SAF GROUP

Energy Tidbits

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Independent Statistics & Analysis
U.S. Energy Information Administration

September 2021

Short-Term Energy Outlook

Forecast highlights

Global liquid fuels

- The September *Short-Term Energy Outlook* (STEO) remains subject to heightened levels of uncertainty related to the ongoing recovery from the COVID-19 pandemic. U.S. economic activity continues to rise after reaching multiyear lows in the second quarter of 2020 (2Q20). U.S. gross domestic product (GDP) declined by 3.4% in 2020 from 2019 levels. This STEO assumes U.S. GDP will grow by 6.0% in 2021 and by 4.4% in 2022. The U.S. macroeconomic assumptions in this outlook are based on forecasts by IHS Markit. Our forecast assumes continuing economic growth and increasing mobility. Any developments that would cause deviations from these assumptions would likely cause energy consumption and prices to deviate from our forecast.

- Brent crude oil spot prices averaged $71 per barrel (b) in August, down $4/b from July but up $26/b from August 2020. Brent prices have risen over the past year as result of steady draws on global oil inventories, which averaged 1.8 million barrels per day (b/d) during the first half of 2021 (1H21). We expect Brent prices will remain near current levels for the remainder of 2021, averaging $71/b during the fourth quarter of 2021 (4Q21). In 2022, we expect that growth in production from OPEC+, U.S. tight oil, and other non-OPEC countries will outpace slowing growth in global oil consumption and contribute to Brent prices declining to an annual average of $66/b.

- More than 90% of crude oil production in the Federal Offshore Gulf of Mexico (GOM) was offline in late August following Hurricane Ida. As a result of the outage, GOM production averaged 1.5 million b/d in August, down 0.3 million b/d from July. We expect that crude oil production in the GOM will gradually come back online during September and average 1.2 million b/d for the month before returning to an average of 1.7 million b/d in 4Q21.

- Total U.S. crude oil production averaged 11.3 million b/d in June—the most recent monthly historical data point. We forecast it will remain near that level through the end of 2021 before increasing to an average of 11.7 million b/d in 2022, driven by growth in onshore tight oil production. We expect growth will result from operators beginning to increase rig additions, offsetting production decline rates.

Note: EIA completed modeling and analysis for this report on Thursday September 2, 2021

- We estimate that 98.4 million b/d of petroleum and liquid fuels was consumed globally in August, an increase of 5.7 million b/d from August 2020 but still 4.0 million b/d less than in August 2019. We forecast that global consumption of petroleum and liquid fuels will average 97.4 million b/d for all of 2021, which is a 5.0 million b/d increase from 2020, and by an additional 3.6 million b/d in 2022 to average 101.0 million b/d, almost even with 2019 levels.

- U.S. regular gasoline retail prices averaged $3.16 per gallon (gal) in August, the highest monthly average price since October 2014. Recent gasoline price increases reflect rising wholesale gasoline margins amid relatively low gasoline inventories. In addition, recent impacts from Hurricane Ida on several U.S. Gulf Coast refineries are adding upward price pressures in the near term. Estimated gasoline margins surpassed 70 cents/gal in late August. We expect margins will remain elevated in the coming weeks as refining operations as U.S. Gulf Coast remain disrupted. We forecast that retail gasoline prices will average $3.14/gal in September before falling to $2.91/gal, on average, in 4Q21. The expected drop in retail gasoline prices reflects our forecast that gasoline margins will decline from currently elevated levels, both as a result of rising refinery runs as operations return in the first half of September following Hurricane Ida and because of typical seasonality.

- Propane net exports in our forecast average close to 1.2 million b/d for the remainder of 2021, reflecting elevated global demand for U.S. propane and reduced supply from other sources related to ongoing OPEC+ production cuts. In 1H22, we assume global production of propane and butanes will rise as OPEC+ countries increase crude oil production. We expect this increase will limit additional demand for U.S. propane exports, despite growing global propane demand, and keep U.S. net propane exports close to 1.2 million b/d in 2022.

Natural Gas

- In August, the natural gas spot price at Henry Hub averaged $4.07 per million British thermal units (MMBtu), which is up from the July average of $3.84/MMBtu. The August increase reflects hotter temperatures in August on average across the United States compared with July, which caused demand for natural gas in the electric power sector to be higher than expected. Prices rose further in late August when Hurricane Ida caused a decline in natural gas production in the GOM.

- Henry Hub spot prices in August were $1.77/MMBtu higher than in August 2020. Steadily rising natural gas prices over the past year primarily reflects: growth in liquefied natural gas (LNG) exports, rising domestic natural gas consumption for sectors other than electric power, and relatively flat natural gas production. We expect the Henry Hub spot price will average $4.00/MMBtu in 4Q21, as the factors that drove prices higher during August lessen. Forecast Henry Hub prices this winter reach a monthly average peak of $4.25/MMBtu in January and generally decline through 2022, averaging $3.47/MMBtu for the year amid rising U.S. natural gas production and slowing growth in LNG exports.

- More than 90% of natural gas production in the GOM was offline in late August following Hurricane Ida. GOM production of marketed natural gas averaged 1.9 billion cubic feet per day (Bcf/d) in August, down 0.4 Bcf/d from July. We expect that natural gas production in the GOM will gradually come back online during the first half of September and average 1.5 Bcf/d for the month before returning to an average of 2.1 Bcf/d in 4Q21.

- We expect dry natural gas production will average 92.7 Bcf/d in the United States during 2H21—up from 91.7 Bcf/d in 1H21—and then rise to 95.4 Bcf/d in 2022, driven by natural gas and crude oil prices, which we expect to remain at levels that will support enough drilling to sustain production growth.

- We expect that U.S. consumption of natural gas will average 82.5 (Bcf/d) in 2021, down 0.9% from 2020. U.S. natural gas consumption declines in 2021, in part, because electric power generators switch to coal from natural gas as a result of higher natural gas prices. In 2021, we expect residential and commercial natural gas consumption combined will rise by 1.2 Bcf/d from 2020 and industrial consumption will rise by 0.6 Bcf/d from 2020. Rising natural gas consumption in sectors other than the electric power sector results from expanding economic activity and colder winter temperatures in 2021 compared with 2020. We expect U.S. natural gas consumption will average 82.6 Bcf/d in 2022, mostly unchanged from 2021.

- We estimate that U.S. natural gas inventories ended August 2021 at about 2.9 trillion cubic feet (Tcf), which is 7% lower than the five-year (2016–20) average for this time of year. Injections into storage this summer have been below the previous five-year average, largely as a result of hot weather and high exports occurring amid relatively flat natural gas production. We forecast that inventories will end the 2021 injection season (end of October) at almost 3.6 Tcf, which would be 5% below the five-year average.

