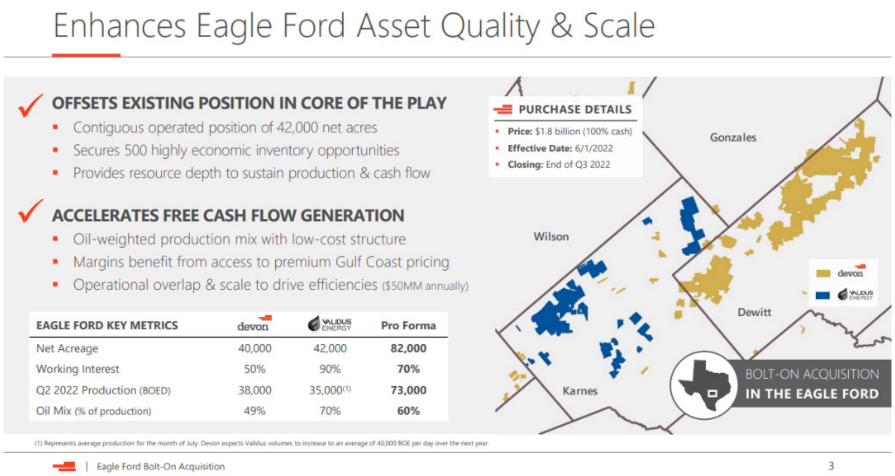
According to Mr. Michelson, the localization of the equipment for Arctic LNG-2, in particular, the cryogenic equipment necessary for the production of LNG, may take two to three years.

While localization is about 50%. Leonid Mikhelson specified that NOVATEK had already begun pre-project work on the construction of a new LNG plant using Russian technology with a capacity of 5 million tons.

NOVATEK plans new LNG plant with Russian equipment

Yury Melnikov, Head of Hydrogen and Energy Efficiency at the Energy Center of the Skolkovo School of Management, notes that aircraft-type gas turbines, typical of the oil and gas industry and known under the General Electric (GE) brand, have been produced and serviced by Baker Hughes since about 2019. In the Russian Federation, the production of turbines that are used in Sakhalin and Yamal is not localized: REP Holding, in partnership with GE, has been engaged in a turbine of a different size since 2013 - MS5002E (32 MW). Therefore, the expert admits, objective difficulties in service can be expected if Baker Hughes decides to stop work on service contracts and the supply of spare parts. The most serious problems, in his opinion, may arise with the maintenance of parts of the hot path - the combustion chamber and the first stages of the turbine.

Tatyana Dyatel



https://www.devonenergy.com/news/2022/Devon-Energy-Announces-Bolt-On-Acquisition-in-the-Eagle-Ford

Devon Energy Announces Bolt-On Acquisition in the Eagle Ford

OKLAHOMA CITY, Aug. 09, 2022 (GLOBE NEWSWIRE) -- Devon Energy Corp. (NYSE: DVN) announced today it has entered into a definitive purchase agreement to acquire Validus Energy, an Eagle Ford operator, for total cash consideration of $1.8 billion. The transaction is subject to customary terms and conditions and is expected to close at the end of the third quarter of 2022, with an effective date of June 1, 2022.

Rick Muncrief, president and CEO stated, “The Validus acquisition captures a top-tier oil resource with a meaningful runway of highly economic inventory that is complementary to our existing footprint in the Eagle Ford. This accretive transaction also enhances our financially-driven strategy that is designed to deliver per-share financial growth and accelerate the return of capital to our shareholders.”

TRANSACTION HIGHLIGHTS

- **Immediately accretive to financial metrics** – The transaction is attractively valued at 2-times cash flow, with a free cash flow yield of 30 percent at strip pricing over the next year. The acquisition is expected to be immediately accretive to all relevant per-share metrics in the first year, including earnings, cash flow, free cash flow and net asset value.
- **Increases cash-return outlook** – Due to the accretive nature of this transaction to free cash flow, the outlook for Devon’s variable dividend increases by up to 10 percent on a per-share basis at strip pricing. In addition to higher dividend payouts, the incremental free cash flow from this acquisition positions the company to accelerate the return of excess cash to shareholders through the ongoing execution of its $2.0 billion share repurchase program.
- **Enhances Eagle Ford asset quality and scale** – This acquisition secures a premier acreage position of 42,000 net acres (90% working interest) adjacent to Devon’s existing leasehold in the basin. Validus’s current production is approximately 35,000 Boe per day (70 percent oil), with volumes expected to increase to an average of 40,000 Boe per day over the next year. The transaction also adds 350 repeatable drilling locations in the core of the Karnes Trough oil window along with 150 high-quality refrac candidates. This highly economic inventory positions the company’s Eagle Ford assets to sustain its high-margin production and free cash flow generation for several years.
- **Captures high-margin production** – The acquired assets provide high cash operating margins through access to premium Gulf Coast pricing and low per-unit expenses. With enhanced scale in the basin, Devon expects to realize $50 million in average annual cash flow savings from capital efficiencies, operating improvements, and marketing synergies.
- **Maintains top-tier balance sheet** – Devon’s pro forma leverage metrics will remain relatively unchanged, exiting the year with an expected net debt-to-EBITDAX ratio of 0.4 times at strip pricing. This balance sheet strength preserves the company’s financial and operational flexibility and allows for the accelerated return of capital to shareholders.

Supplemental slides covering the transaction are available on the company’s website at www.devonenergy.com.

https://biologicaldiversity.org/w/news/press-releases/legal-agreement-blocks-oil-gas-leasing-on-22-million-acres-in-colorado-2022-08-12/

CENTER for BIOLOGICAL DIVERSITY Because life is good.

For Immediate Release, August 12, 2022

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Legal Agreement Blocks Oil, Gas Leasing on 2.2 Million Acres in Colorado

Bureau of Land Management to Reconsider Plan, Protect Gunnison Sage Grouse

DENVER— Conservation groups and the U.S. Bureau of Land Management have finalized a legal agreement that will prevent new oil and gas leasing across 2.2 million acres of southwestern Colorado until the agency supplements its environmental analysis and releases an amended plan for lands in the area.

“The North Fork Valley has been fighting for over a decade to prevent leasing of public lands to oil and gas development around our homes, farms and in our watersheds,” said Natasha Léger, executive director of Citizens for a Healthy Community. “We have seen some of the most extreme warming in the country, and our rare and irreplaceable ecosystem is under increasing climate and ecological stress. This moratorium on leasing has been hard fought and would not have been possible without the unwavering persistence of citizen and environmental groups holding government officials accountable.”

The agreement requires the Bureau to analyze potential harms to the climate from fossil fuel extraction in the Uncompahgre Field Office planning area and to evaluate at least one alternative that reduces oil and gas leasing. This revision process for the Uncompahgre resource management plan is expected to take two years.

Before revising the plan, the agency also must complete a separate regional plan to conserve critically imperiled Gunnison sage grouse, an effort the Bureau started last month, and another plan to promote conservation of big game corridors and important big game habitat on more than 20 million acres of public lands in Colorado, also announced in July.

“The communities of the North Fork Valley have worked hard to declare their independence from the boom-bust cycle of a fossil fuel-dependent economy, with the result that the Valley is now known for its family farms, wineries, recreational opportunities and wildlife,” said Melissa Hornbein, a senior attorney at the Western Environmental Law Center. “For the Bureau to willfully risk these values by adopting a 20-

year plan covering millions of acres without adequately analyzing its climate impacts, and without acknowledging the disproportionate warming that has already occurred in the Valley was reckless. We are happy the government has recognized the need to maintain the status quo while meaningfully considering these impacts. That was the point of this case."

"Any fossil fuel expansion is flatly incompatible with avoiding climate catastrophes and preserving a livable world," said Taylor McKinnon at the Center for Biological Diversity. "For the sake of the Colorado River, the Gunnison sage grouse and the North Fork Valley's organic farms and communities, the Biden administration must end new leasing here, once and for all."

The agreement resolves a lawsuit filed in 2020 by the conservation groups challenging the Bureau's refusal to analyze climate damage and harm to the threatened sage grouse from fossil fuel development and the agency's failure to consider a management alternative that allows for no new fossil fuel leasing.

"This is great news for western Colorado's public lands, communities, wildlife and clean air and water," said Jeremy Nichols, WildEarth Guardians' Climate and Energy Program director. "This agreement opens the door for a true transition away from costly and destructive fossil fuels in the North Fork Valley and beyond."

The Uncompahgre resource management plan is a 20-year blueprint for management of the subject lands. The contested plan would have allowed fracking on more than half of the public land and federal mineral estate included in the 3.1 million-acre planning area, would have opened 95% of the mineral estate underlying BLM surface lands to oil and gas development, and would have allowed coal extraction on another 371,000 acres at a time when the urgency of the climate crisis demands that federal fossil fuels be left in the ground.

"Our public lands are some of our most treasured places, holding important cultural history and providing a home to wildlife and places to recreate with our families," said Dan Ritzman, director of Sierra Club's Lands, Water, Wildlife campaign. "They should be part of the solution to the climate crisis, not leased to fossil fuel companies that are killing our communities and burning our planet."

Temperatures in the region have risen more than 2 degrees Celsius (nearly 4 degrees Fahrenheit), drying Colorado River flows that support endangered fish, agriculture and 40 million downstream water users.

The region spans the northwestern San Juan Mountains, several rivers, the towns of Ouray, Telluride, Montrose and Paonia, and the North Fork Valley, whose organic food growers and communities have opposed oil and gas development. It also includes numerous threatened and endangered species, including the razorback sucker, Colorado pikeminnow and Gunnison sage grouse.

"Lands managed under the Uncompahgre plan are essential conservation priorities if the vanishing Gunnison sage grouse is to have any hope of long-term survival," said Michael Saul, Colorado director with Western Watersheds Project. "Now more than ever, the Bureau of Land Management needs to prioritize the preservation of intact, functional Gunnison sage grouse habitat above private commercial uses of shared public lands."

"Gunnison sage grouse depend on healthy public lands, and healthy public lands are incompatible with expanding fossil fuel development," said Matt Reed, public lands director with Gunnison County-based

High Country Conservation Advocates. "We're grateful that the communities, wildlife and waters that are sustained by this landscape will benefit from this agreement."

The settlement comes as Congress is advancing the Inflation Reduction Act, which would require the Interior Department to offer 2 million acres onshore and 60 million acres offshore for new oil and gas leases each year.

Several analyses show climate pollution from the world's already producing fossil fuel developments, if fully developed, will push warming past 1.5 degrees Celsius. Avoiding such warming requires ending new investment in fossil fuel projects and phasing out production to keep as much as 40% of already-developed fields in the ground.

Thousands of organizations and communities from across the U.S. have called on President Biden to halt federal fossil fuel expansion, phase out production consistent with limiting global warming to 1.5 degrees Celsius, and develop new rules under long-ignored legal authorities to serve those goals.

The Center for Biological Diversity, Citizens for a Healthy Community, High Country Conservation Advocates, WildEarth Guardians, Sierra Club and Western Watersheds Project are represented in the litigation by attorneys from Western Environmental Law Center, the Center for Biological Diversity and Sierra Club.

The Center for Biological Diversity is a national, nonprofit conservation organization with more than 1.7 million members and online activists dedicated to the protection of endangered species and wild places.

The Western Environmental Law Center uses the power of the law to safeguard the wildlife, wildlands, and communities of the American West in the face of a changing climate. As a public interest law firm, WELC does not charge clients and partners for services, but relies instead on charitable gifts from individuals, families, and foundations to accomplish our mission.

Western Watersheds Project is an environmental conservation group working to protect and restore watersheds and wildlife throughout the American West.

Citizens for a Healthy Community (CHC) is a grassroots nonprofit organization dedicated to protecting the air, water and foodsheds of the Delta County region in Southwest Colorado from the impacts of oil and gas development and paving the path to clean and renewable energy future. CHC is located in the North Fork Valley of Colorado, which is home to the largest concentration of organic farms in the state. Learn more at www.chc4you.org.

The Sierra Club is America's largest and most influential grassroots environmental organization, with more than 3.5 million members and supporters. In addition to protecting every person's right to get outdoors and access the healing power of nature, the Sierra Club works to promote clean energy, safeguard the health of our communities, protect wildlife, and preserve our remaining wild places through grassroots activism, public education, lobbying, and legal action. For more information, visit www.sierraclub.org.

Based in Crested Butte since 1977, High Country Conservation Advocates protects the health and natural beauty of the land, rivers, and wildlife in and around Gunnison County now and for future generations.

Trans Mountain Announces New President and Chief Executive Officer

Aug. 10, 2022

The Board of Directors of Trans Mountain Corporation today announced the appointment of Dawn Farrell to the position of President and Chief Executive Officer and member of the Board of Directors. The appointment will be effective August 15, 2022.

Mrs. Farrell brings over 35 years' experience in the energy business, having held various senior level positions, including most recently President and CEO of TransAlta Corporation where she led the company's unprecedented transition away from coal-fired electrical generation. This was one of the most significant carbon emissions reduction achievements in Canada's effort to address climate change.

As a highly experienced large public company executive, Dawn brings a depth of expertise and significant international business presence to Trans Mountain. Her experience at TransAlta, including three years as Chief Operating Officer, highlights her strong expertise in the execution of complex projects, working with Indigenous communities, and completing company-wide cultural transformation; all important areas of expertise that will benefit Trans Mountain. Mrs. Farrell brings extensive experience with capital markets, mergers and acquisitions, and has led the negotiation and evaluation of a critical, intricate transaction with government.

William Downe, Chairman of the Board of Trans Mountain, commented: "We are pleased that Dawn has chosen to join the strong team at Trans Mountain. A community builder with a steadfast commitment to strengthening Canada, Dawn has proven to be a dynamic and thoughtful leader, successfully leading organizations through change and revitalization. We are confident that her broad-based knowledge, experience, and her background with governments and Indigenous communities will be a tremendous asset to Trans Mountain as it completes the expansion project and navigates the next stages of the Company's future."

Downe continues, "On behalf of all Board members, I would like to thank Rob Van Walleghem for his leadership of the Company during this period of transition; he will continue in a senior executive leadership role at the company."

Dawn Farrell commented: "I am excited to be joining the team at Trans Mountain as it continues its work of completing one of Canada's most important infrastructure projects. The Trans Mountain Expansion Project has been in planning and construction for the past 12 years and, as it passes the 60% completion mark, I look forward to leading the organization to this Project's end while steering the next phase of the Company's future."

Dawn Farrell Background

Dawn Farrell spent over 35 years in the energy business and held a variety of positions including President and CEO of TransAlta. TransAlta is one of the largest investor-owned generation and energy marketing companies in Canada with operations in Canada, the U.S. and Australia, and is a publicly listed company on the TSX and NYSE. As CEO of TransAlta for over nine years, Mrs. Farrell led the transformation of the company to competitive power focused on low-cost, clean, and reliable solutions for large commercial and industrial customers.

She is currently the Chair of the Board for The Chemours Company and Portland General Electric. She has held past board positions including the Business Council of Canada, Alberta Business Council, Calgary Stampede, Conference Board of Canada, Mount Royal College/University Board of Governors and Foundation Board of Directors, Fording Coal Income Fund, New Relationship Trust, and Vision Quest Windelectric. Farrell has contributed to electricity and environmental policy development in Alberta, British Columbia, and federally in Canada.

Mrs. Farrell is currently the Chancellor for Mount Royal University and a member of the Trilateral Commission, a non-governmental, policy-oriented international forum, as well as community champion for Momentum.

Ecopetrol Says Colombia Should Pare Back Proposed Oil Export Tax
2022-08-11 21:41:28.808 GMT

By Andrea Jaramillo
(Bloomberg) -- Colombia's state-controlled oil producer Ecopetrol SA is proposing to dilute a planned oil export tax that is a major part of President Gustavo Petro's economic program.
Ecopetrol is asking the government, it's largest shareholder, to raise the reference price for when it starts charging oil export taxes. A bill presented this week includes a 10% export tax on oil, coal and gold when the price is above an international reference, which is $48 a barrel for crude. That compares to an average price of about $105 in the last six months.
The reference price is "too low," CEO Felipe Bayon said in an interview on the sidelines of a business conference in Cartagena. "For me the threshold of $48 would need to go up." A ballpark number of about $65 to $70 a barrel would make sense, he said. The government's proposed level of $48 would deliver up to 5 trillion pesos ($1.2 billion) in export taxes at current prices. As it is, the export tax would reduce Ecopetrol's dividend payments by about half, according to Bayon. The benefit for the government is that it receives payments as soon as crude is exported, "which we understand is relevant."
The leftist government of Gustavo Petro, which took office on Sunday, has said the tax reform is part of its wider plan to cut inequality and finance poverty-fighting programs. Petro has pledged to phase out the economy's dependence on oil and coal, which currently account for about half of Colombia's exports. As part of his campaign promises he said he won't award any more exploration licenses, and has said the transition will take about 12 years.
Read: Petro Targets Rich Colombians and Oil Exports With New Taxes
The tax reform aims to boost 2023 tax revenue by the equivalent of 1.7% of gross domestic product. The tax bill also includes a proposal that halts deductions for royalty payments, which means higher costs for commodity companies.
Speaking at business association ANDI's annual event in Cartagena, it's head Bruce Mac Master cautioned that tax increases may lead companies to reconsider investing in Colombia. The group calculates that the effective tax rate for mining and hydrocarbon companies would jump to 87% if the tax bill passes in its current form, from 53% this year.
Ecopetrol doesn't just have to contend with higher levies. The government also needs to reimburse it for subsidizing fuels. Rather than allow gasoline prices to rise in line with crude this year, the government has capped the increases. That means that at current prices, the subsidy costs the government between 2 and 3 trillion pesos a month.
In March of this year Ecopetrol received 14.2 trillion pesos outstanding, and this month will receive about 3 trillion

pesos.
The Petro administration has shown willingness to continue to pay, said Bayon, pointing to 19.2 trillion pesos earmarked in next year's budget for such payment.
"They are very aware and we'll continue to work with the government," said Bayon. "I sense the right attitude."
Still, the new tax plans won't slow down Ecopetrol's investment plans after it presented record earnings in the second quarter.
"We don't want to slow down our investment," said Bayon. "Prices are in a good place, our ability to execute is good: more rigs, more wells being drilled, more facilities being built."
Production is also up. Ecopetrol produced 704,000 barrels a day in the second quarter and in July it rose to 714,000.
"All in all things are looking good," said Bayon. "But you need to look at the potential implications of the tax reform and the fuel subsidies, the whole thing."

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Oil Market Highlights

Crude Oil Price Movements

The OPEC Reference Basket fell $9.17, or 7.8%, m-o-m in July to average $108.55/b. Oil futures prices remained highly volatile in July, amid a sharp drop in liquidity. The ICE Brent front month declined $12.38, or 10.5%, in July to average $105.12/b and NYMEX WTI declined by $14.96, or 13.1%, to average $99.38/b. The Brent/WTI futures spread widened further by $2.58 to average $5.74/b. The market structure of all three major crude benchmarks – ICE Brent, NYMEX WTI and DME Oman – remained in strong backwardation, particularly Brent. This was despite a sharp decline in front-month prices, as fundamental outlooks remained strong. However, the backwardation structure flattened in the first week of August. Hedge funds and other money managers extended heavy selloffs in July, cutting combined futures and options net long positions in ICE Brent and NYMEX WTI to their lowest level since April 2020.

World Economy

World economic growth is revised down to stand at 3.1% for 2022 and 2023. This is a result of weaker 2Q22 growth in the major economies and an observed soft trend in some key economies. For the US, GDP growth for 2022 is revised down to 1.8%, and to 1.7% for 2023. Euro-zone economic growth for 2022 is expected at 3.2%, while growth in 2023 is revised down to 1.7%. Japan's economic growth for 2022 is revised down to stand at 1.4%, to be followed by growth of 1.6% in 2023. China's 2022 growth forecast is revised down to 4.5%, while the 2023 forecast remains unchanged at 5.0%. The forecast for India remains unchanged at 7.1% in 2022 and 6.0% in 2023. Brazil's economic growth forecasts remain at 1.2% in 2022 and 1.5% in 2023. The 2022 forecast for Russia is unchanged, showing a contraction of 6.0% followed by growth of 1.2% in 2023. Downside risks remain, stemming from the ongoing geopolitical tensions, the continued pandemic, ongoing supply chain issues, rising inflation, high sovereign debt levels in many regions, and expected monetary tightening by central banks in the US, the UK, Japan and the Euro-zone.

World Oil Demand

World oil demand growth in 2022 is revised downwards from the previous month's assessment but still shows healthy growth of 3.1 mb/d, including the recently observed trend of burning more crude in power generation. Oil demand in the OECD is estimated to grow by 1.6 mb/d, while the non-OECD is expected to grow by 1.5 mb/d. Total oil demand is expected to average around 100 mb/d in 2022. The first half of this year is revised higher, amid better-than-anticipated oil demand in the main OECD consuming countries. However, oil demand in 2H22 is revised lower, amid expectations of a resurgence of COVID-19 restrictions and ongoing geopolitical uncertainties. For 2023, the forecast for world oil demand growth remains unchanged at 2.7 mb/d, with total oil demand averaging 102.7 mb/d. The OECD is expected to grow by 0.6 mb/d and the non-OECD by 2.1 mb/d. Oil demand in 2023 is expected to be supported by a still-solid economic performance in major consuming countries, as well as improving geopolitical developments and improvement of COVID-19 in all regions.

World Oil Supply

Non-OPEC liquids supply growth in 2022 is forecast at 2.1 mb/d to average of 65.8 mb/d, broadly unchanged from the previous assessment. An upward revision to Russia is offset by downward revisions to the US, Norway and Kazakhstan. The main drivers of liquids supply growth for 2022 are expected to be the US, Canada, Brazil, China and Guyana, while production is expected to decline mainly in Indonesia and Thailand. In 2023, growth in non-OPEC liquids production remains unchanged at 1.7 mb/d to average 67.5 mb/d. The main drivers for growth in 2023 are expected to be the US, Norway, Brazil, Canada and Guyana. However, uncertainty regarding the operational and financial aspects of US production, as well as the geopolitical situation in Eastern Europe remains high. OPEC NGLs and non-conventional liquids are forecast to grow by 0.1 mb/d in 2022 to average 5.4 mb/d and by 50 tb/d to average 5.4 mb/d in 2023. OPEC-13 crude oil production in July increased by 216 tb/d m-o-m to average 28.90 mb/d, according to available secondary sources.

Product Markets and Refining Operations

Refinery margins in all main trading hubs reversed trends in July, falling back from the multi-year record highs registered in June. A counter-seasonal downturn in US product demand and rising refinery processing rates in Europe and in Asia led to product stock builds, providing partial relief to the product tightness witnessed over the past months. At the same time, concerns over a weakening global economy and a softer product market outlook likely further contributed to the downturn in refining economics globally. This weakness was manifested across the barrel in all regions as product prices retreated from the record-breaking highs witnessed in June. Going forward, transport fuel requirements should remain supportive in line with seasonal trends. Refinery intakes are expected to remain well-sustained to fulfil seasonal fuel consumption and allow continued restocking of product inventories.

Tanker Market

Dirty tanker spot freight rates in July have fully recovered from the decline seen earlier in May, as trade dislocations boosted activities in longer haul routes. VLCC rates on the Middle East-to-East route rose by 26%, while flows West were up 30%. The wide Brent/WTI spread also made US crude more competitive in Asia, supporting VLCC demand. Aframax rates on the Mediterranean to North West Europe route increased 38% m-o-m on average, while Suezmax rates from the US Gulf to Europe rose by 23%, amid strengthening demand for longer haul flows to Europe. Clean rates came down after gaining steadily over the past months, with declines particularly strong in the Med, as trade dislocations generated volatility.

Crude and Refined Products Trade

Preliminary data shows US crude imports reached a three-year high of 6.7 mb/d in July, amid higher flows from OPEC member countries and Brazil. US crude exports jumped to a record high of 3.7 mb/d based on preliminary weekly data, as the wide Brent/WTI spread stimulated a return of Asian buying. China's crude imports fell to an almost four-year low of 8.7 mb/d in June and are expected to remain at low levels, as lockdown measures earlier in the year and a spike in buying triggered by geopolitical developments in February have left inventories at ample levels. India's crude imports edged higher, averaging 4.7 mb/d in June, with Russia flows up 0.9 mb/d y-o-y according to secondary sources. India's crude imports are likely to remain close to current levels in July, with Russian inflows remaining above 1.0 mb/d but with slight lower flows from elsewhere. Japan's crude imports dropped to an 11-month low in June, averaging 2.3 mb/d, although still managed an increase y-o-y. Japan's crude imports are expected to recover with the return of refineries from maintenance in July. Preliminary figures show OECD Europe crude imports remaining at high levels in recent months, while crude exports fell to 7-year lows in April.

Commercial Stock Movements

Preliminary June data indicates total OECD commercial oil stocks rose 20.9 mb m-o-m. At 2,712 mb, inventories were 163 mb below the same period a year ago, 261 mb lower than the latest five-year average, and 236 mb below the 2015–2019 average. Within components, crude and product stocks increased by 6.4 mb and 14.5 mb, respectively, m-o-m. At 1,330 mb, OECD crude stocks were 54 mb lower y-o-y, 125 mb lower than the latest five-year average, and 135 mb below the 2015–2019 average. OECD product stocks stood at 1,381 mb, representing a deficit of 109 mb compared with the same month last year, 136 mb lower than the latest five-year average and 100 mb below the 2015–2019 average. In terms of days of forward cover, OECD commercial stocks rose m-o-m in June by 0.1 to stand at 58.9 days. This is 3.7 days below June 2021 levels, 5.3 days less than the latest five-year average, and 2.9 days lower than the 2015–2019 average.

Balance of Supply and Demand

Demand for OPEC crude in 2022 is revised down by 0.3 mb/d from the previous month's assessment to stand at 28.8 mb/d, which is around 0.9 mb/d higher than in 2021. Similarly, demand for OPEC crude in 2023 is revised down by 0.3 mb/d from the previous month's assessment to stand at 29.8 mb/d, around 0.9 mb/d higher than the 2022 level.

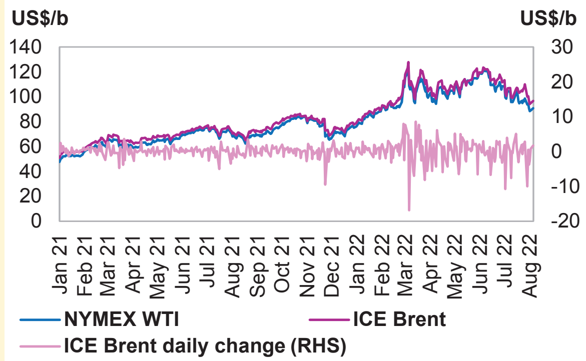
Feature Article

Crude and product price movements

Global oil market fundamentals continued their strong recovery to pre-COVID-19 levels for most of the first half of 2022, albeit signs of slowing growth in the world economy and oil demand have emerged. Global oil supply has risen steadily this year, including from countries participating in the Declaration of Cooperation (DoC), amid their continuing efforts to stabilize the oil market. However, ongoing low overall investment in the upstream and capital discipline are limiting non-OPEC oil supply growth potential.

The oil market has been dominated by elevated price volatility since March 2022, fuelled by the intensifying geopolitical concerns in Eastern Europe. Sanctions on Russian oil by some major oil-consuming countries have sharply raised the risk premium in oil prices, particularly for Brent. Moreover, this has resulted in major changes in inter-regional trade flows, exacerbating concerns about physical oil supply at the onset of the summer holiday season. Consequently, pressure increased on oil markets in some regions, specifically Europe, resulting in crude differentials soaring to record-high levels in 2Q22, along with steepening backwardation structures. Tight oil product markets, specifically for diesel and gasoline, have also pushed up crude oil prices.

Graph 1: Crude futures price volatility



Sources: ICE, CME Group and Thomson Reuters.

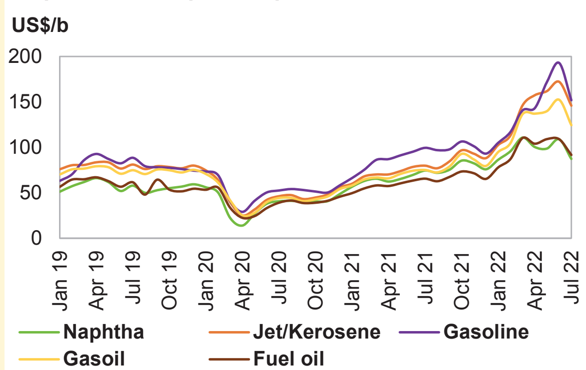
While physical oil market fundamentals remain strong, volatility in futures markets remained fuelled by expectations of lower GDP growth, amid rising global inflation, which prompted key central banks to begin raising interest rates. The US dollar's value strengthened further against a basket of major currencies, which also added concern. Moreover, price volatility contributed to reduced market liquidity, as seen in declining open interest. Combined futures and options open interest in ICE Brent and NYMEX WTI dropped in July 2022 to the lowest since June 2015.

On the product side, fuel prices surged in the first half of the year due to lower supplies amid COVID-19-related refinery closures and a heavy refinery turnaround season. In addition, stronger fuel consumption at the onset of the summer season, as COVID-19-related mobility restrictions were lifted in most regions, and product flow adjustments linked to the geopolitical developments in Eastern Europe further aggravated product tightness, which ultimately pushed product prices to record highs in June. At the same time, jet fuel, the second strongest performer in the US product market, saw its price benefit from improving international air travel activity, leading to notable jet fuel margin gains.

Fuel prices peaked in June with US gasoline prices reaching $193.06/b, up by $97.79/b, or 103%, y-o-y. However, rising refinery run rates in July alleviated some of the tightness, mostly in the USGC, where product prices across the barrel declined by $26.83/b on average. In Europe, average prices declined the least by $20.24/b, m-o-m.

Looking ahead, refined product markets in 2H22 are likely to continue to see seasonal support from transport fuels in the coming months, while fuel sales could benefit from moderating product prices – if the recent trend continues. At the same time, available refinery capacity will be supported by the ongoing operational ramp-up of at least two large capacity additions last year, mainly in the Middle East.

Graph 2: Refined product prices in the USGC



Sources: Argus Media and OPEC.

The countries participating in the DoC will continue to closely monitor ongoing market developments and encourage investment in the upstream sector to ensure adequate levels of capacity along the value chain, in their efforts to maintain a stable oil market balance in the interest of producers and consumers alike.

World Oil Demand

For 2022, world oil demand is foreseen to rise by 3.1 mb/d, a downward revision of 0.3 mb/d from last month's estimate to account for some regional revisions. This still healthy growth includes the recently observed trend of burning more crude in power generation. Total oil demand is projected to average 100.03 mb/d. In 1Q22, demand was revised up amid strong economic growth in most consuming countries and a lower baseline.

In the OECD region, oil demand is anticipated to rise by 1.6 mb/d to reach 46.4 mb/d. OECD Americas demand is anticipated to rise the most in 2022, led by the US on the back of recovering gasoline and diesel demand. Light distillates are also projected to support demand growth this year. In the non-OECD region, total oil demand is anticipated to rise by 1.5 mb/d to reach 53.6 mb/d in 2022. That is nearly 1.2 mb/d higher than 2019 total demand. A steady increase in industrial and transportation fuel demand, supported by a recovery in economic activity, is projected to boost demand in 2022.

In 2023, expectations for healthy global economic growth, combined with expected improvements in the containment of COVID-19 in China, are expected to boost consumption of oil. The 2023 forecast has remained the same as the last MOMR at 2.7 mb/d. Consequently, the 2023 world oil demand is projected to reach 102.72 mb/d.

In the OECD, oil demand is anticipated to rise by 0.6 mb/d, as OECD Americas is expected to climb firmly, with US oil demand above 2019 levels mainly due to the recovery in transportation fuels and light distillate demand. OECD Europe and the Asia Pacific will grow above 2019 consumption levels. In the non-OECD, oil demand is projected to show an increase of 2.1 mb/d, with the largest growth seen in China and India, supported by a recovery in transportation fuels and firm industrial fuel demand, including petrochemical feedstock. Other regions such as Other Asia, Latin America and the Middle East are also expected to see decent gains, supported by a positive economic outlook. In terms of fuels, gasoline and diesel are assumed to lead oil demand growth next year.

Table 4 - 1: World oil demand in 2022*, mb/d

							Change 2022/21	
World oil demand	**2021**	**1Q22**	**2Q22**	**3Q22**	**4Q22**	**2022**	**Growth**	**%**
Americas	24.28	24.88	24.99	25.31	25.45	25.16	0.89	3.65
of which US	*19.93*	*20.38*	*20.37*	*20.74*	*20.91*	*20.60*	*0.67*	*3.39*
Europe	13.08	13.09	13.31	14.16	14.18	13.69	0.60	4.62
Asia Pacific	7.41	7.89	7.12	7.23	7.93	7.54	0.13	1.80
Total OECD	**44.77**	**45.86**	**45.42**	**46.70**	**47.57**	**46.39**	**1.62**	**3.63**
China	14.94	14.67	14.81	15.25	15.75	15.12	0.18	1.23
India	4.77	5.18	5.16	4.91	5.32	5.14	0.37	7.73
Other Asia	8.63	9.09	9.39	8.73	8.90	9.02	0.40	4.60
Latin America	6.23	6.32	6.31	6.55	6.40	6.40	0.17	2.75
Middle East	7.79	8.06	8.02	8.38	8.17	8.16	0.37	4.69
Africa	4.22	4.51	4.19	4.22	4.53	4.36	0.14	3.32
Russia	3.61	3.67	3.35	3.49	3.59	3.52	-0.09	-2.47
Other Eurasia	1.21	1.22	1.15	0.98	1.21	1.14	-0.07	-5.90
Other Europe	0.75	0.79	0.75	0.73	0.80	0.77	0.01	1.70
Total Non-OECD	**52.15**	**53.50**	**53.14**	**53.23**	**54.66**	**53.63**	**1.48**	**2.84**
Total World	**96.92**	**99.36**	**98.56**	**99.93**	**102.22**	**100.03**	**3.10**	**3.20**
Previous Estimate	96.92	99.33	98.33	100.65	102.77	100.29	3.36	3.47
Revision	0.00	0.03	0.22	-0.72	-0.55	-0.26	-0.26	-0.27

*Note: * 2022 = Forecast. Totals may not add up due to independent rounding. Source: OPEC.*

Table 4 - 2: World oil demand in 2023*, mb/d

World oil demand	2022	1Q23	2Q23	3Q23	4Q23	2023	Change 2023/22 Growth	%
Americas	25.16	25.25	25.47	25.86	25.96	25.64	0.48	1.89
of which US	*20.60*	*20.42*	*20.56*	*20.99*	*21.06*	*20.76*	*0.16*	*0.77*
Europe	13.69	13.10	13.35	14.33	14.29	13.77	0.08	0.61
Asia Pacific	7.54	7.92	7.18	7.27	7.94	7.58	0.04	0.48
Total OECD	**46.39**	**46.27**	**46.00**	**47.46**	**48.20**	**46.99**	**0.60**	**1.28**
China	15.12	15.31	15.83	15.97	16.31	15.86	0.73	4.86
India	5.14	5.38	5.41	5.17	5.56	5.38	0.24	4.67
Other Asia	9.02	9.48	9.72	9.09	9.25	9.38	0.36	3.97
Latin America	6.40	6.48	6.44	6.71	6.54	6.54	0.15	2.30
Middle East	8.16	8.43	8.30	8.71	8.46	8.47	0.32	3.87
Africa	4.36	4.70	4.38	4.41	4.72	4.55	0.19	4.30
Russia	3.52	3.68	3.37	3.66	3.77	3.62	0.10	2.70
Other Eurasia	1.14	1.22	1.15	0.99	1.22	1.15	0.01	0.73
Other Europe	0.77	0.80	0.76	0.75	0.82	0.78	0.02	2.32
Total Non-OECD	**53.63**	**55.48**	**55.35**	**55.46**	**56.65**	**55.74**	**2.10**	**3.92**
Total World	**100.03**	**101.75**	**101.34**	**102.92**	**104.85**	**102.72**	**2.70**	**2.70**
Previous Estimate	100.29	101.72	101.12	103.64	105.40	102.99	2.70	2.69
Revision	-0.26	0.03	0.22	-0.72	-0.55	-0.26	0.00	0.01

*Note: * 2022 and 2023 = Forecast. Totals may not add up due to independent rounding. Source: OPEC.*

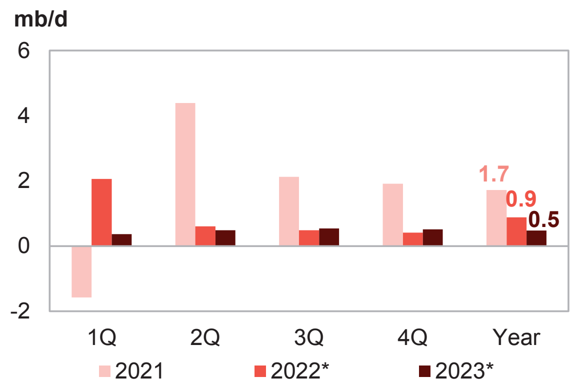
OECD

OECD Americas

Update on the latest developments

US oil demand fell by 20 tb/d, annually in May after annual growth of 0.5 mb/d in April. Consumption of oil in May 2022 has lagged behind 2021 levels. Oil demand in May was driven by strong LPG requirements from three consuming sectors; the industrial, commercial and residential sectors. LPG grew by 0.3 mb/d, equivalent to 15% annual growth. On a monthly basis, demand growth for LPG was 0.1 mb/d below April's 0.4 mb/d consumption. Jet kerosene demand remained at 0.3 mb/d, annually. On a monthly basis, it remained at April's level, according to IATA Air Passenger Market Analysis.

Graph 4 - 1: OECD Americas oil demand, y-o-y change



*Note: * 2022-2023 = Forecast. Source: OPEC.*

The US domestic traffic increased in the month by 3.1% and remained below 2019 levels. Domestic revenue passenger kilometres (RPKs) are down 4.7% compared to the same month in 2019. Capacity is down 6.0% y-o-y. Load factors remain high at 88.7% countrywide. Pressure on traffic might increase in this market with high fuel prices and ongoing labour-related issues. In May, US domestic RPK growth decreased to 26.1% y-o-y from 48.1% y-o-y in April. Diesel demand has slightly recovered from April's contraction. In May, diesel remained flat, y-o-y, compared with a 0.2 mb/d decline in April.

However, gasoline is still struggling to overcome the effects of higher retail prices, despite an approaching summer driving season. For two consecutive months, gasoline consumption has recorded negative growth. In May, it is down by 30 tb/d, annually, compared with a 40 tb/d decline in April. However, naphtha has declined further by 70 tb/d, annually, compared with 60 tb/d annually in April. The demand for naphtha is affected by a squeeze in the US petrochemical industry margins as crude oil prices rose, with a cost advantage from its competitor feedstock liquefied petroleum gas. Finally, other products also posted a sharp decline by 0.5 mb/d, y-o-y as residual fuel oil demand grew marginally by 80 tb/d, y-o-y.

Table 4 - 3: US oil demand, mb/d

			Change May 22/May 21	
By product	May 21	May 22	Growth	%
LPG	3.24	3.52	0.28	8.6
Naphtha	0.21	0.14	-0.07	-32.9
Gasoline	9.14	9.11	-0.03	-0.3
Jet/kerosene	1.32	1.58	0.26	19.4
Diesel	3.87	3.87	0.00	0.0
Fuel oil	0.26	0.34	0.08	32.4
Other products	2.34	1.81	-0.54	-22.9
Total	**20.38**	**20.37**	**-0.02**	**-0.1**

Note: Totals may not add up due to independent rounding. Sources: EIA and OPEC.

Near-term expectations

In 2H22, the US oil demand is expected to improve further to reach 0.4 mb/d in 3Q22 and 4Q22. Gasoline demand is due for a rebound following a relative drop in retail prices that should support the summer driving season. While 3Q22 appears to be promising in terms of travel activities; however, the beginning of cold weather in 4Q22 will dampen mobility activity and affect gasoline demand.

In 2023, US oil demand is forecasted to increase by around 0.2 mb/d y-o-y. The 2023 outlook has many uncertainties, subject to developments in the American economy. These include the possibility of less robust economic activity; the US GDP is forecast to grow by 1.8 mb/d y-o-y combined with high inflation and a rise in interest rates affecting consumer confidence. In addition, industrial output is also in decline. These factors are going to affect oil demand growth. Oil demand will be supported by the petrochemical and transportation sectors requirements for oil products during 2023. Gasoline demand will be backed by improved mobility. Expansion in the petrochemical industry and consequently healthy petrochemical margins will provide support to light distillates in 2023. Furthermore, improvements in aviation sector activity will support the demand for jet kerosene.

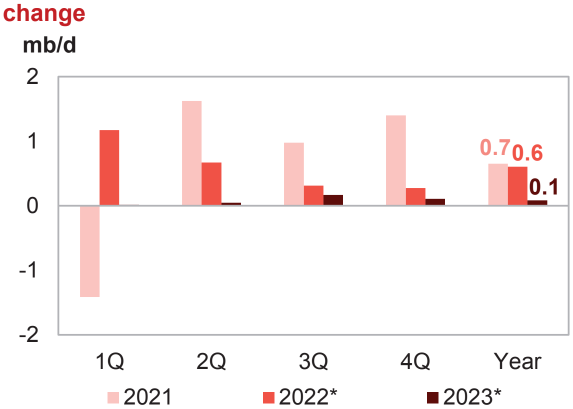
In 1Q23, oil demand will grow marginally by 40 tb/d, annually. The low growth is because of a high baseline comparison with solid growth of 1.8 mb/d in 1Q21; however, the level of demand is expected to reach 20.42 mb/d. In the first quarter, mobility activity is expected to slow down due to the cold winter. This combined with the forecasted slowing in economic growth will weigh on transportation fuels. However, by 2Q23, economic activity is expected to improve and support the industrial sector and mobility, which will aid oil demand to reach 0.2 mb/d y-o-y

OECD Europe

Update on the latest developments

OECD Europe oil demand growth was flat m-o-m in May at a robust 1.0 mb/d y-o-y growth compared with the same growth rate in April. May demand was strongly supported by jet kerosene, as air travel in OECD Europe registered substantial international and regional growth. According to IATA's Air Passenger Market Analysis, airlines based in Europe continued to deliver robust growth in May in y-o-y terms. On the back of this healthy demand; jet kerosene demand grew by 0.6 mb/d, equal to 96% annual growth. Rising pump prices led to weaker m-o-m gasoline demand growth of 0.2 mb/d y-o-y in May compared to 0.3 mb/d in April. As for diesel, the demand in May increased by 0.2 mb/d, annually, showing signs of a slight improvement on a monthly basis, as compared to 0.18 mb/d annual growth in April.

Graph 4 - 2: OECD Europe's oil demand, y-o-y change



*Note: * 2022-2023 = Forecast. Source: OPEC.*

As Europeans are importing naphtha from Russia, which is likely blended with gasoline and resold for a higher margin, naphtha grew by 30 tb/d compared with annual decline of 0.2 mb/d in April. At the same time, residual fuel demand grew by 60 tb/d annually. However, LPG sustained a decline of 90 tb/d annually from a growth of 20 tb/d, y-o-y in April due to a surge in natural gas prices continuing to encourage fuel switching to naphtha in the region's petrochemical sector.

Table 4 - 4: Europe's Big 4* oil demand, mb/d

By product	May 21	May 22	Change May 22/May 21 Growth	%
LPG	0.42	0.40	-0.02	-4.8
Naphtha	0.57	0.48	-0.09	-15.9
Gasoline	1.08	1.18	0.10	8.9
Jet/kerosene	0.37	0.69	0.32	87.7
Diesel	2.92	3.00	0.07	2.5
Fuel oil	0.14	0.17	0.03	21.7
Other products	0.45	0.46	0.01	2.4
Total	**5.95**	**6.37**	**0.42**	**7.1**

*Note: * Germany, France, Italy and the UK. Totals may not add up due to independent rounding.*

Sources: JODI, UK Department for Business, Energy & Industrial Strategy, Unione Petrolifera and OPEC.

Near-term expectations

Looking forward, in 2H22 weakening European economy is expected to weigh on the oil demand growth prospects in the region. After recording a strong of 1.2 mb/d in 1Q22 and 0.7 mb/d in 2Q22, the growth in 2H22 is expected to be lower, aside from the seasonal swing in gasoline, and jet kerosene demand. The surging oil products prices, manufacturing inflation and geopolitically induced trade-related bottlenecks are expected to weigh heavily on manufacturing sectors, with multiplier effects on oil demand. In both 3Q22 and 4Q22, oil demand is projected to grow by 0.3 mb/d, y-o-y each.