Electricity, coal, renewables, and emissions

- We expect the share of electricity generation produced by natural gas in the United States will average 35% in 2021 and 34% in 2022, down from 39% in 2020. In 2021, the forecast share for natural gas as a generation fuel declines in response to our expectation of a higher delivered natural gas price for electricity generators, which we forecast will average $4.69/MMBtu in 2021 compared with $2.39/MMBtu in 2020. The share of natural gas as a generation fuel also declines through 2022 because of expected increases in generation from renewable sources. As a result of the higher expected natural gas prices, the forecast share of electricity generation from coal rises from 20%

in 2020 to about 24% in both 2021 and 2022. New additions of solar and wind generating capacity are offset somewhat by reduced generation from hydropower this year, resulting in the forecast share of all renewables in U.S. electricity generation to average 20% in 2021, about the same as last year, before rising to 22% in 2022. The nuclear share of U.S. electricity generation declines from 21% in 2020 to 20% in 2021 and to 19% in 2022 as a result of retiring capacity at some nuclear power plants.

- We forecast that planned additions to U.S. wind and solar generating capacity in 2021 and 2022 will increase electricity generation from those sources. We estimate that the U.S. electric power sector added 14.7 gigawatts (GW) of new wind capacity in 2020. We expect 17.6 GW of new wind capacity will come online in 2021 and 6.3 GW in 2022. Utility-scale solar capacity rose by an estimated 10.5 GW in 2020. Our forecast for added utility-scale solar capacity is 15.9 GW for 2021 and 16.3 GW for 2022. We expect significant solar capacity additions in Texas during the forecast period. In addition, we project that after increasing by 4.5 GW in 2020, small-scale solar capacity (systems less than 1 megawatt) will grow 5.8 GW and 5.7 GW in 2021 and 2022 respectively.

- Coal production in our forecast totals 601 million short tons (MMst) in 2021, 66 MMst more than in 2020. We expect demand for coal from the electric power sector to increase by 100 MMst in 2021 as a result of high natural gas prices, and coal exports to increase by 21 MMSt. However, production is unlikely to match those increases in demand in the near term due to capacity constraints at coal mines and limited available transportation. In 2022, we expect coal production to increase by 47 MMst to 648 MMst, despite our forecast of declines in coal consumption, as the production and transportation constraints experienced in 2021 ease. Secondary inventories of coal at electric utilities decreased in 1H21, and we forecast this trend will continue into 2H21 and 2022.

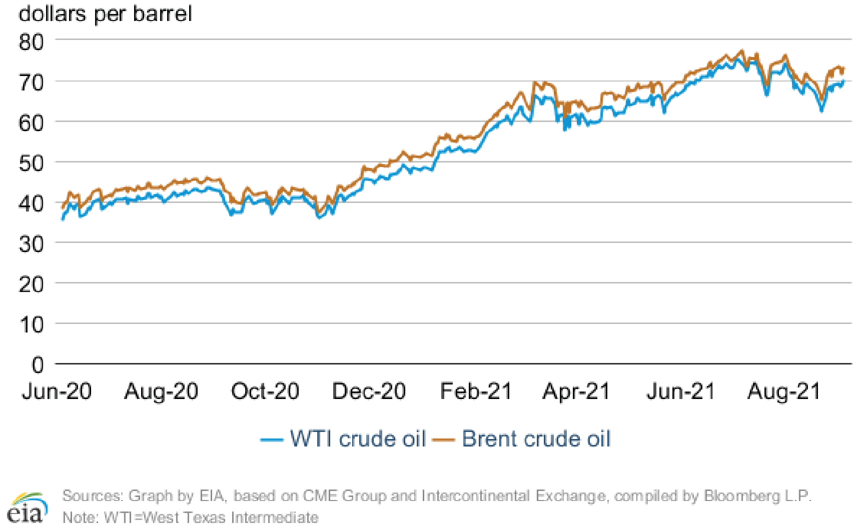
- We estimate that U.S. energy-related carbon dioxide (CO_2) emissions decreased by 11% in 2020 as a result of less energy consumption related to reduced economic activity and responses to COVID-19. For 2021, we forecast energy-related CO_2 emissions will increase about 8% from the 2020 level as economic activity increases and leads to rising energy use. We also expect energy-related CO_2 emissions to rise in 2022 but at a slower rate of 2%. We forecast that after declining by 19% in 2020, coal-related CO_2 emissions will rise by 22% in 2021 and then decrease by 2% in 2022. Short-term changes in energy-related CO_2 can be affected by temperature. A recent STEO supplement examines these dynamics.

Petroleum and natural gas markets review

Crude oil

Prices: The front-month futures price for Brent crude oil settled at $73.03 per barrel (b) on September 2, 2021, up 14 cents/b from $72.89/b on August 2. The front-month futures price for West Texas Intermediate (WTI) crude oil for delivery at Cushing, Oklahoma, decreased by $1.27/b during the same period, settling at $69.99/b on September 2 **(Figure 1)**.

Figure 1. Crude oil front-month futures prices



Sources: Graph by EIA, based on CME Group and Intercontinental Exchange, compiled by Bloomberg L.P.
Note: WTI=West Texas Intermediate

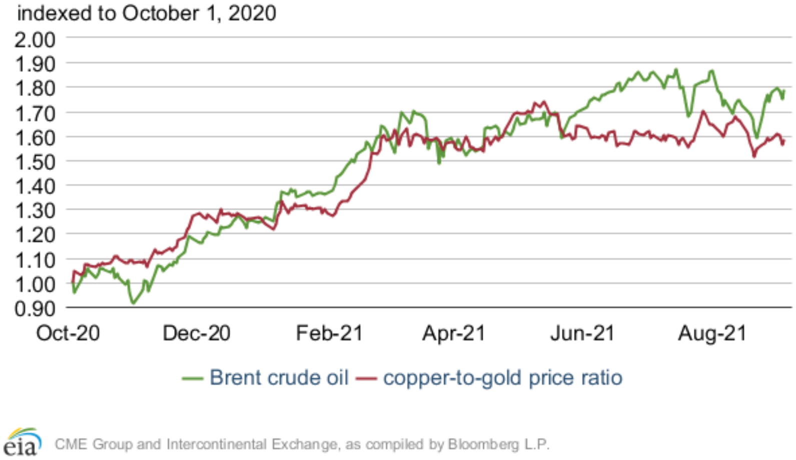
Brent and WTI prices both decreased in the first half of August. Increasing OPEC+ crude oil production and flattening global petroleum demand in response to rising COVID-19 cases contributed to the falling crude oil prices. Both benchmarks reached their low points of the month on August 20: Brent at $65/b and WTI at $62/b. Crude oil prices increased in the latter part of the month, and Brent prices are just above where they started August. On a monthly average basis, the Brent spot price in August decreased $4/b compared with July. Although crude oil prices have been gradually increasing in the wake of the initial COVID-19-induced price decrease, August marks the fourth month since May 2020 in which the price has declined. This price decrease may reflect market concerns about the demand impacts of a possibly continuing COVID-19 pandemic and spread of the Delta variant.

In the September STEO, our outlook for global oil markets is largely unchanged from last month, and we continue to expect Brent prices will average $71/b in the fourth quarter of 2021 (4Q21) and $66/b in 2022. One notable change is that we have revised global oil demand expectations down in 2021, accounting for reactions to the proliferation of the Delta variant. We decreased our oil demand expectations primarily in the middle months of 2021, and we reduced forecast global oil demand by an average of 0.5 million b/d in the 3Q21. We now expect global oil demand to grow by 5.0 million b/d in 2021, down from expected growth of 5.3 million b/d in last month's forecast.

In the near term, the impact of Hurricane Ida on U.S. offshore production, reported incidents at Mexican offshore facilities, and lower-than-expected production in several non-OPEC countries have contributed to lower crude oil production offsetting some of the price effects of lower-than-expected oil demand. How the market will continue to process news about further COVID-19 outbreaks, even in countries with rising numbers of vaccinated people, remains an important uncertainty in our forecast. The production decisions of OPEC+ given an evolving demand outlook will also be a key driver of oil price formation in the coming months. Our forecast assumes that OPEC+ will generally produce at a level that achieves a relatively balanced oil market.

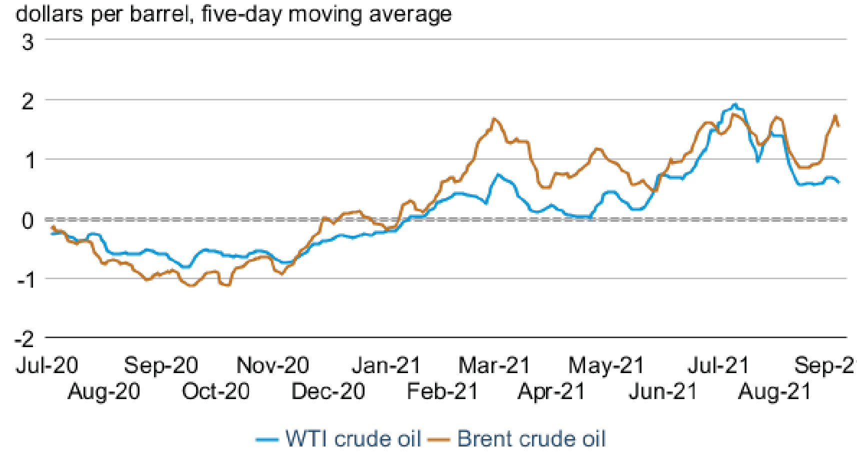
Brent front-month price and copper-to-gold front-month price ratio: Lower crude oil prices in August reflect flattening global petroleum demand, likely driven by responses to rising COVID-19 cases and the spread of the Delta variant. The decline in global commodity prices was not limited to crude oil, however. The copper-to-gold ratio is a measure of the value of copper relative to the value of gold. Copper is a metal whose value increases during periods of growing industrial production and economic activity. Gold is a metal whose value can increase during periods of economic uncertainty or changes in inflation expectations. On August 19, the copper-to-gold ratio (indexed to October 1, 2020, the start of 4Q20) decreased to its lowest level since February 2021 **(Figure 2)**. After rising mostly in tandem with crude oil prices through May 2021, the ratio weakened slightly over the summer, while crude oil prices continued rising through July. The weaker copper-to-gold ratio reflects lower global copper prices over the summer which declined primarily because of responses to rising COVID-19 cases globally. Unlike the copper-to-gold ratio, global crude oil prices were particularly elevated through the summer, reflecting sector-specific impacts on the global crude oil price that are unrelated to other commodities, such as the sustained OPEC+ crude oil production curtailment. However, the recent decreases in crude oil prices have brought its relative change compared to the beginning 4Q20 closer to the change in the copper-to-gold ratio, illustrating the role of macroeconomic demand factors in global commodities markets and the easing of the role of supply side factors that had supported crude oil prices earlier in the summer. Since the August 19 low point for both crude oil and the copper-to-gold ratio, positive reports of reduced COVID-19 cases in China and some other Asian countries have contributed to stronger expectations for global commodities demand, affecting both copper and oil prices.

Figure 2. Brent front-month prices and copper-to-gold front-month price ratio



Crude oil front-month to third-month futures price spread: On August 16, the five-day moving average spread between the front-month and third-month futures price for Brent crude oil fell to its lowest level since May 31, 2021 **(Figure 3)**. Although concerns over rising COVID-19 cases introduced downward price pressure and increased volatility into the market in August, the sustained backwardation (when near-term prices are higher than longer-dated ones) in the 1-3 futures spreads indicate that the global petroleum complex is still relying on petroleum inventories to meet demand. High backwardation typically indicates market participants are selling crude oil from storage, resulting in stock draws. The spread for Brent averaged $1.25/b in June and $1.51/b in July, and rarely narrowed below $1.30/b from mid-June through July. Global oil stocks draws from January through July averaged 1.7 million b/d, bolstered by draws of 2.7 million b/d in June. In August, the Brent 1-3 spread narrowed to less than than 90 cents/b. Although the spread remained positive, the decrease likely reflected lower front-month crude oil prices due to temporarily lower demand expectations. We estimate net global stock draws in August were 1.6 million b/d, and we expect them to continue at 1.3 million b/d in September. In line with sustained inventory withdrawals, the Brent 1-3 spread widened back above $1.00/b on August 25 and was $1.56/b as of September 2. The WTI spread experienced a similarly rapid decline in mid-August, reaching its recent low of $0.55/b on August 12, but unlike Brent, it has not increased as much later in the month and has remained below $1.00/b as of September 2.