Despite these challenges, by 4Q22, the GDP in the region is expected to improve by 3.2% combined with expected improvements in trade-related supply chain activities, will support manufacturing activity in the region. This will boost the demand for distillates for manufacturing sector requirements. Furthermore, the pent-up travel demand amidst summer driving activity is expected to enhance gasoline and jet kerosene demand.

The outlook for European oil demand in 2023 is rather pessimistic. After average growth of 0.6 mb/d in 2022, the oil demand growth in 2023 is expected to be rather weak, averaging 80 tb/d, annually. From a moderate growth of 3.2% in 4Q22, European GDP is projected to slow down to 1.7% in 2023. Furthermore, high inflation combined with high production cost will dampen consumer confidence in the region. These factors are going to weigh on oil demand. Accordingly, in 1Q23, oil demand is forecast to grow by a mere 10 tb/d, y-o-y, Nevertheless, OECD Europe is expected to consume 13.10 mb/d in 1Q23 and will mostly be supported by jet kerosene and petrochemical feedstock requirements for light distillates.

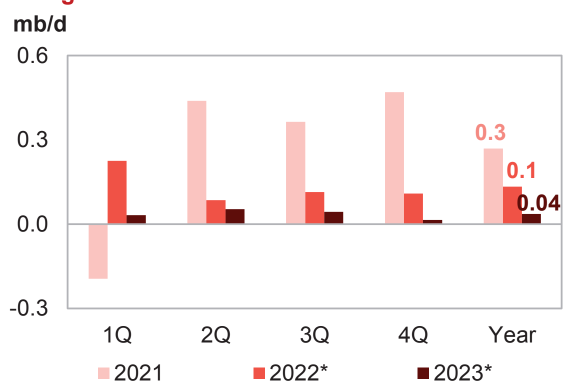
By 2Q23, on the back of resilient aviation industry requirements and improved mobility, oil demand is projected to grow by 50 tb/d, y-o-y. The demand will be supported by transportation fuel requirements for jet kerosene and gasoline. Furthermore, diesel and petrochemical fuels are also expected to aid the demand growth.

OECD Asia Pacific

Update on the latest developments

The **Asia Pacific region** has shown signs of resilience, in spite of the prevalence of COVID-19 in some countries of the region and the drag from the trade-related bottlenecks related to the Chinese lockdowns that weighed heavily on the economy of the region. Oil demand in Asia Pacific recovered in May from a contraction in April, y-o-y. Available data imply an annual growth of 0.1 mb/d in May as compared to 0.1 mb/d, y-o-y contraction in April 2022. Japan and South Korea remained the major consumers of oil in the region, constituting over 80% of regional oil demand. In line with eases in relation to the pandemic situation, South Korea relaxed most of its restrictions in April, as COVID 19 waned and the country saw a gradual return to normalcy.

Graph 4 - 3: OECD Asia Pacific oil demand, y-o-y change



*Note: * 2022-2023 = Forecast. Source: OPEC.*

The lifting of restrictions has helped the reopening of the economy, leading to a rebound of many indicators, including industrial output which recovered by 1% in May (m-o-m) and 7% y-o-y. In addition, facility investment has also rebounded and a pick-up in aggregate demand also lifted service growth in South Korea. To a lesser extent, the Japanese economy has also shown signs of improvements, after lifting of quasi-emergency measures at the end of March. On the back of these developments, transportation fuels; gasoline and diesel recovered from a slump. In May, both gasoline and diesel grew by roughly 70 tb/d y-o-y, as compared to a shrinkage of 0.1 mb/d y-o-y for each in April.

As for jet kerosene, according to a report from the IATA Air Passenger Market Analysis, domestic air traffic volumes are still on a path of recovery in the Asia Pacific as industry-wide domestic RPKs grew 9.3% m-o-m, aided jet/kerosene to recover by 40 tb/d y-o-y from a decline of 10 tb/d in April. LPG also saw an improvement by 10 tb/d, an annual average growth of 2%. However, Asia Pacific naphtha demand has plunged by 0.1 mb/d against annual growth of 45 tb/d in April, affected by low demand for paraxylene in the petrochemical industry of the region.

Table 4 - 5: Japan's oil demand, mb/d

By product	Jun 21	Jun 22	*Change Jun 22/Jun 21* Growth	%
LPG	0.41	0.43	0.03	6.4
Naphtha	0.65	0.63	-0.01	-1.9
Gasoline	0.73	0.72	-0.01	-1.5
Jet/kerosene	0.21	0.22	0.01	3.8
Diesel	0.68	0.68	0.00	-0.7
Fuel oil	0.22	0.21	-0.01	-5.5
Other products	0.17	0.19	0.02	9.4
Total	**3.07**	**3.07**	**0.01**	**0.3**

Note: Totals may not add up due to independent rounding. Sources: JODI, METI and OPEC.

Near-term expectations

Looking forward, as most of the countries in the region are now learning to exist with COVID-19, albeit at an expected slow economic recovery in the region with annual growth of 2.3%, this will affect both manufacturing activity and mobility. On average, oil demand growth in the region is expected to remain flat at 0.1 mb/d until the end of 2022.

Nevertheless, the gradual reopening of the South Korean economy is expected to support consumer confidence and mobility recovery in the region, combined with improvements in the region's air travel activity, which would boost gasoline and jet kerosene demand and provide additional support for oil demand in 2022.

In 2023, the outlook for the region is still not very bright. Slow economic recovery of 1.8% y-o-y expected GDP growth in the region amidst COVID-19 restrictions is a major challenge and will weigh on oil demand in 2023. On average, oil demand is expected growth to remain below 0.1 mb/d on average.

Non-OECD

China

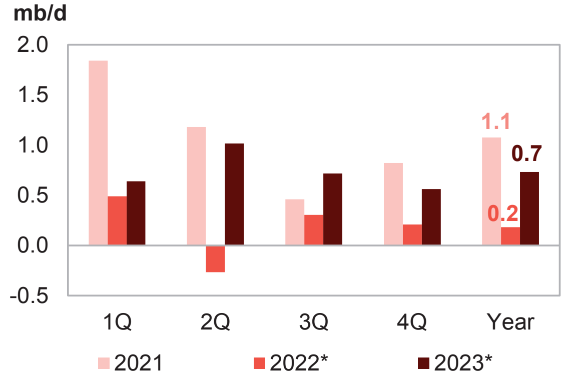
Update on the latest developments

China's oil demand continued to recover in June albeit at sluggish growth, as COVID-19 lockdowns were further relaxed. June data shows a lesser contraction of oil demand growth of 30 tb/d, y-o-y, a significant improvement as compared to the 0.3 mb/d annual decline in May. June oil demand recovery is driven by strong petrochemical requirements for light distillates. LPG is the main driver, which recorded a growth of 0.2 mb/d, annually, compared to monthly growth of 80 tb/d in May. China's June LPG consumption rose 10% y-o-y. The LPG demand recovery is mainly attributable to increased buying from propane dehydrogenation and petrochemical plants amid lower propane and butane prices during the month. To a lesser extent, naphtha grew by 90 tb/d annually, slightly lower than 0.1 mb/d annually in May. As for diesel, the demand is still not very strong, on a monthly basis, the June diesel demand growth of 40 tb/d, annually is below 70 tb/d consumed in the month of May.

Gasoline demand is still sluggish amid the extension of zero COVID lockdown policies, which affected mobility in some cities of China. In June, gasoline demand nosedived by 0.3 mb/d, annually, as compared to a 0.2 mb/d contraction in May.

As for residual fuel oil, the demand grew by 80 tb/d in June, a significant recovery as compared to June 2021 negative growth. Air travel is on the path of recovery from the impact of the zero COVID-19 lockdown policy in China. Daily domestic passenger flights averaged over 7,000 in June, up from the average of 6,000 in May. On the back of these developments, the jet kerosene demand, though still negative on monthly bases, significantly improved from a 0.4 mb/d annual contraction in May to a 0.2 mb/d annual decline in June.

Graph 4 - 4: China's oil demand, y-o-y change



*Note: * 2022-2023 = Forecast. Source: OPEC.*

Table 4 - 6: China's oil demand*, mb/d

By product	Jun 21	Jun 22	Change Jun 22/Jun 21 Growth	%
LPG	2.18	2.40	0.22	10.1
Naphtha	1.43	1.52	0.09	6.3
Gasoline	3.60	3.31	-0.29	-7.9
Jet/kerosene	0.64	0.48	-0.16	-24.7
Diesel	3.36	3.40	0.04	1.3
Fuel oil	0.75	0.83	0.08	10.4
Other products	1.54	1.52	-0.02	-1.3
Total	**13.49**	**13.46**	**-0.03**	**-0.2**

*Note: * Apparent oil demand. Totals may not add up due to independent rounding.*
Sources: Argus Global Markets, China OGP (Xnhua News Agency), Facts Global Energy, JODI, National Bureau of Statistics China and OPEC.

Near-term expectations

Looking forward, despite challenges from the zero-COVID policy restrictions, which affected the oil demand in China during 2Q22, we expect Chinese oil demand to improve in the second half of the year. COVID-19 situation is expected to improve and State-backed infrastructural spending in 2H22 are expected to support industrial and construction sectors. In addition, robust global demand for finished products imports from other countries will support the industrial sector. Accordingly, the industrial demand for distillates will be boosted. Furthermore, Chinese demand is expected to rise despite COVID-19 headwinds, as tightened restrictions are expected to remain localized. Counter-seasonal strength in diesel over the summer is expected, while gasoline should recover as restrictions ease. Finally, as the air travels continue improving, jet fuel will also continue recovering as petrochemical industry demand for light distillates continue to support the demand for LPG and naphtha. In the second half, Chinese oil demand is forecast to grow by 0.3 mb/d annually.

In first half of 2023, Chinese economy is expected to rebound as COVID-19 waned. This will see mobility activity improving to aid the demand for gasoline and transportation diesel. Furthermore, supply chain bottlenecks are expected to ease; construction and industrial activity will pick-up, hence, construction companies and industries will begin to place orders with refiners for fuels and raw materials. These factors will support demand for diesel and bitumen. Finally, air travel, both domestic and international is expected to continue recovering. These factors are expected to support oil demand growth in the 1H23. In the 1Q23, oil demand is forecast to grow by 0.6 mb/d annually. In this quarter, the demand will be driven largely by gasoline and diesel. Furthermore, petrochemical feedstock requirements for LPG and naphtha will boost the demand for oil.

In 2Q23, with expected moderate GDP growth of 5%, oil demand in China is forecast to continue in its growth trajectory, to reach 1.02 mb/d annually, to be led by transportation fuels and supported by petrochemicals feedstock demand. As the aviation sector improves, the jet-kerosene demand will improve farther. However, the prospects for demand largely depend on COVID-19 and the extent of government's zero COVID policy restrictions and the response of the Chinese economy towards the COVID-19 situation.

India

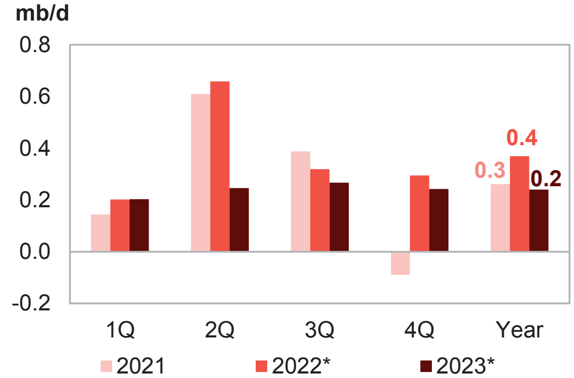
Update on the latest developments

India's oil demand remained healthy at 0.7 mb/d, about 16% y-o-y growth in June, after an annual growth of 0.8 mb/d in May. Oil demand in India is supported by the rising momentum in economic activities, as the economic reopening continued amid an easing of COVID restrictions in India. Some key indicators such as mobility, the index of industrial output and services PMI remained healthy; for example, June manufacturing PMI in India remain strong at 53.9% and services PMI was at 59.2%, respectively. On the back of these developments, diesel, the most-utilized fuel in the country and in various sectors, grew by 0.4 mb/d, equal to 22% annually.

Also aiding the demand for diesel was the start of the harvesting season, which backed oil requirements from the agriculture and transportation sectors. India's gasoline soared in June on the back of summer travels and an overall pick-up in economic activity, on the back of this, gasoline recorded an annual growth of 0.2 mb/d, about 20% annual growth. However, on a monthly basis, India's gasoline and diesel demand were slightly below last month's levels as monsoon rains disrupted transportation, thereby curtailing demand.

As the aviation sector of India opened up after the lockdown, demand for jet kerosene continued to improve. In June, jet kerosene consumption grew by 63 tb/d, about 59% annual growth.

Graph 4 - 5: India's oil demand, y-o-y change



*Note: * 2022-2023 = Forecast. Source: OPEC.*

Other products also recorded a strong growth of 0.2 mb/d, an annual growth of 58%. However, over four consecutive months, naphtha continued to decline, in June.

Naphtha demand slumped by 44 tb/d, annually, as LPG recorded a tightening of 8 tb/d, y-o-y. The decline in demand for LPG was affected by a hike in the price of LPG, whose prices were hiked by Rs 103.50 per cylinder. Overall, Indian oil demand in June was supported by the reduction in excise duty on petrol and diesel by the Central Government, coupled with the delayed arrival of the monsoon season and has led to robust demand for fuels.

Table 4 - 7: India's oil demand, mb/d

By product	Jun 21	Jun 22	Change Jun 22/Jun 21 Growth	%
LPG	0.95	0.94	-0.01	-0.8
Naphtha	0.35	0.30	-0.04	-12.5
Gasoline	0.79	0.95	0.16	20.1
Jet/kerosene	0.11	0.17	0.06	58.8
Diesel	1.59	1.94	0.35	21.9
Fuel oil	0.25	0.26	0.01	3.3
Other products	0.26	0.42	0.15	58.5
Total	**4.30**	**4.98**	**0.68**	**15.8**

Note: Totals may not add up due to independent rounding.

Sources: JODI, Petroleum Planning and Analysis Cell of India and OPEC.

Near-term expectations

Looking ahead, in 3Q22, oil demand in India will remain at 0.3 mb/d annually, supported by healthy economic growth of 7.1%, continuing economic reopening amid ease of COVID restrictions and easing of trade-related bottlenecks supporting both mobility and industrial sector activity. However, the demand for oil is not expected to exceed the 2Q21 growth levels, partly affected by the late arrival of the ongoing monsoon season. By 4Q22 demand will pick-up during the festival and holiday season in India, and oil demand will continue to grow by 0.3 mb/d, annually, despite the slowdown in driving during the winter. Overall, based on the most recent trends, demand for diesel and jet kerosene would likely account for a bigger part of the growth in demand in H2 as consumption of these two products had fallen sharply due to the pandemic.

In 2023, on average, oil demand is expected to moderately remain at 0.2 mb/d, annually. In 1Q23, demand is forecast to be aided by strong GDP growth of 6% y-o-y, steady manufacturing sector requirements and trucking road transport demand for distillates. Additionally, increasing mobility and air travel improvements will back demand for transportation fuels. In 1Q23, both gasoline and jet fuel demand will immensely be favoured by increase in mobility activity. Finally, petrochemical industry and residential requirements for light distillates will aid the demand for naphtha and LPG in 1Q23. In both 1Q23 and 2Q23, oil demand is expected to grow at an average of 0.2 mb/d, annually.

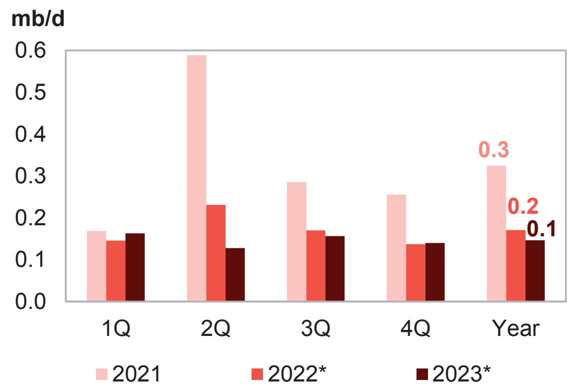
Latin America

Update on the latest developments

Latin America's oil demand growth remained flat m-o-m at a robust 0.3 mb/d, y-o-y in May as compared to April. Oil demand in May was driven by higher requirements for distillates. Diesel posted a 0.1 mb/d annual growth as compared to monthly growth of 10 tb/d in April. Economic indicators suggest that recovery in the region is still gathering momentum, despite the prevalence of COVID-19. The IMF suggested that after the sharp contraction in the second quarter of last year, the brisk recovery in the third quarter exceeded expectations in some larger economies of the region, like Brazil, Peru and Argentina.

Manufacturing output in Argentina increased from 168.28 in April to 170.80 May. Similarly, Brazil also posted a rise in manufacturing output from 80.89 in April to 88.76 in May. However, on a monthly basis, gasoline demand continued to grow, dropping from annual growth of 0.14 mb/d in April to just 90 tb/d in May. Gasoline demand was largely affected by the resurgence of the pandemic in some parts of the region, which affected the mobility and social activity in many countries of the region. As for jet kerosene, consumption grew by 60 tb/d, annually, slightly below 70 tb/d in the previous month. However, LPG improved from negative growth of 10 tb/d in April to annual growth of 10 tb/d in May. Finally, jet/kerosene is still on a positive trajectory in May, with annual growth of 60 tb/d.

Graph 4 - 6: Latin America's oil demand, y-o-y change



*Note: * 2022-2023 = Forecast. Source: OPEC.*

Near-term expectations

Looking ahead, despite the slowing momentum of economic recovery in Latin America, currently the GDP growth in the region is forecast at 2%. The acceleration in vaccination and signs of manufacturing PMI in big consuming countries of the region will support oil demand recovery in the region. Accordingly, oil demand growth in the region is expected to average 0.1 mb/d in 2H22.

In 2023, oil demand growth is forecast to remain at 0.2 mb/d. In 1Q23, oil demand is expected to grow by 0.2 mb/d. However, in 2Q23, oil demand will decline to 0.1 mb/d annually. The prospects of oil demand in the region largely depends on the region's economic recovery and containment of the pandemic; including governments' responses and progress or reintroduction of stricter containment measures in some countries, as well as spillovers from the slowdown in the global economy. Overall, the risk is still skewed downside.

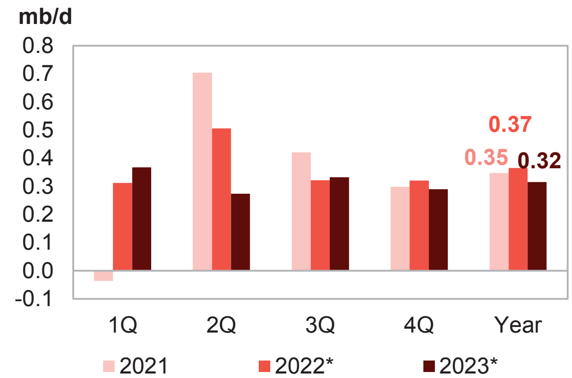
Middle East

Update on the latest developments

Oil demand in the Middle East continued in its robust trajectory; with strong demand growth of 0.5 mb/d y-o-y, in May, which marked the second-largest growth in non-OECD. On the back of high power generation and cooling requirements from Saudi Arabia and Iraq, crude direct use recorded growth of 0.3 mb/d, y-o-y. On the back of strong mobility requirements, gasoline recorded the second largest increase in oil demand growth of 0.1 mb/d y-o-y. The demand for gasoline is strongly backed by mobility requirements, particularly during Hajj operation in Saudi Arabia.

Diesel demand grew by 0.1 mb/d y-o-y, largely driven by industrial sector requirements, particularly in Saudi Arabia, the industrial output increased from 130.17 in April to 131.78 in May.

Graph 4 - 7: Middle East's oil demand, y-o-y change



Note: * 2022-2023 = Forecast. Source: OPEC.

Furthermore, Saudi Arabia's cement production increased 2.9% y-o-y in June. An increase in regional and international air travel due to Hajj and other events hosted in the region aided jet kerosene demand to grow by 60 tb/d y-o-y. However, LPG remained at the same level of 20 tb/d y-o-y as naphtha slightly improved from an annual contraction of 20 tb/d in April to a contraction of 10 tb/d in May.

Table 4 - 8: Saudi Arabia's oil demand, mb/d

By product	Jun 21	Jun 22	Change Jun 22/Jun 21 Growth	%
LPG	0.04	0.04	0.00	-3.5
Gasoline	0.48	0.53	0.05	9.9
Jet/kerosene	0.05	0.08	0.03	73.9
Diesel	0.52	0.59	0.07	12.7
Fuel oil	0.55	0.79	0.25	44.8
Other products	0.67	0.76	0.09	13.3
Total	**2.32**	**2.79**	**0.47**	**20.2**

Note: Totals may not add up due to independent rounding.

Sources: JODI and OPEC.

Near-term expectations

Going forward, strong economic activity in the region will continue to support oil demand in the near future. Saudi Arabia's economy expanded 11.8% in the second quarter, maintaining the fastest pace of growth since 2011. Non-oil gross domestic product gained 5.4% while the oil economy grew 23.1% compared to last year. Similarly, the United Arab Emirates (UAE) is also optimistic its economy will grow robustly this year as it recovers from the pandemic. The expected strong economic growth in the region will aid consumer confidence, accelerate mobility and industrial activity in the region. In addition, the region is hosting the World cup in November and December, and these factors will lead to an inflow of international tourists into the region. Accordingly, demand for services will rise tremendously; mobility requirements and air services will rise accordingly. In 3Q22, the oil demand in the region is expected to rise by 0.3 mb/d y-o-y from 0.5 mb/d in 2Q22. Furthermore, in 4Q22, the oil demand in the region is projected to remain at 0.3 mb/d y-o-y. In 2H22, oil demand growth in the region will be supported mostly by transportation fuels; gasoline, diesel and jet kerosene.

In 2023, fuelled by strong economic growth, the momentum of oil demand will increase from the 2022 pace. In 1Q23, oil demand is projected to grow by 0.4 mb/d y-o-y. Strong economic growth in the region is expected to support consumer confidence, which will raise demand for social services and consumer goods in the region. Gasoline, transportation diesel and jet kerosene are expected to lead in oil demand growth. Gasoil/diesel and fuel oil demand for power generation are also expected to play a significant role in demand growth.

By 2Q23, the oil demand will remain robust, and oil demand growth is expected to settle at 0.3 mb/d in 2Q23. Generally, in near term, the overall prospects of oil demand growth in the region are very high, due to expected strong GDP growth that will boost economic activity and successful COVID-19 management in the region.

World Oil Supply

Non-OPEC liquids supply growth in 2022 (including processing gains) is forecast at 2.1 mb/d for an average of 65.8 mb/d, which is broadly unchanged from the previous assessment. Upward revisions to Russia's oil production were offset by downward revisions to the US, Norway and Kazakhstan. Significant uncertainty regarding Russia's liquids production in the forecast period remains. In the US, solid increases in oil and gas rig counts, as well high fracking activity, are expected to support production going forward. However, ongoing capital discipline by public operators, who are focussing on paying down debt and increasing returns to shareholders, labour and supply chain issues, as well as cost inflation, are expected to limit growth. Moreover, forecasts for above-normal hurricane season activity, as well as an upward revision to the historical base line, have necessitated a downward revision to the US liquids supply growth forecast for 2022 by 138 tb/d, and output is now forecast to grow by 1.15 mb/d y-o-y. The production forecast for Norway was also revised down due to lower-than-expected output in 2Q22, extended fields' maintenance and gas injection plan changes in 2H22. The main drivers of liquids supply growth for the year are expected to be the US, Canada, Brazil, China and Guyana, while production is expected to decline mainly in Indonesia and Thailand.

Non-OPEC liquids production growth in 2023 also remains unchanged and is expected to grow by 1.7 mb/d to average 67.5 mb/d (including 70 tb/d in processing gains). Liquids supply in the OECD countries is forecast to grow by 1.6 mb/d, while the non-OECD region is forecast to grow by 0.1 mb/d. The main drivers for liquids supply growth are expected to be the US, Norway, Brazil, Canada and Guyana, whereas oil production is forecast to decline mainly in Russia and Azerbaijan. Nevertheless, uncertainty about US production growth and the geopolitical situation in Eastern Europe remains high.

OPEC NGLs and non-conventional liquids production in 2022 is forecast to grow by 0.1 mb/d to average 5.39 mb/d. For 2023, it is forecast to grow by 50 tb/d to average 5.44 mb/d. OPEC-13 crude oil production in July increased by 216 tb/d m-o-m to average 28.90 mb/d, according to available secondary sources.

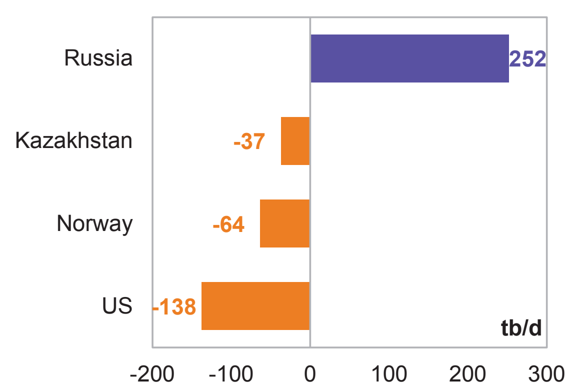
Preliminary non-OPEC liquids production in July, including OPEC NGLs, is estimated to have increased m-o-m by 1.5 mb/d to average 71.7 mb/d, and is up by 2.4 mb/d y-o-y. As a result, preliminary data indicates that global oil supply in July increased by 1.7 mb/d m-o-m to average 100.6 mb/d, up by 4.7 mb/d y-o-y.

The non-OPEC liquids supply forecast for **2022** was revised up by 65 tb/d, to average 65.8 mb/d. Y-o-y growth remains at 2.1 mb/d, which is unchanged from the previous month.

The **OECD** supply growth forecast for 2022 was revised down by 0.2 mb/d. The US and OECD Europe saw downward revisions to their growth forecasts, while the growth forecast for OECD Asia Pacific remained largely unchanged from the previous month's assessment.

The **non-OECD** supply forecast for 2022 was revised up by 0.2 mb/d, mainly due to an upward revision for Russia. On the other hand, Other Eurasia and Other Asia accounted for the major downward revisions in the non-OECD region.

Graph 5 - 1: Major revisions to annual supply change forecast in 2022*, MOMR Aug 22/Jul 22

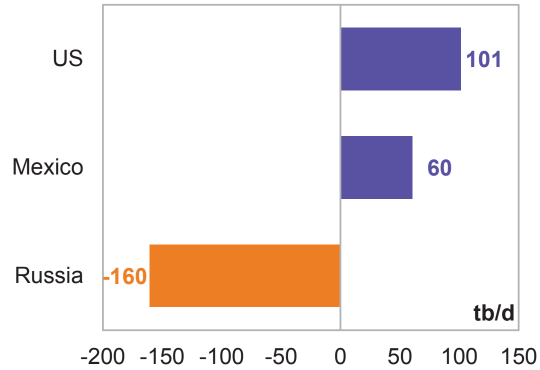


*Note: * 2022 = Forecast. Source: OPEC.*

Non-OPEC liquids production growth in **2023** remained broadly unchanged compared to the previous month's assessment.

The upward revision to the supply forecast for the US and Mexico was entirely offset by the downward revision to Russian supply.

Graph 5 - 2: Major revisions to annual supply change forecast in 2023*, MOMR Aug 22/Jul 22

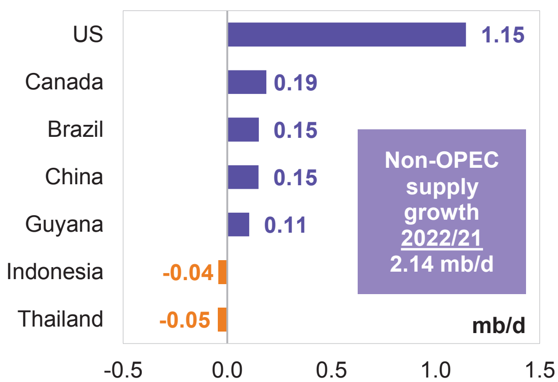


*Note: * 2022 = Forecast. Source: OPEC.*

Key drivers of growth and decline

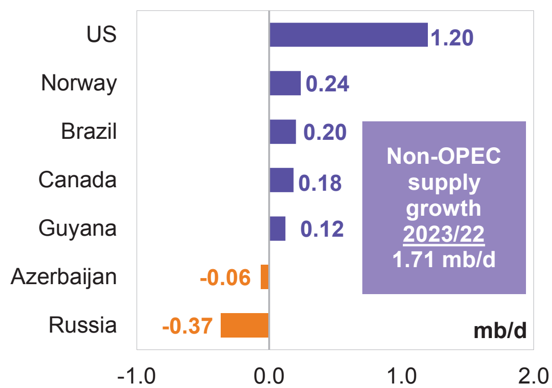
The **key drivers of non-OPEC liquids supply growth in 2022** are projected to be the US, Canada, Brazil, China and Guyana, while oil production is expected to decline mainly in Thailand and Indonesia.

Graph 5 - 3: Annual liquids production changes for selected countries in 2022*



*Note: * 2022 = Forecast. Source: OPEC.*

Graph 5 - 4: Annual liquids production changes for selected countries in 2023*



*Note: * 2023 = Forecast. Source: OPEC.*

For **2023**, the key drivers of non-OPEC supply growth are forecast to be the US, Norway, Brazil, Canada and Guyana, while oil production is projected to decline mainly in Russia and Azerbaijan.

Non-OPEC liquids production in 2022 and 2023

Table 5 - 1: Non-OPEC liquids production in 2022*, mb/d

Non-OPEC liquids production	2021	1Q22	2Q22	3Q22	4Q22	2022	Change 2022/21 Growth	%
Americas	25.22	25.86	26.30	26.87	27.31	26.59	1.36	5.41
of which US	*17.82*	*18.27*	*18.88*	*19.19*	*19.52*	*18.97*	*1.15*	*6.43*
Europe	3.76	3.73	3.44	3.76	4.00	3.73	-0.02	-0.63
Asia Pacific	0.51	0.49	0.52	0.55	0.54	0.53	0.01	2.80
Total OECD	**29.49**	**30.08**	**30.26**	**31.18**	**31.85**	**30.85**	**1.35**	**4.59**
China	4.31	4.49	4.49	4.42	4.43	4.46	0.15	3.49
India	0.77	0.77	0.77	0.80	0.82	0.79	0.02	2.20
Other Asia	2.41	2.37	2.32	2.36	2.35	2.35	-0.06	-2.32
Latin America	5.95	6.14	6.13	6.30	6.43	6.25	0.30	5.00
Middle East	3.24	3.29	3.33	3.38	3.38	3.34	0.11	3.26
Africa	1.35	1.33	1.31	1.33	1.32	1.32	-0.03	-1.88
Russia	10.80	11.33	10.62	10.90	10.70	10.88	0.08	0.77
Other Eurasia	2.93	3.06	2.81	3.09	3.22	3.05	0.11	3.83
Other Europe	0.11	0.11	0.11	0.10	0.10	0.11	-0.01	-6.36
Total Non-OECD	**31.87**	**32.89**	**31.89**	**32.68**	**32.75**	**32.55**	**0.68**	**2.13**
Total Non-OPEC production	61.37	62.97	62.15	63.86	64.60	63.40	2.03	3.31
Processing gains	2.29	2.40	2.40	2.40	2.40	2.40	0.11	4.90
Total Non-OPEC liquids production	**63.65**	**65.37**	**64.55**	**66.26**	**67.00**	**65.80**	**2.14**	**3.37**
Previous estimate	63.59	65.36	64.94	65.74	66.88	65.73	2.15	3.37
Revision	0.07	0.01	-0.40	0.52	0.12	0.06	0.00	-0.01

*Note: * 2022 = Forecast. Totals may not add up due to independent rounding. Source: OPEC.*

Table 5 - 2: Non-OPEC liquids production in 2023*, mb/d

Non-OPEC liquids production	2022	1Q23	2Q23	3Q23	4Q23	2023	Change 2023/22 Growth	%
Americas	26.59	27.58	27.68	28.05	28.41	27.93	1.34	5.05
of which US	*18.97*	*19.78*	*20.08*	*20.28*	*20.51*	*20.17*	*1.20*	*6.32*
Europe	3.73	4.06	3.98	3.89	3.99	3.98	0.25	6.60
Asia Pacific	0.53	0.54	0.50	0.53	0.49	0.51	-0.01	-2.20
Total OECD	**30.85**	**32.18**	**32.16**	**32.47**	**32.89**	**32.43**	**1.58**	**5.11**
China	4.46	4.51	4.50	4.47	4.47	4.49	0.03	0.64
India	0.79	0.82	0.80	0.79	0.78	0.80	0.01	1.09
Other Asia	2.35	2.35	2.31	2.28	2.26	2.30	-0.05	-1.97
Latin America	6.25	6.40	6.61	6.69	6.76	6.61	0.36	5.81
Middle East	3.34	3.37	3.40	3.41	3.40	3.39	0.05	1.49
Africa	1.32	1.33	1.35	1.36	1.38	1.36	0.04	2.67
Russia	10.88	10.49	10.48	10.54	10.57	10.52	-0.37	-3.36
Other Eurasia	3.05	3.14	3.01	2.96	3.04	3.04	-0.01	-0.27
Other Europe	0.11	0.10	0.10	0.10	0.10	0.10	0.00	-2.83
Total Non-OECD	**32.55**	**32.51**	**32.56**	**32.60**	**32.77**	**32.61**	**0.06**	**0.19**
Total Non-OPEC production	63.40	64.69	64.73	65.07	65.66	65.04	1.64	2.59
Processing gains	2.40	2.47	2.47	2.47	2.47	2.47	0.07	2.96
Total Non-OPEC liquids production	**65.80**	**67.16**	**67.20**	**67.54**	**68.13**	**67.51**	**1.71**	**2.60**
Previous estimate	65.73	67.28	67.15	67.37	67.96	67.44	1.71	2.60
Revision	0.06	-0.12	0.04	0.17	0.17	0.07	0.00	0.00

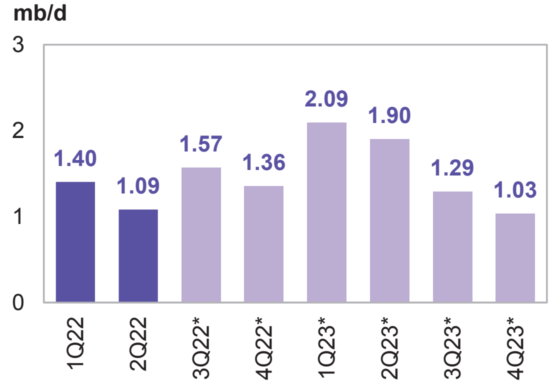
*Note: * 2022-2023 = Forecast. Totals may not add up due to independent rounding. Source: OPEC.*

OECD

OECD liquids production in 2022 is forecast to increase by 1.4 mb/d y-o-y to average 30.9 mb/d. This has been revised down by 0.2 mb/d, compared to a month earlier, on the back of downward revisions for the US and OECD Europe.

OECD Americas was revised down by 0.14 mb/d, compared to last month's assessment. Based on these revisions, OECD Americas is forecast to grow by 1.4 mb/d to average 26.6 mb/d. Oil production in OECD Europe is anticipated to decline slightly y-o-y by 24 tb/d to average 3.7 mb/d, while OECD Asia Pacific is projected to grow y-o-y by 14 tb/d to average 0.5 mb/d.

Graph 5 - 5: OECD quarterly liquids supply, y-o-y changes



*Note: * 3Q22-4Q23 = Forecast. Source: OPEC.*

For **2023**, oil production in the OECD is likely to grow by 1.6 mb/d to average 32.4 mb/d, with growth of 1.3 mb/d from OECD Americas to average 27.9 mb/d. Yearly liquids production in OECD Europe is anticipated to grow by 0.2 mb/d to average 4.0 mb/d, while OECD Asia Pacific is expected to decline by 15 tb/d y-o-y to average 0.5 mb/d.

OECD Americas

US

US liquids production was broadly flat m-o-m in **May 2022** to average 18.7 mb/d, and was up by 0.7 mb/d compared with May 2021.

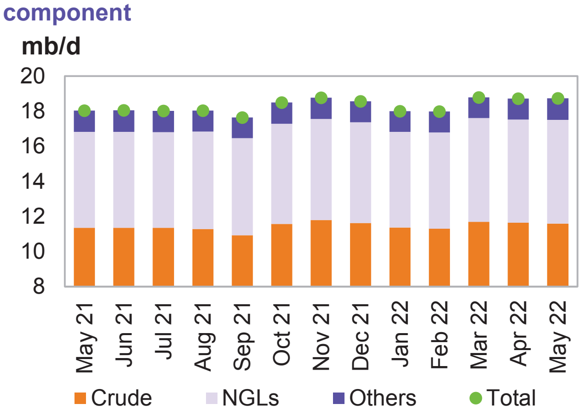
Crude oil and condensate production declined in **May 2022** by 57 tb/d m-o-m to average 11.6 mb/d, but was up by 0.2 mb/d y-o-y.

Regarding the **crude and condensate production breakdown by region (PADDs)**, production increased mainly in the US Midwest by 162 tb/d to average 1.7 mb/d, with output partially recovering from weather-related curtailments in April.

On the other hand, the US Gulf Coast (USGC) showed a decline of 220 tb/d, due to substantial maintenance in Gulf of Mexico (GoM) offshore platforms.

A minor increase in the Rocky Mountains and West Coast was offset by lower East Coast production.

Graph 5 - 6: US monthly liquids output by key component



Source: OPEC.

NGL production was up by 36 tb/d m-o-m to average 5.9 mb/d in May, which was higher by 0.4 mb/d y-o-y. Production of **non-conventional liquids** (mainly ethanol) increased by 27 tb/d m-o-m to average 1.2 mb/d in May, according to the US Department of Energy (DoE). Preliminary estimates see non-conventional liquids averaging 1.3 mb/d in June 2022, up by 53 tb/d compared to the previous month.

Production in the Gulf of Mexico (GoM) fell m-o-m by 157 tb/d in May to average 1.6 mb/d, due to significant maintenance on platforms in the Mars corridor. In the **onshore lower 48**, May production increased m-o-m by 95 tb/d to average 9.5 mb/d.

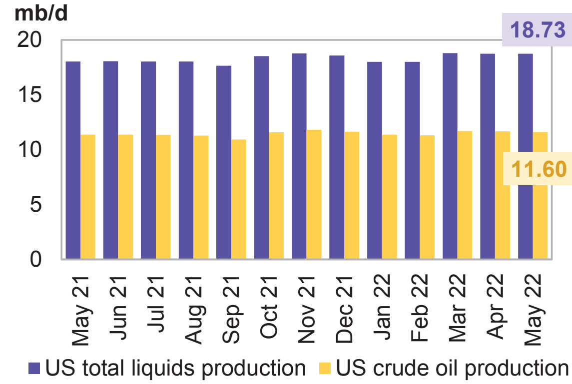
Looking at **individual states**, oil production in New Mexico decreased by 11 tb/d m-o-m to average 1.5 mb/d, 282 tb/d higher than a year ago. Production in Texas was down by 52 tb/d to average 5.0 mb/d, 209 tb/d higher than a year ago. Production in North Dakota increased by 154 tb/d m-o-m to average 0.9 mb/d, down by 70 tb/d y-o-y. Production in Oklahoma was up by 9 tb/d to average 0.4 mb/d. Oil output in Alaska was up by a minor 5 tb/d, while Colorado showed a marginal m-o-m decline of 5 tb/d.

Table 5 - 3: US crude oil production by selected state and region, tb/d

State	May 21	Apr 22	May 22	Change m-o-m	Change y-o-y
Texas	4,756	5,017	4,965	*-52*	*209*
Gulf of Mexico (GOM)	1,816	1,763	1,606	*-157*	*-210*
New Mexico	1,215	1,508	1,497	*-11*	*282*
North Dakota	1,119	895	1,049	*154*	*-70*
Alaska	443	442	447	*5*	*4*
Colorado	423	435	430	*-5*	*7*
Oklahoma	403	416	425	*9*	*22*
Total	**11,356**	**11,652**	**11,595**	***-57***	***239***

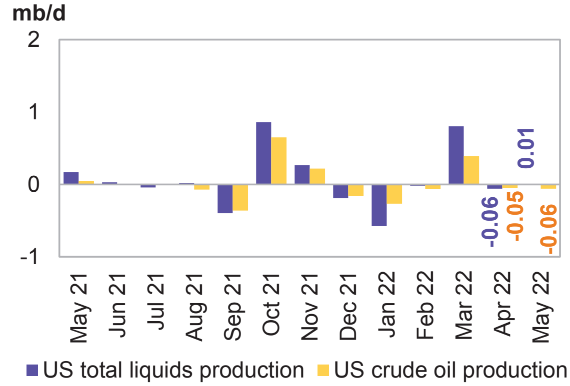
Sources: EIA and OPEC.

Graph 5 - 7: US monthly crude oil and total liquids supply



Sources: EIA and OPEC.

Graph 5 - 8: US monthly crude oil and total liquids supply, m-o-m changes



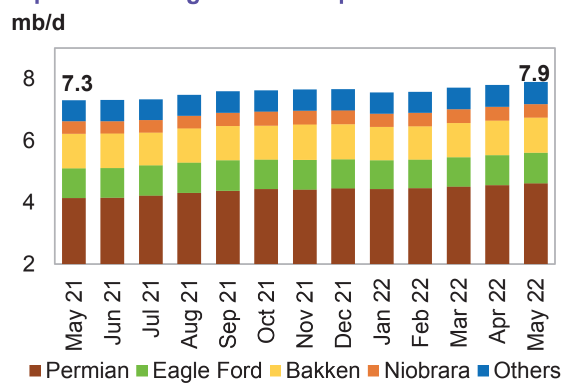
Sources: EIA and OPEC.

US tight crude output in **May 2022** increased by 101 tb/d m-o-m to average 7.9 mb/d, which was 0.6 mb/d higher than the same month a year earlier, according to estimates by the US Energy Information Administration (EIA).

The m-o-m increase from shale and tight formations through horizontal wells came mostly from the Permian, which increased by 51 tb/d to average 4.6 mb/d. This was up by 0.5 mb/d, y-o-y.

In the Williston Basin, production in the Bakken shale increased marginally by 20 tb/d to average 1.1 mb/d, up by a minor 23 tb/d, y-o-y. Tight crude output at Eagle Ford in Texas rose by 24 tb/d to average 1.0 mb/d down by 32 tb/d y-o-y, while production in Niobrara-Codell in Colorado and Wyoming remained broadly unchanged at an average of 0.4 mb/d.

Graph 5 - 9: US tight crude output breakdown



Sources: EIA, Rystad Energy and OPEC.

US liquids production in 2022, excluding processing gains, is forecast to grow y-o-y by 1.15 mb/d to average 19.0 mb/d, revised down by 138 tb/d compared to the previous assessment. The downward revision was due to lower-than-projected production in 2Q22 and downward revisions to 2H22.

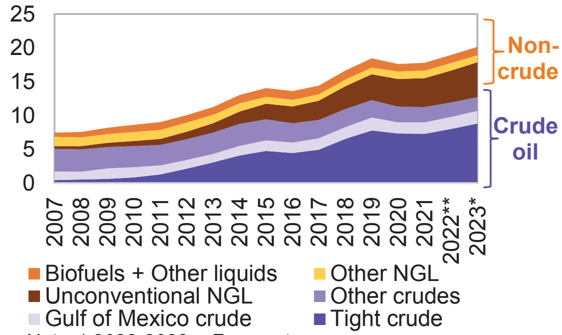
The 2022 gains are due primarily to expected tight crude production growth of 0.7 mb/d, to average 8.0 mb/d. In addition, NGLs, mainly from unconventional basins, are projected to grow by 0.4 mb/d, to average 5.8 mb/d, and production in the GoM is anticipated to increase by 50 tb/d. Non-conventional liquids are projected to grow by 40 tb/d to average 1.2 mb/d. However, the expected growth will be partially offset by natural declines in onshore conventional fields of 0.1 mb/d y-o-y.

Given the current pace of drilling and well completions in oil fields, **production of crude oil and condensate** is forecast to grow by 0.7 mb/d y-o-y to average 11.9 mb/d in 2022. This forecast assumes continued capital discipline, current inflation rates, continuing supply chain issues and the oil field service section limitations (labour and equipment). The hurricane season in the US Gulf Coast is also a source of uncertainty to the forecast.

US liquids production in 2023, excluding processing gains, is expected to grow by 1.2 mb/d y-o-y to average 20.2 mb/d, revised up by 0.1 mb/d, considering a partial shift in tight oil production growth to the next year. In addition, the current level of drilling activity and fewer supply chain issues in the prolific Permian Basin, Eagle Ford and Bakken shale sites are assumed for 2023. Crude oil output is anticipated to jump by 0.8 mb/d y-o-y to average 12.7 mb/d.