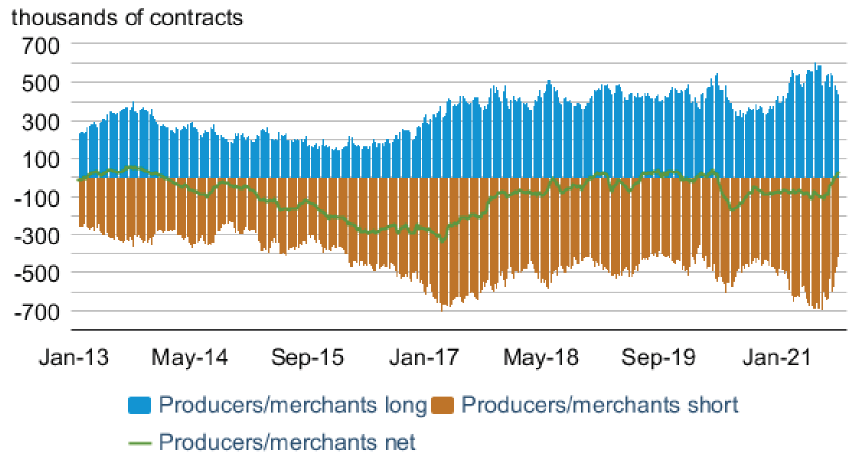
Figure 3. Crude oil front-month to third month futures price spread



Sources: CME Group, Dubai Mercantile Exchange, and Intercontinental Exchange, as compiled by Bloomberg L.P.
Note: WTI=West Texas Intermediate

Producer/merchant open interest in WTI futures: Open interest in WTI futures by producers and merchants shifted to a net long position as of the August 24 Commitment of Traders report from the Commodity Futures Trading Commission (CFTC), and overall open interest from producers and merchants has decreased **(Figure 4)**. The lower open interest reflects both an overall reduction in oil commodity futures trading by producers and merchants and a reduction in short positions. Producers and merchants is a CFTC category that include crude oil producers and refiners. These market participants often use futures as a means of financially hedging against crude oil price changes. The net producer/merchant position is often short.

Figure 4. Producer/merchant open interest in WTI futures contracts



Source: U.S. Commodity Futures Trading Commission, Commitment of Traders Report
Note: WTI=West Texas Intermediatee

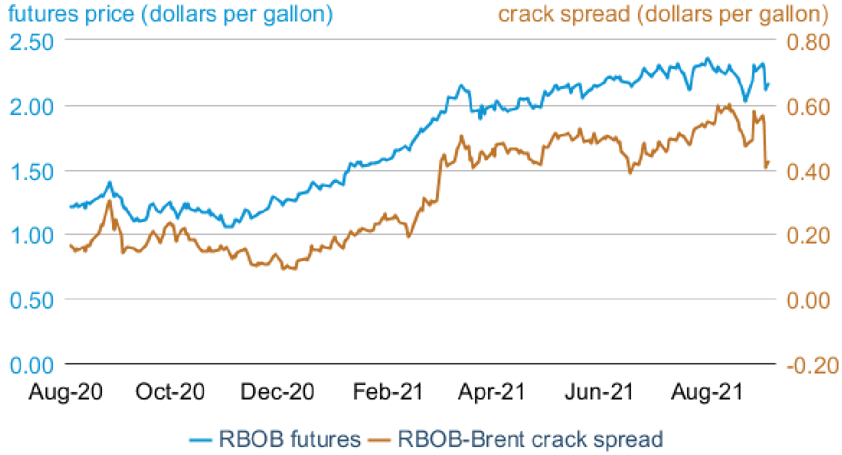
Reduced producer/merchant open interest may reflect an effort by certain upstream producers to reduce their hedged positions because of higher overall crude prices after experiencing particularly high financial losses on hedged crude oil production compared to unhedged barrels in 1H21. Hedged crude oil can often account for relative losses compared to unhedged production when crude oil prices increase, because producers typically deploy hedges to mitigate downside price risks, but hedged barrels of crude oil do not benefit from any price increases. Because of relatively rapid price increases in 1H21, any barrels that producers hedged at a lower price point resulted in foregoing the benefits of crude oil's rapid price increases during that period.

Some upstream producers such as Devon Energy, Diamondback, and Ovintiv reported losses in their second-quarter financial filings because of hedging at around $50/b. With WTI crude oil spot prices averaging $66/b for the quarter, these companies reported losses on their hedged barrels, usually of around $13/b compared with un-hedged barrels. We previously discussed the decreasing volume of net long positions by money managers in the August STEO, and the decreasing availability of market participants with long positions corresponds with decreased volume of producer/merchant short positions, which had been above 600,000 contracts on a monthly average basis since January 2021, but have since decreased to about 415,000 contracts as of the August 24 report. Producer/merchant open interest in long positions has also decreased compared with earlier in the year, but the overall reduction in long contract volume has been relatively less, contributing to the shift in the net long contract volume to 25,000 contracts. The August 24 report also showed combined producer/merchant open interest had decreased to 856,000 contracts, its lowest volume so far in 2021.

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 $2.16 per gallon (gal) on September 2, down 11 cents/gal from August 2 **(Figure 5)**. The RBOB–Brent crack spread (the difference between the price of RBOB and the price of Brent crude oil) decreased by 11 cents/gal to settle at 42 cents/gal during the same period. The RBOB–Brent crack spread declined by 14 cents/gal on September 1 when the front-month RBOB contract rolled over to October delivery, which reflects winter grade gasoline that is cheaper for refineries to produce. In August, however, the RBOB–Brent crack spread averaged 55 cents/gal, the highest monthly average crack spread since July 2015.

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



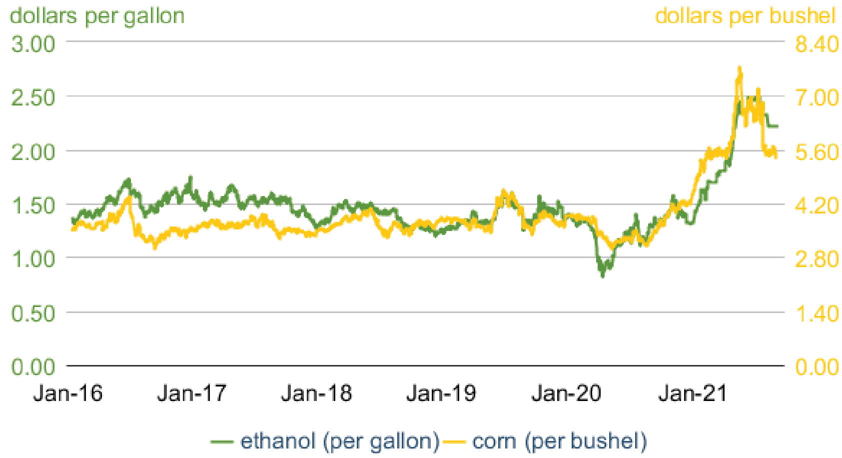
Source: Graph by EIA, based on data from CME Group, as compiled by Bloomberg L.P.
Note: RBOB is the petroleum component of gasoline used in many parts of the country.