At the same time, NGL production and non-conventional liquids, particularly ethanol, are projected to increase by 0.4 mb/d and 40 tb/d y-o-y to average 6.2 mb/d and 1.3 mb/d, respectively. Average tight crude output in 2023 is expected at 8.8 mb/d, up by 0.8 mb/d.

Graph 5 - 10: US liquids supply developments by component



*Note: * 2022-2023 = Forecast.*
Source: OPEC.

Table 5 - 4: US liquids production breakdown, mb/d

US liquids	2021	Change 2021/20	2022*	Change 2022/21	2023*	Change 2023/22
Tight crude	7.29	-0.04	8.03	0.74	8.83	0.80
Gulf of Mexico crude	1.71	0.04	1.76	0.05	1.86	0.10
Conventional crude oil	2.25	-0.06	2.15	-0.10	2.05	-0.10
Total crude	**11.25**	**-0.06**	**11.94**	**0.68**	**12.74**	**0.80**
Unconventional NGLs	4.28	0.20	4.73	0.45	5.14	0.41
Conventional NGLs	1.12	0.03	1.10	-0.02	1.04	-0.05
Total NGLs	**5.40**	**0.22**	**5.83**	**0.43**	**6.18**	**0.35**
Biofuels + Other liquids	1.17	0.02	1.21	0.04	1.25	0.04
US total supply	**17.82**	**0.18**	**18.97**	**1.15**	**20.17**	**1.20**

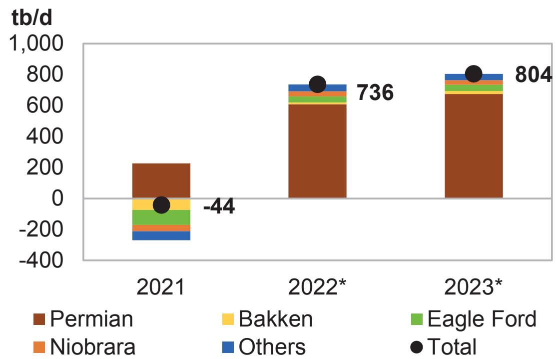
*Note: * 2022-2023 = Forecast. Sources: EIA, OPEC and Rystad Energy.*

US tight crude production in the **Permian** in 2022 is estimated to have increased by 0.6 mb/d to 4.8 mb/d and is forecast to grow by 0.7 tb/d y-o-y to average 5.4 mb/d in 2023.

The decline in **Bakken** shale production that occurred in 2020 and 2021 is expected to reverse to now grow to average 1.1 mb/d in 2022, which is still lower than the pre-pandemic average output of 1.4 mb/d. Tight crude production in the Bakken is forecast to grow by 11 tb/d in 2022, on the back of increased drilling activity in North Dakota and available DUC wells. In 2023, growth is forecast at 20 tb/d, to average 1.1 mb/d.

The **Eagle Ford** in Texas saw output of 1.2 mb/d in 2019, declined in 2020 and 2021, and is forecast to grow in 2022 by 39 tb/d to average 1.0 mb/d. Growth of 40 tb/d is expected for 2023, to average 1.0 mb/d.

Graph 5 - 11: US tight crude output by shale play, y-o-y changes



*Note: * 2022-2023 = Forecast.*
Sources: EIA, Rystad Energy and OPEC.

Production in the **Niobrara** is forecast to grow by 33 tb/d in 2022 and 30 tb/d in 2023, y-o-y, to average 446 tb/d and 476 tb/d, respectively. Other shale plays are expected to show marginal increases totalling 45 tb/d and 40 tb/d in 2022 and 2023, given current drilling and completion activities.

Table 5 - 5: US tight oil production growth, mb/d

US tight oil	2021	Change 2021/20	2022*	Change 2022/21	2023*	Change 2023/22
Permian tight	4.15	0.23	4.75	0.61	5.43	0.67
Bakken shale	1.11	-0.07	1.12	0.01	1.14	0.02
Eagle Ford shale	0.96	-0.10	1.00	0.04	1.04	0.04
Niobrara shale	0.41	-0.04	0.45	0.03	0.48	0.03
Other tight plays	0.67	-0.06	0.72	0.05	0.76	0.04
Total	7.29	-0.04	8.03	0.74	8.83	0.80

*Note: * 2022-2023 = Forecast. Source: OPEC.*

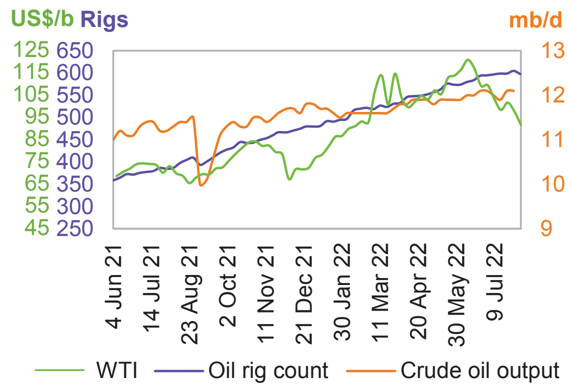
US rig count, spudded, completed, DUC wells and fracking activity

Total **US active drilling rigs** decreased by three units to 764 rigs in the week ending 5 August, but were up by 273 rigs compared to a year ago. The number of active offshore rigs declined by one w-o-w to 16, two rigs more than the same month in 2021. On the other hand, onshore oil and gas rigs remained unchanged w-o-w to stand at 746 rigs, with two rigs in inland waters.

The **US horizontal rig count** rose by one w-o-w to 698, compared with 449 horizontal rigs a year ago. The number of drilling rigs for oil declined by seven to 598 w-o-w, while gas-drilling rigs increased by four to 161.

The rig count in the Permian declined by four w-o-w to 347 rigs. At the same time, the number of active rigs fell by one in the Cana Woodford to 27. However, the rig count increased by one in the Williston and the DJ-Niobrara basins to 39 and 17, respectively. There were the same number of operating rigs w-o-w in the Eagle Ford and Barnett basins, 72 and 4, respectively.

Graph 5 - 12: US weekly rig count vs. US crude oil output and WTI price



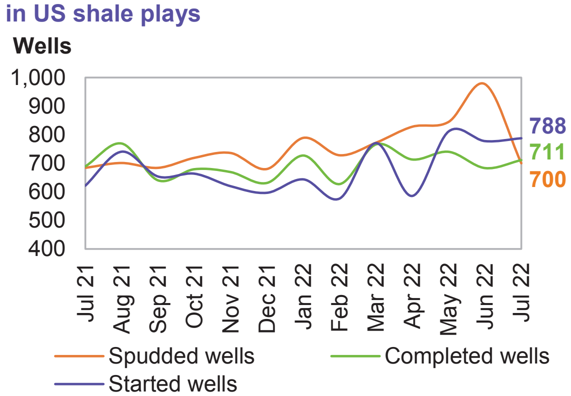
Sources: Baker Hughes, EIA and OPEC.

Drilling and completion (D&C) activities for spudded, completed and started wells in all US shale plays, based on the EIA-DPR regions, saw 977 horizontal wells spudded in June 2022 (as per preliminary data), up by 132 m-o-m, and 54% higher than in June 2021.

In June 2022, preliminary data indicates a lower number of completed wells at 683 m-o-m, but up by 16% y-o-y. Moreover, the number of started wells was estimated at 778, which is 32% higher than in June 2021.

Preliminary data for July estimates 700 spudded, 711 completed and 788 started wells, according to Rystad Energy.

Graph 5 - 13: Spudded, completed and started wells in US shale plays

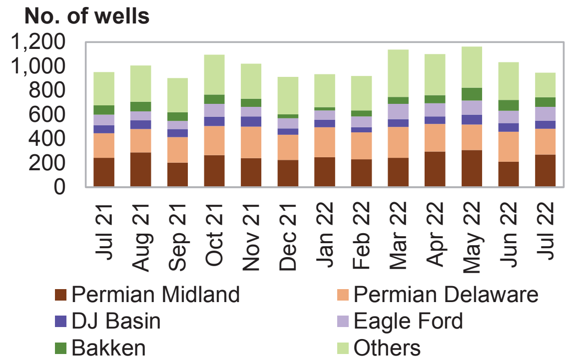


Note: Jun 22-Jul 22 = Preliminary data.
Sources: Rystad Energy and OPEC.

In terms of identified **US oil and gas fracking operations by region**, Rystad Energy reported that following a peak in January 2020, 1,161 wells were fracked in May 2022, and 1,034 and 946 wells started to frack in June and July, respectively. These preliminary numbers are based on an analysis of high-frequency satellite data.

Preliminary data on fracking in June shows that 210 and 249 wells were fracked in the Permian Midland Tight and Permian Delaware Tight, respectively. In comparison with May, there was a jump of 41 wells fracked in the Delaware and a decline of 99 wells fracked in the Midland tight, according to preliminary data. Data also indicated that 71 wells were fracked in the DJ Basin, 103 in the Eagle Ford and 89 in the Bakken during June.

Graph 5 - 14: Fracked wells count per month



Note: Jun 22-Jul 22 = Preliminary data.
Sources: Rystad Energy Shale Well Cube and OPEC.

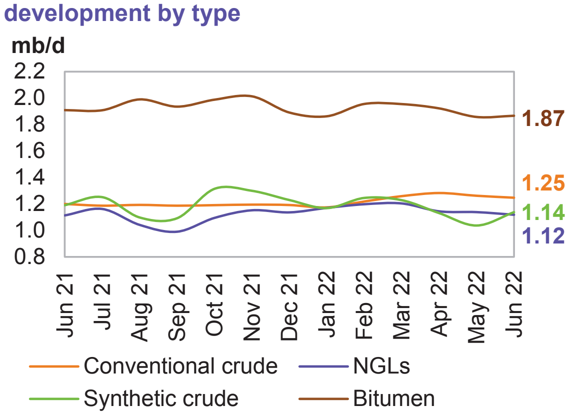
Canada

Canada's liquids production in June is estimated to have increased by 75 tb/d m-o-m to average 5.4 mb/d. However, 2Q22 shows a q-o-q decline of 0.16 mb/d, due to seasonal maintenance.

Crude bitumen production and synthetic crude output increased by 9 tb/d and 101 tb/d, m-o-m in June, respectively. Taken together, crude bitumen and synthetic crude production rose by 110 tb/d to 3.3 mb/d. However, production of conventional crude decreased by a slight 15 tb/d m-o-m to average 1.2 mb/d, and NGL output declined by 20 tb/d m-o-m to average 1.1 mb/d.

Seasonal maintenance at several key projects resulted in softer 2Q22 output. Thermal in-situ and upgraded mining projects are likely to see sequential quarterly declines, which were partially offset by an estimated increase in non-upgraded mining output. The main quarterly declines were estimated to be driven by Syncrude, CNRL, Suncor, and MEG Energy, while the return to a two-train operation in Fort Hills is estimated to increase non-upgraded oil. However, the project ramp-ups and optimization in oil sands output are expected to drive production in 4Q22.

Graph 5 - 15: Canada's monthly liquids production development by type

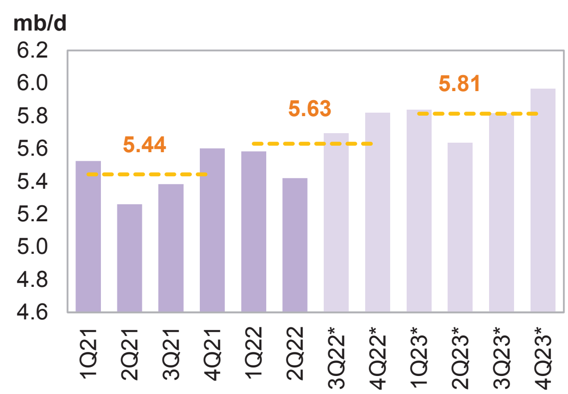


Sources: National Energy Board and OPEC.

Canadian liquids supply in **2022** is forecast to grow by 0.2 mb/d to average 5.6 mb/d, broadly unchanged from the previous assessment. Oil sands project expansion and the return of upgraders from maintenance are expected to increase output up to December.

For **2023**, Canada's liquids production is forecast to increase gradually at a pace similar to 2022, rising by 0.2 mb/d to average 5.8 mb/d. Incremental production will come mainly from Alberta's oil sands, which saw average output of 3.1 mb/d in 1H22.

Graph 5 - 16: Canada's quarterly liquids production and forecast



*Note: * 3Q22-4Q23 = Forecast. Source: OPEC.*

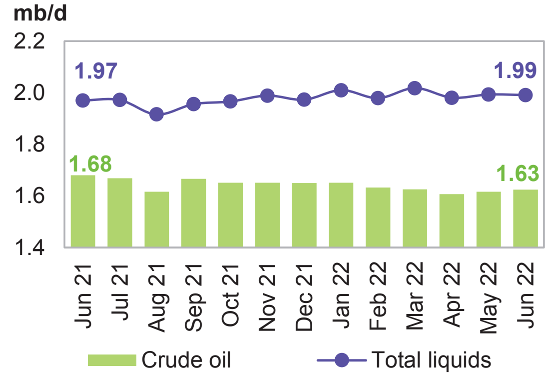
Mexico

Mexico's crude output rose by a slight 8 tb/d in **June** to average 1.6 mb/d, while NGL output decreased by 10 tb/d. Therefore, Mexico's total liquids output in June was broadly unchanged m-o-m to average 1.99 mb/d, according to national oil company Pemex.

For **2022**, liquids production in Mexico is forecast to grow by 30 tb/d to average 2.0 mb/d, unchanged from the previous month. The increase is expected to be driven by foreign-operated fields like the ones managed by Lukoil, ENI and Pan American. Minor growth is also expected in Pemex-operated fields.

For **2023**, liquids production is forecast to decline by 0.04 mb/d to average 1.9 mb/d. Pemex's total crude production decline in mature fields like Ku-Maloob-Zaap, Abkatun-Pol-Chuc, and Integral Yaxche-Xanab is forecast to outweigh production ramp-ups in other fields.

Graph 5 - 17: Mexico's monthly liquids and crude production development



Sources: PEMEX and OPEC.

OECD Europe

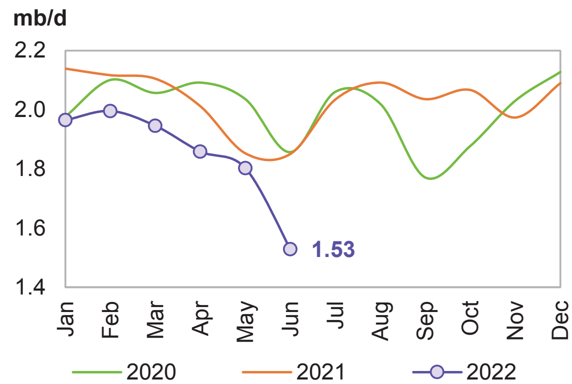
Norway

Norwegian liquids production in **June** declined by 0.27 mb/d m-o-m to average 1.5 mb/d. This was due to continued heavy maintenance in offshore platforms and the prioritization of gas production by some operators.

Norway's crude production decreased by 328 tb/d m-o-m in June to average 1.3 mb/d, down by 322 tb/d y-o-y. Oil production in June was 0.2% lower than the Norwegian Petroleum Directorate's (NPD) forecast.

By contrast, production of NGLs and condensates increased by 54 tb/d m-o-m to average 0.2 mb/d, according to NPD data.

Graph 5 - 18: Norway's monthly liquids production development



Sources: NPD and OPEC.

For **2022**, the growth forecast has been revised down by 64 tb/d m-o-m due to lower-than-expected output for 2Q22 and maintenance at Johan Sverdrup and in the Greater Ekofisk Area. Production is now expected to decrease by 39 tb/d y-o-y and average 2.0 mb/d. In addition to some small start-ups, growth is expected in 4Q22, following the return from maintenance and when the second phase of the Johan Sverdrup field development starts production.

For **2023**, Norwegian liquids production is forecast to grow by 0.24 mb/d to average 2.3 mb/d. Plenty of small-to-large projects are scheduled to ramp up in 2023 in the Njord, Nova, Ringhorne, Alvheim, Oseberg and Snohvit fields. However, the Johan Sverdrup is projected to be the main source of increased output for the year. Neptune has also completed drilling at Fenja with the first oil on track for 1Q23. Fenja is expected to produce about 24 tb/d at peak production.

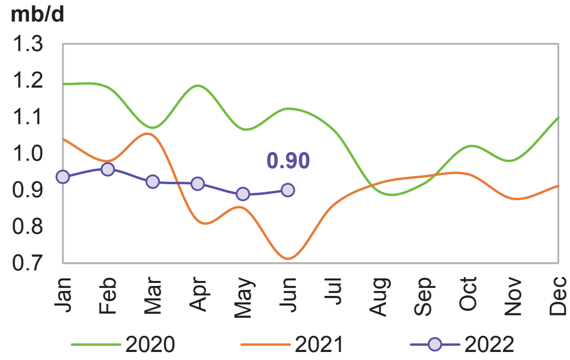
UK

UK liquids production increased in **June** by 11 tb/d m-o-m to average 0.9 mb/d. Crude oil output increased by 18 tb/d m-o-m to average 0.8 mb/d, according to official data, and was up by 140 tb/d y-o-y. NGL output fell slightly, by 7 tb/d, to 86 tb/d.

For **2022**, UK liquids production is forecast to grow by 23 tb/d to average 0.9 mb/d, revised down by a minor 7 tb/d from the previous assessment, due to lower-than-expected production in 2Q22. Low investment levels, COVID-19-related delays and poor mature reservoir performance have impacted the growth forecast.

For **2023**, UK liquids production is forecast to stay steady for an average of 0.9 mb/d. Production ramp-ups will be seen in the Penguins oil field (Redevelop), ETAP, Clair, the Schiehallion quad and at some other small fields. However, project sanctioning is essential for maintaining future oil and gas output at a time when the UK is already facing production declines due to lack of new developments.

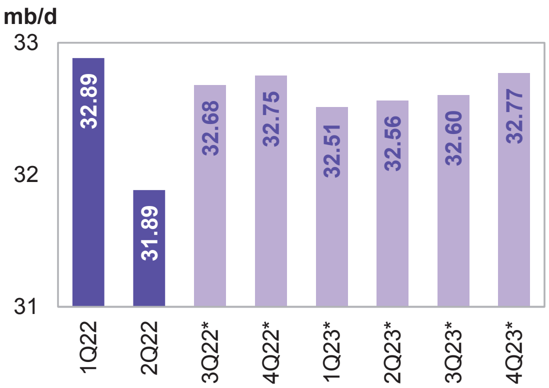
Graph 5 - 19: UK monthly liquids production development



Sources: Department of Energy & Climate Change and OPEC.

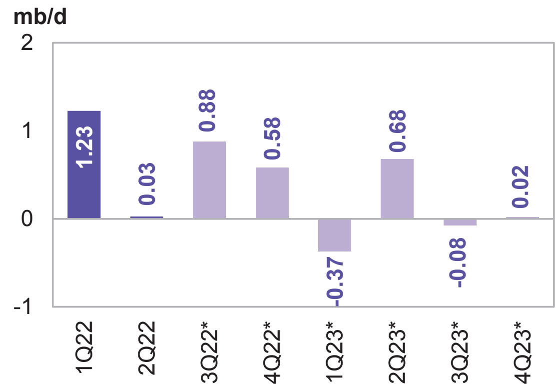
Non-OECD

Graph 5 - 20: Non-OECD quarterly liquids production and forecast



*Note: * 3Q22-4Q23 = Forecast. Source: OPEC.*

Graph 5 - 21: Non-OECD quarterly liquids supply, y-o-y changes

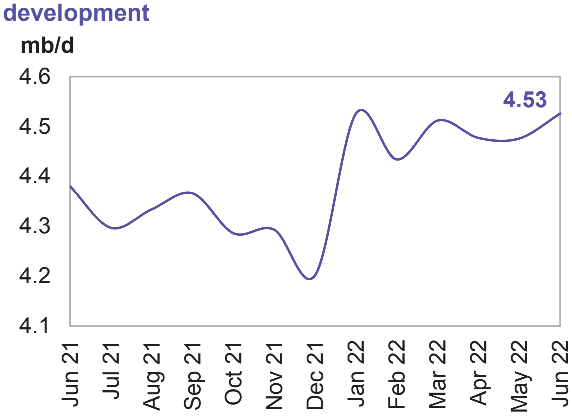


*Note: * 3Q22-4Q23 = Forecast. Source: OPEC.*

China

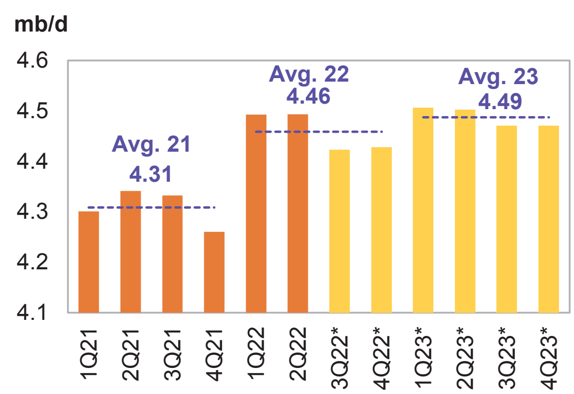
China's liquids production increased m-o-m in **June** by 50 tb/d to average 4.5 mb/d, which was up by 146 tb/d y-o-y, according to official data. Crude oil output in June averaged 4.2 mb/d, up by 46 tb/d compared to the previous month, and higher by 127 tb/d y-o-y. Liquids production over the first five months of the year averaged 4.5 mb/d, higher by 4% compared to the same period last year.

Graph 5 - 22: China's monthly liquids production development



Sources: CNPC and OPEC.

Graph 5 - 23: China's quarterly liquids production and forecast



*Note: * 3Q22-4Q23 = Forecast. Sources: CNPC and OPEC.*

For **2022**, growth of 150 tb/d is forecast for an average of 4.5 mb/d, broadly unchanged from the previous assessment. Natural decline rates are expected to be offset by Chinese national oil companies' investments. Sinopec, China National Petroleum Corporation and China National Offshore Oil Corporation are expected to drive growth with additional in-fill wells and EOR projects.

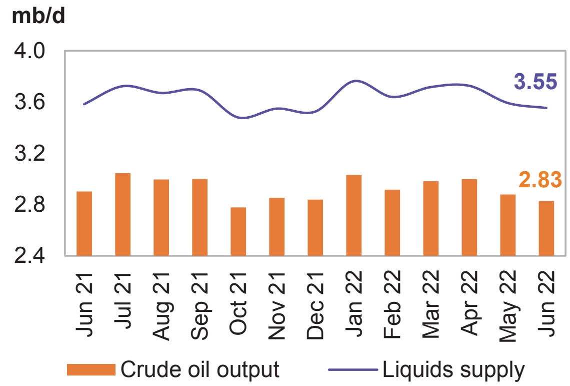
For **2023**, y-o-y growth of 30 tb/d is forecast for an average of 4.5 m/d, with Bozhong 29-6, Wushi 17-2 and Kenli 10-1N planned to come on stream under CNOOC. At the same time, ramp-ups are expected from the Changqing, Jilin and Liaohe projects, which are managed by Petro China.

Latin America

Brazil

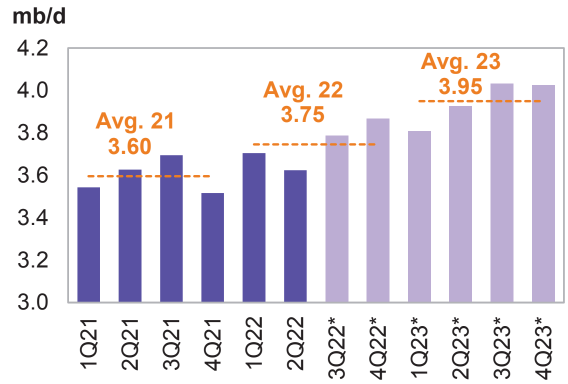
Brazil's crude output in **June** decreased by 50 tb/d m-o-m to average 2.8 mb/d. NGL production was up by 11 tb/d to average 93 tb/d and is expected to remain flat in July. Biofuel output (mainly ethanol) remained unchanged in June to average 632 tb/d, with preliminary data showing a flat trend in July as well. Therefore, in June, total liquids production decreased by 39 tb/d to average 3.6 mb/d, down by 30 tb/d y-o-y. This was primarily due to continued downtime at the Tupi oilfield during the first half of the month.

Graph 5 - 24: Brazil's monthly liquids production development by type



Sources: ANP, Petrobras and OPEC.

Graph 5 - 25: Brazil's quarterly liquids production



*Note: * 3Q22-4Q23 = Forecast. Sources: ANP and OPEC.*

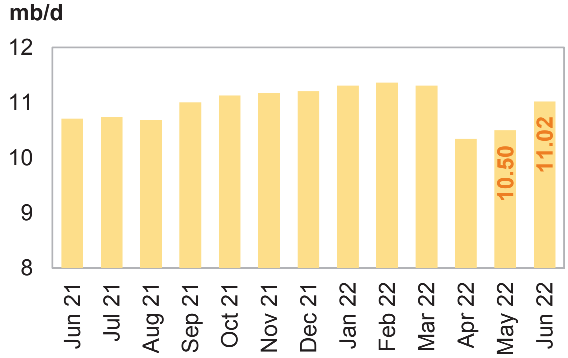
For **2022,** Brazil's liquids supply, including biofuels, is forecast to increase by 0.2 mb/d y-o-y to average 3.8 mb/d, unchanged from the previous month's assessment. Growth in 2022 will be driven by the continued ramp-up of the Sepia field along with the start-up of Mero 1 in the pre-salt Santos basin and Peregrino Phase 2. The Peregrino Field came back on stream in July, with Peregrino Phase 2 on track for start-up in the third quarter, according to the Offshore Magazine. Equinor's Peregrino Phase 1 project (platforms A & B), located in the Campos basin, went offline back in May 2020 due to operational issues with a turbine at the field FPSO. The FPSO is now intended to serve both Phase 1 and Phase 2 of the field's development.

For **2023**, Brazil's liquids supply, including biofuels, is forecast to increase by 0.2 mb/d y-o-y to average 3.9 mb/d. Crude oil output is expected to increase through production ramp-ups in the Mero (Libra NW), Buzios (Franco), Tupi (Lula), Peregrino, Sepia and Itapu (Florim) fields. However, offshore maintenance is expected to cause interruptions in the major fields.

Russia

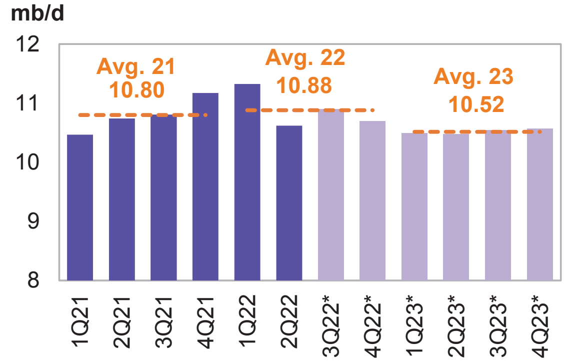
Russia's liquids production in June increased m-o-m by 520 tb/d to average 11.0 mb/d. This includes 9.8 mb/d of crude oil and condensate, and 1.2 mb/d of NGLs. A preliminary estimate for Russia's crude and condensate production in July 2022 shows an increase of 58 tb/d m-o-m to average 9.9 mb/d, while around a 32 tb/d decline is expected for NGLs.

Graph 5 - 26: Russia's monthly liquids production



Sources: Nefte Compass, The Ministry of Energy of the Russian Federation and OPEC.

Graph 5 - 27: Russia's quarterly liquids production



*Note: * 3Q22-4Q23 = Forecast.*
Sources: Nefte Compass and OPEC.

Russian liquids output in **2022** is forecast to increase by 80 tb/d y-o-y to average 10.9 mb/d, an upward revision of 0.25 mb/d from the previous month's assessment, due to higher-than-expected production in the last two months.

For **2023**, Russian liquids production is forecast to decrease by 0.4 mb/d to average 10.5 mb/d. It should be noted that the Russian oil forecast is subject to high uncertainty.

Caspian

Kazakhstan & Azerbaijan

Liquids output in Kazakhstan decreased by 386 tb/d to average 1.5 mb/d in **June**. Crude production was down by 341 tb/d m-o-m to average 1.2 mb/d. Production of NGLs also decreased by 45 tb/d m-o-m to average 0.3 mb/d. This was mainly due to extensive maintenance in the Kashagan oil field.

Kazakhstan's liquids supply for **2022** is now forecast to grow by 80 tb/d to average 1.9 mb/d, down by 37 tb/d compared to the previous month's assessment.

For **2023**, liquids supply is forecast to increase by 60 tb/d, due to production ramp-ups in the Kashagan oil field. Oil production in the Tengiz field and gas condensate output in the Karachaganak field are also expected to rise marginally.

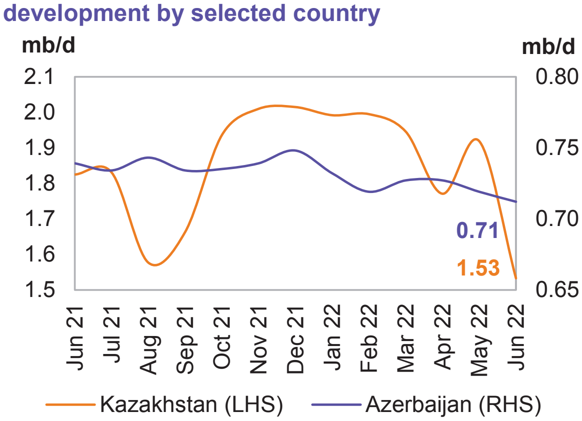
Azerbaijan's liquids production in June declined by a minor 7 tb/d m-o-m to average 0.7 mb/d, and was down by 27 tb/d y-o-y. Crude production decreased by 9 tb/d m-o-m to average 562 tb/d, while NGL output averaged at 150 tb/d, according to official sources.

No new projects are expected to come online in the country in 2022, and the main declines in the legacy fields are expected to be offset by ramp-ups in other fields, such as Shah Deniz Phase 2.

For **2022**, liquids supply in Azerbaijan is forecast to grow by 39 tb/d y-o-y to average 0.8 mb/d, down by 8 tb/d, because of lower-than-expected production in the major oil fields in 2Q22.

Azerbaijan's liquids supply for **2023** is forecast to decline by 60 tb/d for an average of 0.7 mb/d. The overall decline rate will be higher than the planned ramp-ups in the three major producing fields.

Graph 5 - 28: Caspian monthly liquids production development by selected country



Sources: Nefte Compass and OPEC.

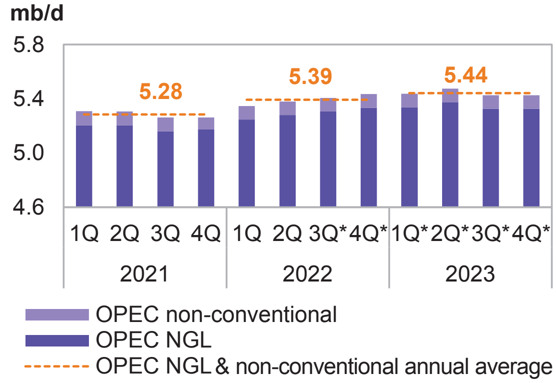
OPEC NGLs and non-conventional oils

OPEC NGLs and non-conventional liquids in 2022 are forecast to grow by 0.1 mb/d to average 5.4 mb/d, unchanged from the previous assessment.

Output of NGLs in 1Q22 is estimated to have averaged 5.2 mb/d, while OPEC non-conventionals remained steady at 0.1 mb/d.

The preliminary **2023** forecast indicates growth of 50 tb/d for an average of 5.4 mb/d. NGL production is projected to grow by 50 tb/d to average 5.3 mb/d, while non-conventional liquids are projected to remain unchanged at 0.1 mb/d.

Graph 5 - 29: OPEC NGLs and non-conventional liquids quarterly production and forecast



*Note: * 3Q22-4Q23 = Forecast. Source: OPEC.*

Table 5 - 6: OPEC NGL + non-conventional oils, mb/d

OPEC NGL and non-coventional oils	2021	Change 21/20	2022	Change 22/21	1Q23	2Q23	3Q23	4Q23	2023	Change 23/22
OPEC NGL	**5.18**	*0.12*	**5.29**	*0.11*	5.34	5.37	5.33	5.33	**5.34**	*0.05*
OPEC non-conventional	**0.10**	*0.00*	**0.10**	*0.00*	0.10	0.10	0.10	0.10	**0.10**	*0.00*
Total	**5.28**	***0.12***	**5.39**	***0.11***	**5.44**	**5.47**	**5.43**	**5.43**	**5.44**	***0.05***

Note: 2022-2023 = Forecast. Source: OPEC.

OPEC crude oil production

According to secondary sources, total **OPEC-13 crude oil production** averaged 28.90 mb/d in July 2022, higher by 216 tb/d m-o-m. Crude oil output increased mainly in Saudi Arabia, the UAE and Kuwait, while production in Venezuela and Angola declined.

Table 5 - 7: OPEC crude oil production based on *secondary sources*, tb/d

Secondary sources	2020	2021	4Q21	1Q22	2Q22	May 22	Jun 22	Jul 22	*Change Jul/Jun*
Algeria	904	913	959	984	1,014	1,014	1,023	1,020	*-3*
Angola	1,247	1,117	1,124	1,152	1,173	1,164	1,184	1,165	*-19*
Congo	289	265	266	263	268	270	272	263	*-9*
Equatorial Guinea	114	98	89	92	90	87	88	101	*13*
Gabon	191	182	185	199	185	171	188	202	*14*
IR Iran	1,991	2,392	2,472	2,528	2,559	2,543	2,569	2,558	*-11*
Iraq	4,076	4,049	4,240	4,286	4,438	4,414	4,466	4,496	*30*
Kuwait	2,439	2,419	2,532	2,614	2,691	2,689	2,724	2,772	*47*
Libya	367	1,143	1,111	1,063	752	725	643	632	*-11*
Nigeria	1,575	1,372	1,321	1,376	1,205	1,153	1,176	1,183	*6*
Saudi Arabia	9,204	9,111	9,878	10,163	10,450	10,427	10,556	10,714	*158*
UAE	2,804	2,727	2,861	2,954	3,045	3,038	3,082	3,131	*48*
Venezuela	512	553	657	678	712	710	710	661	*-49*
Total OPEC	**25,713**	**26,342**	**27,694**	**28,352**	**28,582**	**28,406**	**28,680**	**28,896**	***216***

Notes: Totals may not add up due to independent rounding, given available secondary sources to date. Source: OPEC.

Table 5 - 8: OPEC crude oil production based on *direct communication*, tb/d

Direct communication	2020	2021	4Q21	1Q22	2Q22	May 22	Jun 22	Jul 22	*Change Jul/Jun*
Algeria	899	911	958	984	1,016	1,015	1,027	1,040	*13*
Angola	1,271	1,124	1,123	1,161	1,173	1,162	1,175	1,180	*5*
Congo	300	267	260	267	258	261	251	250	*-1*
Equatorial Guinea	114	93	79	95	91	89	91	89	*-2*
Gabon	207	181	183	197	184	183	194	191	*-3*
IR Iran	..	..	..	..	..	..	..	..	*..*
Iraq	3,997	3,971	4,167	4,188	4,472	4,470	4,515	4,584	*69*
Kuwait	2,438	2,415	2,528	2,612	2,694	2,694	2,724	2,768	*44*
Libya	389	1,207	1,182	1,151	..	..	..	..	*..*
Nigeria	1,493	1,323	1,260	1,299	1,133	1,024	1,158	1,084	*-74*
Saudi Arabia	9,213	9,125	9,905	10,224	10,542	10,538	10,646	10,815	*169*
UAE	2,779	2,718	2,854	2,949	3,042	3,032	3,083	3,133	*50*
Venezuela	569	636	817	756	745	735	727	629	*-98*
Total OPEC	**..**	**..**	**..**	**..**	**..**	**..**	**..**	**..**	***..***

Notes: .. Not available. Totals may not add up due to independent rounding. Source: OPEC.

Commercial Stock Movements

Preliminary June data sees total OECD commercial oil stocks up m-o-m by 20.9 mb. At 2,712 mb, they were 163 mb less than the same time one year ago, 261 mb lower than the latest five-year average and 236 mb below the 2015-2019 average. Within the components, crude and product stocks rose m-o-m by 6.4 mb and 14.5 mb, respectively.

At 1,330 mb, OECD crude stocks were 54 mb lower than the same time one year ago, 125 mb lower than the latest five-year average and 135 mb below the 2015-2019 average. OECD product stocks stood at 1,381 mb, representing a deficit of 109 mb with the same time one year ago, 136 mb lower than the latest five-year average and 100 mb below the 2015-2019 average.

In terms of days of forward cover, OECD commercial stocks rose m-o-m by 0.1 days in June to stand at 58.9 days. This is 3.7 days below June 2021 levels, 5.3 days less than the latest five-year average and 2.9 days lower than the 2015-2019 average.

Preliminary data for July show that total US commercial oil stocks rose by 23.2 mb m-o-m to stand at 1,209 mb. This is 60.0 mb lower than the same month in 2021 and 103.3 mb below the latest five-year average. Crude and product stocks rose by 2.8 mb and 20.4 mb m-o-m, respectively.

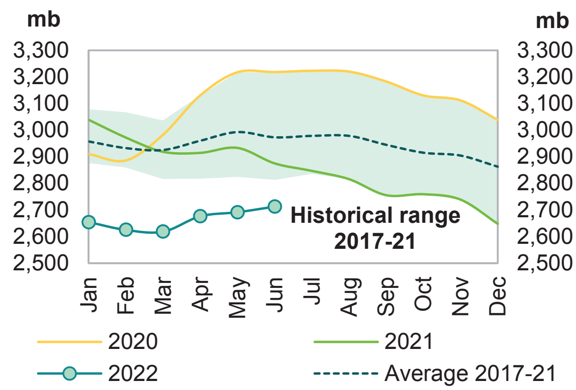
OECD

Preliminary **June** data sees **total OECD commercial oil stocks** up m-o-m by 20.9 mb. At 2,712 mb, they were 163 mb less than the same time one year ago, 261 mb lower than the latest five-year average and 236 mb below the 2015-2019 average.

Within the components, crude and product stocks rose m-o-m by 6.4 mb and 14.5 mb, respectively. Total commercial oil stocks in June rose in OECD Americas, while they declined in OECD Europe, and OECD Asia-Pacific

OECD commercial **crude stocks** stood at 1,330 mb in June. This is 54 mb lower than the same time a year ago and 125 mb below the latest five-year average. Compared with the previous month, OECD Asia Pacific saw a stock draw of 4.1 mb, OECD Americas stocks rose by 9.5 mb and stocks in OECD Europe increased by 0.9 mb.

Graph 9 - 1: OECD commercial oil stocks



Sources: Argus, EIA, Euroilstock, IEA, METI and OPEC.

Total product inventories stood at 1,381 mb in June. This is 109 mb less than the same time a year ago, and 136 mb lower than the latest five-year average. Product stocks in OECD Americas rose by 17.3 mb, while they fell m-o-m by 0.7 mb and 2.1 mb in OECD Asia Pacific and OECD Europe, respectively.

Table 9 - 1: OECD's commercial stocks, mb

OECD stocks	Jun 21	Apr 22	May 22	Jun 22	*Change* Jun 22/May 22
Crude oil	1,384	1,316	1,324	1,330	*6.4*
Products	1,491	1,360	1,367	1,381	*14.5*
Total	**2,875**	**2,676**	**2,691**	**2,712**	***20.9***
Days of forward cover	**62.7**	**59.1**	**58.8**	**58.9**	***0.1***

Note: Totals may not add up due to independent rounding.

Sources: Argus, EIA, Euroilstock, IEA, METI and OPEC.

In terms of **days of forward cover**, OECD commercial stocks rose by 0.1 days m-o-m in June to stand at 58.9 days. This is 3.7 days below June 2021 levels, 5.3 days less than the latest five-year average and 2.9 days lower than the 2015-2019 average. All three OECD regions were below the latest five-year average: the Americas by 5.1 days at 58.6 days; Asia Pacific by 6.4 days at 46.5 days; and Europe by 5.4 days at 65.6 days.

OECD Americas

OECD Americas total commercial stocks rose by 26.8 mb m-o-m in June to settle at 1,460 mb. This is 83 mb less than the same month in 2021 and 118 mb lower than the latest five-year average.

Commercial **crude oil stocks** in OECD Americas rose m-o-m by 9.5 mb in June to stand at 745 mb, which is 33 mb lower than in June 2021 and 48 mb less than the latest five-year average. The monthly build in crude oil stocks can be attributed to additional oil released from the strategic petroleum reserves (SPR).

Total product stocks in OECD Americas also rose m-o-m by 17.3 mb in June to stand at 715 mb. This was 50 mb lower than in the same month in 2021 and 70 mb below the latest five-year average. Lower total consumption in the region was behind the stock build.

OECD Europe

OECD Europe total commercial stocks fell m-o-m by 1.2 mb in June to settle at 926 mb. This is 48 mb less than the same month in 2021 and 77 mb below the latest five-year average.

OECD Europe's **commercial crude stocks** rose in June by 0.9 mb m-o-m to end the month at 418 mb, which is 1.4 mb lower than one year ago and 24 mb below the latest five-year average. The build in crude oil inventories came despite slightly higher m-o-m refinery throughputs in the EU-14, plus the UK and Norway, which increased by 70 tb/d to stand at 9.9 mb/d.

In contrast, Europe's **product stocks** fell m-o-m by 2.1 mb to end June at 508 mb. This is 47 mb lower than a year ago and 52 mb below the latest five-year average.

OECD Asia Pacific

OECD Asia Pacific's total commercial oil stocks fell m-o-m by 4.8 mb in June to stand at 326 mb. This is 31 mb lower than a year ago and 67 mb below the latest five-year average.

OECD Asia Pacific's **crude inventories** fell by 4.1 mb m-o-m to end June at 168 mb, which is 19 mb lower than one year ago and 53 mb below the latest five-year average.

OECD Asia Pacific's **total product inventories** also fell m-o-m by 0.7 mb to end June at 158 mb. This is 12 mb lower than the same time a year ago and 14 mb below the latest five-year average.

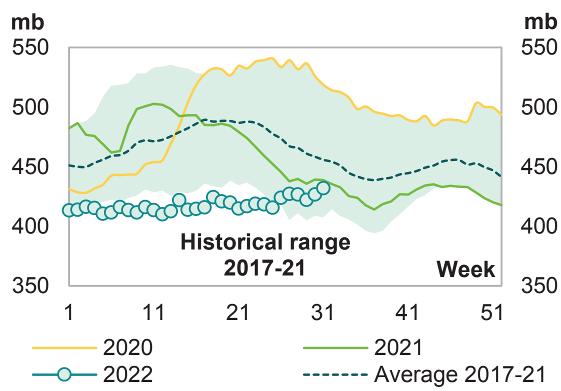
US

Preliminary data for July showed that **total US commercial oil stocks** rose by 23.2 mb m-o-m to stand at 1,209 mb. This is 60.0 mb, or 4.7%, lower than the same month in 2021 and 103.3 mb, or 7.9%, below the latest five-year average. Crude and product stocks rose by 2.8 mb and 20.4 mb, m-o-m, respectively.

US **commercial crude stocks** in July stood at 427 mb. This is 12.4 mb, or 2.8%, lower than the same month of the previous year, and 32.2 mb, or 7.0%, below the latest five-year average. The monthly build in crude oil stocks can be attributed to lower crude runs, as well as additional barrels released from SPR.

Total product stocks also rose in July to stand at 782.4 mb. This is 47.6 mb, or 5.7%, below July 2021 levels, and 71.2 mb, or 8.3%, lower than the latest five-year average. The stock build was mainly driven by lower product consumption.

Graph 9 - 2: US weekly commercial crude oil inventories



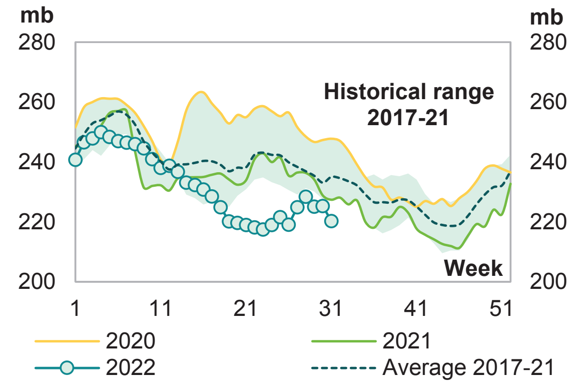
Sources: EIA and OPEC.

Gasoline stocks in July rose m-o-m by 6.2 mb to settle at 225.3 mb. This is 5.5 mb, or 2.4% lower than in the same month of 2021, and 11.4 mb, or 4.8%, lower than the latest five-year average. The monthly stock build came mainly on the back of lower gasoline consumption.

Jet fuel stocks also rose m-o-m by 1.7 mb, ending July at 41.6 mb. This is 2.2 mb, or 5.0%, lower than the same month of 2021, and 0.4 mb, or 0.8%, below the latest five-year average.

In contrast, **distillate stocks** fell m-o-m in July by 1.8 mb to stand at 109.3 mb. This is 32.7 mb, or 23.0%, lower than the same month of the previous year, and 38.1 mb, or 25.9%, below the latest five-year average.

Graph 9 - 3: US weekly gasoline inventories



Sources: EIA and OPEC.

Residual fuel oil stocks also fell by 0.3 mb m-o-m in July. At 28.2 mb, this was 0.9 mb, or 3.2%, lower than a year earlier, and 3.1 mb, or 9.8%, below the latest five-year average.

Table 9 - 2: US commercial petroleum stocks, mb

US stocks	Jul 21	May 22	Jun 22	Jul 22	*Change* *Jul 22/Jun 22*
Crude oil	**438.9**	**414.3**	**423.8**	**426.6**	***2.8***
Gasoline	230.8	220.7	219.1	225.3	*6.2*
Distillate fuel	142.0	109.5	111.1	109.3	*-1.8*
Residual fuel oil	29.1	29.2	28.4	28.2	*-0.3*
Jet fuel	43.8	41.4	39.9	41.6	*1.7*
Total products	**830.0**	**758.2**	**762.0**	**782.4**	***20.4***
Total	**1,268.9**	**1,172.5**	**1,185.8**	**1,208.9**	***23.2***
SPR	**621.3**	**523.1**	**492.0**	**469.9**	***-22.2***

Sources: EIA and OPEC.

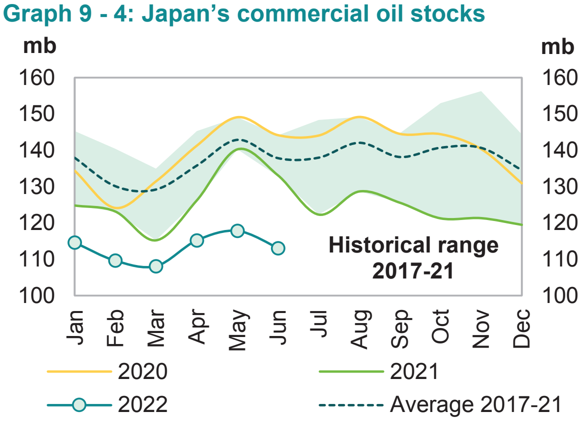
Japan

In **Japan**, **total commercial oil stocks** in June fell m-o-m by 4.8 mb to settle at 113.1 mb. This is 20.1 mb, or 15.1%, lower than the same month in 2021 and 24.7 mb, or 17.9%, below the latest five-year average. Crude and product stocks fell by 4.1 mb and 0.7 mb, respectively.

Japanese **commercial crude oil stocks** declined in June to stand at 59.8 mb. This is 10.8 mb, or 15.3% lower than the same month of the previous year, and 19.1 mb, or 24.2%, lower than the latest five-year average. The drop came on the back of lower crude imports, along with higher crude runs.

Japan's **total product inventories** also fell m-o-m by 0.7 mb to end June at 53.3 mb. This is 9.3 mb, or 14.9%, lower than the same month in 2021 and 5.6 mb, or 9.5%, below the latest five-year average.

Graph 9 - 4: Japan's commercial oil stocks



Sources: METI and OPEC.

Gasoline stocks fell by 0.4 mb m-o-m to stand at 10.0 mb in June. This was 4.4 mb, or 30.8% lower than a year earlier, and 1.4 mb, or 12.3%, lower than the latest five-year average. Lower gasoline production, along with lower gasoline imports, contributed to the decline in gasoline stocks.

Total residual fuel oil stocks also fell m-o-m by 0.4 mb to end June at 11.3 mb. This is 0.4 mb, or 3.7%, lower than in the same month of the previous year, and 1.3 mb, or 10.4%, below the latest five-year average. Within the components, fuel oil A and fuel oil B.C stocks fell by 6.0% and 1.4%, m-o-m, respectively.

In contrast, **distillate stocks** rose m-o-m by 0.3 mb to end June at 22.3 mb. This is 4.8 mb, or 17.6%, lower than the same month in 2021, and 3.2 mb, or 12.5%, below the latest five-year average. Within distillate components, jet fuel and kerosene stocks went up by 1.4% and 5.7%, respectively, while gasoil stocks fell by 2.8%.

Table 9 - 3: Japan's commercial oil stocks*, mb

Japan's stocks	Jun 21	Apr 22	May 22	Jun 22	*Change* Jun 22/May 22
Crude oil	**70.6**	**64.8**	**63.9**	**59.8**	***-4.1***
Gasoline	14.4	10.4	10.4	10.0	*-0.4*
Naphtha	9.3	8.8	9.8	9.6	*-0.2*
Middle distillates	27.1	20.3	22.0	22.3	*0.3*
Residual fuel oil	11.8	11.0	11.7	11.3	*-0.4*
Total products	**62.6**	**50.4**	**54.0**	**53.3**	***-0.7***
Total**	**133.2**	**115.2**	**117.9**	**113.1**	***-4.8***

*Note: * At the end of the month. ** Includes crude oil and main products only.*

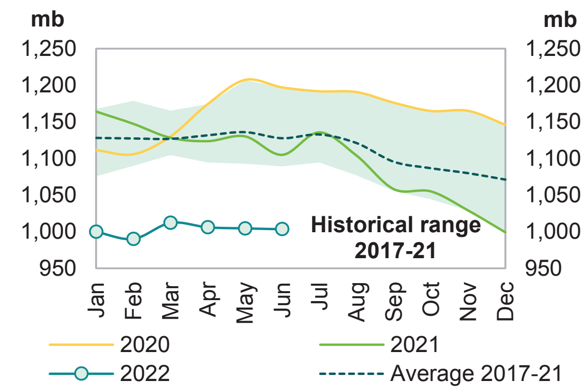
Sources: METI and OPEC.

EU-14 plus UK and Norway

Preliminary data for June showed that **total European commercial oil stocks** fell m-o-m by 1.2 mb to stand at 1,003.5 mb. At this level, they were 101.7 mb, or 9.2%, below the same month a year earlier, and 124.3 mb, or 11.0%, lower than the latest five-year average. Crude stocks rose by 0.9 mb, while product stocks fell by 2.1 mb.

European **crude inventories** rose in June to stand at 429.5 mb. This is 36.3 mb, or 7.8%, lower than the same month in 2021, and 61.6 mb, or 12.5%, below the latest five-year average. The build in crude oil inventories came despite slightly higher m-o-m refinery throughput in the EU-14, plus the UK and Norway, which increased by 70 tb/d to stand at 9.9 mb/d.

Graph 9 - 5: EU-14 plus UK and Norway's total oil stocks



Sources: Argus, Euroilstock and OPEC.

In contrast, **total European product stocks** fell m-o-m by 2.1 mb to end June at 574.1 mb. This is 65.4 mb, or 10.2%, lower than the same month of the previous year, and 62.7 mb, or 9.8%, below the latest five-year average.

Gasoline stocks fell m-o-m by 0.6 mb in June to stand at 110.2 mb. At this level, they were 2.6 mb, or 2.4%, higher than the same time a year earlier, but 2.2 mb/d, or 2.0%, less than the latest five-year average.

Residual fuel stocks also fell m-o-m by 2.1 mb in June to stand at 60.8 mb. This is 3.1 mb, or 4.8%, lower than the same month in 2021, and 5.8 mb, or 8.7%, below the latest five-year average.

Naphtha stocks fell by 0.2 mb in June, ending the month at 29.4 mb. This is 1.4 mb, or 4.9% higher than June 2021 levels, and 0.6 mb, or 2.2%, higher than the latest five-year average.

In contrast, **distillate stocks** rose m-o-m by 0.8 mb in June to stand at 373.7 mb. This is 66.3 mb, or 15.1%, below the same month in 2021, and 55.3 mb, or 12.9%, less than the latest five-year average.

Table 9 - 4: EU-14 plus UK and Norway's total oil stocks, mb

EU stocks	Jun 21	Apr 22	May 22	Jun 22	*Change* Jun 22/May 22
Crude oil	**465.8**	**429.8**	**428.5**	**429.5**	***0.9***
Gasoline	107.5	112.0	110.8	110.2	*-0.6*
Naphtha	28.0	27.3	29.6	29.4	*-0.2*
Middle distillates	440.1	376.5	373.0	373.7	*0.8*
Fuel oils	63.8	60.6	62.9	60.8	*-2.1*
Total products	**639.4**	**576.3**	**576.2**	**574.1**	***-2.1***
Total	**1,105.2**	**1,006.1**	**1,004.7**	**1,003.5**	***-1.2***

Sources: Argus, Euroilstock and OPEC.

Singapore, Amsterdam-Rotterdam-Antwerp (ARA) and Fujairah

Singapore

In June, **total product stocks in Singapore** rose m-o-m by 1.3 mb to 44.3 mb. This is 6.1 mb, or 12.2%, lower than the same month in 2021.

Light distillate stocks rose m-o-m by 0.2 mb in June to stand at 15.5 mb. This is 2.7 mb, or 21.5%, higher than the same month of the previous year.

Middle distillate stocks also rose m-o-m by 0.9 mb in June to stand at 7.9 mb. This is 5.9 mb, or 42.7%, lower than a year earlier.

Residual fuel oil stocks likewise rose m-o-m by 0.2 mb, ending June at 20.9 mb. This is 3.0 mb, or 12.6%, lower than in June 2021.

ARA

Total product stocks in ARA rose m-o-m in June by 2.1 mb, reversing the stock draw of the last two months. At 39.3 mb, they were 7.2 mb, or 15.5%, lower than the same month in 2021.

Gasoline stocks in June fell by 0.3 mb m-o-m to stand at 10.3 mb, which is 1.6 mb, or 18.0%, higher than the same month of the previous year.

In contrast, **gasoil stocks** rose by 0.1 mb m-o-m, ending June at 11.3 mb. This is 6.3 mb, or 35.9%, lower than levels seen in May 2021.

Fuel oil stocks also rose by 1.1 mb m-o-m in June to stand at 8.0 mb, which is 1.4 mb, or 14.6%, lower than in June 2021.

Meanwhile, **jet oil stocks** remained unchanged m-o-m at 6.3 mb. This is 2.3 mb, or 27.0%, lower than levels seen in June 2021.

Fujairah

During the week ending 1 August 2022, **total oil product stocks in Fujairah** rose w-o-w by 1.01 mb to stand at 23.39 mb, according to data from Fed Com and S&P Global Platts. At this level, total oil stocks were 4.46 mb higher than the same time a year ago.

Light distillate stocks rose by 1.16 mb w-o-w to stand at 7.60 mb in the week to 1 August 2022, which is 2.12 mb higher than the same period a year ago. **Middle distillate stocks** also rose by 0.19 mb to stand at 3.31 mb, which is 0.17 mb higher than a year ago. In contrast**, heavy distillate stocks** fell w-o-w by 0.33 mb to stand at 12.48 mb, which is 2.16 mb higher than the same time last year.

https://www.iea.org/reports/oil-market-report-august-2022

Oil Market Report - August 2022

Part of Oil Market Report
Flagship report — August 2022

About this report

The IEA Oil Market Report (OMR) is one of the world's most authoritative and timely sources of data, forecasts and analysis on the global oil market – including detailed statistics and commentary on oil supply, demand, inventories, prices and refining activity, as well as oil trade for IEA and selected non-IEA countries.

Highlights

- Soaring oil use for power generation and gas-to-oil switching are boosting demand. In this Report, we have raised our estimates for 2022 global demand growth by 380 kb/d, to 2.1 mb/d. Gains mask relative weakness in other sectors, and a slowdown in growth from 5.1 mb/d at the start of the year to less than 100 kb/d by 4Q22. World oil demand is now forecast at 99.7 mb/d in 2022 and 101.8 mb/d in 2023.

- World oil supply hit a post-pandemic high of 100.5 mb/d in July as maintenance wound down in the North Sea, Canada and Kazakhstan. OPEC+ ramped up total oil production by 530 kb/d in line with higher targets and non-OPEC+ rose by 870 kb/d. World oil supply is set to rise by a further 1 mb/d by year-end. In this Report, we revise up our forecast for Russian oil output but have lowered the outlook for North America.

- Refinery throughputs rose by 1.1 mb/d in July and are set for a further 350 kb/d gain this month, when runs will reach their highest level since January 2020. The increase was above refined product demand, driving cracks and refinery margins sharply below the all-time highs seen in June. Global refinery runs are now on track to rise by 2.6 mb/d in 2022 and 1.3 mb/d next year.

- Russian oil exports fell by 115 kb/d in July to 7.4 mb/d, from about 8 mb/d at the start of the year. Crude and oil product flows to the US, UK, EU, Japan and Korea have slumped by nearly 2.2 mb/d since the outbreak of the war, two-thirds of which have been rerouted to other markets. Export revenues fell from 21 bn in June to $19 bn in July, on both reduced volumes and lower oil prices.

- Global observed inventories fell by a marginal 5 mb in June, with a drawdown in both OECD and non-OECD stocks partially offset by an increase in oil on water. OECD total industry stocks increased by 6.2 mb, to 2 681 mb but remained 292.1 mb below the five-year average. Government stocks released to the market totalled 33.8 mb in June, the largest drawdown since March.

- Benchmark crude oil futures have sunk by around $30/bbl since a June peak as worsening economic prospects and oil demand growth weighed on sentiment. At the time of writing, Brent traded at around $97/bbl and WTI $92/bbl. Steadier forward prices flattened backwardation across the futures curve and prompt physical premiums eased.

Summer heat

Rising oil supplies and escalating concerns over the deteriorating economic outlook have knocked around $30/bbl off prices from a peak in June. For product prices and refinery margins, the plunge has been even steeper as a sharp run-up in refinery activity collided with lacklustre driving demand during the Northern Hemisphere summer season. At the time of writing, ICE Brent futures were around $97/bbl while NYMEX WTI were trading at $92/bbl.

At the same time, natural gas and electricity prices have soared to new records, incentivising gas-to-oil switching in some countries. With several regions experiencing blazing heatwaves, the latest data confirm increased oil burn in power generation, especially in Europe and the Middle East but also across Asia. Fuel switching is also taking place in European industry, including refining. In this Report, we have revised our forecast for world oil demand higher for the remainder of the year, but growth is nonetheless expected to slow from 5.1 mb/d in 1Q22 to a marginal 40 kb/d by 4Q22. World oil demand is now seen rising by 2.1 mb/d in 2022 to 99.7 mb/d and by a further 2.1 mb/d next year, when it surpasses pre-Covid levels at 101.8 mb/d.

The outlook for world oil supply has been revised upward, with more limited declines in Russian supply than previously forecast. While Russia's exports of crude and oil products to Europe, the US, Japan and Korea have fallen by nearly 2.2 mb/d since the start of the war, the rerouting of flows to India, China, Türkiye and others, along with seasonally higher Russian domestic demand has mitigated upstream losses. By July, Russian oil production was only 310 kb/d below pre-war levels while total oil exports were down just 580 kb/d. The EU embargo on Russian crude and product imports that comes into full effect in February 2023 is expected to result in further declines, as some 1 mb/d of products and 1.3 mb/d of crude would have to find new homes.

In a largely symbolic move, OPEC+ agreed in early August to raise its supply target by just 100 kb/d for September, significantly lower than the July and August scheduled increases of 648 kb/d. The group noted that "severely limited" spare capacity should be used with "great caution in response to severe supply disruptions", suggesting that substantial further OPEC+ output increases are unlikely in the coming months.

Even so, builds in global inventories are now projected at around 900 kb/d during the rest of this year and 500 kb/d over the first half of 2023. The release of additional emergency stocks through at least October will provide further relief. By end-June, around 150 mb of the volumes committed through IEA collective actions and individual IEA member SPR sales had yet to find its way to the market. With OECD industry stocks still some 290 mb below their five-year average, such builds could help ease market tensions. But with supply increasingly at risk to disruptions, another price rally cannot be excluded.

OPEC+ crude oil production[1]
million barrels per day

	June 2022 supply	July 2022 supply	July 2022 compliance	July 2022 target	Sustainable capacity[2]	Effective spare capacity vs. July[3]
Algeria	1.02	1.02	206%	1.04	1.01	
Angola	1.18	1.18	1338%	1.50	1.16	
Congo	0.28	0.26	1300%	0.32	0.28	0.02
Equatorial Guinea	0.09	0.10	1350%	0.13	0.11	0.00
Gabon	0.19	0.21	-575%	0.18	0.20	-0.01
Iraq	4.44	4.49	223%	4.58	4.70	0.21
Kuwait	2.68	2.77	95%	2.77	2.79	0.02
Nigeria	1.16	1.08	2497%	1.80	1.33	0.25
Saudi Arabia	10.58	10.83	102%	10.83	12.22	1.39
UAE	3.24	3.28	-273%	3.13	4.12	0.84
Total OPEC-10	**24.86**	**25.22**	**359%**	**26.28**	**27.92**	**2.73**
Iran[4]	2.57	2.52			3.80	
Libya[4]	0.63	0.68			1.20	0.52
Venezuela[4]	0.73	0.63			0.76	0.13
Total OPEC	**28.79**	**29.05**			**33.69**	**3.38**
Azerbaijan	0.52	0.56	1301%	0.71	0.58	0.02
Kazakhstan	1.25	1.42	1007%	1.68	1.65	0.23
Mexico[5]	1.62	1.63		1.75	1.66	0.03
Oman	0.85	0.85	200%	0.87	0.86	0.01
Russia	9.78	9.80	719%	10.83	10.20	
Others[6]	0.88	0.86	1381%	1.09	0.93	0.07
Total Non-OPEC	**14.90**	**15.12**	**800%**	**16.93**	**15.88**	**0.36**
OPEC+-19 in cut deal[4]	**38.14**	**38.71**	**523%**	**41.45**	**42.14**	**3.07**
Total OPEC+	**43.69**	**44.17**			**49.57**	**3.74**

1. Excludes condensates. 2. Capacity levels can be reached with 90 days and sustained for extended period. 3. Excludes shut in Iranian, Russian crude. 4. Iran, Libya, Venezuela exempt from cuts. 5. Mexico excluded from OPEC+ compliance. Only cut in May, June 2020. 6. Bahrain, Brunei, Malaysia, Sudan and South Sudan.

IEA World Oil Supply and Demand Forecasts: Summary (Table)
2022-08-11 08:00:00.11 GMT

By Kristian Siedenburg
(Bloomberg) -- Following is a summary of world oil supply and demand forecasts from the International Energy Agency in Paris:

	4Q 2023	3Q 2023	2Q 2023	1Q 2023	4Q 2022	3Q 2022	2Q 2022	1Q 2022	2023	2022
	Demand									
Total Demand	103.3	102.5	101.1	100.3	100.8	100.0	98.5	99.4	101.8	99.7
Total OECD	46.9	46.8	45.9	46.2	46.4	45.8	45.3	45.8	46.4	45.8
Americas	25.1	25.2	25.1	24.8	24.8	24.6	24.8	24.8	25.0	24.7
Europe	13.8	14.1	13.6	13.4	13.8	14.1	13.5	13.2	13.7	13.6
Asia Oceania	7.9	7.5	7.2	8.0	7.7	7.2	7.0	7.9	7.7	7.4
Non-OECD countries	56.5	55.7	55.2	54.1	54.5	54.2	53.2	53.6	55.4	53.9
FSU	4.9	4.8	4.5	4.4	4.7	4.8	4.7	4.7	4.6	4.7
Europe	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
China	16.8	16.3	16.1	15.8	15.8	15.6	14.6	15.4	16.3	15.4
Other Asia	14.9	14.2	14.5	14.5	14.1	13.4	14.0	14.1	14.5	13.9
Americas	6.1	6.1	6.0	5.9	6.1	6.1	6.1	5.9	6.0	6.1
Middle East	8.9	9.5	9.2	8.7	8.8	9.4	9.0	8.5	9.1	8.9
Africa	4.2	4.0	4.1	4.1	4.1	4.0	4.1	4.2	4.1	4.1
	Supply									
Total Supply	n/a	n/a	n/a	n/a	n/a	n/a	98.7	98.7	n/a	n/a
Non-OPEC	66.9	66.7	66.2	65.5	66.5	66.1	64.6	64.9	66.3	65.5
Total OECD	31.5	31.0	30.7	30.5	30.5	29.7	28.9	28.8	30.9	29.5
Americas	27.5	27.2	26.9	26.6	26.6	26.0	25.4	25.0	27.1	25.7
Europe	3.5	3.3	3.3	3.4	3.4	3.2	3.0	3.3	3.4	3.2
Asia Oceania	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Non-OECD	30.0	29.9	30.0	30.1	30.7	30.8	30.4	31.4	30.0	30.8
FSU	12.5	12.4	12.5	12.7	13.5	13.6	13.4	14.4	12.5	13.7
Europe	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
China	4.2	4.3	4.3	4.3	4.2	4.2	4.2	4.2	4.3	4.2
Other Asia	2.6	2.6	2.6	2.6	2.7	2.7	2.7	2.8	2.6	2.7
Americas	6.1	6.0	5.9	5.9	5.8	5.7	5.5	5.4	6.0	5.6
Middle East	3.3	3.3	3.3	3.2	3.2	3.2	3.2	3.2	3.3	3.2
Africa	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Processing Gains	2.4	2.4	2.4	2.3	2.3	2.3	2.3	2.3	2.4	2.3
Total OPEC	n/a	n/a	n/a	n/a	n/a	n/a	34.0	33.8	n/a	n/a
Crude	n/a	n/a	n/a	n/a	n/a	n/a	28.7	28.5	n/a	n/a
Natural gas liquids NGLs	5.5	5.5	5.4	5.4	5.4	5.4	5.4	5.3	5.4	5.4
Call on OPEC crude and stock change *	31.0	30.3	29.4	29.4	29.0	28.5	28.5	29.3	30.0	28.8

NOTE: Figures are in million of barrels per day. (*) equals total demand minus non-OPEC supply and OPEC natural gas liquids.
IEA changed the way it measures OPEC supply, adopting the industry-standard approach of counting most of Venezuela's Orinoco heavy oil as "crude oil."
SOURCE: International Energy Agency

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IEA: July Crude Oil Production in OPEC Countries (Table)
2022-08-11 08:00:00.10 GMT

By Kristian Siedenburg
(Bloomberg) -- Following is a summary of oil production in
OPEC countries from the International Energy Agency in Paris:

	July 2022	June 2022	July MoM
Total OPEC	29.05	28.79	0.26
Total OPEC10	25.22	24.86	0.36
Algeria	1.02	1.02	0.00
Angola	1.18	1.18	0.00
Congo	0.26	0.28	-0.02
Equatorial Guinea	0.10	0.09	0.01
Gabon	0.21	0.19	0.02
Iraq	4.49	4.44	0.05
Kuwait	2.77	2.68	0.09
Nigeria	1.08	1.16	-0.08
Saudi Arabia	10.83	10.58	0.25
UAE	3.28	3.24	0.04
Iran	2.52	2.57	-0.05
Libya	0.68	0.63	0.05
Venezuela	0.63	0.73	-0.10

NOTE: Figures are in million of barrels per day. Monthly
level change calculated by Bloomberg. Production data excludes
condensates.
OPEC10 excludes Iran, Libya and Venezuela.
SOURCE: International Energy Agency

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IEA REPORT WRAP: Oil Demand Forecasts Raised as Gas Crunch Looms
2022-08-11 08:55:57.150 GMT

By Stephen Voss
(Bloomberg) -- Summary including stories from IEA's monthly
Oil Market Report on Thursday:
* Oil use grows faster as natural gas crisis spurs fuel-switch
** Outright 2022, 2023 world demand both raised 0.5m b/d
** Demand growth est. for 2022 raised by 380k b/d

** Extraordinary growth gains concentrated in Mideast, Europe
* See summary of key IEA world oil supply demand forecasts
** Click here for detailed forecast table
* China overtakes EU as biggest buyer of Russian crude
** Final June data for seaborne exports showed that 2.1m b/d of crude went to China, exceeding for the first time the 1.8m b/d to the EU
* Russian oil output seen down 20% once EU ban takes effect
** Ban to affect most crude from Dec. 5, products Feb. 5
* IEA sees little chance that OPEC+ will supply more oil
** OPEC+'s Sept. supply increase simply a 'symbolic' move
* OPEC crude output rose 260k b/d in July, to 29.05m b/d: IEA
** Led by increase in Saudi, Kuwait volumes
** See full table for the 13 members
** OPEC will release its own secondary-source estimates later today
* Diesel is main driver of 0.5m b/d 2022 demand revision jump
* Gas-to-oil switch prompts "exceptional" demand in Europe
** Substitution adds about 300k b/d to oil product deliveries
* West Africa crude prices drop on weaker oil products, Libya
* Global refineries to run most in August since early 2020
* NOTE: The US EIA issued its monthly short-term energy outlook on Aug. 9 and OPEC will issue its own monthly report later Thursday

--With assistance from Jack Wittels, Grant Smith, James Herron, Bill Lehane, Rachel Graham, Kristian Siedenburg, Sherry Su and Amanda Jordan.
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Oil Demand Accelerates as Gas Crisis Spurs Switch, IEA Says (1)
2022-08-11 09:19:45.176 GMT

By Grant Smith
(Bloomberg) -- The International Energy Agency boosted its forecast for global oil demand growth this year as soaring natural gas prices and heatwaves spur industry and power generators to switch their fuel to oil.
World oil consumption will now increase by 2.1 million barrels a day this year, or about 2%, up 380,000 a day from the

previous forecast, the Paris-based agency said in its latest monthly report. The extra demand that prompted the revision is "overwhelmingly concentrated" in the Middle East and Europe.

Natural gas prices have surged this year as Russia restricts gas flows to Europe, a move that is widely seen as retaliation for sanctions imposed over its invasion of Ukraine. The increase has prompted many industrial consumers, including refiners and power plants, to switch from gas to oil. Scorching temperatures have also spurred demand for air conditioning, particularly in the Middle East, where a significant amount of oil is burned during summer to generate electricity.

"Natural gas and electricity prices have soared to new records, incentivizing gas-to-oil switching in some countries," said the IEA, which advises most major economies on energy policy. "With several regions experiencing blazing heatwaves, the latest data confirm increased oil burn in power generation, especially in Europe and the Middle East."

Even as consumption accelerates, the IEA doubts that oil markets will face a supply crunch, with stockpiles projected to swell at a rate of 900,000 barrels a day for the rest of this year.

Russia's oil output has proved more resilient than expected in the face of international sanctions, while supplies are being topped up by the release of barrels from governments' emergency reserves announced earlier this year.

These releases are scheduled to continue through to October, and could be extended for longer, Toril Bosoni, head of the IEA's oil market division, said in a Bloomberg television interview.

"We still have a lot of emergency stocks in our member countries," she said. "This is something that will be discussed once this current release is completed."

Still, Russian production may fall again in the coming months as new European sanctions bite, and little further assistance can be expected from its allies in the Organization of Petroleum Exporting Countries, the IEA said.

READ: IEA Sees Russian Oil Output Down 20% Once EU Ban Takes Effect

OPEC+ offered only a "symbolic" output increase of 100,000 barrels a day for September at its latest meeting, despite a visit by US President Joe Biden to group leader Saudi Arabia. The alliance is unlikely to shift course by announcing further substantial hikes in the months ahead because its spare capacity is limited, according to the IEA.

"They're worried about spare capacity -- it's basically only Saudi Arabia and the UAE that are holding any substantial amount of spare capacity," said Bosoni. "There's a lot of uncertainty on the demand side, this is also something that OPEC is factoring in."

--With assistance from Francine Lacqua.
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IEA World Oil Supply/Demand Key Forecasts
2022-08-11 08:00:00.17 GMT

By Kristian Siedenburg
(Bloomberg) -- World oil demand 2023 forecast was revised to 101.8m b/d from 101.3m b/d in Paris-based Intl Energy Agency's latest monthly report.
* 2022 world demand was revised to 99.7 from 99.2m b/d
* Demand change in 2023 est. 2.1% y/y or 2.1m b/d
* Non-OPEC supply 2023 was revised to 66.3m b/d from 65.6m b/d
* Call on OPEC crude 2023 was revised to 30.0m b/d from 30.2m b/d
* Call on OPEC crude 2022 was revised to 28.8 m b/d from 28.3m b/d
** OPEC crude production in July rose by 260k b/d on the month to 29.05m b/d
* Detailed table: FIFW NSN RGFXHJGFR4SG <GO>
* NOTE: Fcasts based off IEA's table providing one decimal point

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China Overtakes EU as Biggest Single Buyer of Russian Crude: IEA
2022-08-11 08:00:00.7 GMT

By Sherry Su
(Bloomberg) -- China surpassed EU as the largest destination of Russian crude oil, the IEA said in its monthly Oil Market Report.

* Final June data for seaborne exports showed that 2.1m b/d of crude went to China, exceeding the 1.8m b/d to the EU for the first time
* Total oil shipments from Russia to the EU fell by 250k b/d m/m to 2.8m b/d in July, with crude oil exports down 130k b/d
** Total exports are 1.1m b/d lower compared with the January-February average
** Crude oil loadings dropped by almost 700k b/d, while products fell by 430k b/d
** Diesel shipments were maintained at average pre-war levels, but fuel oil, naphtha, gasoline and VGO fell
* Russia was also the biggest crude supplier to China in May and June
** 35% of Russian crude exports went to China in the two months, while 20% of total Chinese imports came from Russia
* Russian exports to India increased to a new high of 975k b/d in July
* READ: Aug. 1, Russia's Slump in Oil Exports Abates, Moscow's Revenues Go Up

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IEA Sees Russia Oil Output Down 20% When EU Ban Takes Effect (1)
2022-08-11 08:53:09.874 GMT

By Bloomberg News
(Bloomberg) -- Russia's oil output is set to fall roughly 20% by the start of next year as a European Union import ban comes into force, according to the International Energy Agency.
Gradual monthly declines will start as soon as this month as Russia cuts back refining, and will quicken as the embargo takes effect, the IEA said in a market report. The agency expects to see close to 2 million barrels a day shut in by the start of 2023, despite a healthy recovery in production in recent months.
The EU is set to halt most crude purchases from Russia from Dec. 5 in a bid to cut off revenue streams that the Kremlin uses to finance its war in Ukraine. From Feb. 5, an EU ban on Russian oil-product shipments takes effect.
Some 1 million barrels per day of Russian products and 1.3

million barrels per day of crude would have to find new homes due to the planned EU restrictions, according to the IEA estimates.

Russia's oil output has risen in the past three months, reaching almost 10.8 million barrels a day in July amid higher domestic crude-processing and robust exports as the country redirects crude flows to Asia.

As western nations and their allies have imposed several waves of energy sanctions on Russia in relation for its invasion in Ukraine, the country has been successfully redirecting its crude supplies to Asia, away from the EU, historically its single-largest energy market. The Asia-Pacific buyers not constrained by the western restrictions have been willingly snapping Russian barrels that became cheaper due to the sanctions.

READ: In the Energy Markets, Putin Is Winning the War: Javier Blas

In June, China for the first time overtook the EU to become the top market for Russia's seaborne crude, the IEA data shows. The Asian nation imported 2.1 million barrels per day compared to the EU's 1.8 million barrels per day, according to the report.

"July numbers for now are identical for the two regions, but China-bound volumes are likely to gain more as the "unknown" destination voyages are completed," it said.

READ: China Overtakes EU as Biggest Single Buyer of Russian Crude: IEA

However, Russia's crude shipments to Asia have stabilized in the recent weeks, Bloomberg data shows, raising concerns over whether the region can sharply increase the imports further, offsetting the effects of the planned EU ban on Russian imports.

Russia's oil output in the first three days of August averaged around 10.51 million barrels per day, according to data from the Energy Ministry's CDU-TEK unit seen by Bloomberg. That's a decline of some 2.5% on July, yet so far it seems driven by seasonality, not by long-term factors such as sanctions. The bulk of cut barrels came from a group of smaller oil producers, which includes gas giant Gazprom PJSC, the data shows.

Gazprom has been actively cutting its gas output amid lower exports to the European Union. Because the producer pumps not only gas from its fields but also condensate, a type of light oil, the lower pipeline flows to Europe lead to a decline in Gazprom's condensate volumes as well.

Yet as the producer raises its gas output ahead of the winter heating season, to meet higher domestic demand, its condensate output will likely rebound as well and Gazprom's effects on Russia's production may wane.

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IEA Sees Little Chance That OPEC+ Will Supply More Oil
2022-08-11 08:00:00.5 GMT

By James Herron
(Bloomberg) -- OPEC+ is unlikely to increase output in the coming months because of limited spare capacity, according to the International Energy Agency.
Furthermore, the "largely symbolic" 100,000 barrel-a-day hike promised for September may actually turn into a cut as Russian production declines, the IEA said.
"Comparatively low levels of operational spare production capacity, held mainly by Saudi Arabia and the United Arab Emirates, may thus all but rule out substantial further OPEC+ output increases in the coming months," the IEA said in its monthly report on Thursday.
The outlook from the Paris-based organization that advises major developed economies on energy policy suggests the burden of satisfying global oil demand growth in the latter part of the year will fall on countries outside the Organization of Petroleum Exporting Countries and its allies.
Non-OPEC+ supply is projected to rise by 1.7 million barrels a day this year and 1.9 million next year, according to the IEA. That's a significant acceleration compared with last year, but still falls short of 2.1 million barrels a day of demand growth expected in 2022 and 2023.

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OPEC Crude Output Rose 260k B/D in July on Saudi Increase: IEA
2022-08-11 08:00:00.6 GMT

By Amanda Jordan
(Bloomberg) -- OPEC's July crude output rose 260k b/d from a month earlier to 29.05m b/d, led by Saudi volumes, the IEA said in its monthly report.
* Saudi Arabia produced 10.83m b/d, up 250k b/d from June
* Elsewhere in the Mideast, Kuwaiti output rose 90k b/d to 2.77m b/d; UAE production gained 40k b/d to 3.28m b/d; Iraqi volumes climbed 50k b/d to 4.49m b/d; Iranian supply slipped 50k b/d to 2.52m b/d
* In Africa, Nigerian supply sank to a near 40-year monthly low of 1.08m b/d
* Output in Libya increased 50k b/d to 680k b/d after the National Oil Corp. lifted force majeure at oil fields and terminals
* Angolan production was unchanged at 1.18m b/d
* Venezuelan output slumped 100k b/d to 630k b/d, the lowest since September, due to unplanned downtime
* OPEC's compliance with the OPEC+ output-cuts deal was 359% in July
* NOTE: OPEC is due to release its own production figures for the month later on Thursday

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Diesel Is Main Driver of 0.5m B/d 2022 Demand Revision Jump: IEA
2022-08-11 08:00:00.32 GMT

By Jack Wittels
(Bloomberg) -- The IEA increased its expectation for 2022 oil product demand by just over 0.5m b/d in its August oil market report.
* Estimates changed from the July report
* All segments were revised up, apart from LPG and ethane.
* Global demand by product, all units in k b/d:

Product	2022 (July OMR)	2022 (August OMR)	Revision
LPG & Ethane	14368	14321	-47
Naphtha	6809	6831	22
Motor Gasoline	25846	25932	86
Jet Fuel & Kerosene	6095	6143	48
Gas/Diesel Oil	27849	28077	228
Residual Fuel Oil	6247	6395	148
Other Products	11967	11997	30
Total Products	99181	99695	514

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Gas-to-Oil Switch Prompts 'Exceptional' Demand in Europe: IEA
2022-08-11 08:00:00.18 GMT

By Rachel Graham
(Bloomberg) -- Europe is seeing exceptional demand for oil for use in industry, as well as for heat and power generation, the IEA said in its monthly Oil Market Report.
* Total substitution will add almost 300k b/d to oil product deliveries from now until the end of 2023 in OECD Europe
* Use of fuel oil rose in 2Q in Portugal, UK, Spain, Germany and Italy
* Demand for non-road gasoil is also forecast to rise
* Refiners are "especially well-placed" to use oil to cut consumption of natural gas, the IEA said
* The use of oil in refinery fuels increased by an average of 11% in the first five months of 2022 in OECD Europe
* Also see BNEF: Expensive Gas Could See European Refinery Oil Use Jump 40%

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West Africa Crude Prices Drop on Weaker Oil Products, Libya: IEA
2022-08-11 08:00:00.31 GMT

By Bill Lehane
(Bloomberg) -- West African crude differentials eased through early August, with spot prices dampened by waning oil product cracks and the return of Libyan crude to the market, IEA says in monthly report.
* "Differentials eroded suddenly in late-July and early-August as waning demand for gasoline and diesel narrowed their cracks and undercut refinery margins"; it also cited higher crude stocks, flatter backwardation and the recovery of Libyan production
* Nigeria's Forcados crude differentials reached almost $9.60/bbl vs Dated Brent before collapsing to around $2/bbl in early August
** READ: Exports of Nigeria Forcados Crude Suspended Due to Repair Works
* Angola's Girassol rose by $3/bbl during July, peaking at $7.70/bbl in 2H July before easing in early August

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Global Refineries to Run Most in August Since Early 2020: IEA
2022-08-11 08:00:00.26 GMT

By Rachel Graham
(Bloomberg) -- Global refinery runs are forecast to rise in August to the highest since January 2020, the IEA said in its monthly Oil Market Report.
* 3Q will see the first quarterly build in product inventories in two years
* Product stockpiles may start to draw in 4Q, partly as gas-to-oil switching contributes to robust oil demand
* Global crude throughput is forecast to rise by 2.9m b/d to 81.8m in August
* Global runs set to add 2.6m b/d to 80.7m b/d in 2022, and then increase to 82.1m b/d in 2023

* In 2023, refined product markets look “balanced overall,” helped by the ramp-up of 1.6m b/d of new refining capacity
* The IEA has raised its forecast for Russian crude throughput, as it expects product exports will not slow until the official start of the EU embargo for Russian refined product imports in February 2023

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https://www.argusmedia.com/en/news/2360965-aramco-2q-profit-at-record-on-high-oil-prices-demand

Aramco 2Q profit at record on high oil prices, demand

Published date: 14 August 2022

Saudi state-controlled Aramco's second-quarter profit exceeded that of the three largest-earning oil majors combined, pushed higher by increases in oil prices, sales volumes and refining margins.

Aramco said today it broke its quarterly profit record posted in May, with a 90pc year-on-year jump to $48.4bn in the second quarter, more than it made in the first six months of 2021.

Comparatively, ExxonMobil, Shell and Chevron recorded a collective profit of $47.61bn in the second quarter, according to *Argus* calculations.

Aramco's free cash flow rose by 53pc on the year to $34.6bn in the second quarter, with the company citing increases in cash from operating activities. It left its dividend guidance unchanged at $18.8bn, to be paid in the third quarter. Almost all of this goes to the Saudi state.

"We all know the energy market has been characterised by volatility and instability during the first half of this year," Aramco chief executive Amin Nasser told reporters, attributing the record second-quarter results to higher demand for the company's products. The company forecast oil demand will continue to grow for the remainder of the decade, "despite downward economic pressures on short-term global forecasts." Nasser assessed current global oil demand as "healthy," based on customer nominations "especially from Asia."

But he flagged supply-side constraints.

"Ongoing investment in our industry is essential — both to help ensure markets remain well supplied and to facilitate an orderly energy transition," he said, describing "strained" global spare capacity of less than 2mn b/d and "declining fast." Saudi and Opec+ officials have faced consumer pressure to increase output this year. The producers' alliance will this month unwind the roughly 9.7mn b/d of cuts it implemented in May 2020 in response to the Covid-19 pandemic, and will add a further 100,000 b/d of output in September.

"Our commitment is, any time we have been asked [by the Saudi government]… to go to our maximum sustained capacity, which is currently 12mn b/d, we'll be able to bring this on the stream quickly and sustainably," Nasser said. Aramco said it produced 13.6mn b/d of oil equivalent (boe/d) in the second quarter, up from 13mn boe/d in the January-March period. It did not break out crude output, which *Argus* estimates at 10.46mn b/d in the second quarter and 10.14mn b/d in the first.

Nasser said Aramco is "progressing very well" with plans to raise capacity from 12mn b/d to 13mn b/d by 2027. "In 2025, we should go to 12.3mn b/d, in 2026 we should go to 12.7[mn b/d]," he said. He expects a 75,000 b/d increase from the Dammam field, a 300,000 b/d addition from Marjan, 250,000 b/d from Berri and 600,000 b/d from Zuluf. Beyond 2027, Nasser said there should be a 700,000 b/d hike from the Safaniyah field.

Aramco's gearing ratio narrowed to 7.9pc in June, from 14.2pc at the end of December last year. The company's capital expenditure (capex) was $9.4bn in the second quarter, up by 25pc from a year earlier. It retained guidance of $40bn-50bn for 2022, and continues to expect rises until the middle of the decade.

"There will be an increase year-on-year to meet our growth… in oil, in gas, in hydrogen, in crude to chemical… until 2025, and then we will hope it will stabilise later," Nasser said.

He did not confirm plans for a partial listing of its trading arm, but said there is "some expectation that we will do some of that [floating] with some entities within Aramco."

By Ruxandra Iordache

https://www.arabnews.com/node/2128761

Secret or reality: can Aramco produce 15 million barrels a day?

WAEL MAHDI

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I guess by now we all know that Saudi Arabia will not raise its production capacity beyond 13 million barrels a day by 2027 after the Kingdom's Crown Prince Mohammed bin Salman made it clear in his address during the regional summit this month that was attended by US President Joe Biden.

“The Kingdom will contribute to this field to increase its production capacity to 13 million barrels per day, and after that the Kingdom will not have any additional ability to increase production,” the Crown Prince said.

To many who are still under the influence of what Matt Simmons wrote 17 years ago in his book "Twilight in the Desert", the Saudi statement was a testament to the argument laid in the book that Saudi Arabia can't rescue the world anymore as its oil fields are aging and reaching a peak.

Those who remember the days of peak oil theory will definitely remember the many statements put out by officials from the ministry of petroleum and Aramco. Communication and PR practices back then weren't as elaborate and sophisticated as today because at that time Aramco wasn't listed yet on the Saudi stock exchange and the petroleum ministry was running the show.

The result was many statements that sounded contradictory or unrealistic when everyone was trying to defend their position against Matt Simmons' theories.

Those statements maybe were needed at that time to maintain confidence in Aramco but it surely didn't serve it well two decades later.

Aramco's officials thought that the market has very short memories that won't last this long, but they tend to forget that there are observers who have an agenda against the company because Aramco treated them with negligence or denial — the most common practice for Aramco officials when someone from outside the company has any say about it.

Those who remember that period would certainly recall Aramco's statements about being able to pump 12 or even 15 million barrels a day for decades.

So in retaliation, some observers now are trying to show how Aramco was contradictory about its production capacity in the light of the Crown Prince's recent statement.

In fact, the issue is more complicated than this.

Yes there were some contradictions because Aramco's officials were always speaking in fear in public.

They always feared that something they said would upset someone in the ministry in Riyadh so the focus was on keeping Riyadh happy but not explaining it right to the media what the company is capable of producing.

Thank God things have improved significantly today as the listing of Aramco on the Saudi stock market has served us all well.

Everything is public after being documented, audited, and scrutinized. We have better sourcing and understanding of the numbers of the company now than ever.

This, however, didn't solve all the problems because officials in the past left many ends untied. Former minister of petroleum Ali Al-Naimi, for example, explained many technical terms with reporters who didn't have any knowledge about petroleum engineering practices or who simply weren't interested in more than a simple statement they needed to send back to their editors.

Other officials from Aramco were even very aggressive in their response to the media on the output capacity issue. The result we all know: more confusion and less trust in the statements.

The issue of Aramco's ability to produce massive amounts of oil was at the center of any media discussion with Al-Naimi for years. Yet, there were periods when the issue was more pressing, especially during supply crises and skyrocketing oil prices.

In 2008, when oil prices were already on their way to $147, the world was looking for solutions and an energy meeting in Jeddah was held where tens of energy and oil ministers from around the world met to discuss the root cause of the crisis and where to go next.

As consuming countries like the US were accusing OPEC of being responsible for the crisis due to its inability to increase capacity, the producers were claiming that speculation and paper market trading practices are behind the price hikes.

As a response and to assure the market and consumers that there was never a supply crisis, Saudi Arabia told the ministers in Jeddah that it's already on its way to complete its program to increase maximum sustainable capacity to 12.5 million barrels a day by end of 2009, and it pledged to raise it further to 15 million if the world needed it.