August's high RBOB–Brent crack spread was likely a result of high summer driving demand, low gasoline stocks, refinery disruptions from Hurricane Ida, and relatively high ethanol costs. We estimate U.S. gasoline consumption averaged 9.4 million barrels per day (b/d) in August, which is 0.9 million b/d (10%) higher than in August 2020 but 0.4 million b/d (4%) lower than the August 2019 level. Several months of relatively high gasoline consumption during the summer driving months have combined with low gasoline production to contribute to low gasoline stocks. We estimate gasoline stocks ended August at 225.6 million barrels, the lowest end-of-August level since 2015. Furthermore, refinery disruptions from Hurricane Ida likely supported increased crack spreads at the end of August. The RBOB–Brent crack spread, which was 49 cents/gal on August 24, increased on August 25 and remained around 55 cents/gal through the end of the month. At least nine refineries in Louisiana reduced or shut in operations prior to Hurricane Ida, and we forecast refinery operations in the U.S. Gulf Coast will gradually restart operation over the first half of September. Because of the refinery disruptions, we expect monthly average refinery runs will be about 700,000 b/d lower in September than they would be without the disruptions. Lower refinery runs will likely contribute to continuing declines in gasoline stocks during September and support gasoline crack spreads in the coming weeks.

Recently, record-high prices for renewable identification number (RIN) credits have been another contributing factor to higher-than-average RBOB prices. RINs are the compliance mechanisms used for the Renewable Fuel Standard (RFS) program, which the U.S. Environmental Protection Agency (EPA) administers. For most of the history of RFS, RIN prices have typically been at a level that only minimally affected RBOB prices. In late 2020 and 2021, however, RIN prices have been high in large part because of high biofuel feedstock costs. The higher cost of RFS compliance for gasoline producers and importers as a result of higher RIN prices may pass through to affect RBOB prices. Although RIN prices have decreased from their record highs in August, they still remain high relative to their average levels prior to 2021 and are likely still adding upward pressure to RBOB prices.

Fuel ethanol and corn prices: Corn and ethanol prices have decreased slightly since corn prices peaked at $7.73 per bushel on May 7 and ethanol prices peaked at $2.48/gal in late June. The front-month futures price of corn closed at $5.16 per bushel on September 2, an increase of $1.67 per bushel from September 2, 2020, but $2.57 per bushel lower than the peak price on May 7. The front-month futures price of fuel ethanol settled at $2.22/gal on September 2, 2021, an increase of 86 cents/gal from September 2, 2020, and 6 cents/gal higher than the front-month RBOB contract. The fuel ethanol–corn crush spread (the difference between the price of fuel ethanol and the price of its corn inputs) has been positive since mid-July after a few atypical months of negative spreads **(Figure 6)**.

Figure 6. Corn and fuel ethanol futures prices



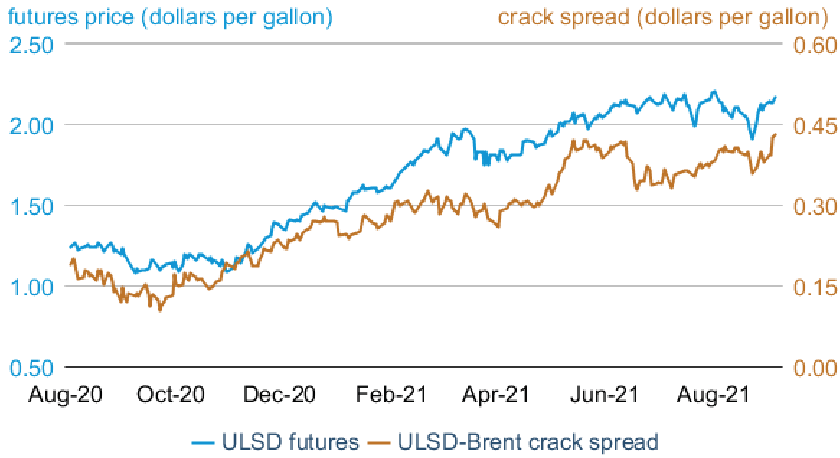
Source: CME Group, as compiled by Bloomberg L.P.
Note: About 2.8 bushels of corn go into each gallon of ethanol.

The decrease in fuel ethanol prices is mostly the result of lower prices for corn, which is the feedstock for fuel ethanol. Corn prices increased in the first half of 2021 because of high demand in China, concerns of low production as a result of cold weather in the Midwest, and a La Niña weather pattern that brought hot and dry weather, which is not ideal for corn production, to major exporters Brazil and Argentina. Corn prices have come down since June because of increased planted acreage of corn and increased production forecasts in the United States as well as uncertain demand in Asia.

Ethanol prices have decreased by less than corn prices because ethanol is primarily used for gasoline blending and therefore ethanol prices are also tied to gasoline demand, which has been relatively high. In addition, the uncertainty concerning RVO levels for 2021 has supported high RIN demand and ethanol prices. The fact that RBOB prices generally increased in July and August, despite lower ethanol prices and lower RIN prices in late August, suggests that gasoline inventory draws in August likely contributed to the crack spread increases seen in the second half of August.

Ultra-low sulfur diesel prices: The front-month futures price for ultra-low sulfur diesel (ULSD) for delivery in New York Harbor settled at $2.17/gal on September 2, up 3 cents/gal from August 2 **(Figure 7)**. The ULSD–Brent crack spread (the difference between the price of ULSD and the price of Brent crude oil) increased 3 cents/gal during the same period, settling at 43 cents/gal.

Figure 7. Historical ULSD front-month futures prices and crack spreads



Source: Graph by EIA, based on data from CME Group, as compiled by Bloomberg L.P.
Note: ULSD=ultra-low sulfur diesel

The average ULSD–Brent crack spread increased 3 cents/gal from July to 39 cents/gal in August as a result of higher distillate demand and low production. We estimate that distillate consumption increased by 0.3 million b/d (8%) from July to 4.10 million b/d in August. High freight demand expectations and record congestion at Southern Californian ports suggest that trucking and rail demand will remain high in the upcoming months before winter heating demand provides an additional increase in distillate demand. We forecast distillate demand to exceed 4 million b/d from October 2021 through June 2022.