For Saudi output capacity to hit 15 million barrels, the further daily capacity includes 900,000 barrels from the Zuluf field, 700,000 barrels from Safaniyah, 300,000 barrels from Berri, 300,000 barrels from Khurais and 250,000 barrels from Shaybah, as explained by minister Naimi at the time.

When Saudi officials were asked in later years about the 15 million barrels a day figure, they responded by saying that this was a scenario and never was a solid program.

I think the world now can say goodbye to the 15-million-barrels-a-day scenario. Many of these increments have already been developed to maintain Aramco's 12 million MSC. Khurais 300,000 and 250,000 are history now. As for Berri's increment, it is coming online over the next two years.

Now we will rely on Zuluf and Safaniyah to hit the 13 million barrels a day target and to compensate for the declines in older fields such as Abqaiq and Ghawar.

But is it really "that's it" for Saudi Arabia?

The confusion about Saudi production capacity always starts when answering this question. It's confusing for people inside Aramco, let alone people outside of it.

The simple answer is NO, but let's clear few misunderstandings about the issue first.

First of all, Saudi Aramco as a company has 12 million barrels a day as a maximum sustainable production capacity. This means Saudi oil reservoirs can only go up to this level without being damaged.

It can produce 12 million barrels and keep this level for a long period but this won't happen without massive investment in managing and maintaining the wells and without an aggressive drilling program.

The more an oil company produces from a well, the faster output declines. So oil companies keep drilling new wells all the time to first replace the oil produced, and second to keep the production rate steady from the field.

However, Saudi Aramco doesn't produce at this maximum production capacity as per policy. The Kingdom took on its shoulders the responsibility of keeping between 1 and 2 million barrels a day of oil as spare capacity. By industry definition, this is the amount of oil it can produce within 30 days and sustain for 90 days.

So in order for Aramco to increase production from 10 million barrels a day — its current comfortable level that forms the high end of the comfort zone for the company — to 11 or 12 million barrels a day and dive into its spare capacity, it needs more drilling and one month at the minimum. It's not a switch it can hit and output will go up by a million or two barrels.

Second of all, there is a big difference between maximum sustainable capacity or MSC and potential production. Whereas MSC is the amount of oil the reservoirs will allow Aramco to produce for a long period, potential production is what the company's surface facilities can process at any given day.

The shocking number for many of those who don't know the reality of Saudi oil production, is that the surface facilities of Aramco can allow it to produce up to 15 million barrels a day.

Yes, you heard it right, 15 million barrels as of today.

Then, how come Aramco only said it can pump 12 million barrels a day?!!

Aramco's daily production is constrained by many factors. First, it can't produce whatever it likes. It gets its output targets from the minister of energy based on the agreement the Kingdom has under OPEC and OPEC+.

Second, the government policy mandates Aramco to always keep 1 to 2 million barrels a day at any given time as a spare capacity that is to be used during any energy crisis. This spare capacity is a buffer for the global oil market and the unique proposition for Aramco and the Kingdom as there is no other producer in the world who has this much oil idled.

This idle capacity isn't free. It comes at a cost. There is an economic cost of not selling that oil, and there is a financial cost in the form of capex and opex to keep these wells and the surface facilities ready to pump this crude at any time.

The next question is, did Aramco ever produce 12 or 15 million barrels a day in its history? Are these numbers real or just on paper?

Let's look into history.

A decade ago, Al-Naimi told a limited number of journalists in one of the briefings that Aramco did process 14 million barrels a day in one single day and it loaded that much crude on ships on that day. Now, supplying 14 million barrels a day is totally different from producing that quantity from below the ground on that single day. What Al-Naimi was trying to sell to reporters was that Aramco can put that much crude out because its surface facilities can handle that much.

He also went on to say that the company actually hit near 12 million historically but that was in a "flush production" and he said "you guys don't need to worry about this." Flush production is the amount of high oil flow rate that comes out from new wells. As Society of Petroleum Engineers explains on its website, it "delivers a small, high rate flow every time the well is shut-in (recharges) and is brought back on line".

Al-Naimi didn't give much details about the timing for all this or any further information.
Moving on to recent times, in April 2020, Aramco finally showed the world it has 12 million barrels a day and it did pump at that level but not for too long. It was just a matter of days.
Aramco did produce at 11 million barrels a day, though, for weeks.

This year it will need to revisit this number when its OPEC+ agreement comes to an end in September.

I don't doubt the ability of Aramco to produce at 11 or 12 million barrels a day because I didn't get my information from the officials who smile at the media but from those who were against seeing the company producing at that level.

Aramco can do it but it will require more work for petroleum engineers who don't want to walk the extra mile and it will need massive investments and above all more reservoir management.

The internal pushback isn't new and as former Aramco's executive Sadad Al-Husseini pointed out in his account of the launch of Aramco's MSC program, engineers were against seeing Aramco producing more than 9 million in the late 1970s. Things haven't changed today.

Othman Al-Khowaiter, another Aramco veteran, is among those who made it publicly that he doesn't want to see Aramco pumping at more than 10 million barrels a day and sometimes stressed on the need to keep output at lower levels.

The decision, at the end, rests with the government. There are international commitments for Saudi Arabia and there are state financial needs that have to be covered. There is also a monetization strategy for oil resources that the government is implementing to ensure that the oil wealth is turned into cash income.

In the end, no matter what Aramco said or tried to prove when it comes to MSC, its words will fall on deaf ears as the jury is out and there has been an agenda against Aramco for years.

I can't blame the media entirely because the responsibility also falls on the shoulders of Aramco's and other officials who unfortunately confused the public or were unable to tell the truth in the best possible way.

They had no trust in the media and the media had no trust in them.

Setting the issue of trust aside, we need to know if Aramco can produce more oil. The world needs to know this.

I can't speak for the company but I can share all what I've learned about this issue throughout the years.

I can comfortably register my testimony on this knowing that my words will be remembered years from now.

Aramco can hit 13 million barrels a day and Saudi Arabia as a whole can hit 13 million barrels a day or even more.

First, there are tens of fields that are still not developed. There are more than 100 discovered fields but the majority if not all of production is coming from less than 25 of them.

Yes all these undeveloped fields are giant but when combined can add something between 500,000 and 1 million barrels a day extra. However, the economics for bringing them online is still not there, not until the big fields are on decline.

Second, observers tend to forget that Saudi Arabia shares massive resources in the partitioned zone with Kuwait. Khafji network of offshore fields can produce up to 300,000 barrels a day, while onshore fields in Wafra are able to add 200,000 barrels a day.

Saudi Arabia was trying for years through Chevron to implement a steam flooding program that can unlock at least 5 billion barrels extra of heavy oil from Wafra. The steam injection project was undergoing until the two countries halted production from the entire zone between 2014 and 2015. With operations resuming normally in the zone, the prospect for seeing more oil from Wafra and Khafji is high.

Third, Aramco can supply the world with more oil not only by pumping more but freeing more oil for exports. Let's be reminded that Saudi Arabia is embarking on a program to replace liquids in all power plants with natural gas. In addition, the energy mix in Saudi Arabia by 2030 should be split between gas and renewables, which can free an additional 1 million barrels a day of oil at least.

Fourth, Saudi Arabia is turning to unconventional gas in its massive Jafurah field to power its future and that will free more oil.

Fifth, technology, technology, technology. No one can predict the impact of technological breakthroughs on oil production. The life of Aramco's reservoirs was extended thanks to horizontal drilling practices that the company followed in the 1990s. It's now investing big on research and development in an effort to find better ways to extend the lives of its fields. From small robots that can go into the reservoirs to better water and carbon injection methods, Aramco is not standing still.
It even has one of the largest supercomputers in the world at its EXPEC ARC center to simulate reservoirs.

So in conclusion, the world can still expect to see more oil from Saudi Arabia above the nameplate capacity.

The question that the world needs to answer is whether there is enough demand in the future for Saudi Arabia to make big investments in its oil production?

What the world must know is that producing an extra barrel of oil comes at huge cost. Why would the government allocate billions of dollars a year to invest in new capacity at a time when it needs every dollar to move its economy away from oil?

If the world wants Saudi Arabia to carry the responsibility of opening its oil taps endlessly, it must secure demand for oil.

What we are seeing, nevertheless, is the opposite. Therefore, I think the Crown Prince's statement seems to be fair and the world should live with 13 million barrels a day instead of complaining about it.

• *Wael Mahdi is a senior business editor at Arab News and co- author of "OPEC in a Shale Oil World: Where to Next?"* **twitter: @waelmahdi**

US said Russia oil refined in India is making it to US cos: RBI deputy governor
2022-08-14 01:09:58.50 GMT

(Times of India)--MUMBAI: US government has shared with Indian authorities how sanctioned Russian oil processed in India is making it to US manufacturers. This was revealed by a senior Reserve Bank of India official on Saturday.

RBI deputy governor Michael Patra in an event to mark 75 years of Indian independence, spoke about how India is resilient to the war. In his speech, Patra said that discounted oil purchased from Russia is being used to build up strategic reserves and India is now better off than most countries.

In his speech, Patra said that the US treasury department has informed the Indian authorities of Russian oil being processed into inputs for plastic manufacture in India and exported to the US. He narrated this incident as an example of how 'topsy turvy' the world has become in the wake of the Russian-Ukraine war and how the 'war works in strange ways'.

"You know that there are sanctions against people who are buying Russian oil. It turns out that an Indian ship met a Russian tanker mid-sea, picked up oil, came to a port in Gujarat, it was processed in that port and converted into a distillate that is used in the manufacture of single-use plastic," said Patra. The twist in the story was how the refined output ended up in the United States despite US sanctions barring import of Russian-origin energy products into the country.

"The refined output was put back on the ship, and it set sail without a destination; in the midseas, it received a destination, so it recharted its course and went to New York and handed its stuff," said Patra. Patra said that even when it comes to food grains while many countries are facing shortages, India has buffer stock.

The deputy governor said that RBI has projected high growth for the first half.

-0- Aug/14/2022 01:09 GMT

To view this story in Bloomberg click here:
https://blinks.bloomberg.com/news/stories/RGKZ8MCEX0QO

SAF Group created transcript of RBC's Helima Croft comments with CNBC's Melissa Lee and Risk Reversal's Guy Adami on CNBC Aug 11, 2022. https://www.cnbc.com/video/2022/08/11/russia-will-continue-to-turn-off-the-gas-for-europe-rbcs-helima-croft.html?&qsearchterm=croft

Items in "italics" are SAF Group created transcript

Croft "*I think we have to be very, very concerned about what happens, everything in the last month of this year because that's when these European sanctions on Russian oil are set to kick in. which would not only mean that you will have two million barrels a day of Russian oil that can't go into Europe. But if these shipping and insurance sanctions actually take effect as well. It's going to be very hard to move those barrels to Asia as well. So you could be talking about a multi-million barrel Russian disruption come December 5. The US government is working with the Europeans on this potential price cap solution that would potentially allow those barrels to move to refiners like Reliance if they certify that they're discounted barrels. But it's not clear they can get this mechanism up and running by December. So I think a lot of market participants are saying, well Russian production has actually remained quite elevated, India and China is taking the product, the worst is behind us. But I would say we have not yet seen really significant Russian sanctions on energy. Those are coming in December*."

Croft "*But we have not seen any signs of wholesale demand destruction. Yes, China is soft, but we have not seen a significant fall off. For example, in gasoline demand here. So the question is do you have enough supply. Again, as I look out at the back half, the last quarter of this year, we're going to have this SPR release, a million barrel a day SPR release, that winds down in October. These Russian energy sanctions, they hit in December. OPEC does not have additional barrels to put on the market to plug this type of gap. So I do think we should be particularly focused on what happens with these sanctions when the US SPR release winds down*".

Croft "*Melissa, that is the top question, will Europe have the stomach to see these sanctions through. The Russians have every intention to make this as painful for Europe as possible. So what do they do, they turn off the gas. Gas is not the revenue earner for Russia that oil is. Gas is the Weapon of Choice. There is no easy replacement product for Russian piped natural gas into Europe. That's why they're not sanctioning natural gas. But that's what the Russians are doing. They're cutting gas flows off into Europe, forcing Europeans to have to think about heating and eating, who suffers in terms of industrial curtailment because it's going to be a really difficult supply situation in Europe, especially if it's a cold winter. That's what the Russians are saying – How much do you want to support Ukraine, Europe? Are you willing to risk massive economic dislocation to do so?"*

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

Oil price outlook – Snapshot: August 9, 2022

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

Category	Indicator	Signal	Comment
Fundamentals	**Refinery margins**	↔	• Refinery margins weakened in the US but were relatively stable in Northwest Europe and Singapore over the past week.
	Crude stocks	↓	• In the week ending July 29, land crude-oil storage levels in BloombergNEF's tracked regions (the US, ARA and Japan) rose by 0.5% to 542.9 million barrels (m bbl). The stockpile **deficit** against the five-year average (2015-19) **narrowed from 56.8m bbl to 53.9m bbl**. • Including global floating crude stockpiles from the same week, total crude oil inventories increased by 1.8% to 638.0m bbl, with the stockpile **deficit narrowing from 22.2m bbl to 7.8m bbl.**
	Product stocks	↔	• In the week ending July 29, gasoline and light distillate stockpiles in BNEF's tracked regions (the US, ARA, Singapore, Japan and Fujairah) grew by 0.4% week-on-week to 271.0m bbl, with the stockpile level against the three-year average (2017-19) **flipping from a surplus of 1.9m bbl to a deficit of 0.7m bbl**. Gasoil and middle distillate stockpiles in BNEF's tracked regions were down 0.8% to 140.8m bbl, with the stockpile **deficit** against the three-year average **widening from 38.7m bbl to 39.6m bbl**. • Oil product stockpiles in tracked regions grew by 0.3% to 945.7m bbl, with the stockpile **deficit** against the three-year seasonal average **widening from 56.6m bbl to 57.3m bbl**. Altogether, crude and product stockpiles rose by 0.9% to 1,583.7m bbl, with the stockpile **deficit narrowing from 78.8m bbl to 65.2m bbl.**
	Demand indicators	↔	• In the week to August 9, global jet fuel demand from commercial passenger flights was virtually flat at 5.76 million barrels per day. Jet fuel consumption by international passenger flight departures was down by 3,400 barrels per day (or -0.1%) week-on-week, while consumption by domestic passenger flight departures increased by 4,800 barrels per day (or +0.2%). In the week to August 7, flight departures in the Eurocontrol area grew to 88.5% of the equivalent week in 2019, up from 87.8% last week. The four-week moving average inched higher to 87.7%, from 87.4%. Meanwhile, in the same week, US passenger throughput rose to 89.1% of the equivalent week in 2019, up from 88.9% last week. The four-week moving increased to 88.4%, from 87.6%. • The global mobility index rose over the past week, according to BNEF's calculation based on Google mobility data. It climbed by 1.7% in the week to August 4, driven by growth in the Americas (+1.8%), Asia Pacific ex-China (+1.4%) and Europe (+0.6%). Meanwhile, in the week to August 3, TomTom's peak congestion data showed growth in Asia Pacific ex-China (+1.6%) and North America (+1.0%), but this was met with a strong decline in Europe (-6.9%). Road congestion in China's key 15 cities was down by 1.5 percentage points to 100.5% of January 2021 levels in the week to August 3, according to BNEF's calculation based on Baidu data. • In the week to August 2, global daily average Covid-19 cases fell by 4% to 990,000 new cases. The Asia Pacific number grew by 10% to 412,000 daily cases (with the number in China more recently falling by 13% to 535 cases in the week to August 7), Europe dropped by 7% to 319,000 daily cases, and the Americas was down 12% to 224,000 daily cases.
Financial	**Macro indicators**	↔	• The dollar index averaged 106.1 over the past week and was 0.4% lower than the week before.
	Hedge fund positioning	↓	• In the week to July 26, Managed Money net positioning in the oil complex was down by 16.7m bbl (or -3.4%) week-on-week to 472.4m bbl, and fell to the 12th percentile (versus the 13th percentile last week) of the past five years.
	Options chains and volatility	↓	• Open interest for WTI Sep-to-Nov-22 calls and Dec-22 puts saw an increase, while WTI Sep-to-Nov-22 puts and Dec-22 calls saw a decrease. Open interest for Brent Oct-to-Dec-22 puts saw notable growth. Brent and WTI 1M volatility skews fells over the past week.
Outlook	**Weekly call**	↔	• Due to ongoing developments around the suspension of oil flows via the Southern leg of the Druzhba pipeline to Eastern Europe, BNEF is neutral on oil prices for the week ahead, with Brent Oct-22 trading at $97.60/bbl and WTI Sep-22 trading at $91.50/bbl at the time of writing. • The global mobility index inched slightly higher over the past week, as year-on-year growth bounced back slightly due to Asia Pacific rising from a significantly lower base last year. However, year-on-year road traffic growth in Europe and the Americas is still hovering at the lowest levels since March 2021. Weekly road congestion levels in China fell again, hanging around levels last seen in May during the Covid-19 restrictions. Global jet fuel demand was flat week-on-week, although air traffic in Europe and passenger throughput in the US improved slightly against their 2019 levels. • Weekly crude inventories saw a bearish move over the past week, driven by a jump in floating crude stockpiles. While the crude and oil product stockpile deficits have eased over the past several weeks, the product inventory deficit has remained sizable, primarily due to middle distillates. The middle distillate market is likely to remain tight through the winter season as elevated natural gas prices constrict hydrocracking runs, while jet fuel and industrial demand remain resilient. • OPEC+ eased its output quota for September by a mere 100,000 barrels a day (b/d). The two members with substantial effective spare capacity – Saudi Arabia and the United Arab Emirates – make up 33,000 b/d of the output hike. This week's implied motor gasoline demand data from the US Energy Information Administration (EIA) will be particularly important as the market assesses whether four-week average motor gasoline demand will remain below 2020 seasonal levels.

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
August 9	↔	↓	↔	↔	↓	↓	↔	Brent-Oct: 97.60 WTI-Sep: 91.50	
August 2	↔	↑	↔	↔	↔	↔	↓	Brent-Oct: 99.38 WTI-Sep: 93.42	
July 26	↔	↓	↔	↓	↑	↔	↔	Brent-Oct: 101.94 WTI-Sep: 98.46	
July 19	↔	↓	↓	↓	↔	↔	↓	Brent-Sep: 105.88 WTI-Sep: 99.03	
July 11	↓	↓	↑	↓	↓	↓	↓	Brent-Sep: 105.18 WTI-Aug: 102.34	
July 5	↓	↑	↓	↑	↓	↓	↔	Brent-Sep: 111.71 WTI-Aug: 107.91	
June 21	↑	↓	↑	↑	↓	↓	↔	Brent-Aug: 115.81 WTI-Aug: 110.34	
June 13	↔	↑	↔	↔	↑	↔	↔	Brent-Aug: 120.06 WTI-Jul: 118.58	
June 6	↔	↑	↑	↔	↑	↔	↔	Brent-Aug: 119.88 WTI-Jul: 118.94	
May 30	↔	↑	↓	↔	↔	↔	↔	Brent-Aug: 116.46 WTI-Jul: 115.81	
May 23	↑	↑	↑	↔	↑	↑	↑	Brent-Aug: 110.88 WTI-Jul: 111.11	
May 16	↓	↓	↔	↑	↓	↓	↔	Brent-Jul: 112.22 WTI-Jul: 109.69	
May 9	↔	↓	↔	↑	↓	↔	↑	Brent-Jul: 109.93 WTI-Jun: 107.22	
May 2	↑	↔	↑	↑	↔	↔	↑	Brent-Jul: 103.87 WTI-Jun: 101.25	

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

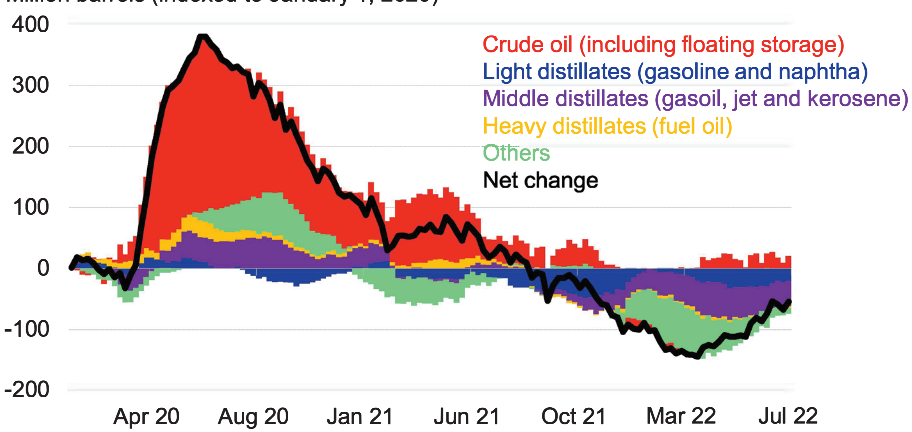
Fundamentals Financial

Weekly oil inventories

Oil product stockpile growth slowed over the past week

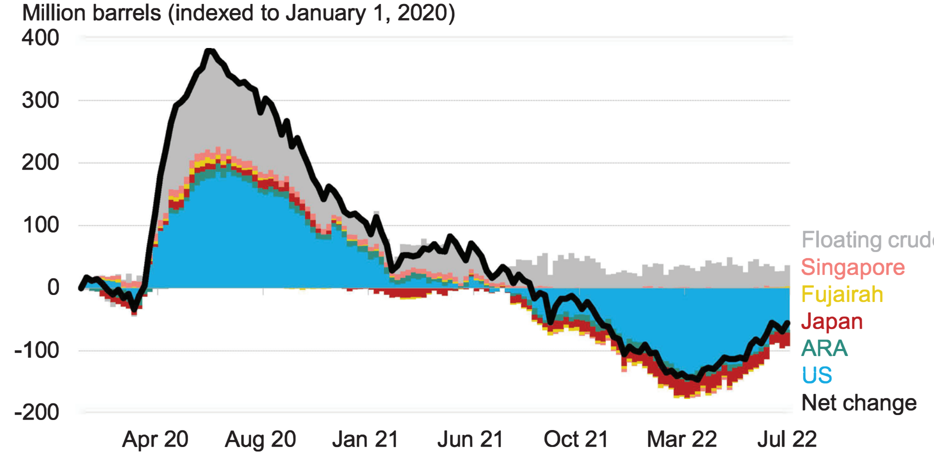
Weekly oil inventories by type

Million barrels (indexed to January 1, 2020)



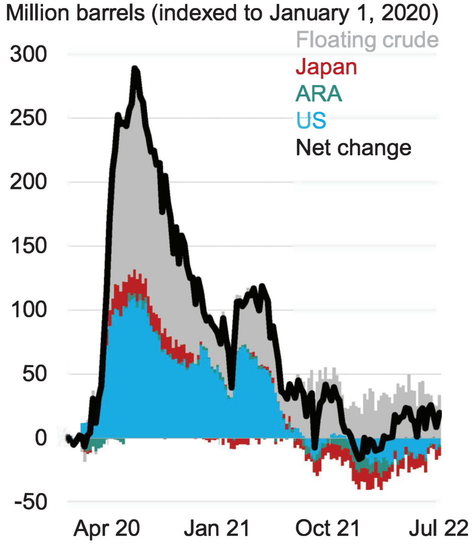
Weekly oil inventories by region

Million barrels (indexed to January 1, 2020)



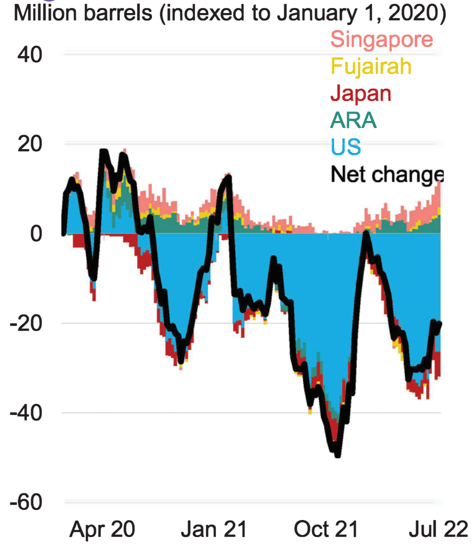
Crude inventories

Million barrels (indexed to January 1, 2020)



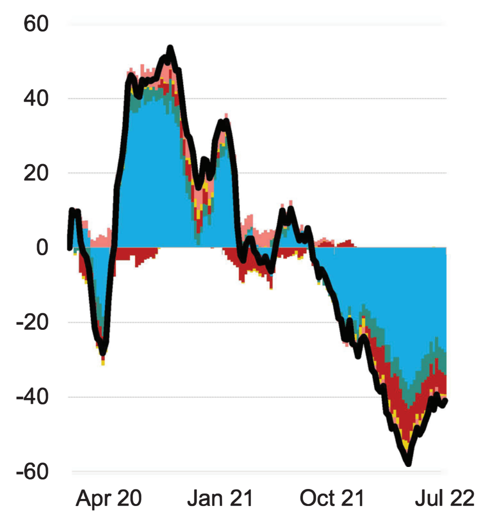
Light distillate inventories

Million barrels (indexed to January 1, 2020)



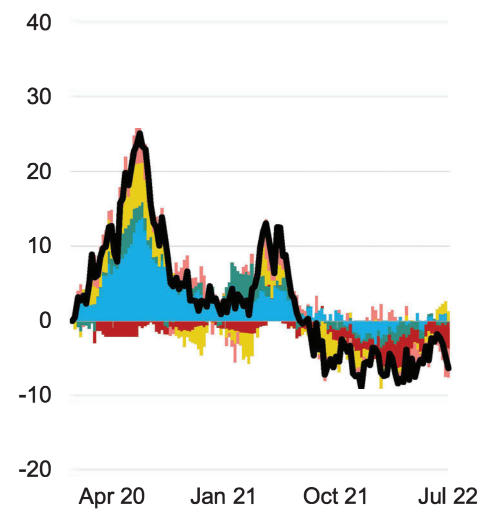
Middle distillate inventories

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 **July 29, 2022**.*

Fundamentals | Financial

Aggregated oil stockpiles

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

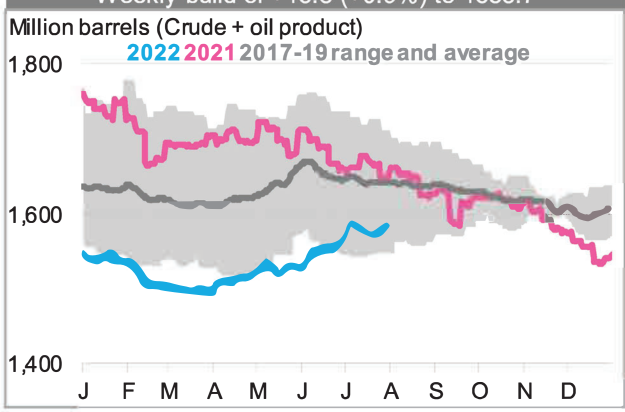
Bearish: Stockpiles deficit narrowed from 78.8m bbl to 65.2m bbl

- 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

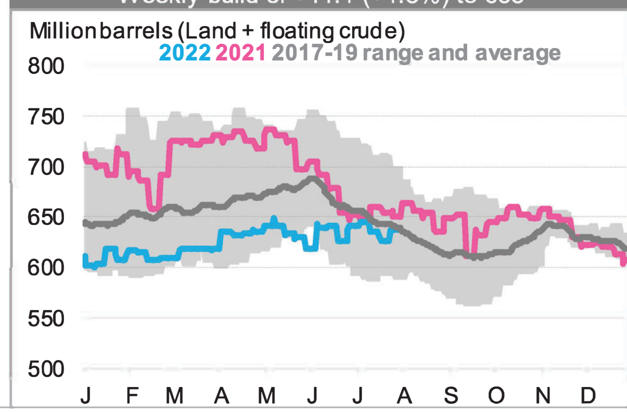
Total oil and product stocks

Weekly build of +13.8 (+0.9%) to 1583.7



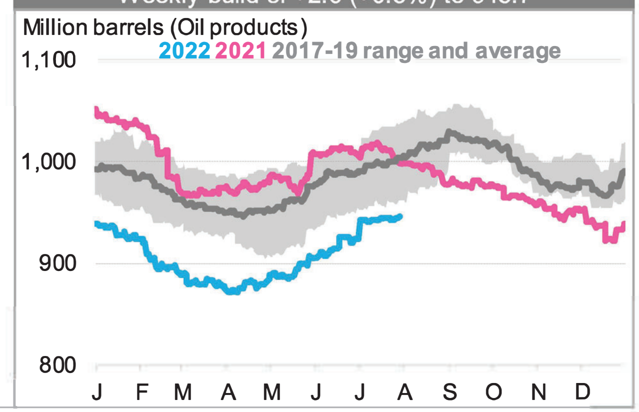
Total crude stocks (land + floating)

Weekly build of +11.1 (+1.8%) to 638



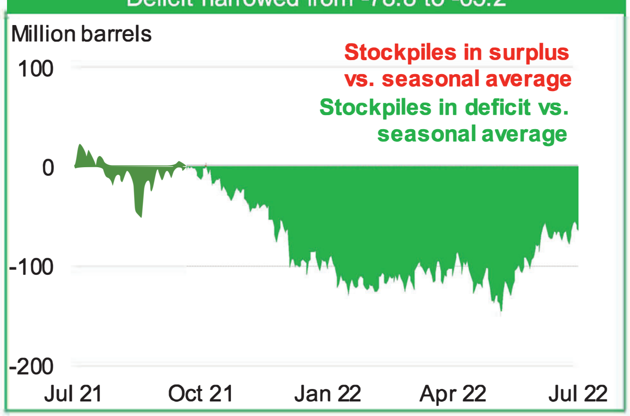
Total oil product stockpiles

Weekly build of +2.6 (+0.3%) to 945.7

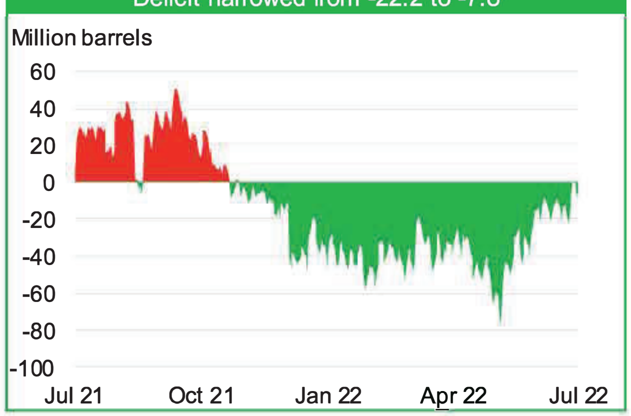


Charts below subtract current stockpiles by the 2017-19 (three-year) seasonal average

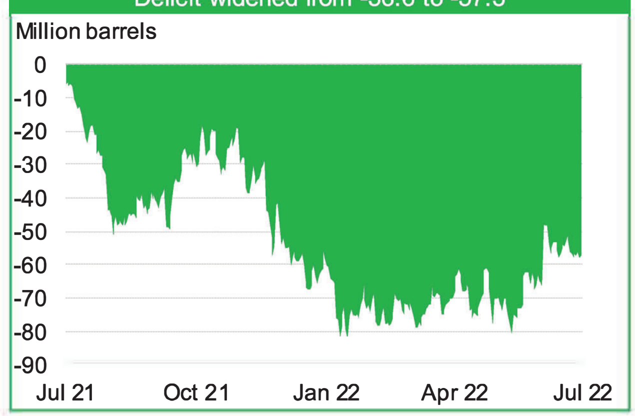
Deficit narrowed from -78.8 to -65.2



Deficit narrowed from -22.2 to -7.8



Deficit widened from -56.6 to -57.3



*Source: BloombergNEF, US EIA, PJK, IE Singapore, FEDCom/Platts, PAJ ,Vortexa, Genscape. Note: As of the **week ending July 29, 2022.***

Crude stocks: Land

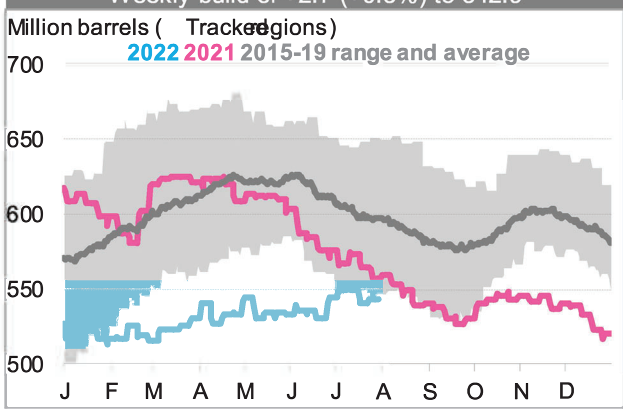
Note: We will continue to compare current inventory levels with the three-year (2017-19) seasonal average for the time being. Crude inventory data for Shandong teapots have been excluded since January 10.

Bearish: Deficit narrowed from 56.8m bbl to 53.9m bbl against the seasonal average

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

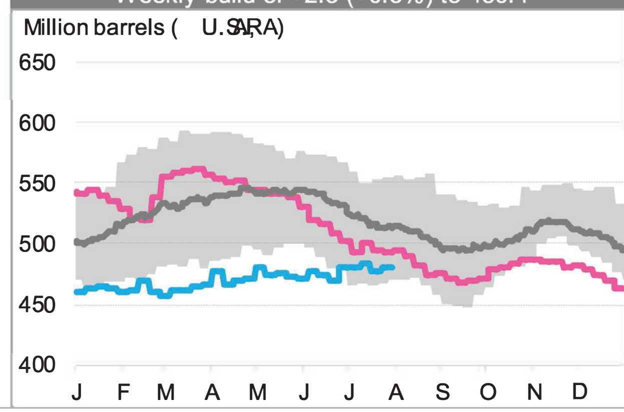
Land storage: Total

Weekly build of +2.7 (+0.5%) to 542.9



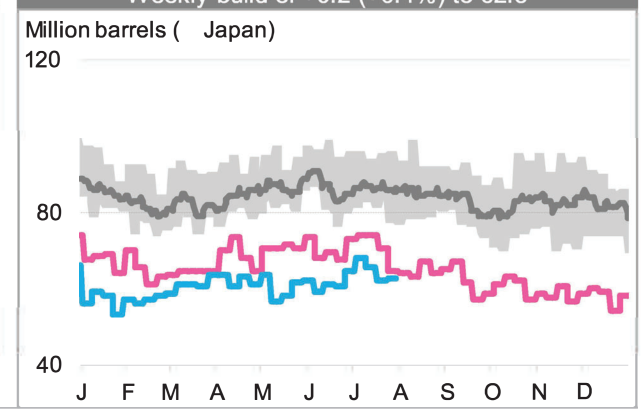
Land storage: West of Suez

Weekly build of +2.5 (+0.5%) to 480.4



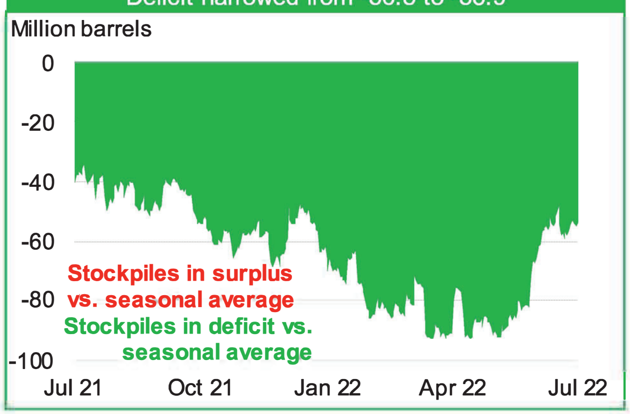
Land storage: East of Suez

Weekly build of +0.2 (+0.4%) to 62.5

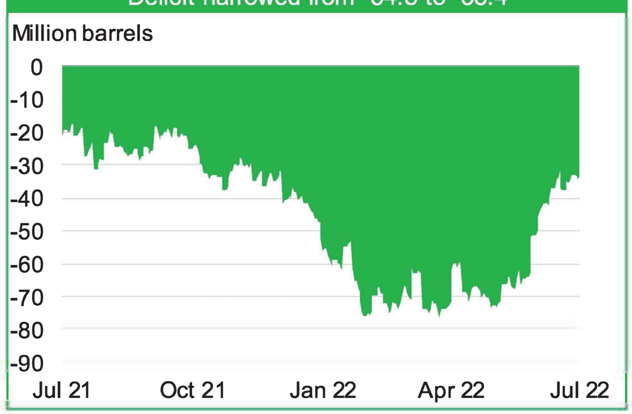


Charts below subtract current stockpiles by the 2015-19 (five-year) seasonal average

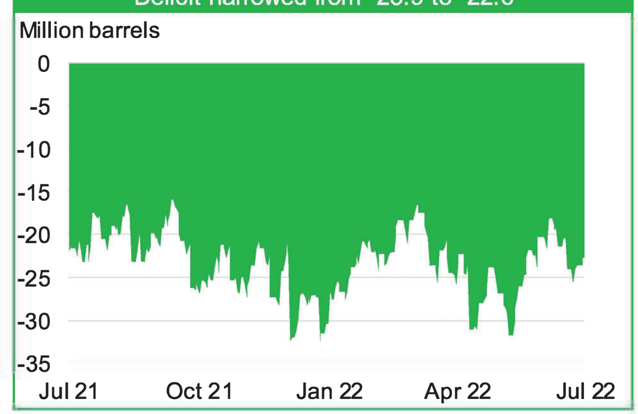
Deficit narrowed from -56.8 to -53.9



Deficit narrowed from -34.8 to -33.4



Deficit narrowed from -23.9 to -22.6



*Source: BloombergNEF, US EIA, Genscape, PAJ. Note: As of the **week ending July 29, 2022.***

Fundamentals | Financial

Crude stocks: Floating

Bearish: Surplus widened over the past week

- 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). That data are available in the table to the right.

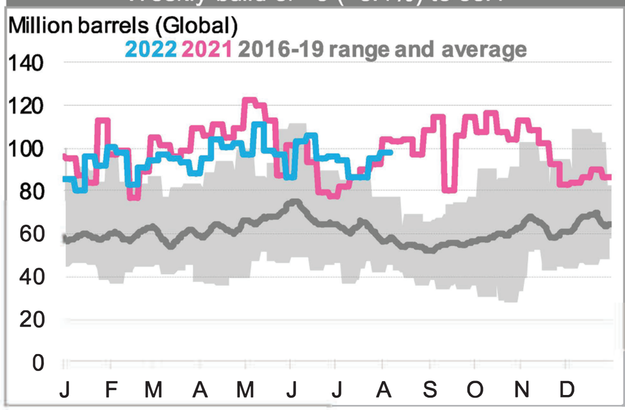
Vortexa's revision to global floating crude inventories

Million barrels	Previous report	Current report	Vortexa's revision
Inventories in week of July 29	90.5	**95.1***	+4.6
Inventories in week of July 22	86.8	**86.7***	-0.1

*Note: *Figure used to aggregate total oil inventories on page 8.*

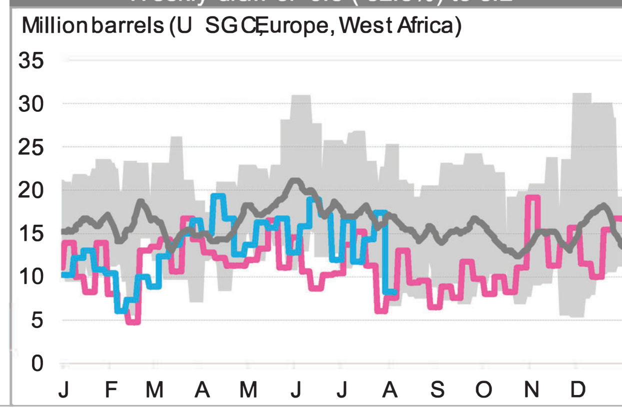
Floating storage: Total

Weekly build of +3 (+3.1%) to 98.1



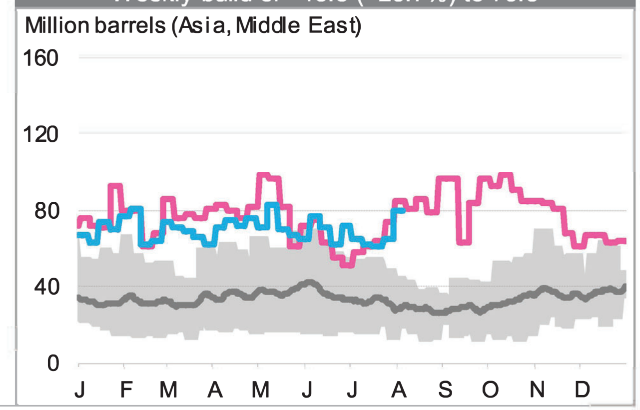
Floating storage: West of Suez

Weekly draw of -9.3 (-52.8%) to 8.2



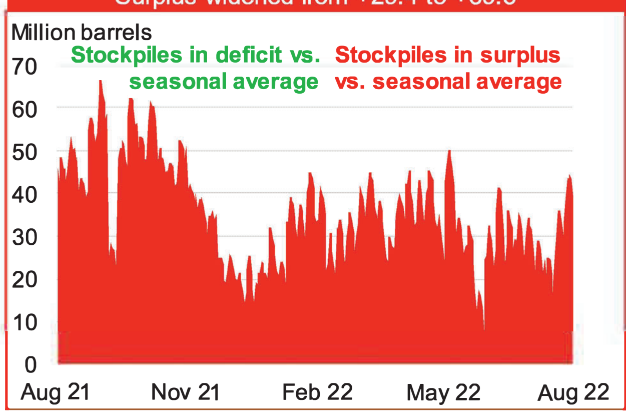
Floating storage: East of Suez

Weekly build of +15.3 (+23.7%) to 79.8

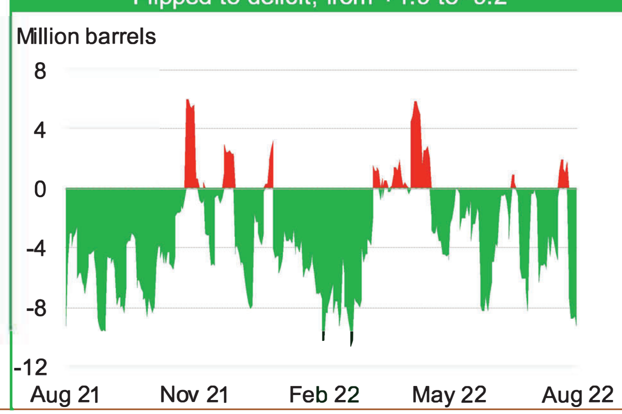


Charts below subtract current stockpiles by the 2016-19 (four-year) seasonal average

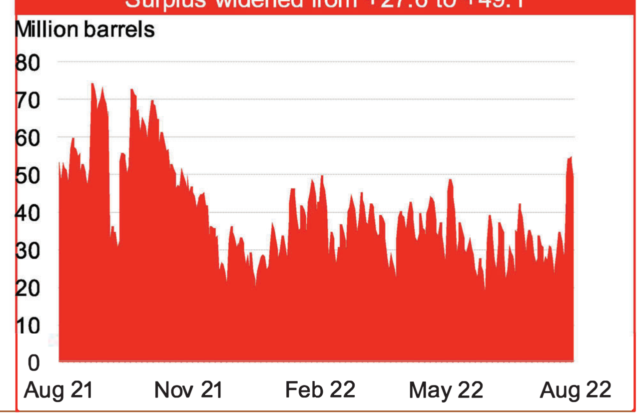
Surplus widened from +29.4 to +39.3



Flipped to deficit, from +1.9 to -9.2



Surplus widened from +27.6 to +49.1



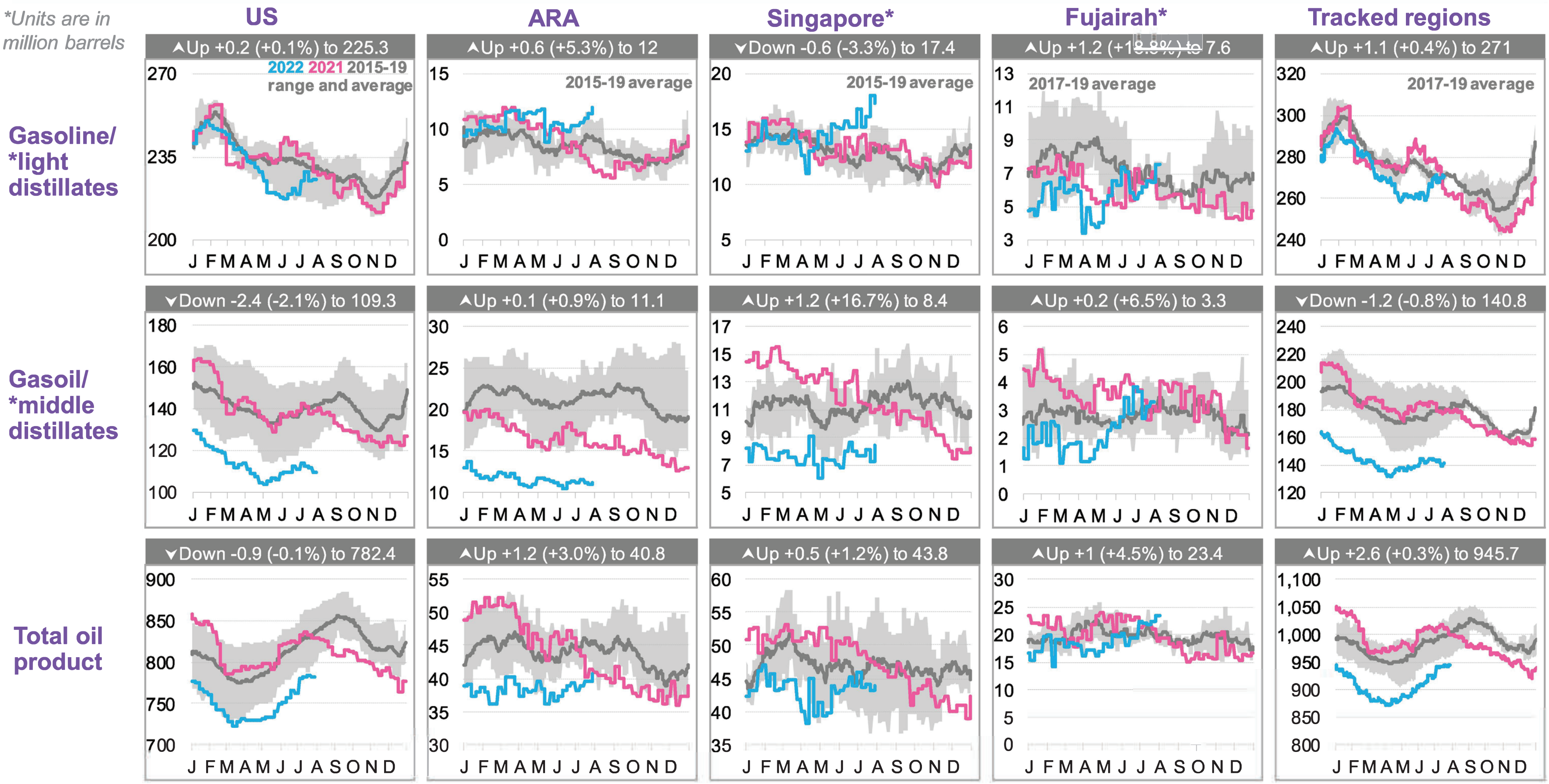
*Source: BloombergNEF, Vortexa. Note: As of the **week ending August 5, 2022**. ***Raw data from Vortexa are revised frequently, so the data in this report might change week-to-week.***

Fundamentals Financial

Product stocks: Current versus seasonal average

Neutral: Oil product stockpiles in tracked regions grew by 0.3% over the past week, while middle distillate stockpiles fell by 0.8%

- 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

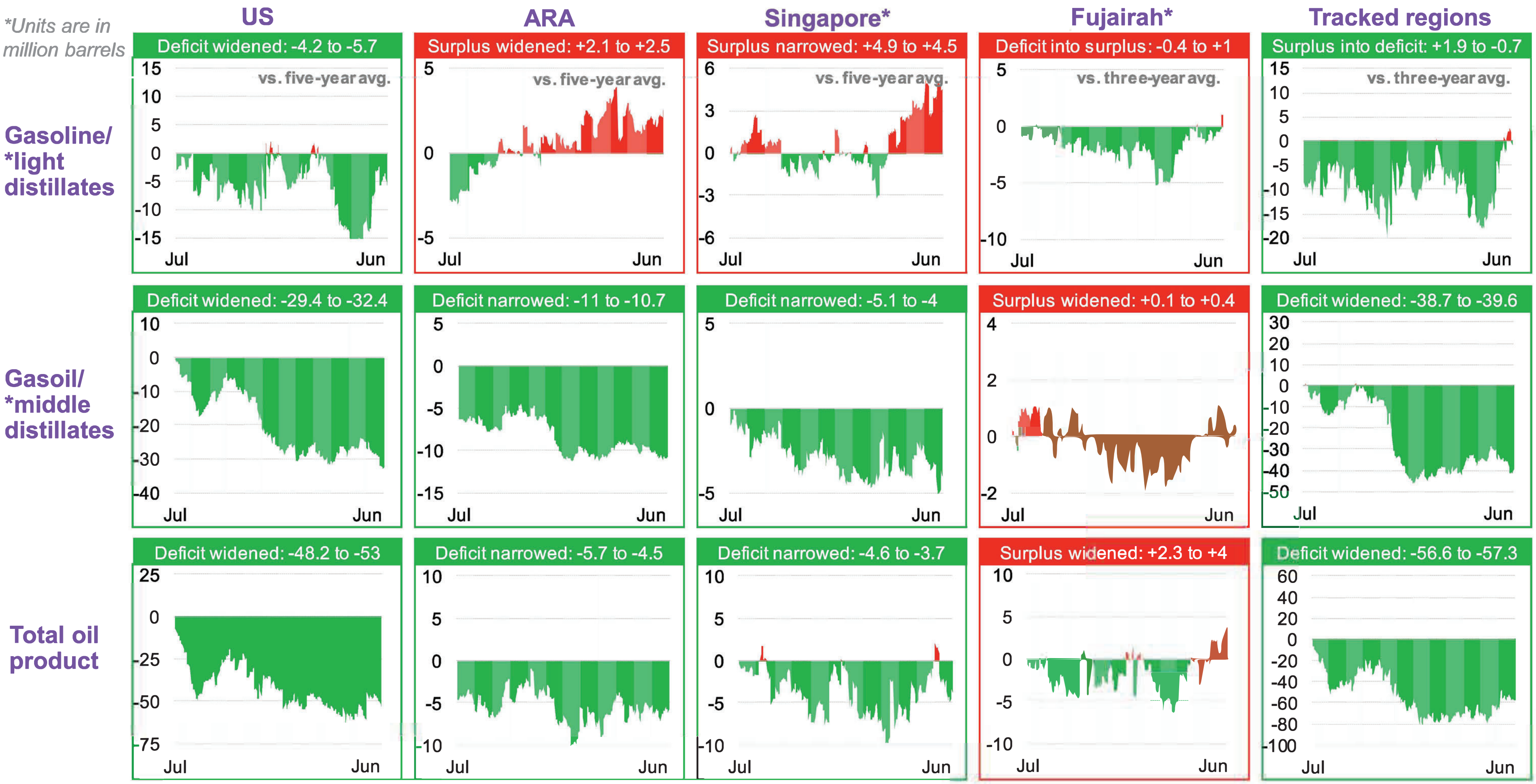


Source: BloombergNEF, US EIA, PJK, IE Singapore, FEDCom/Platts, PAJ. Note: As of the ***week ending July 29, 2022.***

Product stocks: Current versus seasonal average

Neutral: Oil product stockpile deficit against the seasonal average widened from 56.6m bbl to 57.3m 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 July 29, 2022.***

Aug 12, 2022 07:42:22

OIL DEMAND MONITOR: Airline Activity Picking Up in China

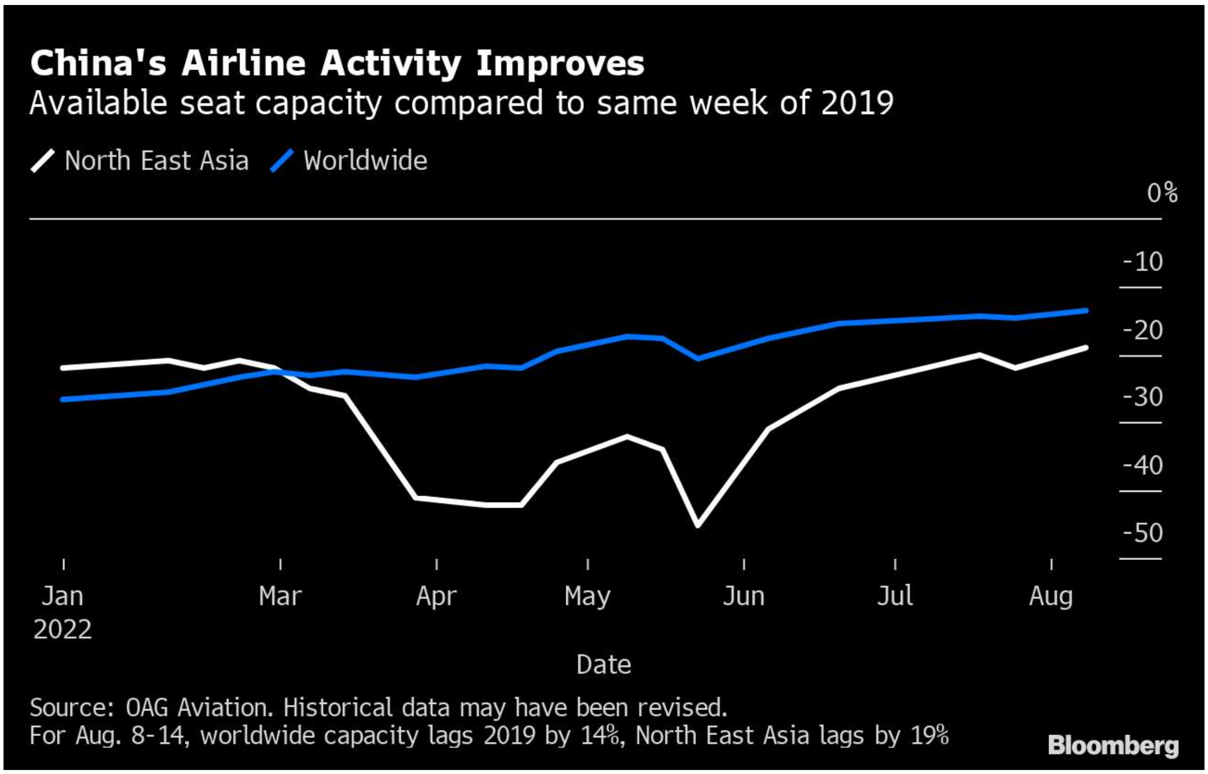
Global seat capacity on planes lags pre-Covid era by 14%: OAG
US gasoline product supplied rises from prior week's slump

By Stephen Voss

(Bloomberg) -- Airline traffic is picking up in China and some other parts of Asia while still lagging the more vibrant recovery seen elsewhere in the world, such as in Latin America, where the number of seats available exceeds pre-pandemic times.

Jet fuel consumption, inextricably linked to airline activity, has long been the weakest pillar in oil demand since the coronavirus pandemic began, and the marked absence of international travel to and from major Chinese cities has been the biggest hole in that market.

Seat capacity for North East Asia -- an area that includes China -- in the week starting Aug. 8 was 19% less than the same week of 2019, according to OAG Aviation estimates. Back in late May, that deficit was as large as 45%. The global situation, measuring all airline seats, has steadily improved this year, and now lags the pre-pandemic week by about 14%, the OAG information shows.



That 14% deficit estimated by OAG is similar to a 13% dip from 2019 levels in a separate set of tracking data compiled by Flightradar24, which counts the number of worldwide commercial flights.

At first glance, the latest set of OAG data appeared to show a drop in seat capacity in western Europe, and an increase in eastern Europe, though OAG said this was due to a recategorization of some data. Overall European capacity edged down by 0.1% week-on-week, and is 12.5% below where it was in the same week of 2019.

Four regions where seat capacity has consistently exceeded prepandemic times are Central/Western Africa, Central Asia, Central America and Upper South America. For this week, schedules show their capacities between 4% and 12% above 2019 levels.

Conversely, the areas lagging are Southern Africa, South East Asia, Southwest Pacific and North East Asia, with deficits of 38%, 31%, 20% and 19%, respectively.

Hong Kong

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Hong Kong's status has been hammered by Covid travel restrictions that continue to shackle the city, said Augustus Tang, the chief executive officer of Cathay Pacific Airways Ltd., the city's main airline.

"It is clear that Hong Kong has fallen far behind other international aviation hubs and that it is taking longer to see a recovery with travel restrictions not yet completely easing," Tang said in a memo to staff on Aug. 10.

Even so, Cathay signaled a stronger second-half outlook and reduced its first-half loss from a year earlier. Online searches for flights out of Hong Kong surged by 290% in the 24 hours after the government announced shorter hotel quarantine requirements on Monday, according to travel company Expedia Group Inc.

Gasoline, Diesel

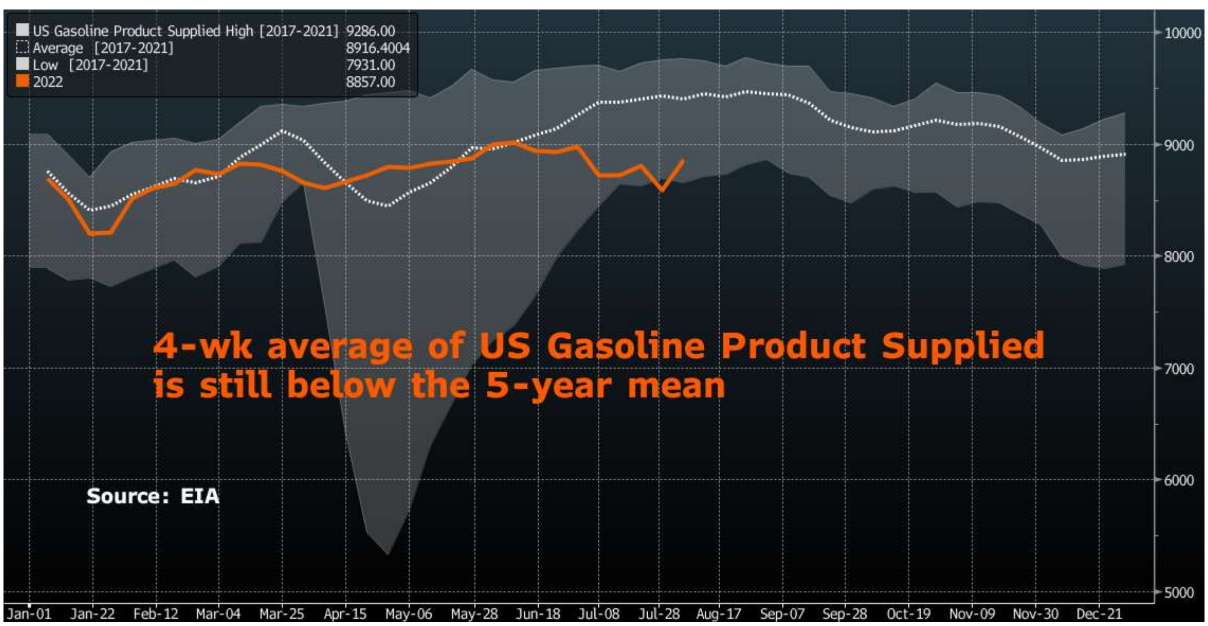
Turning to road fuels, the mainstay of the oil market, summer vacations have sucked activity out of city centers and high retail prices appear to be reining in consumption. That hasn't swayed the International Energy Agency from raising its global oil demand forecasts in a report Thursday, versus its previous estimate.

The Paris-based agency sees little chance of the OPEC+ alliance adding much more oil to the market in coming months, and expects a looming natural-gas supply crunch in Europe will spur more demand-switching to oil-based fuels such as diesel.

READ: IEA REPORT WRAP: Oil Demand Forecasts Raised as Gas Crunch Looms

An oft-used measure of gasoline demand in the U.S. bounced back above 9 million barrels a day in the week ended Aug. 5 following controversy over an abnormally low level the prior week. The Energy Information Administration defines its measure, called product supplied, as an estimate of how much fuel leaves primary sources such as refineries and bulk terminals, rather than an actual tally of retail sales.

Since week-to-week estimates can be erratic as they're impacted by exports, imports and stockpile flows, many analysts use the EIA's four-week average product supplied as a better gauge of gasoline demand. That measure has risen to 8.86 million barrels a day, though it is still noticeably below the five-year mean.



City Traffic

City traffic levels around the world show further evidence of a lack of regular commuter activity in the middle of the summer vacation season in the Northern Hemisphere. For a fifth consecutive week, none of the 13 cities regularly tracked in this monitor had congestion above typical 2019 levels at 8 a.m. local time on Monday morning, according to data from navigation technology company TomTom NV.

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In China, a separate set of data shows nationwide congestion broadly has leveled off, after intensifying in recent months once lockdowns in several major cities ended.

Still, congestion levels in two of the country's biggest cities, Shanghai and Guangzhou, are rising again after a lull in mid-July.

A seven-day moving average of 15 Chinese cities with the highest number of cars shows congestion was about 3% higher than an early-2021 baseline as of Aug. 8, according to Baidu traffic data analyzed by BloombergNEF. That measure had fallen 12% below the baseline in early May when Shanghai was in the middle of a draconian coronavirus lockdown, before soaring to +15% in the first few days of July.

The UK's once-a-week update on road fuel sales is moving to a monthly basis, starting on Aug. 11, which will show sales for the month of July. The latest weekly data, with information on sales through July 24, showed combined gasoline and diesel sales were 14% below a pre-pandemic baseline of early 2020 and were also 9% down from the same week of 2021.

In India, sales of gasoline and diesel by India's top three fuel retailers in July dropped from a month earlier as seasonal rains trimmed consumption in some sectors and restricted vehicle movement, according to refinery officials with knowledge of the matter who asked not to be identified.

Diesel, the most widely used petroleum product in India, had a 13% month-on-month decline in sales to 6.42 million tons, though that's still 5% more than the corresponding month in 2019, prior to the pandemic.

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

Following are the latest indicators. The first three tables shows fuel demand and road congestion, the next shows air travel globally and the fifth is refinery activity:

Demand Measure	Location	% y/y	% vs 2020	% vs 2019	% m/m	Freq	Latest Date	Latest Value	Source
Gasoline	US	-3.3	+2.7	-5.5	+13	w	Aug. 5	9.12m b/d	EIA
Distillates	US	-0.3	-3.6	-4.2	+11	w	Aug. 5	3.72m b/d	EIA
Jet fuel	US	+40	+81	-1.6	+31	w	Aug. 5	1.78m b/d	EIA
Total oil products	US	-0.2	+0.5	-9.4	+4	w	Aug. 5	19.47m	EIA

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								b/d	
All motor vehicle use index	UK	+1	+6.5	-1	-2	w	Aug. 8	99	DfT
Car use	UK	+1.1	+5.6	-5	-1	w	Aug. 8	95	DfT
Light commercial vehicle use	UK	+2.8	+11	+11	-3.5	w	Aug. 8	111	DfT
Heavy goods vehicle use	UK	-3.7	+4	+3	-5.5	w	Aug. 8	102	DfT
Gasoline (petrol) avg sales per filling station	UK	-8.3	+6.7	-12	-5.3	w	July 24	6,427 liters/d	BEIS
Diesel avg sales per station	UK	-9.6	-1.4	-16	-3.8	w	July 24	8,761 liters/d	BEIS
Total road fuels sales per station	UK	-9	+1.9	-14	-4.4	w	July 24	15,188 liters/d	BEIS
China 15 cities congestion	China				-2.6	d	Aug. 8	103	Baidu / BNEF
Gasoline	India	+12		+16	-5	2/m	July 1-31	2.66m tons	Bberg
Diesel	India	+18		+5	-13	2/m	July 1-31	6.42m tons	Bberg
LPG	India	+4.1		+12	+8.7	2/m	July 1-31	2.47m tons	Bberg
Jet fuel	India	+79		-14	-1.1	2/m	July 1-31	534k tons	Bberg
Total Products	India	+6.1	+13	-2.1	-5.7	m	July	17.6m tons	PPAC
Toll roads volume	France	+5.3		+3.8		m	July	n/a	Atlantia
Toll roads volume	Italy	+0.3		-2.2		m	July	n/a	Atlantia
Toll roads volume	Spain	+0.1		-1.9		m	July	n/a	Atlantia
Toll roads volume	Brazil	+7.3		+6.9		m	July	n/a	Atlantia
Toll roads volume	Chile	-1.7		+5.2		m	July	n/a	Atlantia
Toll roads volume	Mexico	+3.5		+6.3		m	July	n/a	Atlantia
Gasoline	Spain	+1.7			+6.3	m	July	555 m3	Exolum
Diesel (and heating oil)	Spain	-2			-1.4	m	July	2205k m3	Exolum
Jet fuel	Spain	+53			+12	m	July	647 m3	Exolum
Total oil products	Spain	+5.6			+2.2	m	July	3407 m3	Exolum
Road fuel sales	France	-2.4			+0.8	m	June	4.278m m3	UFIP
Gasoline	France			+16		m	1H 2022	n/a	UFIP
Road diesel	France			-6.2		m	1H 2022	n/a	UFIP
Jet fuel	France	+80		-23	+2	m	June	615k m3	UFIP
All petroleum products	France	+1.5		-3.4	+0.9	m	June	4.615m tons	UFIP
All vehicles traffic	Italy	-1.3			+1.7	m	July	n/a	Anas
Heavy vehicle traffic	Italy	-6.4			-6.9	m	July	n/a	Anas
Gasoline	Portugal	+3.3	+13	+2.7	-6.1	m	June	87k tons	ENSE
Diesel	Portugal	+1.5	+3.8	-3.4	-9.5	m	June	381k tons	ENSE
Jet fuel	Portugal	+120	+809	-4.4	+6.5	m	June	143k tons	ENSE
Total fuel sales	Italy	+1.4	+20	-2	+0.7	m	June	4.53m tons	Ministry
Gasoline	Italy	+3.3	+28	+4.7	+5.2	m	June	692k tons	Ministry
Diesel /gasoil	Italy	-1.9	+15	+0.5	+0.5	m	June	2.30m tons	Ministry
Jet fuel	Italy	+126	+419	-19	+13	m	June	379k tons	Ministry

Notes: Click here for a PDF with more information on sources, methods. The frequency column shows w for data updated weekly, 2/m for twice a month and m for monthly. The column showing "vs 2020" is used for some data, such as comparing Italian jet fuel sales for June 2022 vs June 2020.

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

In BEIS 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 data 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, and DoT also switched to monthly data after the week ended April 3.

City congestion:

Measure	Location	% chg vs avg 2019	% chg m/m	Aug 8	Aug 1	Jul 25	Jul 18	Jul 11	Jul 4	Jun 27	Jun 20	Jun 13	Jun 6
		(for Aug. 8)				Congestion mins added to 1 hr trip at 8am* local time							
Congestion	Tokyo	-15	+2	32	31	32	7	31	38	35	29	29	38
Congestion	Taipei	-24	+2	27	26	26	26	26	25	23	23	22	20
Congestion	Jakarta	-6	+39	37	37	34	35	26	29	28	33	37	43

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Congestion	Mumbai	-45	-2	26	25	26	29	27	26	22	30	20	18
Congestion	New York	-44	unch	17	20	17	21	17	zero	22	11	29	27
Congestion	Los Angeles	-46	+10	19	18	16	20	17	2	20	12	22	29
Congestion	London	-54	-45	17	17	21	26	32	35	38	42	44	43
Congestion	Rome	-84	-75	8	19	25	32	32	33	30	43	41	57
Congestion	Madrid	-92	-76	3	5	zero	11	13	14	13	21	27	28
Congestion	Paris	-78	-69	10	13	25	28	31	37	37	41	49	2
Congestion	Berlin	-54	-7	16	13	15	14	17	29	27	40	27	1
Congestion	Mexico City	-35	+26	32	26	23	23	25	26	28	29	33	34
Congestion	Sao Paulo	-7	+116	40	26	20	19	19	20	21	24	25	29

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: m/m comparisons are Aug. 8 vs July 11. There was a regional holiday in Madrid on July 25 that likely reduced traffic flow, and in Tokyo on July 18. TomTom has been unable to provide Chinese data since April 2021. Taipei and Jakarta were added to the table in December 2021.

Chinese City Congestion:

Measure	Location	% chg vs Jan. 2021	% chg m/m	% chg w/w	Aug. 8	Aug. 1	Jul. 25	Jul. 18	Jul. 11	Jul. 4	Jun. 27	Jun. 20	Jun. 13	Jun. 6
			(compare vs Aug. 8)											
Congestion	Beijing	+9	-12	-4.4	109	114	109	116	124	130	109	97	99	84
Congestion	Guangzhou	+12	+2.4	+2.6	112	109	105	103	109	116	113	115	121	112
Congestion	Shanghai	+13	+7.1	+5	113	108	105	103	106	119	111	105	106	89
Congestion	China-15	+3	-2.6	+1.9	103	101	101	103	106	115	111	109	109	103

Source: BNEF calculations based on Baidu congestion data, showing a seven-day moving average indexed against a January 2021 baseline of 100. China-15 is the weighted average of the 15 cities with the highest number of vehicle registrations. m/m comparisons are Aug. 8 vs July 11

Air Travel:

Measure	Location	y/y	vs 2 yrs ago	vs 2019	m/m	w/w	Freq.	Latest Date	Latest Value	Source
		changes shown as %								
Airline passenger throughput	US	+19	+256	-20	-3	-0.1	d	Aug. 10	2.103m	TSA
Airline passenger throughput (7d avg)	US	+15	+220	-9.9	+1.3	-0.8	d	Aug. 10	2.258m	TSA
All flights	Worldwide	+15	+42	+5.1	+4.8	+0.8	d	Aug. 10	218,555	Flightradar24
Commercial flights	Worldwide	+19	+60	-13	+1.2	+0.1	d	Aug. 10	107,427	Flightradar24
Air traffic (flights)	Europe			-12	-0.5	+0.3	d	Aug. 10	30,632	Eurocontrol
Air traffic (flights)	UK			-15	-4.2	-0.8	d	Aug. 10	5,521	Eurocontrol
Air traffic (flights)	Germany			-18	-1.1	-0.5	d	Aug. 10	4,963	Eurocontrol
Seat capacity	Worldwide	+35	+72	-14	+0.4	+0.2	w	Aug. 8-14	102.6m	OAG
Seat capacity	North America			-8.1		+0.2	w	Aug. 8-14	n/a	OAG
Seat capacity	North East Asia			-19		+0.9	w	Aug. 8-14	n/a	OAG
Seat capacity	South East Asia			-31		-1.3	w	Aug. 8-14	n/a	OAG
Seat capacity	South Asia			-4.5		+2.5	w	Aug. 8-14	n/a	OAG
Seat capacity	Western Europe			-21		-0.1	w	Aug. 8-14	n/a	OAG
Seat capacity	Central America			+8.4		+0.1	w	Aug. 8-14	n/a	OAG
Heathrow airport passengers	UK	+526	+1610	-17	+12		m	June 2022	5.99m	Heathrow

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

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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	y/y	chg vs 2019	m/m chg	Latest as of Date	Latest Value	Source
		Changes are in ppt unless noted					
Crude intake	US	+2.4%	-6.7%	-0.4%	Aug. 5	16.6m b/d	EIA
Utilization	US	+2.5	-2.1	-0.6	Aug. 5	94.3 %	EIA
Utilization	US Gulf	+4.4	+1.3	-0.1	Aug. 5	98 %	EIA
Utilization	US East	+9	+26	+1.8	Aug. 5	100.4 %	EIA
Utilization	US Midwest	+0.7	-9.8	-2.8	Aug. 5	91 %	EIA
Apparent Oil Demand	China	-5.6%	+6.2%	+4.7%	June 2022	13.04m b/d	NBS

NOTE: All of the refinery data is weekly, except NBS apparent demand, which is usually monthly. Changes are shown in percentages for the rows on crude intake and Chinese apparent oil demand, while refinery utilization changes are shown in percentage points. SCI99 data on Chinese refinery run rates was discontinued in late 2021.

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(Updates Chinese city congestion data in table and 16th to 18th paragraphs, and adds related graphic.)

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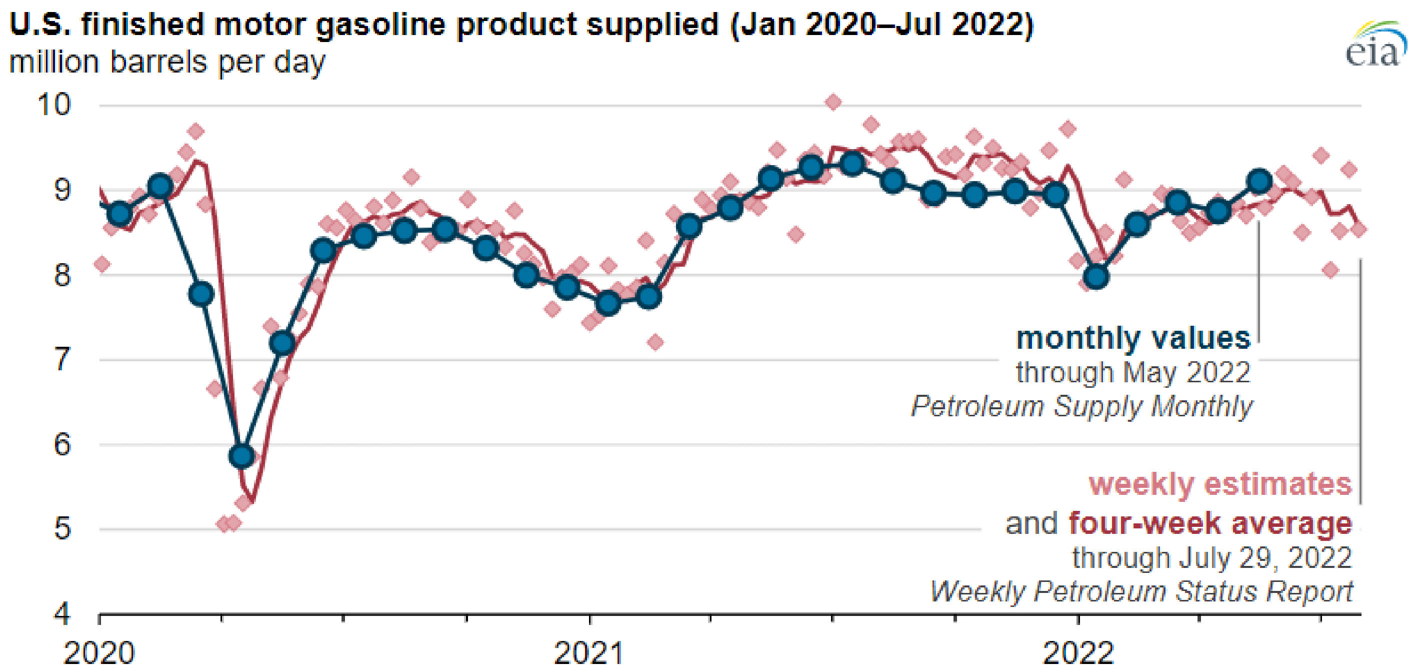
https://www.eia.gov/todayinenergy/detail.php?id=53399

AUGUST 10, 2022

EIA's Weekly Petroleum Status Report provides a snapshot of petroleum balances



Data source: U.S. Energy Information Administration, *Weekly Petroleum Status Report* and *Petroleum Supply Monthly*

EIA's *Weekly Petroleum Status Report* (WPSR) provides our most comprehensive data for weekly U.S. crude oil and refined petroleum product balances. Each week, WPSR provides detailed regional and national supply information on crude oil and major petroleum products used in the United States, including motor gasoline, distillate fuel oil, jet fuel, residual fuel, and propane. Our weekly estimates of inventories, refinery operations, and consumption are some of the most timely data series available anywhere to assess physical U.S. crude oil and petroleum product markets.

We generate weekly estimates of U.S. crude oil and petroleum product supply and disposition based on a combination of our weekly surveys, U.S. Customs and Border Protection (CBP) data, and modeled estimates. The surveys we use to develop our WPSR estimates, published on Wednesdays with information as of the previous Friday morning, collect data from about 1,200 respondents across the primary petroleum supply chain.

The weekly survey respondents are a sample selected from more than 3,000 respondents who report on our monthly surveys for data published in our *Petroleum Supply Monthly* (PSM). We consider the monthly survey data, which lag by two months, to be definitive because they capture information from all respondents as opposed to a sample used for the weekly estimates. As a result, we do not generally revise the WPSR data, which are intended to serve as a snapshot in time.

In our WPSR, we do not estimate the ultimate consumption of petroleum products by consumers. Instead, we estimate the movement of products through the wholesale distribution system before they reach the ultimate point of sale, such as retail stations. We use *product supplied* as a proxy for consumption, which is calculated as follows:

product supplied = production + imports - stock change - exports

Our surveys track production, imports, and stock changes; exports are estimated using data collected by CBP. Product supplied is the net amount inferred to move through the wholesale distribution system to retail outlets. Each term—production, imports, exports, and stock changes—carries some uncertainty, so any over- or under-estimation of these components directly affects the accuracy of our product supplied estimates.

In addition to the uncertainty in each term, our estimate of product supplied is not the same as the volume of the product sold by the retail outlets. When motor gasoline products are removed from the primary supply chain, they are then delivered to retailers who may hold them in their inventories until the products are purchased and then consumed, usually in vehicles. As a result, market events such as retail price fluctuations and anticipated spikes in refueling (such as holiday weekends) can lead to timing differences between our measure of product supplied and ultimate consumption. In summary, our measure of product supplied is a measure of product flowing to retailers, and demand is a measure of the product sold by retailers to final customers.

We recommend focusing on the four-week moving average given the week-to-week variability arising from our WPSR estimates. The moving average tends to represent recent market activity better than focusing on a single week's estimate. Four-week moving averages are particularly useful for data series such as imports and exports, which can vary significantly week to week and are subject to timing issues because of how they are reported. As PSM data are released, monthly statistics should serve as a benchmark against which subsequent weekly series are compared.

Principal contributors: Warren Wilczewski, Owen Comstock

Excerpt Kayrros Weekly Roundup – August 8, 2022

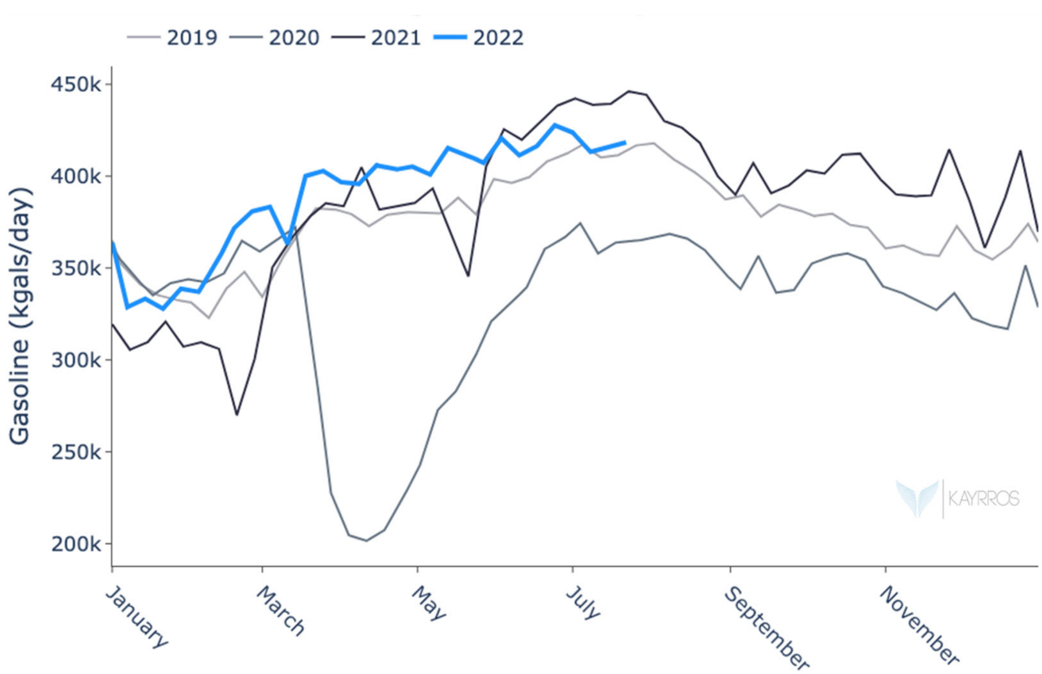
KAYRROS

Summer doldrums

A similar trend can be observed in the U.S., where on-road gasoline consumption has fallen significantly below last year's level since Memorial Day weekend and where the year-on-year gap has been widening.

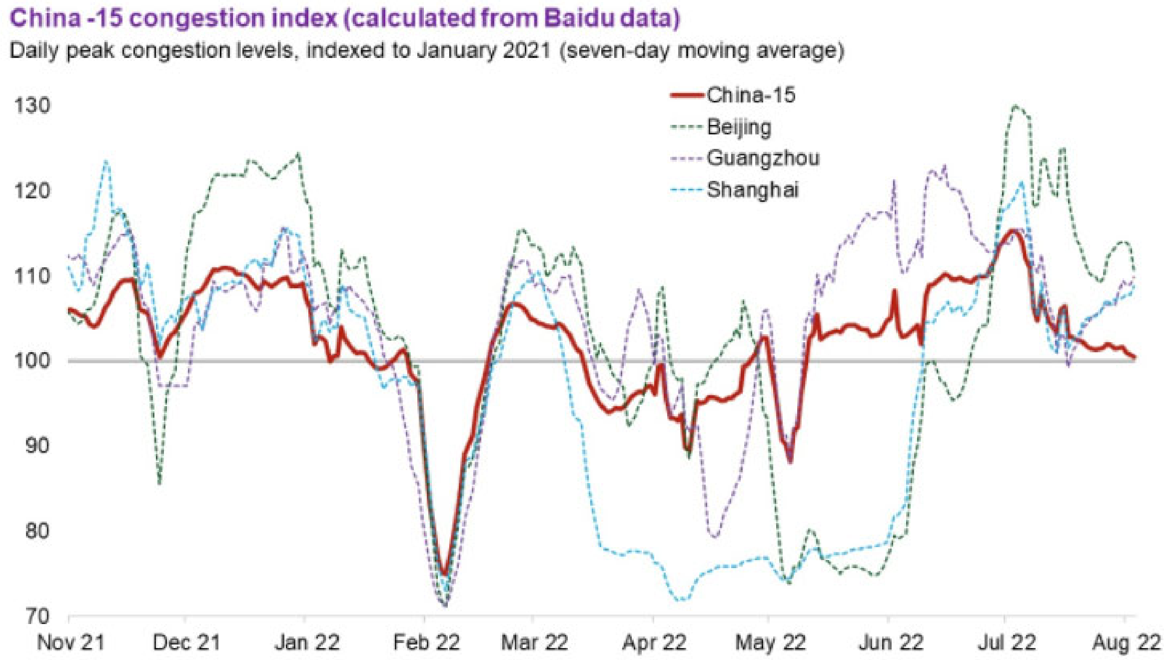
Kayrros measures actual miles traveled and end-user consumption by U.S motorists, as opposed to deliveries into secondary storage as reported in U.S. EIA weekly surveys.

Figure: **On road gasoline consumption in the U.S.**



China’s Traffic Downturn Shows No Sign of Stopping: BNEF Chart
2022-08-09 07:28:35.907 GMT

Road traffic index comprising the 15 cities in China with the most vehicle registrations



By Claudio Lubis
(BloombergNEF) -- Road traffic levels in China have now fallen for five consecutive weeks, as the re-emergence of Covid-19 cases compounded a weakening national economy in July.
A congestion index comprising the 15 cities in China with the highest number of vehicle registrations dropped by 1.5% week-on-week in the seven days to August 3. The picture is similarly bearish in Europe, with weekly traffic levels having plunged by 6.9%, according to TomTom data.
See the full research report here

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Frankfurt airport stops taking jet fuel by barge

Published date: 12 August 2022

Share:

Jet fuel deliveries by barge to Germany's Frankfurt airport have stopped in recent days because extremely low water levels on the Rhine river make them too risky. Northwest Europe jet fuel barge trade liquidity has stalled in turn.

The airport, Germany's largest, stopped taking jet fuel by barge last week, German airline Lufthansa told *Argus*. The dry weather has meant water levels at Kaub, a key measuring point on the Rhine north of Frankfurt, could drop to 37cm by 14 August, which would be the lowest since 2018 and within the 30-40cm range at which river operations are completely halted.

Although there are no official restrictions on navigation, some barge owners have stopped sending vessels south of Kaub.

"The last thing we now need is an accident on the river Rhine and an extension of the closure due to retrieving a barge or, even worse, a contamination," Lufthansa said, as air travel demand rises at Frankfurt. Airport operator Fraport recently expanded its 2022 outlook to 45mn-50mn passengers, from 39mn-46mn. German flight numbers lagged pre-pandemic levels by 18pc this week, Eurocontrol data show, from a 21pc lag at the start of July.

A jet fuel shortage at Frankfurt is unlikely, as it also receives fuel through the Nato and RMR pipelines, both of which are pumping jet at full capacity. As long as this continues supply will be adequate, Lufthansa said.

Other airports that receive jet fuel by barge include Zurich in Switzerland and Amsterdam in the Netherlands. Swiss strategic reserve organisation Carbura has released jet fuel from stocks to alleviate any shortage arising while Zurich airport cannot receive fuel by barge. While it is unclear what if any contingency plans are in place at Amsterdam's Schiphol airport, it is way north of the problem area on the Rhine. It limited the number of daily passengers in August to 72,500, due to staff shortages, which may cap jet fuel demand.

Jet fuel barge trading has stalled in recent days, and barge prices have risen. No barges have been reported to *Argus* to have traded since 27 July, and the jet fuel barge price premium to the underlying Ice August gasoil contract has widened to $54.75/t as of 10 August, from $49/t on 27 July.

By Bea O'Kelly

SUMMARY OF 1999 ATLANTIC TROPICAL CYCLONE ACTIVITY AND VERIFICATION OF AUTHORS' SEASONAL ACTIVITY PREDICTION

A Very Active Hurricane Season and a Successful Seasonal Forecast

(as of 24 November 1999)

By
William M. Gray,[1], Christopher W. Landsea,[2]
Paul W. Mielke, Jr. and Kenneth J. Berry,[3]

[with special assistance from Todd Kimberlain, William Thorson and Eric Blake[4]]

[This and past forecasts are available via the World Wide Web:
http://tropical.atmos.colostate.edu/forecasts/index.html] — also,

David Weymiller and Thomas Milligan, Colorado State University Media Representatives (970-491-6432) are available to answer questions about this forecast.

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[2] Meteorologist with NOAA/AOML HRD Lab., Miami, FL
[3] Professors of Statistics
[4] Dept. of Atmospheric Science

Table 1: Summary of information for named tropical cyclones occurring during the 1999 Atlantic season. Information on Tropical Storms (TS), Hurricanes (H) and Intense Hurricanes (IH) and the highest Saffir/Simpson category of each is shown. This information was supplied by of the National Hurricane Center.

Highest Category	Name	Dates of Named Storms	Peak Sustained Winds (kts)/ lowest SLP in mb	NSD	HD	IHD	HDP
*TS	Arlene	Jun.11-18	50/1006	4.50			
IH-4	Bret	Aug.18-24	125/944	4.25	2.50	1.25	9.8
IH-4	Cindy	Aug.19-31	120/944	11.00	6.00	1.50	17.4
H-2	Dennis	Aug.24-Sep.5	90/963	11.50	5.75		14.0
TS	Emily	Aug.24-28	45/1004	4.00			
IH-4	Floyd	Sep.7-17	135/921	9.25	6.25	3.75	27.6
IH-4	Gert	Sep.11-23	130/930	11.25	9.75	6.25	42.1
TS	Harvey	Sep.19-22	50/995	2.25			
H-2	Irene	Oct.13-19	90/958	5.75	5.00		9.9
H-2	Jose	Oct.17-25	85/977	7.25	2.50		5.4
TS	Katrina	Oct. 28-Nov.1	35/999	0.25			
H-4	Lenny	Nov. 13-21	130/934	6.00	5.00	2.25	18.9

* Indicates that prelim best track data utilized, other track operation estimates

Table 2: Summary of 1999 hurricane activity in comparison with long-term and recent average year conditions.