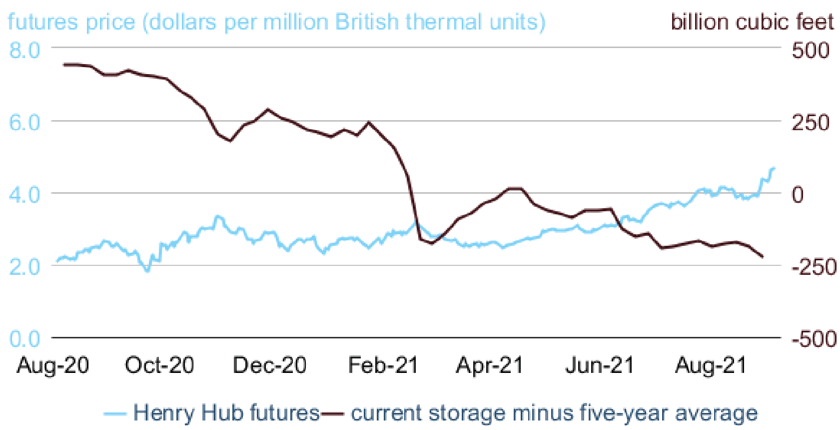
We also estimate that distillate production in August fell to its lowest level for that month since 2012. Although a reduction in net exports of distillate partly offset the high distillate demand and low distillate production, distillate stocks decreased in August, a month in which distillate stocks typically build.

We expect distillate stocks to continue to decrease through November. The forecast decrease partly reflects Hurricane Ida's refinery disruptions on the U.S. Gulf Coast and partly reflects our expectations of high distillate demand during the crop harvesting season. Low inventories and expectations of inventory draws through November are likely supporting current above-average distillate crack spreads.

Natural Gas

Prices: The front-month natural gas futures contract for delivery at the Henry Hub settled at $4.64 per million British thermal units (MMBtu) on September 2, 2021, which was up 71 cents/MMBtu from August 2, 2021 **(Figure 9)**. The average price for front-month natural gas futures contracts in August was $4.03/MMBtu. August was warmer than normal, with 355 cooling degree days (CDD), 8.6% more than the 2011–2020 average. The United States this summer (June—August) had 3.9% more CDDs than the 2011–20 average. The hot weather this summer combined with record exports of liquefied natural gas (LNG) has contributed to month-on-month increases in the Henry Hub futures price since March 2021, leading to the highest August average since 2010. Further upward price pressures came from the arrival of Hurricane Ida, which resulted in more than 90% of offshore natural gas production in the Federal Offshore Gulf of Mexico being shut in during late August.

Figure 8. U.S. natural gas front-month futures prices and storage deviation from five-year average

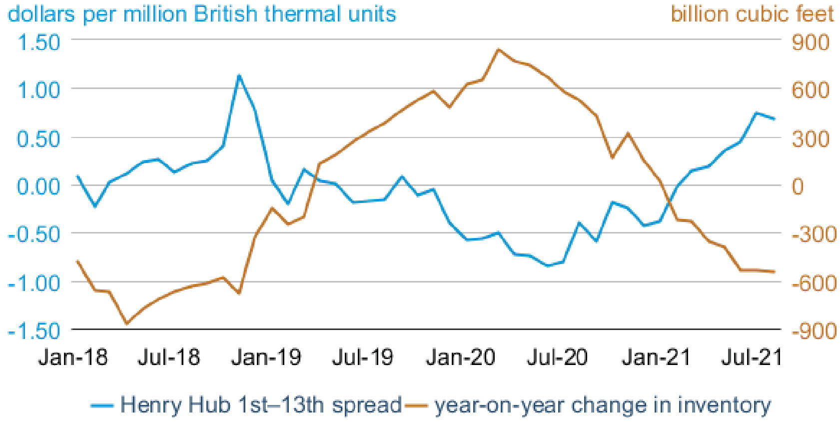


Source: Graph by EIA, based on data from CME Group, as compiled by Bloomberg L.P.

The Henry Hub front-month futures price increased by 47 cents/MMBtu from $3.90/MMBtu on August 25 to $4.37/MMBtu on August 27, as Hurricane Ida approached the U.S. Gulf Coast, leading producers to evacuate personnel from offshore platforms and to shut in production. On August 27, the U.S. Bureau of Safety and Environmental Enforcement (BSEE) began posting daily Gulf of Mexico hurricane impact updates, indicating that from August 27 to August 31, 9.3 billion cubic feet (Bcf), or 1.9 Bcf/d, of natural gas production was shut in. As of September 2, 91.3% of GOM natural gas production remained shut in. Since the arrival of Hurricane Ida, natural gas prices have remained elevated, and they ended August at $4.38/MMBtu.

Futures price spreads: The natural gas 1st–13th trading month price spread averaged 74 cents/MMBtu in July, the most backwardation (where near-term contract prices are higher than longer-dated ones) since December 2018 **(Figure 10)**. In August, the natural gas 1st–13th month price spread averaged 70 cents/MMBtu. Typically, the 1st–13th price spread will increase when natural gas inventories decrease and will decrease when natural gas inventories increase. The August natural gas inventory level was 578 Bcf below last year's August level, its largest year-on-year deficit since November 2018, and 222 Bcf below the 2016–2020 average.

Figure 9. Natural gas 1st–13th futures spread and year-on-year change in inventory

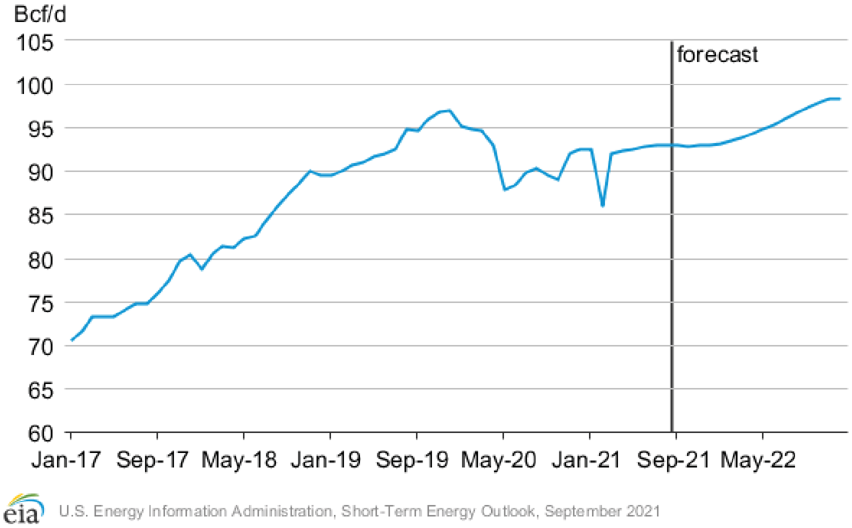


Source: CME Group, as complied by Bloomberg L.P.; U.S. Energy Information Administration
Note: Futures spreads are monthly averages.