Forecast Parameter	1950-1990 Mean	Obs. 1999	1999 in percent as 1950-1990 Ave.	1999 in percent of 1970-1994 Ave.	1999 in percent of 1990-94 Ave.
Named Storms (NS)	9.3	12	129	140	143
Named Storm Days (NSD)	46.9	77	165	199	208
Hurricanes (H)	5.8	8	138	161	174
Hurricane Days (HD)	23.7	43	180	267	316
Intense Hurricanes (IH)	2.2	5	217	329	500
Intense Hurricane Days (IHD)	4.7	15	319	595	1200
Hurricane Destruction Potential (HDP)	70.6	145	204	322	338
Maximum Potential Destruction (MPD)	61.7	114	173	288	347
Net Tropical Cyclone Activity (NTC)	100	193	193	257	357

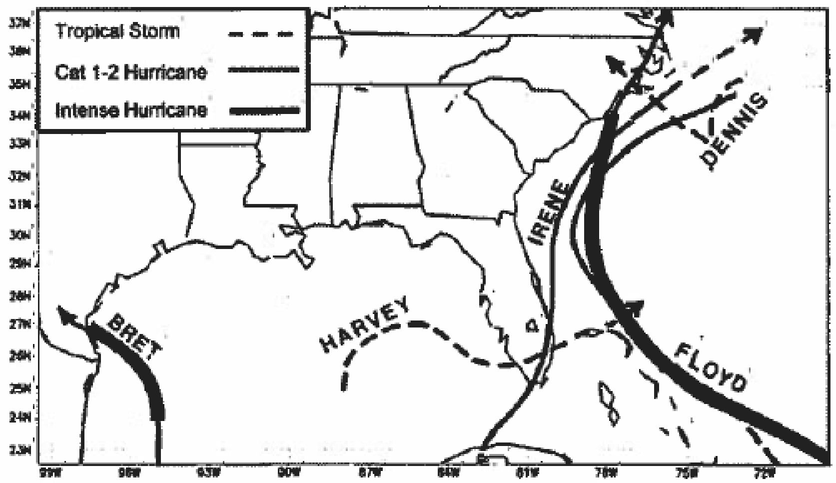

Figure 5: All 1999 U.S. landfalling tropical cyclones by intensity class.

1999. Extending this comparison back to 1880, only the 1887, 1893, 1906, 1916, 1926 and 1933 hurricane seasons were comparable to or greater than 1999.

4 Special Characteristics of the 1999 Season

The 1999 season saw the following:

1. Five major hurricanes, all of which were category-4 on the Saffir/Simpson scale. Records show no prior season with as many as five category-4 hurricanes. (Accurate intensity records are only available back to the mid-1940s). Regardless, 1999 continued the recent strong upturn in major hurricane activity which began in 1995.

2. Major hurricane Lenny (category-4, near category-5)formed in mid November. Records indicate that there have been only two other major hurricanes of this intensity this late in the season. These occurred in 1912 and 1932. There has never been a hurricane or tropical storm with so long an easterly track in the Caribbean.

3. Bret was the strongest hurricane to strike the South Texas coast since hurricane Celia in 1970. Fortunately, it made landfall in a largely unpopulated coastal area of south Texas.

4. An exceptional outbreak of tropical cyclone activity occurred during the latter part of August. Four tropical cyclones (Bret, Cindy, Dennis, and Emily) formed within a six-day period.

5. All of the 1999 Caribbean hurricane activity came during October and November; most Caribbean basin hurricane activity typically occurs in August and September.

Hurricane Days (IHD).

6. A total of three hurricanes and two tropical storms made landfall on the U.S. coast during 1999. Whereas Bret was a major hurricane, Floyd made landfall in North Carolina as a strong category-2 hurricane. The unusually heavy rainfall with Floyd was due, in part, to its interaction with a strong upper-air trough to the west. Most landfalling cyclones do not have such interactions.

5 Individual 1999 Tropical Cyclone Characteristics

Tropical Storm Arlene originated in the subtropical Atlantic about 550 miles southeast of Bermuda from a non-tropical disturbance on 11 June and strengthened into a tropical storm while drifting northward the following day. Arlene then turned westward and peaked with winds of 60 mph. For a brief time Arlene threatened Bermuda but passed about 100 miles to the east and did not significantly impact these islands. Arlene dissipated on the 18th to the northeast of Bermuda.

Hurricane Bret formed in the southern Gulf of Mexico on the 18th of August about 310 miles east-southeast of Tampico, Mexico. It reached tropical storm strength during the afternoon of the 19th. Bret moved on a general northward course and became a hurricane late on the 20th. The hurricane began to strengthen rapidly on the 21st and reached category-4 status over the western Gulf of Mexico. The following day Bret turned toward the west-northwest and is estimated to have reached its peak intensity of 140 mph on the morning of the 22nd about 100 miles east of the south Texas coast. Bret made landfall later that evening in a sparsely-populated area midway between Brownsville and Corpus Christi, Texas as a category-3 hurricane with maximum sustained winds of 125 mph. Bret gradually weakened while producing heavy rains of 5 to 10 inches as it moved slowly west-northwest over extreme southern Texas and the Rio Grande Valley.

Hurricane Cindy formed in the eastern tropical Atlantic near the Cape Verde Islands late on the 18th of August. It intensified to a tropical storm on the afternoon of the 20th and became a hurricane late on the 21st. By the 22nd Cindy began to experience strong easterly vertical shear and was downgraded to a tropical storm that afternoon. The shear decreased on the 25th and Cindy regained hurricane status later that day. While turning north-northwest the hurricane reached its peak intensity of 140 mph as a category-4 storm on the morning of the 28th. Cindy then moved west-northwest through the 24th and then northwest from the 25th the 28th. On the 29th the system turned northeast and began to accelerate on the 30th. Cindy became extratropical on the morning of the 31st as it merged with a mid-latitude low over the North Atlantic about 1000 miles west of the Azores.

Hurricane Dennis formed in the western Atlantic a couple hundred miles east of the S.E. Bahamas late on the 23rd of August. The system moved slowly west-northwest to northwest for the next several days. It became a tropical storm on the afternoon of the 24th of August and a hurricane early on the 26th. Dennis reached a peak intensity of 105 mph (category-2) on the afternoon of the 28th and maintained this intensity until early on the 30th while paralleling the lower southeast U.S. coast. The hurricane buffeted the North Carolina coast on the 30th and part of the 31st with sustained tropical storm force winds with gusts to hurricane force. Large waves and high surf were observed. Dennis turned northeastward away from the coast on the morning of the 30th. It stalled about 150 miles east of Cape Hatteras on the morning of the 31st and then began to drift westward and weaken as a tropical storm. Dennis meandered about 100 miles east and southeast of Cape Hatteras through 2 September. By 4 September Dennis re-intensified as it turned back toward the coast and made landfall as a strong tropical storm on the North Carolina outer banks, about 35 miles east-northeast of Morehead City. Dennis weakened to a depression early on the 5th while moving northwestward into north central North Carolina. It dissipated in south central Virginia on 6 September. Dennis produced heavy rains over North Carolina and the mid-Atlantic states and contributed (through raising the water table) to the catastrophic North Carolina flooding that took place 10 days later with Hurricane Floyd.

Tropical Storm Emily formed about 400 miles east of the Windward Islands during the afternoon of the 24th of August. The system was upgraded to a tropical storm later that day. By the 26th hurricane Cindy began to adversely affect the small circulation of Emily. Emily was downgraded to a depression that afternoon while moving northwestward. Emily turned northward on the 27th and briefly regained tropical storm status. Cindy continued to influence Emily and Emily became absorbed within Cindy's circulation on the 28th while moving northward.

Hurricane Floyd was the most powerful hurricane of the 1999 season. It formed from a tropical wave which moved off the coast of Africa on 2 September. The system became a tropical depression on 7 September about 1000 miles east of the Lesser Antilles. It strengthened into a tropical storm early the next day while located about 850 miles east of the Lesser Antilles. Floyd developed into a hurricane about 240 miles northeast of the northern Leeward Islands. Turning west and then northwest Floyd avoided the Caribbean Islands and leveled off in strength as it interacted with a mid/upper-level weather system to the northwest. However, as Floyd turned back to the west it strengthened into a major hurricane, a strong category-4 system packing winds of 155 mph winds. Weakening only slightly the hurricane lashed portions of the central and northwest Bahamas on 13-14 September. It posed a serious threat to Florida and the southeast U.S. coast but turned northward just before reaching the South Florida Coast.

Hurricane Floyd turned northwestward and then north while slowly weakening. It eventually made landfall near Cape Fear, NC as a strong category-2 hurricane during the early morning hours of 16 September. After hitting North Carolina Floyd raced north-northeastward up the coast and weakened to a tropical storm before entering New England and losing its tropical characteristics early on the 17th. Floyd is responsible for massive inland flooding over portions of the eastern United States, particularly in North Carolina. The current death toll as reported by the media was about 70. This would make this the deadliest United States tropical cyclone since Agnes of 1972. The damage (mostly from flooding) total is estimated to be between 5 and 6 billion dollars. Floyd will be retired as one of the deadliest and costliest hurricanes to affect the U.S. coast this century. A sizable portion of the unusual U.S. flooding damage from Floyd can be attributed to its interaction with a strong upper-air trough on its west side.

Hurricane Gert formed over the eastern Atlantic about 200 miles south of the Cape Verde Islands on 11 September. It became a tropical storm on the 12th while centered about 560 miles west of the Cape Verde Islands. Gert moved toward the west and strengthened into a hurricane about 1400 miles east of the Lesser Antilles on 13 September. Gert continued to strengthen and became the fourth major hurricane of the season reaching a peak intensity on the 15th about 750 miles east of the Leeward Islands with winds near 150 mph. Gert maintained major hurricane status for nearly 6 days. During this time it turned northwest and then north and passed 130 miles to the east of Bermuda on the 21st as a strong category-2 hurricane. Gusts to hurricane force were experienced on that island. Gert then turned north-northeastward and accelerated into the far North Atlantic. It passed very close to Newfoundland on the 23rd where large waves caused some damage.

Tropical Storm Harvey formed from a tropical wave which moved through the Caribbean Sea and into the Gulf of Mexico. The system became a tropical depression on 19 September over the Central Gulf and began to move toward the east-northeast. Despite unfavorable upper-level westerly winds the cyclone became a tropical storm while centered about 315 miles south-southeast of New Orleans. Winds peaked at 60 mph while Harvey was located about 250 miles west-southwest of Tampa, Florida. The storm then took an abrupt turn toward the southeast and weakened before moving inland south of Naples, Florida. Harvey produced tropical storm force winds over portions of the Keys and extreme South Florida as it moved across the Peninsula. The cyclone was then absorbed by a frontal system just off the southeast Florida coast on 22 September.

Hurricane Irene originated from a broad area of low pressure in the southwest Caribbean in the second week of October. The low gradually became better organized over a period of several days and a tropical depression formed on the 13th. Tropical storm strength was reached later that day with the center about 230 miles south of the Isle of Youth, Cuba. Irene moved northward turned north-northeastward making landfall on the Isle of Youth on the 14th. The center of Irene continued north-northeastward over western Cuba and into the Florida Straits and became a hurricane around this time. The center passed over Key West early on the 15th. However, most of the hurricane force winds were east of the center over the Florida Keys. Later that day the center made landfall on the Florida Peninsula near Flamingo moving across southeast Florida. Torrential rains with accumulations of 10-20 inches were experienced over mainland Florida with hurricane force winds over the east Florida coastal waters. The center of Irene emerged in the Atlantic near Jupiter, Florida later on the 15th. It retained hurricane strength as it moved northward parallel to the Florida coast. Irene then turned and accelerated to the northeast just east of the North Carolina outer banks early on the 18th. After passing the outer banks Irene rapidly strengthened nearing category-3 status with an intensity of 105 mph on the 18th. Irene continued northeastward and was absorbed by an extratropical low on the 19th. Although damage estimates are not yet available, Irene caused considerable damage due to flooding in South Florida. Seven deaths are indirectly attributed to Irene in Florida.

Hurricane Jose originated from a tropical wave that moved off the west coast of Africa on the 8 October. The wave moved slowly westward across the tropical Atlantic for several days. When the system was located about midway between Africa and the Lesser Antilles it became better organized. It developed into a tropical depression about 700 miles east of the southern Windward Islands on the 17th. Moving west-northwestward, the depression strengthened into tropical storm Jose on the 18th while centered about 400 miles east of the Windward Islands. After turning to the northwest Jose became a hurricane late on the 19th about 150 miles east of the Leeward Islands. Hurricane Jose struck the northern Leeward Islands. It passed over Antigua and St. Maarten on the 20th and 21st. There was severe flooding due to very heavy rains over portions of these islands. Jose then weakened to a tropical storm just before moving over the British Virgin Islands on the 21st. The storm passed just northeast of Puerto Rico before turning northward and then north-northeastward on the 22nd. It regained hurricane strength and passed 300 miles east of Bermuda on the 24th. Jose accelerated into the North Atlantic and lost tropical characteristics on the 25th.

Tropical Storm Katrina developed from a broad area of low pressure in the southwest Caribbean. It reached tropical depression status on the 28th while located about 200 miles east of the central Nicaraguan Coast. The depression initially moved west then northwest as it approached the Nicaraguan Coast. It reached tropical storm strength just prior to making landfall south of Puerto Cabezas, Nicaragua on the 29th. It maintained tropical storm status for only one day. Katrina rapidly weakened to a tropical depression as it moved northwestward across northeastern Nicaragua and Honduras. The depression then moved into the Gulf of Honduras on the 30th and across Belize and the Yucatan Peninsula on the 31st. Katrina was absorbed by a non-tropical low pressure area over the southern Gulf of Mexico on 1 November.

Hurricane Lenny originated from an enhanced equatorial trough that had moved over the southwest Caribbean Sea in the second week of November. A disturbance gradually formed. For several days the tropical disturbance drifted slowly northward and became better organized on 11 November close to the Cayman Islands. The system became a tropical depression on 12 November while located midway between Jamaica and the Yucatan Peninsula. On the 13th, the depression turned southeast and then east and acquired tropical storm strength a few hundred miles southwest of Jamaica. By the 14th Lenny was rapidly intensifying and became a hurricane about 150 miles south-southwest of Jamaica. Lenny continued on its unusual eastward path south of Jamaica and Hispaniola between 14 and 16 November. It strengthened to category-2 intensity for a brief time early on the 14th with 100 mph winds. It then weakened to a category-1 system. By the 15th Lenny had begun to reintensify and reclaimed category-2 strength about 240 miles south-southwest of Santo Domingo. On the 16th Lenny became a major hurricane over the east central Caribbean Sea and continued to intensify threatening Puerto Rico and the U.S./British Virgin islands. Between 16 and 17 November Lenny intensified into a rare category-4 hurricane during for the month of November. The hurricane turned more east-northeast and then northeast by the morning of the 17th as winds increased to 150 mph. Lenny lashed St. Croix during the early afternoon of 17 November. Its forward motion then staled and it brought massive amounts of rainfall to the northern Leeward Island. Its forecast motion to the northeast never materialized. It gradually filled from the 18th to the 21st and then slowly moved eastward as a weak tropical storm and depression and dissipated late on the 21st.

Lenny was one of the most unusual tropical cyclones ever to exist in the Atlantic. Only two other hurricanes (1912, 1932) of this approximate intensity have been recorded as late in the season as Lenny. And, there has never been a hurricane or tropical storm, that we know of, to track eastward across nearly the whole Caribbean Sea.

6 Variation of 1999 Forecast Parameters – Factors Known to be Associated with Seasonal Variation of Hurricane Activity

Factors known to be associated with seasonal variation of hurricane activity that were present during 1999 include the following:

a) La Niña Conditions. Equatorial Pacific SSTAs (in °C) in Niño-1-2, 3, 3.4 and 4 (see Fig. 1 for locations) are shown in Table 3. Cold water (or La Niña) conditions were present throughout this season. In addition, the Tahiti minus Darwin surface pressure difference or Southern Oscillation Index (SOI) was generally positive (as occurs during La Niña) while Outgoing Longwave Radiation (OLR) values near the Dateline were high, indicating diminished deep convection. These conditions greatly enhanced this year's hurricane activity.

b) Stratospheric QBO Winds

August 11, 2022

Honorable Nancy Pelosi
Speaker
U.S. House of Representatives
Washington, D.C. 20515

Honorable Kevin McCarthy
Republican Leader
U.S. House of Representatives
Washington, D.C. 20515

Dear Speaker Pelosi and Leader McCarthy:

The undersigned trade associations, representing thousands of businesses across the United States that collectively employ millions of Americans, write to express our opposition to the *Inflation Reduction Act* (IRA) as passed by the U.S. Senate. Further, we write to urge you to reconsider policies within the legislation before proceeding.

The United States has experienced its second consecutive quarter of negative GDP growth, and American consumers are facing record high inflation. We share the goal of addressing climate change, as evidenced in the policies we support and in the actions that we take every day. However, the considerable tax increases and new government spending in the IRA amount to the wrong policies at the wrong time.

We are also facing the most significant global energy crisis since the 1970's, and U.S. energy security—and that of our strategic allies abroad—is being put to the test. Further, U.S. energy costs have increased 40% over the past twelve months, creating a serious strain on American household incomes.

With these current conditions as the backdrop for this legislation, there are several specific policies included in the IRA which are particularly troubling and deserve re-consideration. We would like to draw your attention to three such provisions:

1. The IRA imposes a new corporate minimum tax, increasing taxes on Americans by more than $300 billion over the next 10 years. As President Obama noted in 2009, "the last thing you want to do is raise taxes in the middle of a recession."

2. The IRA imposes an $11.7 billion tax on crude oil and petroleum products. At a time of record-high energy prices, Congress should not add additional costs on American energy companies competing globally.

3. The IRA imposes additional constraints on the ability of companies to develop and produce the energy that Americans need to fuel our economy and strengthen our energy security. This includes increased fees on domestic production and the establishment of a new $6.3 billion natural gas tax.

Finally, the IRA fails to address permitting reform, which is desperately needed and is essential to effectively deliver affordable, reliable energy to consumers in a growing economy.

To date, neither the House nor the Senate have introduced comprehensive permitting reform legislation. We urge Congress to quickly consider and pass permitting reform without delay.

For the above-stated reasons, we express our opposition to the IRA and request that you reconsider passage of this legislation.

Sincerely,

American Petroleum Institute
American Exploration and Production Council
American Fuel & Petrochemical Manufacturers
Independent Petroleum Association of America
Energy Workforce & Technology Council
Plumbing-Heating-Cooling Contractors—National Association
Manufacture Alabama
The Coalbed Methane Association of Alabama
Arkansas Independent Producers and Royalty Owners
Arkansas Oil Marketers Association
California Independent Petroleum Association
Colorado Oil and Gas Association
West Slope Colorado Oil & Gas Association
Colorado Wyoming Petroleum Marketers Association
Associated Industries of Florida
Florida Independent Petroleum Producers Association
Florida Natural Gas Association
Florida Petroleum Marketers Association
Florida Propane Gas Association
Florida State Hispanic Chamber of Commerce
Florida Transportation Builders Association
Floridians for Better Transportation
The James Madison Institute
Georgia Association of Convenience Stores
Georgia Mining Association
Illinois Fuel Retails Association
Illinois Manufacturers Association
Illinois Retail Merchants Association
Chemistry Industry Council of Illinois
Fuel Iowa
Kansas Independent Oil & Gas Association
Louisiana Association of Business and Industry
Louisiana Oil and Gas Association
Michigan Association of Convenience Stores
Michigan Oil and Gas Association
Michigan Petroleum Association
Minnesota Service Station & Convenience Store Association
Associated Industries of Missouri

New Mexico Business Coalition
New Mexico Oil and Gas Association
North Carolina Chamber
North Carolina Petroleum & Convenience Marketers Association
North Dakota Petroleum Council
Ohio Energy and Convenience Association
Ohio Manufacturers Association
Ohio Oil and Gas Association
The Petroleum Alliance of Oklahoma
Pennsylvania Chamber of Business & Industry
Pennsylvania Grade Crude Oil Coalition
Pennsylvania Independent Oil & Gas Association
Pennsylvania Independent Petroleum Producers
Pennsylvania Manufacturers Association
South Dakota Petroleum and Propane Marketers Association
Texas Alliance of Energy Producers
Texas Independent Producers & Royalty Owners Association
Permian Basin Petroleum Association
Associated Builders & Contractors West Virginia
Petroleum Association of Wyoming

The findings of the latest liveability survey:

- EIU's Liveability Index has risen sharply in the 2022 survey (conducted between February 14th and March 13th). Scores for culture and environment, healthcare and education have improved on the back of covid-19 curbs being eased. However, the global average score remains below pre-pandemic levels.
- A rollback of covid-19 restrictions has translated into liveability rankings resembling those seen before the pandemic. Vienna (Austria) tops the rankings in 2022, as it did in 2019 and 2018.
- Russia's invasion of Ukraine on February 24th has forced us to exclude Kiev (Ukraine) from our survey. The conflict has influenced rankings for Moscow and St Petersburg (Russia). Both cities record a fall in scores owing to increased instability, censorship, imposition of Western sanctions and corporates withdrawing their operations from the country.
- Eastern European cities slip in the rankings amid increased geopolitical risks. If the cost-of-living crisis were to trigger further discord in international ties or domestic politics, stability scores would be likely to slide further for such cities next year.
- Western European and Canadian cities dominate the top of our rankings. Life is almost back to normal in these cities on account of high covid-19 vaccination rates and the easing of restrictions. Copenhagen (Denmark) has moved up 13 places from its position 12 months ago, to second, and Zurich (Switzerland) now shares third place with Calgary (Canada), which has risen from 18th position.
- Damascus (Syria) and Tripoli (Libya) continue to languish at the bottom of the list—along with Lagos (Nigeria)—as they face social unrest, terrorism and conflict. However, most of the cities in the bottom ten have improved their scores compared with last year, as pandemic-induced pressures have eased.
- We have added 33 new cities to our rankings, one-third of them in China. This brings the total number of cities to 172, excluding Kiev. Many of the new entrants, such as Surabaya (Indonesia) and Chongqing (China), are already fast-growing business destinations.

Overview

For the past two years, EIU's global liveability rankings have been largely driven by the covid-19 pandemic, with lockdowns and social distancing measures affecting scores for culture, education and healthcare in cities across the world. However, in our most recent survey, the index has normalised, as restrictions have been lifted in many countries. Vienna, which slipped to 12th place in our rankings in early 2021 as its museums and restaurants were closed, has since rebounded to first place, the position it held in 2018 and 2019. Stability and good infrastructure are the city's main charms for its inhabitants, supported by good healthcare and plenty of opportunities for culture and entertainment.

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Top ten positions

City	Location	Rank	Index	Stability	Healthcare	Culture & Environment	Education	Infrastructure
Vienna	Austria	1	99.1	100.0	100.0	96.3	100.0	100.0
Copenhagen	Denmark	2	98.0	100.0	95.8	95.4	100.0	100.0
Zurich	Switzerland	3	96.3	95.0	100.0	96.3	91.7	96.4
Calgary	Canada	3	96.3	95.0	100.0	90.0	100.0	100.0
Vancouver	Canada	5	96.1	90.0	100.0	100.0	100.0	92.9
Geneva	Switzerland	6	95.9	95.0	100.0	94.9	91.7	96.4
Frankfurt	Germany	7	95.7	90.0	100.0	96.3	91.7	100.0
Toronto	Canada	8	95.4	95.0	100.0	95.4	100.0	89.3
Amsterdam	Netherlands	9	95.3	90.0	100.0	97.2	91.7	96.4
Osaka	Japan	10	95.1	100.0	100.0	83.1	100.0	96.4
Melbourne	Australia	10	95.1	95.0	83.3	98.6	100.0	100.0

Source: EIU.

However, although the pandemic has receded, a new threat to liveability emerged when Russia invaded Ukraine on February 24th 2022, in the middle of our survey period. We were forced to abort our survey for Kiev, excluding Ukraine's capital from our rankings. Russia's capital, Moscow, saw its liveability ranking fall by 15 places, while St Petersburg slipped by 13 places. Increased censorship accompanies the ongoing conflict. Russian cities are additionally seeing restrictions on culture and environment as a result of Western economic sanctions—the effects of which are likely to be more apparent in our next survey. Other cities in eastern Europe, such as Warsaw (Poland) and Budapest (Hungary), also saw their stability scores slip amid raised diplomatic tensions.

With the war likely to drag on for the remainder of 2022 at least, before settling into a political stand-off, the threat to security will continue. Moreover, the war—by impeding exports of Russian and Ukrainian energy and food—is worsening global inflation and dampening global growth. This may bring other sources of conflict.

However, in the latest survey, the picture that emerges is a broadly positive one. Amid the gradual—and ongoing—shift in the status of covid-19 from pandemic to endemic and a rise in global vaccination rates, the global average liveability score has rebounded. The score now stands at 73.6 (out of 100), up from 69.1 a year ago; this is still lower than the average of 75.9 reported before the pandemic. Of our five categories, the main improvements over the past year have been in culture and environment, education, and healthcare, all of which were badly affected by lockdowns. The scores for infrastructure remain broadly stable, while stability has deteriorated.

Thirty-three new cities enhance comparability

These averages only cover the 139 cities (excluding Kiev) for which we have comparable scores from previous surveys. However, this year we have added 33 new cities to the rankings, taking the total to 172 (excluding Kiev). The additions bring our liveability survey in line with our Worldwide Cost of Living (WCOL) survey, which was expanded in 2021 to include important new business centres. Many of the new cities are in developing markets: they include 11 in China, which face longer-term problems such

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as censorship, relatively weaker infrastructure and developing education systems. However, around one-third are in developed countries and score more highly, including six cities in the US. The highest-ranked new city is Rotterdam (Netherlands), at 28.

The top ten of our rankings remains dominated by western European cities, along with several from Canada. In second place, behind Vienna, is Copenhagen, while Calgary has jumped from 18th (owing to the removal of covid restrictions) to join Zurich in joint third. In general, mid-sized cities in the wealthiest countries tend to fare exceptionally well in the survey. The top ten cities are also among those with few covid restrictions. Shops, restaurants and museums have reopened, as have schools, and pandemic-led hospitalisation has declined, leading to less stress on healthcare resources and services, and even the requirement to wear masks is no longer in force in most situations. As a result, cities that were towards the top of our rankings before the pandemic have rebounded on the back of their stability, good infrastructure and services, as well as enjoyable leisure activities.

The bottom ten cities in our rankings remain fairly stable, with none of the new cities dipping this low. As in previous surveys, living conditions remain worst in Damascus, the capital of Syria. Also scraping along the bottom are Tripoli in Libya, Lagos in Nigeria and Algiers in Algeria, which continue to score low across the five categories. Wars, conflicts and terrorism are the biggest factors weighing down the ten lowest-ranked cities, of which seven are from the Middle East and Africa. Encouragingly, however, all of the bottom ten, apart from Tripoli, have seen their score improve in the past year as covid restrictions have eased, with both Dhaka (Bangladesh) and Port Moresby (Papua New Guinea) moving up three places each.

Bottom ten positions

City	Location	Rank	Index	Stability	Healthcare	Culture & Environment	Education	Infrastructure
Tehran	Iran	163	44.0	55.0	45.8	32.9	50.0	39.3
Douala	Cameroon	164	43.3	60.0	25.0	45.6	33.3	42.9
Harare	Zimbabwe	165	40.9	40.0	20.8	51.9	66.7	35.7
Dhaka	Bangladesh	166	39.2	55.0	29.2	40.5	41.7	26.8
Port Moresby	PNG	167	38.8	30.0	37.5	38.0	50.0	46.4
Karachi	Pakistan	168	37.5	20.0	33.3	35.2	66.7	51.8
Algiers	Algeria	169	37.0	35.0	29.2	45.4	50.0	30.4
Tripoli	Libya	170	34.2	30.0	29.2	33.8	41.7	41.1
Lagos	Nigeria	171	32.2	20.0	20.8	44.9	25.0	46.4
Damascus	Syria	172	30.7	20.0	29.2	40.5	33.3	32.1

Source: EIU.

The pandemic continues to drive the biggest moves

The biggest moves up our rankings are by cities in western Europe. Most German, UK and French cities had slipped in our survey a year ago because they were still under covid restrictions imposed as the Delta wave spread across the continent. This has changed with covid-19 in the process of becoming endemic and normalcy largely being restored. Frankfurt has climbed by an impressive 32 places over

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the past year to seventh, while Hamburg is up by 31 places to 16th. Three Canadian cities have seen a similar trajectory and have made it back into the top ten.

Cities in New Zealand and Australia are listed among the biggest fallers in our rankings, including Wellington and Auckland, which tumbled by 46 and 33 places respectively. Both countries benefited in early 2021, when covid vaccines were scarce: their closed borders kept cases down, keeping liveability high. Auckland actually came top of the early 2021 survey. However, this changed as a more infectious covid-19 wave struck in late 2021, which made closed borders less of a defence. Although New Zealand's lockdowns ended in December, before our survey period, its cities no longer have a covid advantage over well-vaccinated European and Canadian cities. In Australia, some states were slower to lift restrictions than others. As a result, Perth and Adelaide have lost ground since last year, and Melbourne is once again Australia's highest-ranked city. Adjusting policy dynamically will remain key to staying on top.

Biggest movers up the ranking in the past 12 months

City	Location	Rank	Index	Rank move	Index move
Frankfurt	Germany	7	95.7	32	12.9
Hamburg	Germany	16	94.4	31	12.5
Dusseldorf	Germany	22	93.0	28	12.8
London	UK	33	89.9	27	13.2
Manchester	UK	28	91.3	26	13.0
Paris	France	19	93.6	23	11.1
Brussels	Belgium	24	92.7	22	10.6
Amsterdam	Netherlands	9	95.3	21	11.2
Athens	Greece	73	74.5	19	11.6
Los Angeles	US	37	88.6	18	10.6

Source: EIU.

Biggest movers down the ranking in the past 12 months

City	Location	Rank	Index	Rank move	Index move
Wellington	New Zealand	50	85.7	-46	-8.0
Auckland	New Zealand	34	89.2	-33	-6.8
Adelaide	Australia	30	90.7	-27	-3.3
Perth	Australia	32	90.0	-26	-3.3
Houston	US	56	84.2	-25	0.2
Reykjavik	Iceland	48	86.6	-25	0.6
Madrid	Spain	43	87.6	-24	0.8
Taipei	Taiwan	53	85.1	-20	1.2
Barcelona	Spain	35	89.1	-19	0.8
Brisbane	Australia	27	91.6	-17	-0.8

Source: EIU.

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The same is true of Houston (US). An early lifting of covid restrictions made the city one of our biggest risers in the early 2021 survey. However, it has fallen 25 places in 2022 as other cities have followed suit. Russian cities have also fallen in our most recent rankings, owing to the war in Ukraine. However, it is worth noting that some of the fastest-falling cities in our rankings have seen far smaller drops in their liveability score compared with what we have seen on the index more recently, while some (including Houston) have seen their score improve. A rising tide may not lift all boats, but it has kept them from sinking by too much.

China is one country that has not yet benefited from the gradual lifting of covid-19 restrictions. Its zero-covid policy aims to keep cases under control by limiting international travel and imposing strict lockdowns as needed. This helped to keep domestic life fairly normal during much of 2020-21, but has proved less effective against the more contagious Omicron variant of the virus. Although cases appeared to be under control during our period of data collection, very soon afterwards a group of cities, including Shanghai, experienced major outbreaks that caused the reimposition of strict lockdowns.

Liveability is at risk over the next year

The war in Ukraine and covid restrictions will continue to affect cities' liveability over the next year. The pandemic is not yet over. Our core assumption is that a new variant will cause a global wave of cases later this year, but that it will not be more aggressive than Delta or prove resistant to current vaccines. High- and middle-income cities will use a combination of social restrictions and a renewed vaccination push to contain the variant, affecting liveability again. Those with low vaccination rates and a poor social safety net, particularly cities in Africa, are more likely to live with rising caseloads and the resulting disruption. China, although it is lifting its city lockdowns for now, is expected to keep its zero-covid policies in place until at least late 2022.

Meanwhile, the war in Ukraine will continue to be a threat to security throughout the next year at least. EIU expects the active phase of the war to continue during 2022 before giving way to more entrenched hostility. Even without escalation, the conflict will continue to fuel global inflation and dampen economic growth. Higher global commodity prices, particularly for energy and food, will weigh on liveability in many cities over the coming months and could spark conflict in some. Even where stability is not threatened, the cost-of-living crisis will dampen investment in infrastructure, healthcare and education, as well as the consumer spending that supports cultural life.

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The cost-of-living crisis

Global prices for many goods, particularly food and fuel, rose sharply in 2021 and have since soared as a result of the war in Ukraine. Russia is a major oil and gas exporter, but together with Ukraine accounts for 30% of global trade in wheat, 17% in maize and more than 50% in sunflowerseed oil. EIU has raised its 2022 forecast for global average consumer price inflation to 8.5%, the highest for 26 years. Inflation rates will subsequently ease, but we expect prices to remain high for as long as the conflict rages. Although costs do not form part of our liveability survey, this assessment is confirmed by our accompanying Worldwide Cost of Living (WCOL) survey, which shows that prices have already soared in the world's major cities, particularly for energy.

This sharp spike in inflation will put quality of life in many cities at risk, particularly if there are also interruptions to food and fuel supplies caused by the war in Ukraine. Either residents will be forced to pay much higher prices (making it harder to enjoy the culture and environment of their cities) or governments will take on more of the burden (which will risk their ability to provide high-quality public services). Rising interest rates in most countries will also make borrowing and debt repayments more expensive, reducing consumer spending further. Some businesses, including hotels and restaurants already weakened by the pandemic, may not survive, reducing liveability further.

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About EIU's liveability survey

How the rating works

The concept of liveability is simple: it assesses which locations around the world provide the best or the worst living conditions. Assessing liveability has a broad range of uses, from benchmarking perceptions of development levels to assigning a hardship allowance as part of expatriate relocation packages. Our liveability rating quantifies the challenges that might be presented to an individual's lifestyle in any given location and allows for direct comparison between locations.

Every city is assigned a rating for relative comfort for over 30 qualitative and quantitative factors across five broad categories: stability, healthcare, culture and environment, education and infrastructure. Each factor in a city is rated as *acceptable, tolerable, uncomfortable, undesirable* or *intolerable*. For qualitative indicators, a rating is awarded based on the judgment of our team of expert analysts and in-city contributors. For quantitative indicators, a rating is calculated based on the relative performance of a number of external data points.

The scores are then compiled and weighted to provide a score in the range 1-100, where 1 is considered *intolerable* and 100 is considered *ideal*. The liveability rating is provided both as an overall score and as a score for each category. To provide points of reference, the score is also given for each category relative to a control city (New York) and an overall position in the ranking of 172 cities is provided.

The covid-19 pandemic has affected living conditions in many cities, owing to its impact on the healthcare infrastructure, and restrictions and lockdown measures imposed by governments, which have put the healthcare, culture and environment, and education categories under stress. The impact of the pandemic has been incorporated into our overall liveability score, with the introduction of new indicators to assess these stress and restriction levels for each city.

- Stress on healthcare resources
- Restrictions on local sporting events
- Restrictions on theatre
- Restrictions on classic and modern music concerts
- Restrictions on restaurants, bars, coffee shops and nightclubs
- Restrictions on educational institutes

The scores for these new indicators and its effect are incorporated in our existing healthcare, culture and environment and education ratings.

The suggested liveability scale

Companies pay a premium (usually a percentage of a salary) to employees who move to cities where living conditions are particularly difficult, such as excessive physical hardship or a notably unhealthy environment.

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EIU has given a suggested allowance to correspond with the rating. However, the actual level of the allowance is often a matter of company policy. It is not uncommon, for example, for companies to pay higher allowances—perhaps up to double EIU's suggested level.

Rating description

Suggested allowance (%)
80-100 There are few, if any, challenges to living standards 0
70-80 Day-to-day living is fine, in general, but some aspects of life may entail
60-70 Negative factors have an impact on day-to-day living 10
50-60 Liveability is substantially constrained 15
50 or less Most aspects of living are severely restricted 20

How the rating is calculated

The liveability score is reached through category weights, which are divided equally into relevant subcategories to ensure that the score covers as many indicators as possible. Indicators are scored as *acceptable, tolerable, uncomfortable, undesirable* or *intolerable*. These are then weighted to produce a rating, where 100 indicates that liveability in a city is ideal and 1 means that it is intolerable.

For qualitative variables, an "EIU rating" is awarded based on the judgment of in-house expert geography analysts and a field correspondent based in each city. For quantitative variables, a rating is calculated based on the relative performance of a location using external data.

Category 1: Stability (weight: 25% of total)

Indicator	Source
Prevalence of petty crime	EIU rating
Prevalence of violent crime	EIU rating
Threat of terror	EIU rating
Threat of military conflict	EIU rating
Threat of civil unrest/conflict	EIU rating

Category 2: Healthcare (weight: 20% of total)

Indicator	Source
Availability of private healthcare	EIU rating
Quality of private healthcare	EIU rating
Availability of public healthcare	EIU rating
Quality of public healthcare	EIU rating
Availability of over-the-counter drugs	EIU rating
General healthcare indicators	Adapted from World Bank

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Category 3: Culture & Environment (weight: 25% of total)

Indicator	Source
Humidity/temperature rating	Adapted from average weather conditions
Discomfort of climate for travellers	EIU rating
Level of corruption	Adapted from Transparency International
Social or religious restrictions	EIU rating
Level of censorship	EIU rating
Sporting availability	EIU field rating of 3 sport indicators
Cultural availability	EIU field rating of 4 cultural indicators
Food and drink	EIU field rating of 4 cultural indicators
Consumer goods and services	EIU rating of product availability

Category 4: Education (weight: 10% of total)

Indicator	Source
Availability of private education	EIU rating
Quality of private education	EIU rating
Public education indicators	Adapted from World Bank

Category 5: Infrastructure (weight: 20% of total)

Indicator	Source
Quality of road network	EIU rating
Quality of public transport	EIU rating
Quality of international links	EIU rating
Availability of good-quality housing	EIU rating
Quality of energy provision	EIU rating
Quality of water provision	EIU rating
Quality of telecommunications	EIU rating

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Liveability Ranking and Overview

View EIU's complete liveability ranking and average scores for all 173 cities across five broad categories: stability, healthcare, culture and environment, education and infrastructure.

What's included?

- EIU's liveability rankings for 173 cities
- Summary of findings and a description of the methodology used
- Ranking position and overall liveability scores for all cities across each of the five categories

Find out more

Global Liveability Survey

The liveability survey quantifies the challenges that might be presented to an individual's lifestyle in 173 cities worldwide and provides a profile for each city. Appraise each city through its individual city profile and review regional trends.

What's included?

- EIU's liveability rankings for 173 cities
- Overall liveability scores for all cities across five broad categories: stability, healthcare, culture and environment, education and infrastructure
- Individual city profiles for each city within the survey

Find out more

Global Liveability Matrix

Our complete dataset ranks the challenges to an individual's lifestyle in 173 cities worldwide. Build your own models and evaluate key trends that might affect the development of cities in the future.

What's included?

- EIU's liveability rankings for 173 cities
- Overall liveability scores for all cities across five broad categories: stability, healthcare, culture and environment, education and infrastructure
- Customisable dataset with city ratings across 30 qualitative and quantitative factors

Find out more

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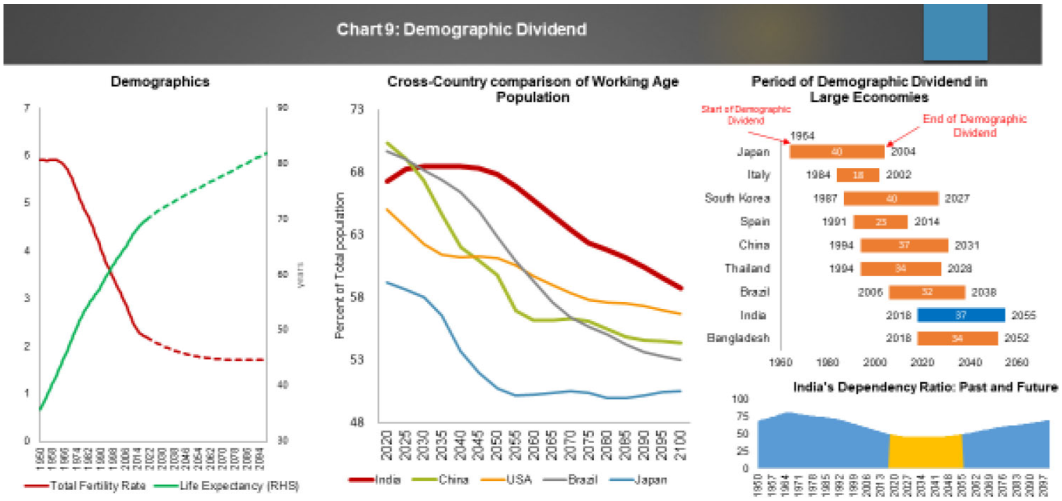
Excerpt from
https://rbidocs.rbi.org.in/rdocs/Speeches/PDFs/INDIA75DG13820228D1A9D3C113F4271AA2351981E546BCB.PDF

INDIA@75 - Speech delivered by Dr. Michael Debabrata Patra, Deputy Governor, Reserve Bank of India in an event to celebrate Azadi Ka Amrit Mohotsav organised by Reserve Bank of India, - August 13, 2022, Bhubaneswar



Demographics

I will start with the underlying realities of the widely cited demographic dividend. The world's population growth fell below 1 per cent for the first time in 2021. It will slow down through the rest of this century. India's population at 1.38 billion is the world's youngest at 28.4 years. By 2023 (that is next year), India will be the most populous country in the

Aging will close India's youth dividend by 2045, as it did for Japan in 2004 and Italy in 2002. This is evident from the changing structure of the population. A key indicator is the total fertility rate – the average number of children born to a woman over her lifetime. As per the findings of India's latest National Family Health Survey (2019-21), the total fertility rate (TFR) of 2.0 (down from 2.2 in 2015-16 and 2.7 in 2005-06) has fallen below the replacement level for the first time. According to the United Nations (UN), a generation with a total fertility rate6 lower than 2.1 is not producing enough children to replace itself. Such a situation results in an outright reduction in the population of that country. On the other hand, the life expectancy of Indians has been rising and is likely to increase from the current level of about 70 years to about 82 years by 2099.

A comparison of the ratio India's working-age7 population (WAP) to the total population with that of other countries, viz., China, Brazil, USA, and Japan, shows that India stands at an advantageous position. The working-age populations of these countries have started declining already while India's WAP ratio will increase till 2045, even exceeding that of China by 2030. Making the most of this demographic dividend is India's opportunity as well as a challenge.

Dan Tsubouchi @Energy_Tidbits · 2h

apologies to @RMIordache for misspelling her name. thank you for reporting the key #Aramco CEO comments on declining fast global spare oil capacity

> **Dan Tsubouchi** @Energy_Tidbits · 3h
>
> Buckle Up! Available #Oil capacity is declining fast. EU sanctions on RUS #Oil start in Dec. @ArgusMedia reports #Aramco CEO Nasser said "describing "strained" global spare capacity of less than 2mn b/d and "declining fast." Oil looks good for Q4. Thx Ruxandra Jordache #OOTT

https://www.argusmedia.com/en/news/2360965-aramco-2q-profit-at-record-on-high-oil-prices-demand

Aramco 2Q profit at record on high oil prices, demand

Published date: 14 August 2022

Saudi state-controlled Aramco's second-quarter profit exceeded that of the three largest-earning oil majors combined, pushed higher by increases in oil prices, sales volumes and refining margins.

Aramco said today it broke its quarterly profit record posted in May, with a 90pc year-on-year jump to $48.4bn in the second quarter, more than it made in the first six months of 2021.

Comparatively, ExxonMobil, Shell and Chevron recorded a collective profit of $47.61bn in the second quarter, according to *Argus* calculations.

Aramco's free cash flow rose by 53pc on the year to $34.6bn in the second quarter, with the company citing increases in cash from operating activities. It left its dividend guidance unchanged at $18.8bn, to be paid in the third quarter. Almost all of this goes to the Saudi state.

"We all know the energy market has been characterised by volatility and instability during the first half of this year," Aramco chief executive Amin Nasser told reporters, attributing the record second-quarter results to higher demand for the company's products. The company forecast oil demand will continue to grow for the remainder of the decade, "despite downward economic pressures on short-term global forecasts." Nasser assessed current global oil demand as "healthy," based on customer nominations "especially from Asia."

But he flagged supply-side constraints.

"Ongoing investment in our industry is essential — both to help ensure markets remain well supplied and to facilitate an orderly energy transition," he said, describing "strained" global spare capacity of less than 2mn b/d and "declining fast." Saudi and Opec+ officials have faced consumer pressure to increase output this year. The producers' alliance will this month unwind the roughly 9.7mn b/d of cuts it implemented in May 2020 in response to the Covid-19 pandemic, and will add a further 100,000 b/d of output in September.

"Our commitment is, any time we have been asked [by the Saudi government]… to go to our maximum sustained capacity, which is currently 12mn b/d, we'll be able to bring this on the stream quickly and sustainably," Nasser said. Aramco said it produced 13.6mn b/d of oil equivalent (boe/d) in the second quarter, up from 13mn boe/d in the January-March period. It did not break out crude output, which *Argus* estimates at 10.46mn b/d in the second quarter and 10.14mn b/d in the first.