Above-average withdrawals of U.S. natural gas from storage during the 2020–2021 winter heating season and below-average injections into storage this summer contributed to our forecast of below-average inventories of natural gas. Relatively flat dry natural gas production and high natural gas exports also contributed to the forecast low inventories. U.S. dry natural gas production and U.S. exports of natural gas (by pipeline and as LNG) were relatively flat from July to August. We expect storage to begin the winter heating season (November 1) at 3,570 Bcf, 182 Bcf below the 2016–2020 average and 359 Bcf below the 2020 level, when natural gas inventories were at near-record highs.

Production: U.S. dry natural gas production has been almost flat this year after its brief decline in February because of severely cold weather in Texas, and we expect production to remain relatively flat for the rest of 2021 **(Figure 11)**. Although production has been increasing, the increase has been relatively small. We expect U.S. dry natural gas production in 2021 to average 92.2 Bcf/d, a 0.8 Bcf/d increase from 2020, compared with an annual average increase of 3.3 Bcf/d from 2011 through 2020. In our forecast, production increases accelerate in 2022, driven by the increase in Henry Hub prices this year. In 2022, we expect production to average 95.4 Bcf/d, an increase of 3.2 Bcf/d from 2021. The increase in production from 2021 to 2022 will put some downward pressure on the Henry Hub price, which we expect to average $3.47/MMBtu next year, a decrease of 16 cents/MMBtu from the average forecast price for 2021.

Figure 10. U.S. dry natural gas production



Notable forecast changes

- In the September STEO, we revised our global liquid fuels consumption forecast down by 0.2 million barrels per day in both 2021 and 2022. The decreased consumption reflects a lower GDP forecast as well as expectations of lower consumption because of travel and other restrictions in response to increases in COVID-19 cases.
- We forecast OPEC crude oil production will average 26.4 million b/d in 2021, down 0.1 million b/d from the August STEO, reflecting our expectation that Iran's crude oil production will be lower in the second half of 2021 (2H21) than we previously expected. We expect OPEC to produce 28.3 million b/d in 2022, down 0.3 million b/d compared with the August STEO. The downward revision to supply growth is driven by lower global oil demand growth, and we expect some producers to continue to restrain output to maintain relatively balanced oil markets in 2022.
- We forecast Henry Hub spot prices will average $4.00 per million British thermal unit (MMBtu) in 2H21, an increase of 41 cents/MMBtu from last month's STEO. Forecast prices average $3.47/MMBtu in 2022, an increase of 39 cents from last month's STEO. The increase largely reflects a higher starting point for our price forecast.
- We forecast U.S. coal production to total 648 million short tons (MMst) in 2022, up 47 MMst (8%) from last month's STEO. Higher U.S. coal production in this forecast is the result of a 54 MMst increase in our forecast for electric power sector demand for coal in 2022.

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

U.S. Energy Information Administration | Short-Term Energy Outlook - September 2021

	2020				2021				2022				Year		
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	2020	2021	2022
Supply (million barrels per day) (a)															
OECD	33.05	29.27	29.95	30.66	30.18	30.89	31.22	31.90	32.17	32.45	32.79	33.37	30.73	31.05	32.70
U.S. (50 States)	20.33	17.44	18.29	18.29	17.62	19.05	18.76	19.12	19.38	19.81	20.26	20.58	18.58	18.64	20.01
Canada	5.64	4.90	4.94	5.54	5.63	5.41	5.64	5.81	5.84	5.81	5.83	5.86	5.26	5.62	5.83
Mexico	2.00	1.94	1.91	1.90	1.93	1.95	1.86	1.90	1.88	1.84	1.81	1.77	1.94	1.91	1.82
Other OECD	5.08	4.99	4.81	4.93	5.00	4.48	4.96	5.07	5.08	5.00	4.89	5.16	4.95	4.88	5.03
Non-OECD	67.69	63.02	61.06	62.08	62.61	63.90	66.08	67.70	67.62	68.63	69.41	69.32	63.45	65.09	68.75
OPEC	33.50	30.72	28.65	30.00	30.37	30.78	32.30	33.53	33.71	33.80	33.97	34.01	30.71	31.76	33.87
Crude Oil Portion	28.28	25.65	23.63	24.88	25.08	25.51	26.94	28.10	28.12	28.34	28.45	28.45	25.60	26.42	28.34
Other Liquids (b)	5.22	5.07	5.02	5.12	5.29	5.27	5.36	5.43	5.59	5.47	5.52	5.56	5.11	5.34	5.53
Eurasia	14.72	13.16	12.70	13.12	13.38	13.62	13.59	14.19	14.46	14.66	14.77	14.97	13.42	13.70	14.72
China	4.96	4.91	4.95	4.90	5.05	5.09	5.04	5.06	5.05	5.08	5.08	5.13	4.93	5.06	5.08
Other Non-OECD	14.51	14.22	14.75	14.06	13.82	14.42	15.15	14.91	14.40	15.08	15.59	15.21	14.39	14.58	15.07
Total World Supply	100.74	92.30	91.01	92.74	92.80	94.80	97.30	99.60	99.79	101.08	102.20	102.68	94.18	96.14	101.45
Non-OPEC Supply	67.24	61.57	62.36	62.74	62.43	64.02	64.99	66.06	66.07	67.28	68.23	68.68	63.47	64.39	67.57
Consumption (million barrels per day) (c)															
OECD	45.50	37.45	42.27	42.84	42.30	43.68	45.48	45.89	45.51	45.25	46.30	46.36	42.02	44.35	45.86
U.S. (50 States)	19.50	16.07	18.45	18.72	18.45	20.03	20.30	20.15	20.01	20.51	21.02	20.94	18.19	19.74	20.63
U.S. Territories	0.17	0.15	0.16	0.17	0.20	0.18	0.18	0.19	0.20	0.18	0.19	0.20	0.16	0.19	0.19
Canada	2.42	1.97	2.25	2.14	2.12	2.09	2.29	2.31	2.27	2.22	2.32	2.31	2.19	2.20	2.28
Europe	13.34	11.01	12.88	12.51	11.90	12.51	13.73	13.55	13.14	13.27	13.59	13.26	12.43	12.93	13.31
Japan	3.78	2.93	3.06	3.53	3.73	3.01	2.99	3.38	3.63	2.96	3.04	3.35	3.33	3.27	3.24
Other OECD	6.30	5.34	5.47	5.77	5.89	5.86	5.98	6.30	6.25	6.10	6.14	6.31	5.72	6.01	6.20
Non-OECD	50.33	47.44	51.21	52.59	52.37	52.81	53.07	53.88	54.08	55.37	55.49	55.64	50.40	53.04	55.15
Eurasia	4.86	4.48	5.28	5.17	4.92	5.01	5.41	5.25	5.04	5.12	5.51	5.37	4.95	5.15	5.26
Europe	0.71	0.69	0.71	0.72	0.73	0.73	0.74	0.75	0.74	0.74	0.74	0.75	0.71	0.74	0.74
China	13.89	14.08	14.65	15.11	15.26	15.46	14.77	15.30	15.75	16.01	15.71	15.99	14.43	15.20	15.86
Other Asia	13.35	11.63	12.59	13.61	13.78	13.35	13.21	13.89	14.30	14.51	14.10	14.53	12.80	13.56	14.36
Other Non-OECD	17.53	16.55	17.98	17.99	17.67	18.26	18.94	18.69	18.24	19.00	19.42	19.00	17.51	18.39	18.92
Total World Consumption	95.83	84.90	93.47	95.43	94.66	96.49	98.55	99.77	99.59	100.62	101.79	102.00	92.42	97.38	101.01
Total Crude Oil and Other Liquids Inventory Net Withdrawals (million barrels per day)															
U.S. (50 States)	-0.49	-1.67	0.53	0.91	0.47	0.51	0.33	0.54	-0.11	-0.69	-0.08	0.40	-0.18	0.46	-0.12
Other OECD	-0.51	-1.16	0.04	0.69	0.76	0.10	0.30	-0.12	-0.03	0.07	-0.10	-0.34	-0.23	0.26	-0.10
Other Stock Draws and Balance	-3.91	-4.57	1.90	1.09	0.64	1.08	0.62	-0.25	-0.06	0.16	-0.23	-0.74	-1.36	0.52	-0.22
Total Stock Draw	-4.91	-7.40	2.46	2.69	1.87	1.69	1.25	0.17	-0.20	-0.46	-0.41	-0.68	-1.76	1.24	-0.44
End-of-period Commercial Crude Oil and Other Liquids Inventories (million barrels)															
U.S. Commercial Inventory	1,327	1,458	1,423	1,343	1,302	1,271	1,241	1,211	1,221	1,284	1,291	1,265	1,343	1,211	1,265
OECD Commercial Inventory	2,970	3,206	3,168	3,025	2,916	2,876	2,818	2,800	2,812	2,869	2,885	2,890	3,025	2,800	2,890