Nasser said Aramco is "progressing very well" with plans to raise capacity from 12mn b/d to 13mn b/d by 2027. "In 2025, we should go to 12.3mn b/d, in 2026 we should go to 12.7[mn b/d]," he said. He expects a 75,000 b/d increase

Dan Tsubouchi @Energy_Tidbits · 3h

Buckle Up! Available #Oil capacity is declining fast. EU sanctions on RUS #Oil start in Dec. @ArgusMedia reports #Aramco CEO Nasser said "describing "strained" global spare capacity of less than 2mn b/d and "declining fast." Oil looks good for Q4. Thx Ruxandra Jordache #OOTT

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"We all know the energy market has been characterised by volatility and instability during the first half of this year," Aramco chief executive Amin Nasser told reporters, attributing the record second-quarter results to higher demand for the company's products. The company forecast oil demand will continue to grow for the remainder of the decade, "despite downward economic pressures on short-term global forecasts." Nasser assessed current global oil demand as "healthy," based on customer nominations "especially from Asia."

But he flagged supply-side constraints.

"Ongoing investment in our industry is essential — both to help ensure markets remain well supplied and to facilitate an orderly energy transition," he said, describing "strained" global spare capacity of less than 2mn b/d and "declining fast." Saudi and Opec+ officials have faced consumer pressure to increase output this year. The producers' alliance will this month unwind the roughly 9.7mn b/d of cuts it implemented in May 2020 in response to the Covid-19 pandemic, and will add a further 100,000 b/d of output in September.

"Our commitment is, any time we have been asked [by the Saudi government]… to go to our maximum sustained capacity, which is currently 12mn b/d, we'll be able to bring this on the stream quickly and sustainably," Nasser said. Aramco said it produced 13.6mn b/d of oil equivalent (boe/d) in the second quarter, up from 13mn boe/d in the January-March period. It did not break out crude output, which *Argus* estimates at 10.46mn b/d in the second quarter and 10.14mn b/d in the first.

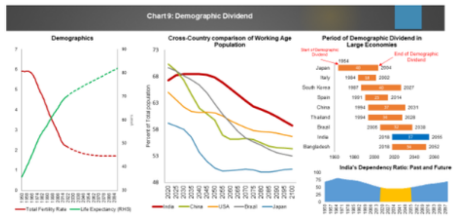
Nasser said Aramco is "progressing very well" with plans to raise capacity from 12mn b/d to 13mn b/d by 2027. "In 2025, we should go to 12.3mn b/d, in 2026 we should go to 12.7[mn b/d]," he said. He expects a 75,000 b/d increase from the Dammam field, a 300,000 b/d addition from Marjan, 250,000 b/d from Berri and 600,000 b/d from Zuluf. Beyond 2027, Nasser said there should be a 700,000 b/d hike from the Safaniyah field.

Dan Tsubouchi @Energy_Tidbits · 10h

India's demographics advantage for growth. Yes fertility rate fell to 2.0 for 1st time, but India's working-age population to the total population ratio will increase till 2045, even exceeding that of China by 2030. India's economic growth = increased #LNG #Oil imports. #OOTT

Excerpt from
https://rbidocs.rbi.org.in/rdocs/Speeches/PDFs/INDIA75DG13820228D1A9D3C113F4271AA2351981E546BCB.PDF

INDIA@75 - Speech delivered by Dr. Michael Debabrata Patra, Deputy Governor, Reserve Bank of India in an event to celebrate Azadi Ka Amrit Mohotsav organised by Reserve Bank of India, - August 13, 2022, Bhubaneswar



Demographics

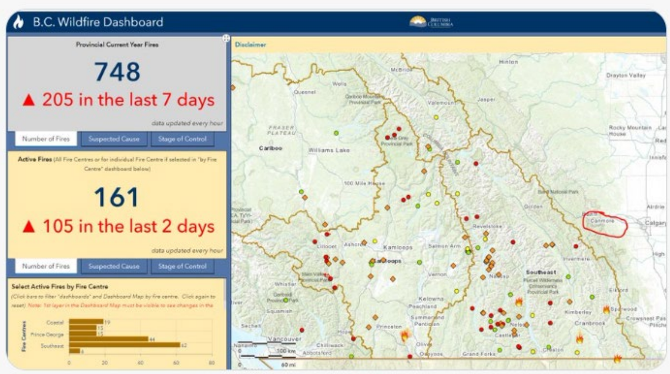
I will start with the underlying realities of the widely cited demographic dividend. The world's population growth fell below 1 per cent for the first time in 2021. It will slow down through the rest of this century. India's population at 1.38 billion is the world's youngest at 28.4 years. By 2023 (that is next year), India will be the most populous country in the

Aging will close India's youth dividend by 2045, as it did for Japan in 2004 and Italy in 2002. This is evident from the changing structure of the population. A key indicator is the total fertility rate – the average number of children born to a woman over her lifetime. As per the findings of India's latest National Family Health Survey (2019-21), the total fertility rate (TFR) of 2.0 (down from 2.2 in 2015-16 and 2.7 in 2005-06) has fallen below the replacement level for the first time. According to the United Nations (UN), a generation with a total fertility rate6 lower than 2.1 is not producing enough children to replace itself. Such a situation results in an outright reduction in the population of that country. On the other hand, the life expectancy of Indians has been rising and is likely to increase from the current level of about 70 years to about 82 years by 2099.

A comparison of the ratio India's working-age7 population (WAP) to the total population with that of other countries, viz., China, Brazil, USA, and Japan, shows that India stands at an advantageous position. The working-age populations of these countries have started declining already while India's WAP ratio will increase till 2045, even exceeding that of China by 2030. Making the most of this demographic dividend is India's opportunity as well as a challenge.

Dan Tsubouchi @Energy_Tidbits · 17h

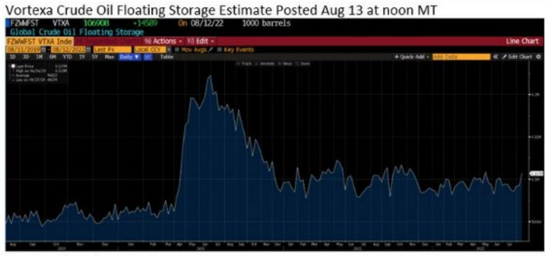
Didn't realize there was the big pickup in BC wildfires in the last few days until stepped onto our balcony in #Canmore and can smell smoke in the air. Hope everyone stays safe!



Dan Tsubouchi @Energy_Tidbits · 19h

Should be a Monday morning market story unless revised down over weekend. #Vortexa crude #Oil floating storage at 08/12 est 106.91 mmb, +14.59 mmb WoW vs revised down 08/05 of 92.32 mmb. 1st time >100 mmb since 06/17. Thx @Vortexa @business. #OOTT

Vortexa Crude Oil Floating Storage Estimate Posted Aug 13 at noon MT



Source: Bloomberg, Vortexa

Posted Aug 13, noon MT

	Date	Last Px
Fr	08/12/2022	106.908k
Fr	08/05/2022	92319
Fr	07/29/2022	91794
Fr	07/22/2022	85237
Fr	07/15/2022	87468
Fr	07/08/2022	93508
Fr	07/01/2022	94246
Fr	06/24/2022	92554
Fr	06/17/2022	101.729k
Fr	06/10/2022	98995
Fr	06/03/2022	82782

Aug 6, noon MT

	Date	Last Px
Fr	08/05/2022	97720
Fr	07/29/2022	95816
Fr	07/22/2022	87022
Fr	07/15/2022	86619
Fr	07/08/2022	96039
Fr	07/01/2022	96794
Fr	06/24/2022	96394
Fr	06/17/2022	106.642k
Fr	06/10/2022	103.827k
Fr	06/03/2022	86967
Fr	05/27/2022	97566

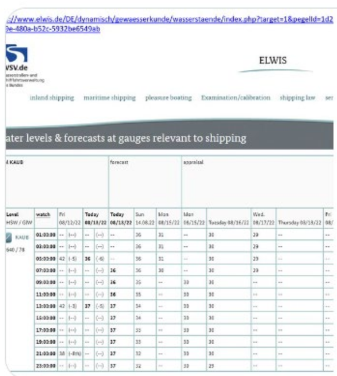
July 30, noon MT

	Date	Last Px
Fr	07/29/2022	78861
Fr	07/22/2022	85128
Fr	07/15/2022	87534
Fr	07/08/2022	92763
Fr	07/01/2022	95352
Fr	06/24/2022	94533
Fr	06/17/2022	104.531k
Fr	06/10/2022	103.166k
Fr	06/03/2022	85334
Fr	05/27/2022	96018
Fr	05/20/2022	97847

Source: Bloomberg, Vortexa

Dan Tsubouchi @Energy_Tidbits · Aug 13

An even worse forecast for Rhine River water levels at Kaub. Yesterday was 34 cm (13.4 inch) for Tues am, today 30 cm (11.8 inch). Forecast for Wed am is 29 cm (11.4 inch). #JetFuel barging already stopped, other #PetroleumProducts has to follow. #OOTT Thx @JWittels for link.



Dan Tsubouchi @Energy_Tidbits · Aug 12

ICYMI. Usual clear insights from @CroftHelima. #Oil, not seeing wholesale demand destruction, where will supply come from when EU RUS sanctions kick in & SPR release 1 mmb/d is over? #NatGas, will EU risk economic dislocation this winter to support Ukraine? #OOTT

SAF Group created transcript of RBC's Helima Croft comments with CNBC's Melissa Lee and Risk Reversal's Guy Adami on CNBC Aug 11, 2022. https://www.cnbc.com/video/2022/08/11/russia-will-continue-to-turn-off-the-gas-for-europe-rbcs-helima-croft.html?&qsearchterm=croft

Items in "italics" are SAF Group created transcript

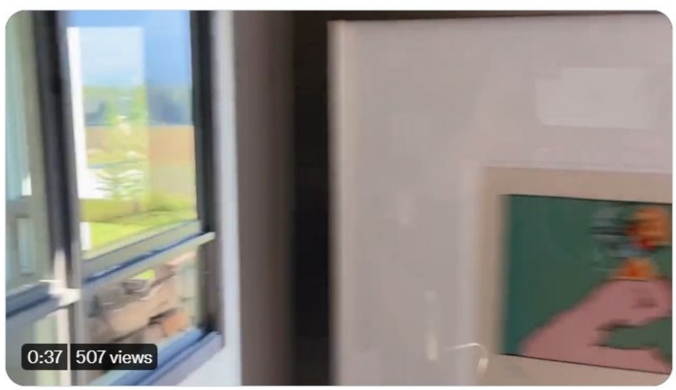
Croft "*I think we have to be very, very concerned about what happens, everything in the last month of this year because that's when these European sanctions on Russian oil are set to kick in. which would not only mean that you will have two million barrels a day of Russian oil that can't go into Europe. But if these shipping and insurance sanctions actually take effect as well. It's going to be very hard to move those barrels to Asia as well. So you could be talking about a multi-million barrel Russian disruption come December 5. The US government is working with the Europeans on this potential price cap solution that would potentially allow those barrels to move to refiners like Reliance if they certify that they're discounted barrels. But it's not clear they can get this mechanism up and running by December. So I think a lot of market participants are saying, well Russian production has actually remained quite elevated, India and China is taking the product, the worst is behind us. But I would say we have not yet seen really significant Russian sanctions on energy. Those are coming in December.*"

Croft "*But we have not seen any signs of wholesale demand destruction. Yes, China is soft, but we have not seen a significant fall off. For example, in gasoline demand here. So the question is do you have enough supply. Again, as I look out at the back half, the last quarter of this year, we're going to have this SPR release, a million barrel a day SPR release, that winds down in October. These Russian energy sanctions, they hit in December. OPEC does not have additional barrels to put on the market to plug this type of gap. So I do think we should be particularly focused on what happens with these sanctions when the US SPR release winds down*".

Croft "*Melissa, that is the top question, will Europe have the stomach to see these sanctions through. The Russians have every intention to make this as painful for Europe as possible. So what do they do, they turn off the gas. Gas is not the revenue earner for Russia that oil is. Gas is the Weapon of Choice. There is no easy replacement product for Russian piped natural gas into Europe. That's why they're not sanctioning natural gas. But that's what the Russians are doing. They're cutting gas flows off into Europe, forcing Europeans to have to think about heating and eating, who suffers in terms of industrial curtailment because it's going to be a really difficult supply situation in Europe, especially if it's a cold winter. That's what the Russians are saying – How much do you want to support Ukraine, Europe? Are you willing to risk massive economic dislocation to do so?*"

Dan Tsubouchi @Energy_Tidbits · Aug 12

always a good day when you look away from the screen to see our local #Canmore neighbours munching on some of the wild raspberry bushes in our yard.



Dan Tsubouchi @Energy_Tidbits · Aug 12

"last thing we now need is an accident on the river Rhine & an extension of the closure due to retrieving a barge or, even worse, a contamination" says #Lufthansa. Rhine River levels still okay, but why take the risk to barge #JetFuel to @Airport_FRA? Thx @beatrice_okelly. #OOTT


https://www.argusmedia.com/en/news/2360517-frankfurt-airport-stops-taking-jet-fuel-by-barge

Frankfurt airport stops taking jet fuel by barge

Published date: 12 August 2022

Share:

Jet fuel deliveries by barge to Germany's Frankfurt airport have stopped in recent days because extremely low water levels on the Rhine river make them too risky. Northwest Europe jet fuel barge trade liquidity has stalled in turn.

The airport, Germany's largest, stopped taking jet fuel by barge last week, German airline Lufthansa told *Argus*. The dry weather has meant water levels at Kaub, a key measuring point on the Rhine north of Frankfurt, could drop to 37cm by 14 August, which would be the lowest since 2018 and within the 30-40cm range at which river operations are completely halted.

Although there are no official restrictions on navigation, some barge owners have stopped sending vessels south of Kaub.

"The last thing we now need is an accident on the river Rhine and an extension of the closure due to retrieving a barge or, even worse, a contamination," Lufthansa said, as air travel demand rises at Frankfurt. Airport operator Fraport recently expanded its 2022 outlook to 45mn-50mn passengers, from 39mn-46mn. German flight numbers lagged pre-pandemic levels by 18pc this week, Eurocontrol data show, from a 21pc lag at the start of July.

A jet fuel shortage at Frankfurt is unlikely, as it also receives fuel through the Nato and RMR pipelines, both of which are pumping jet at full capacity. As long as this continues supply will be adequate, Lufthansa said.

Other airports that receive jet fuel by barge include Zurich in Switzerland and Amsterdam in the Netherlands. Swiss strategic reserve organisation Carbura has released jet fuel from stocks to alleviate any shortage arising while Zurich airport cannot receive fuel by barge. While it is unclear what if any contingency plans are in place at Amsterdam's Schiphol airport, it is way north of the problem area on the Rhine. It limited the number of daily passengers in August to 72,500, due to staff shortages, which may cap jet fuel demand.

Jet fuel barge trading has stalled in recent days, and barge prices have risen. No barges have been reported to *Argus* to have traded since 27 July, and the jet fuel barge price premium to the underlying Ice August gasoil contract has widened to \$54.75/t as of 10 August, from \$49/t on 27 July.

By Bea O'Kelly

Dan Tsubouchi @Energy_Tidbits · Aug 12

ICYMI, crazy high #NatGas #LNG prices. Thurs settle #JKM Oct contract \$51.96/mmbtu, Dutch #TTF Oct contract \$64.23/mmbtu. Hate to think the level of panic if it's a cold start to winter and not the warm winter 21/22. Thx @SStapczynski @MessageAnnKoh. #OOTT


d Spot Prices:

Japan-Korea Marker futures for September contract +63c t
\$45.335/mmbtu on Thursday

- Oct. contract +\$1.325 to \$51.955

Dutch TTF futures for September delivery on ICE settled at
equivalent of +96c to \$62.928/mmbtu on Thursday, accordi
Bloomberg calculations

- October contract +\$1.31 to \$64.23

Dan Tsubouchi @Energy_Tidbits · Aug 12

ICYMI. Brent back over \$100. #Oil #OOTT

Dan Tsubouchi @Energy_Tidbits · Aug 12

Rhine river at Kaub forecast to hit key 15.75 inches (40 cm) today and down to almost nothing at 13.4 inches (34 cm) on Tues. No wonder fuel, coal barges is impassable. that's about the 👇 minimum depth for rafters down the Elbow River in Calgary. Thx @JWittels for link. #OOTT

https://www.elwis.de/DE/dynamisch/gewaesserkunde/wasserstaende/index.php?target=1&pegelId=1d26e504-7f9e-480a-b52c-5932be6549ab

WSV.de
Wasserstraßen- und Schifffahrtsverwaltung des Bundes

ELWIS

inland shipping | maritime shipping | pleasure boating | Examination/calibration | shipping law | service

Water levels & forecasts at gauges relevant to shipping

Level KAUB						forecast			appraisal				
Level HSW / GlW	watch	Thursday 08/11/22		Today 08/12/22		Today 08/12/22	Sat 08/13/22	Sun 14.08.22	Sun 14.08.22	Mon 08/15/22	Tuesday 08/16/22	Wed. 08/17/22	Thursday 08/18/22
KAUB 640 / 78	01:00:00	--	(--)	--	(--)	--	41	40	--	37	35	--	--
	03:00:00	--	(--)	--	(--)	--	41	40	--	37	35	--	--
	05:00:00	47	(-1)	**42**	(-5)	--	41	40	--	36	35	--	--
	07:00:00	--	(--)	--	(--)	**42**	41	39	--	36	34	--	--
	09:00:00	--	(--)	--	(--)	**41**	41	--	39	36	--	--	--
	11:00:00	--	(--)	--	(--)	**41**	41	--	39	36	--	--	--
	13:00:00	45	(-1)	--	(--)	**41**	41	--	39	36	--	--	--
	15:00:00	--	(--)	--	(--)	**41**	41	--	38	36	--	--	--
	17:00:00	--	(--)	--	(--)	**40**	41	--	38	35	--	--	--
	19:00:00	--	(--)	--	(--)	**40**	41	--	38	35	--	--	--
	21:00:00	46	(+1)	--	(--)	**40**	41	--	37	35	--	--	--
	23:00:00	--	(--)	--	(--)	**40**	41	--	37	35	--	--	--

Dan Tsubouchi @Energy_Tidbits · Aug 11

Huge hit coming on #Oil #NatGas #Mining Co's if new CO Pres Petro tax reform enacted. @ANDI_Colombia @BruceMacMaster estimate effective tax rate would jump from 53% to 87%. There are other hits noted in the @anjaralop report. #OOTT

Ecopetrol Says Colombia Should Pare Back Proposed Oil Export Tax
2022-08-11 21:41:28.808 GMT

By Andrea Jaramillo
(Bloomberg) -- Colombia's state-controlled oil producer Ecopetrol SA is proposing to dilute a planned oil export tax that is a major part of President Gustavo Petro's economic program.
Ecopetrol is asking the government, it's largest shareholder, to raise the reference price for when it starts charging oil export taxes. A bill presented this week includes a 10% export tax on oil, coal and gold when the price is above an international reference, which is $48 a barrel for crude. That compares to an average price of about $105 in the last six months.
The reference price is "too low," CEO Felipe Bayon said in an interview on the sidelines of a business conference in Cartagena. "For me the threshold of $48 would need to go up." A ballpark number of about $65 to $70 a barrel would make sense, he said. The government's proposed level of $48 would deliver up to 5 trillion pesos ($1.2 billion) in export taxes at current prices. As it is, the export tax would reduce Ecopetrol's dividend payments by about half, according to Bayon.
The benefit for the government is that it receives payments as soon as crude is exported, "which we understand is relevant."
The leftist government of Gustavo Petro, which took office on Sunday, has said the tax reform is part of its wider plan to cut inequality and finance poverty-fighting programs. Petro has pledged to phase out the economy's dependence on oil and coal, which currently account for about half of Colombia's exports. As part of his campaign promises he said he won't award any more exploration licenses, and has said the transition will take about 12 years.
Read: Petro Targets Rich Colombians and Oil Exports With New Taxes
The tax reform aims to boost 2023 tax revenue by the equivalent of 1.7% of gross domestic product. The tax bill also includes a proposal that halts deductions for royalty payments, which means higher costs for commodity companies.
Speaking at business association ANDI's annual event in Cartagena, it's head Bruce Mac Master cautioned that tax increases may lead companies to reconsider investing in Colombia. The group calculates that the effective tax rate for mining and hydrocarbon companies would jump to 87% if the tax bill passes in its current form, from 53% this year.
Ecopetrol doesn't just have to contend with higher levies. The government also needs to reimburse it for subsidizing fuels. Rather than allow gasoline prices to rise in line with crude this year, the government has capped the increases. That means that at current prices, the subsidy costs the government between 2 and 3 trillion pesos a month.
In March of this year Ecopetrol received 14.2 trillion pesos outstanding, and this month will receive about 3 trillion pesos.
The Petro administration has shown willingness to continue to pay, said Bayon, pointing to 19.2 trillion pesos earmarked in next year's budget for such payment.
"They are very aware and we'll continue to work with the government," said Bayon. "I sense the right attitude."
Still, the new tax plans won't slow down Ecopetrol's investment plans after it presented record earnings in the second quarter.
"We don't want to slow down our investment," said Bayon. "Prices are in a good place, our ability to execute is good: more rigs, more wells being drilled, more facilities being built."
Production is also up. Ecopetrol produced 704,000 barrels a day in the second quarter and in July it rose to 714,000.
"All in all things are looking good," said Bayon. "But you need to look at the potential implications of the tax reform and the fuel subsidies, the whole thing."

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To view this story in Bloomberg click here:
https://blinks.bloomberg.com/news/stories/RGGQX7T0AFB4

Dan Tsubouchi @Energy_Tidbits · Aug 11

Will US national average #Gasoline prices below $4 get more people on the road? @AAAnews says now $3.99. down $0.69 in last month, up $0.80 vs yr ago. But #Diesel still tight at $5.08, down $0.56 in last mth, but up $1.79 vs yr ago. #OOTT

GAS PRICES

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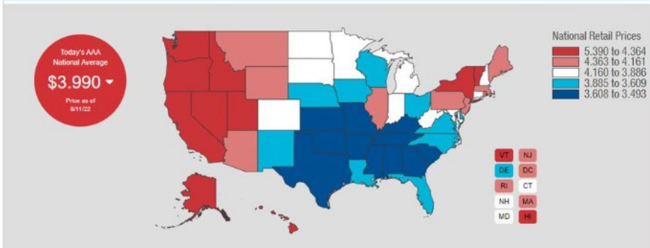

NEWS: Gas Prices Fall, But Not Enough to Lure Drivers Back to the Pump Read more »

NATIONAL AVERAGE GAS PRICES

	Regular	Mid-Grade	Premium	Diesel	E85
Current Avg.	$3.990	$4.442	$4.744	$5.077	$3.262
Yesterday Avg.	$4.010	$4.460	$4.763	$5.098	$3.278
Week Ago Avg.	$4.139	$4.586	$4.886	$5.215	$3.407
Month Ago Avg.	$4.678	$5.118	$5.415	$5.642	$3.997
Year Ago Avg.	$3.185	$3.537	$3.811	$3.293	$2.685

Dan Tsubouchi @Energy_Tidbits · Aug 11

It's not just "soaring oil use for power generation and gas-to-oil switching are boosting demand", @IEA also increased motor gasoline & jet fuel demand MoM. Brent #Oil +$1.54 to $98.34 since #IEAOMR at 2am MT. Thx @JWittels. #OOTT

Diesel Is Main Driver of 0.5m B/d 2022 Demand Revision Jump: IEA
2022-08-11 08:00:00.32 GMT

By Jack Wittels
(Bloomberg) -- The IEA increased its expectation for 2022 oil product demand by just over 0.5m b/d in its August oil market report.
* Estimates changed from the July report
* All segments were revised up, apart from LPG and ethane.
* Global demand by product, all units in k b/d:

Product	2022 (July OMR)	2022 (August OMR)	Revision
LPG & Ethane	14368	14321	-47
Naphtha	6809	6831	22
Motor Gasoline	25846	25932	86
Jet Fuel & Kerosene	6095	6143	48
Gas/Diesel Oil	27849	28077	228
Residual Fuel Oil	6247	6395	148
Other Products	11967	11997	30
Total Products	99181	99695	514

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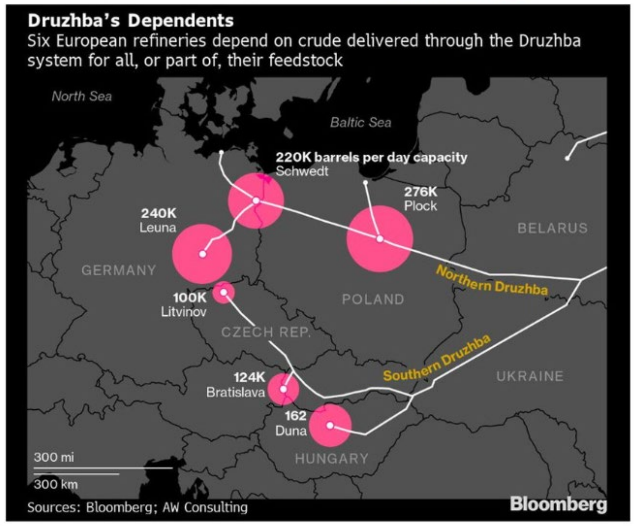
To view this story in Bloomberg click here:
https://blinks.bloomberg.com/news/stories/RGFVIVT1UM0Y

Dan Tsubouchi @Energy_Tidbits · Aug 10

"Crude flows via the southern leg of the Druzhba link may reach Slovakia by the end of Wednesday, Transneft PJSC spokesman Igor Dyomin told Bloomberg on Wednesday" reports @ja_herron. #OOTT

Excerpt from Bloomberg report "Russian Oil Flows Halted Through Pipeline to Central Europe (1)"
2022-08-09 11:14:14.163 GMT

To contact Bloomberg News staff for this story: James Herron in London at jherron9@bloomberg.net



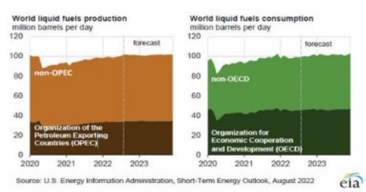
Dan Tsubouchi @Energy_Tidbits · Aug 10

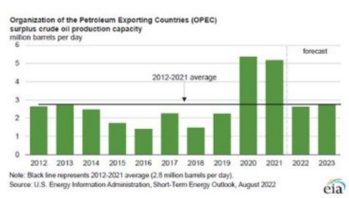
Hmmm! #EIA STEO fcasts increasing YoY OPEC spare capacity in 23 after call on #OPEC is +0.56 mmbd YoY in 23? ie. Wonder what OPEC members account for this assumed #OPEC YoY increase in #Oil capacity of ~0.7 mmbd YoY in 2023? #OOTT

Excerpts EIA Short Term Energy Outlook August 2022 https://www.eia.gov/outlooks/steo/pdf/steo_full.pdf

Table 3a. International Petroleum and Other Liquids Production, Consumption, and Inventories
U.S. Energy Information Administration | Short-Term Energy Outlook - August 2022

	2021				2022				2023				Year		
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	2021	2022	2023
Production (million barrels per day) (a)															
OECD	30.21	30.79	31.11	32.22	31.66	32.13	32.84	33.56	33.82	33.93	34.12	34.70	31.09	32.55	34.14
U.S. (50 States)	17.74	19.11	19.00	19.90	19.44	20.18	20.55	21.05	21.11	21.26	21.56	21.97	18.94	20.31	21.48
Canada	5.62	5.37	5.49	5.68	5.66	5.71	5.74	5.85	5.92	5.88	5.90	5.91	5.54	5.74	5.90
Mexico	1.93	1.95	1.90	1.92	1.91	1.89	1.89	1.86	1.90	1.87	1.83	1.79	1.92	1.89	1.85
Other OECD	4.92	4.37	4.73	4.71	4.65	4.34	4.66	4.79	4.88	4.92	4.84	5.02	4.68	4.61	4.91
Non-OECD	62.58	63.99	65.62	66.13	67.21	66.98	68.38	67.68	66.91	67.33	67.52	67.01	64.59	67.57	67.19
OPEC	30.34	30.88	32.28	33.10	33.75	33.77	34.11	34.23	34.58	34.53	34.53	34.51	31.66	33.97	34.54
Crude Oil Portion	25.08	25.40	26.84	27.67	28.19	28.34	28.63	28.71	29.02	29.10	29.05	28.99	26.28	28.47	29.04
Other Liquids (b)	5.26	5.39	5.44	5.44	5.56	5.43	5.48	5.52	5.56	5.43	5.48	5.52	5.38	5.50	5.50
Eurasia	13.42	13.66	13.63	14.27	14.39	13.43	13.92	13.48	12.66	12.33	12.27	12.27	13.75	13.80	12.38
China	4.99	5.03	5.01	4.93	5.18	5.19	5.14	5.18	5.22	5.25	5.24	5.28	4.99	5.17	5.25
Other Non-OECD	13.82	14.42	14.70	13.82	13.90	14.59	15.21	14.78	14.45	15.22	15.48	14.94	14.19	14.62	15.03
Total World Production	92.79	94.79	96.73	98.35	98.87	99.11	101.21	101.24	100.72	101.26	101.64	101.71	95.68	100.12	101.33
Non-OPEC Production	62.45	63.91	64.45	65.24	65.13	65.34	67.10	67.01	66.14	66.73	67.11	67.19	64.02	66.15	66.80



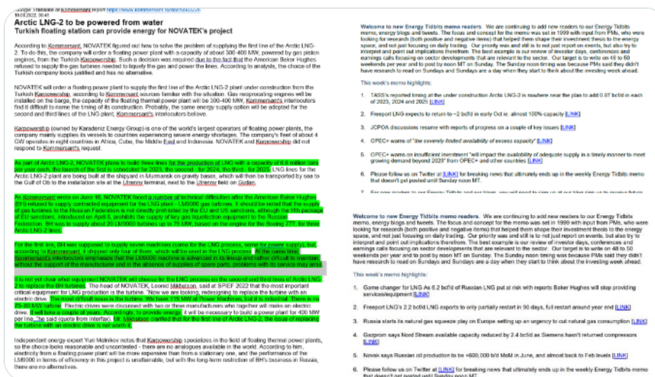


Dan Tsubouchi @Energy_Tidbits · Aug 11

Brent #Oil +$1.42 to $98.22 since @IEA OMR released 2am MT. #IEA increased oil demand for 2022 to 99.7 mmbd (was 99.2) and 2023 to 101.8 mmbd (was 101.3). "But with supply increasingly at risk to disruptions, another price rally cannot be excluded." #OOTT
iea.org/reports/oil-ma...

Dan Tsubouchi @Energy_Tidbits · Aug 9

#LNG Game Changer. RUS Arctic LNG-2 was to add 2.6 bcfd by 26 in 3 phases. Looks like only 0.47 bcf in 23 Phase 1 as only 4/7 turbines, no idea for Phase 2/3 timing. Warns risk to LNG without $BKR service & parts, would apply to existing 3.6 bcfd. See 👇 06/16 thread #NatGas #OOTT

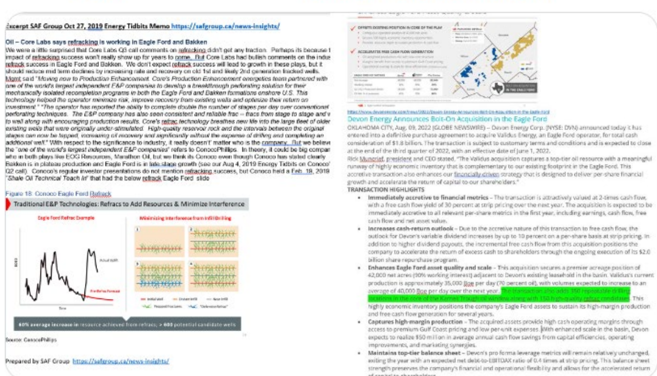


Arctic LNG-2 to be powered from water

Turkish floating station can provide energy for NOVATEK's project

Dan Tsubouchi @Energy_Tidbits · Aug 9

DUCs inventory don't tell the full story as don't incl existing wells that will be refrac'd. Devon's #EagleFord deal incl 350 locations + 150 refrac candidates. Refrac success is now new, see 👇 SAF 10/27/19 Energy TIdbits, $CLB highlighted refac in #Bakken #EagleFord. #OOTT



Excerpt SAF Group Oct 27, 2019 Energy Tidbits Memo https://safgroup.ca/news-insights/

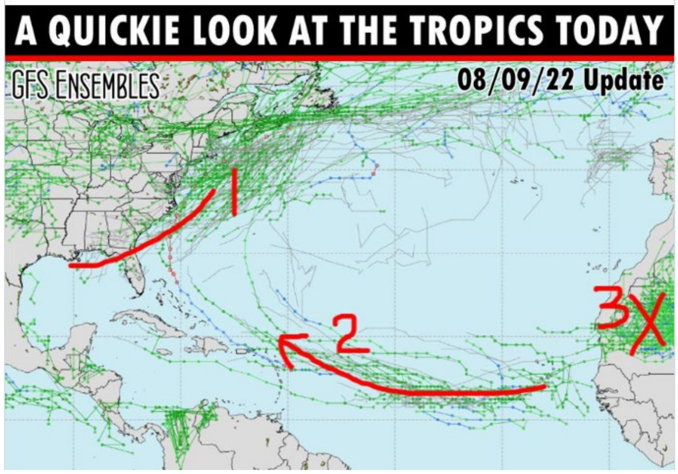
Oil – Core Labs says refracking is working in Eagle Ford and Bakken

Devon Energy Announces Bolt-On Acquisition in the Eagle Ford

Dan Tsubouchi @Energy_Tidbits · Aug 9

Reminder from #Hurricane spaghetti models - there's a range of path projections and it's tough (impossible) for any one expert to forecast hurricane paths. In this case #2 looks to be north of Puerto Rico & into Atlantic, not GoM #Oil #NatGas #LNG. Thx @tropicalupdate. #OOTT

> **Mike's Weather Page** @tropicalupdate · Aug 9
>
> A look at the Tropics. #1 weekend front dips south. Outside chance something off the east coast. Gulf unlikely. #2 is Invest 97. Still looks to tug NW some and eventually weaken into next week. #3 showing African juice brewing for our next wave to watch. spaghettimodels.com

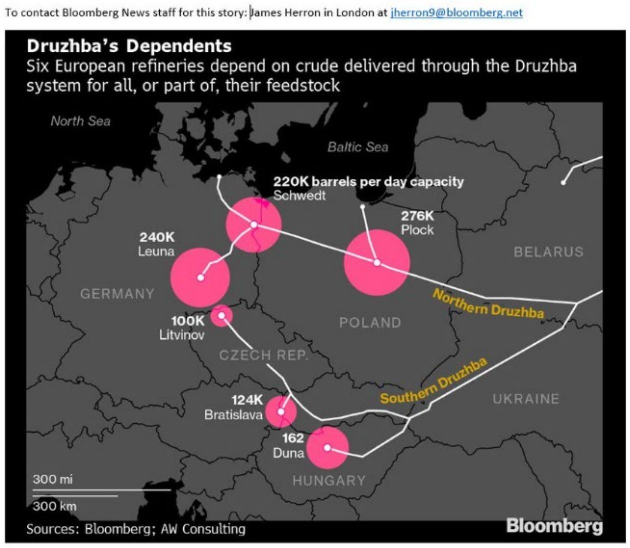


Dan Tsubouchi @Energy_Tidbits · Aug 9

Who doesn't love a great map. #Oil transport halted Aug 4 on southern leg of Transneft Druzhba oil pipeline that transits thru Ukraine to refineries 162 mbd in Hungary, 124 mbd in Slovakia, 100 mbd in Czech Rep. Brent flipped $2 on news, now $98. Thx @business @ja_herron. #OOTT

Excerpt from Bloomberg report "Russian Oil Flows Halted Through Pipeline to Central Europe (1)"
2022-08-09 11:14:14.163 GMT

To contact Bloomberg News staff for this story: James Herron in London at jherron9@bloomberg.net



Dan Tsubouchi @Energy_Tidbits · Aug 8

Widening YoY deficit gap in US on-road gasoline consumption, but far above 2020 levels. Good @Kayrros graph "measures actual miles traveled and end-user consumption by US motorists, as opposed to deliveries into secondary storage as reported in US @EIAgov weekly surveys" #OOTT

Excerpt Kayrros Weekly Roundup – August 8, 2022

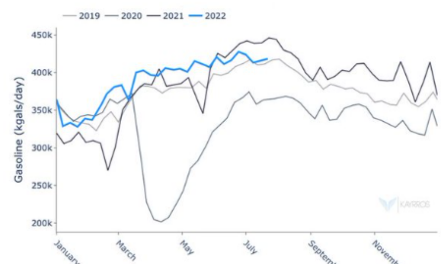
KAYRROS

Summer doldrums

A similar trend can be observed in the U.S., where on-road gasoline consumption has fallen significantly below last year's level since Memorial Day weekend and where the year-on-year gap has been widening.

Kayrros measures actual miles traveled and end-user consumption by U.S motorists, as opposed to deliveries into secondary storage as reported in U.S. EIA weekly surveys.

Figure: **On road gasoline consumption in the U.S.**



Dan Tsubouchi @Energy_Tidbits · Aug 8

ICYMI, 🇨🇦 is only country with 3 cities in top 10 cities in @TheEIU #GlobalLiveabilityIndex2022 with #Calgary 3rd, #Vancouver 5th, #Toronto 8th. i have been fortunate to live in all three of these great cities of the world.

1 © The Economist Intelligence Unit Limited 2022

THE GLOBAL LIVEABILITY INDEX 2022

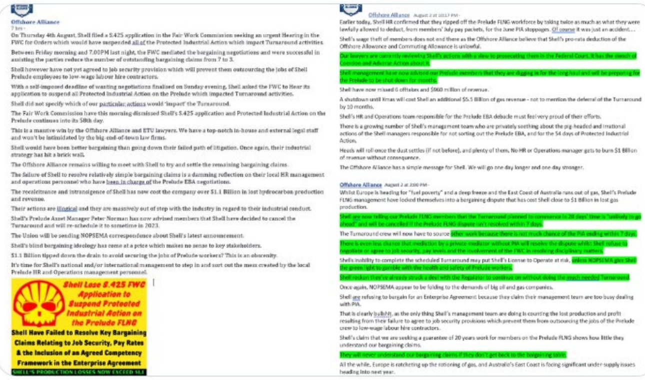
Top ten positions

City	Location	Rank	Index	Stability	Healthcare	Culture & Environment	Education	Infrastructure
Vienna	Austria	1	99.1	100.0	100.0	96.3	100.0	100.0
Copenhagen	Denmark	2	98.0	100.0	95.8	95.4	100.0	100.0
Zurich	Switzerland	3	96.3	95.0	100.0	96.3	91.7	96.4
Calgary	Canada	3	96.3	95.0	100.0	90.0	100.0	100.0
Vancouver	Canada	5	96.1	90.0	100.0	100.0	100.0	92.9
Geneva	Switzerland	6	95.9	95.0	100.0	94.9	91.7	96.4
Frankfurt	Germany	7	95.7	90.0	100.0	96.3	91.7	100.0
Toronto	Canada	8	95.4	95.0	100.0	95.4	100.0	89.3
Amsterdam	Netherlands	9	95.3	90.0	100.0	97.2	91.7	96.4
Osaka	Japan	10	95.1	100.0	100.0	83.1	100.0	96.4
Melbourne	Australia	10	95.1	95.0	83.3	98.6	100.0	100.0

Source: EIU.

Dan Tsubouchi @Energy_Tidbits · Aug 8

See 👇 , looks like big shift in union messaging. Potential for end to #Shell 0.47 bcfd #PreludeFLNG labor dispute? 08/02 union 1st warning for potential lengthy shutdown. Today, some mediation progress, big change in union tone & no long term shutdown threat? #LNG #NatGas #OOTT



Dan Tsubouchi @Energy_Tidbits · Aug 8

See 👇 transcript. @ea_amrita on next 2 mths vs after Nov. Headline will be she thinks #Oil prices can continue to weaken in near term. But after Nov, "the market is going to tighten up very, very quickly. So we still maintain forecast of over $120 for Brent". #OOTT

SAF Group created transcript of Energy Aspects Amrita Sen comments with Tom Keene and Lisa Abramowicz on Bloomberg Surveillance on Aug 8, 2022

Items in "italics" are SAF Group created transcript

At 4:51am MT. Abramowicz *"… where should oil prices be based on what you're seeing in the raw data?"* Sen *"… in terms of where prices should be, I think, in the near term, we can continue to weaken. We've got seasonally refinery maintenance coming up, this is always a weak period for crude. I'm not expecting to see a sudden increase in prices, but, come the winter, particularly after November. First of November, the SPR stops. First of December, Russia, the European embargo on Russian embargo starts as well. You've got the China Party Congress, which should allow, we believe, at least some easing in Covid restrictions. The market is going to tighten up very, very quickly. So we still maintain forecast of over $120 for Brent."*

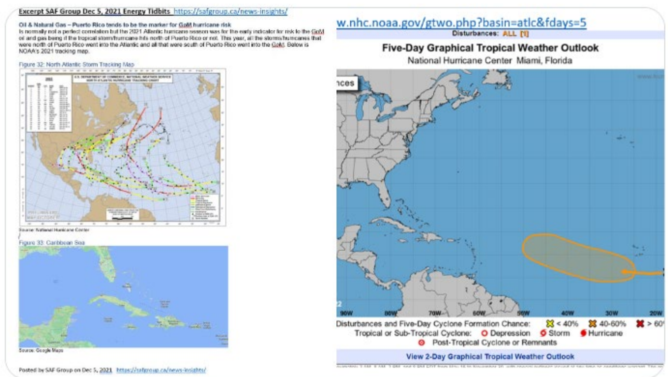
Prepared by SAF Group https://safgroup.ca/news-insights/

Dan Tsubouchi @Energy_Tidbits · Aug 7

perfect day in #Calgary. sunn and 28C. and a steady steam of rafters down the slow moving Elbow River

Dan Tsubouchi @Energy_Tidbits · Aug 7

Forecasting Atlantic hurricane paths is impossible even for experts. But hurricane risk to GoM #Oil #NatGas #LNG #Refinery tends to increase if hurricanes are south of Puerto Rico. See 👇 excerpt SAF Group Dec 5, 2021 Energy Tidbits safgroup.ca/news-insights/ #OOTT



Dan Tsubouchi @Energy_Tidbits · Aug 7

Our weekly SAF Aug 7, 2022 Energy Tidbits memo is posted on SAF Group website. this 57-pg energy research memo expands upon & covers more items than tweeted this week. See news/insights section of SAF website #Oil #OOTT #LNG #NatGas #EnergyTransition safgroup.ca/news-insights/

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Energy Tidbits

Aug 7, 2022

Produced by: Dan Tsubouchi

Bullish For LNG: Russia Confirms Arctic LNG-2 is Nowhere Near Timing to Add 0.87 bcf/d in Each of 2023, 2024 & 2025

Welcome to new Energy Tidbits memo readers. We are continuing to add new readers to our Energy Tidbits memo, energy blogs and tweets. The focus and concept for the memo was set in 1999 with input from PMs, who were looking for research (both positive and negative items) that helped them shape their investment thesis to the energy space, and not just focusing on daily trading. Our priority was and still is to not just report on events, but also try to interpret and point out implications therefrom. The best example is our review of investor days, conferences and earnings calls focusing on sector developments that are relevant to the sector. Our target is to write on 48 to 50 weekends per year and to post by noon MT on Sunday. The Sunday noon timing was because PMs said they didn't have research to read on Sundays and Sundays are a day when they start to think about the investing week ahead.

This week's memo highlights:

1. TASS's reported timing at the under construction Arctic LNG-2 is nowhere near the plan to add 0.87 bcf/d in each of 2023, 2024 and 2025 [LINK]
2. Freeport LNG expects to return to ~2 bcf/d in early Oct ie. almost 100% capacity [LINK]
3. JCPOA discussions resume with reports of progress on a couple of key issues [LINK]
4. OPEC+ warns of "*the severely limited availability of excess capacity*" [LINK]
5. OPEC+ warns on insufficient investment "will impact the availability of adequate supply in a timely manner to meet growing demand beyond 2023" from OPEC+ and other countries [LINK]
6. Please follow us on Twitter at [LINK] for breaking news that ultimately ends up in the weekly Energy Tidbits memo that doesn't get posted until Sunday noon MT.
7. For new readers to our Energy Tidbits and our blogs, you will need to sign up at our blog sign up to receive future Energy Tidbits memos. The sign up is available at [LINK].

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