(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 September 2, 2021.

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 - September 2021

	2020				2021				2022				Year		
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	2020	2021	2022
Supply (million barrels per day)															
Crude Oil Supply															
Domestic Production (a)	12.81	10.67	10.79	10.87	10.69	11.28	11.06	11.28	11.42	11.58	11.81	12.06	11.28	11.08	11.72
Alaska	0.48	0.41	0.44	0.46	0.46	0.44	0.40	0.44	0.43	0.42	0.39	0.43	0.45	0.43	0.42
Federal Gulf of Mexico (b)	1.99	1.66	1.43	1.50	1.80	1.80	1.52	1.73	1.76	1.73	1.74	1.78	1.64	1.71	1.75
Lower 48 States (excl GOM)	10.35	8.60	8.92	8.91	8.44	9.04	9.14	9.12	9.22	9.43	9.67	9.86	9.19	8.94	9.55
Crude Oil Net Imports (c)	2.89	3.06	2.24	2.50	2.87	2.96	3.60	3.49	3.77	4.71	4.82	3.84	2.67	3.23	4.29
SPR Net Withdrawals	0.00	-0.23	0.15	0.04	0.00	0.18	0.00	0.22	0.00	0.00	0.00	0.10	-0.01	0.10	0.03
Commercial Inventory Net Withdrawals	-0.56	-0.54	0.38	0.13	-0.18	0.59	0.22	-0.09	-0.31	-0.03	0.27	-0.02	-0.14	0.14	-0.02
Crude Oil Adjustment (d)	0.63	0.20	0.46	0.36	0.42	0.63	0.50	0.16	0.22	0.22	0.23	0.16	0.41	0.43	0.21
Total Crude Oil Input to Refineries	15.77	13.16	14.02	13.90	13.81	15.65	15.39	15.06	15.09	16.48	17.12	16.14	14.21	14.98	16.21
Other Supply															
Refinery Processing Gain	1.02	0.82	0.93	0.92	0.84	0.97	1.00	1.04	1.05	1.09	1.14	1.13	0.92	0.96	1.10
Natural Gas Plant Liquids Production	5.17	4.96	5.34	5.22	4.86	5.46	5.40	5.50	5.62	5.81	5.95	6.04	5.17	5.30	5.86
Renewables and Oxygenate Production (e)	1.11	0.81	1.03	1.07	1.03	1.13	1.09	1.09	1.08	1.11	1.13	1.13	1.01	1.09	1.12
Fuel Ethanol Production	1.02	0.70	0.92	0.97	0.90	0.99	0.99	0.98	0.98	1.01	1.02	1.01	0.91	0.97	1.01
Petroleum Products Adjustment (f)	0.22	0.19	0.20	0.19	0.19	0.22	0.21	0.21	0.20	0.22	0.22	0.22	0.20	0.21	0.22
Product Net Imports (c)	-3.86	-2.96	-3.07	-3.33	-2.94	-3.13	-2.90	-3.15	-3.24	-3.53	-4.20	-4.04	-3.30	-3.03	-3.76
Hydrocarbon Gas Liquids	-1.95	-1.84	-1.83	-2.06	-2.02	-2.23	-2.24	-2.15	-2.14	-2.25	-2.31	-2.27	-1.92	-2.16	-2.24
Unfinished Oils	0.37	0.23	0.35	0.18	0.14	0.25	0.40	0.30	0.21	0.26	0.30	0.20	0.29	0.27	0.24
Other HC/Oxygenates	-0.09	-0.04	-0.04	-0.04	-0.08	-0.04	-0.07	-0.08	-0.09	-0.08	-0.08	-0.09	-0.05	-0.07	-0.08
Motor Gasoline Blend Comp.	0.40	0.37	0.49	0.44	0.55	0.79	0.46	0.21	0.54	0.76	0.42	0.21	0.42	0.50	0.48
Finished Motor Gasoline	-0.71	-0.41	-0.58	-0.76	-0.66	-0.66	-0.32	-0.60	-0.74	-0.60	-0.63	-0.71	-0.62	-0.56	-0.67
Jet Fuel	-0.07	0.09	0.12	0.08	0.03	0.09	0.14	0.13	-0.04	-0.03	0.04	0.12	0.05	0.10	0.02
Distillate Fuel Oil	-1.14	-0.86	-1.16	-0.72	-0.49	-0.90	-0.83	-0.45	-0.54	-0.98	-1.30	-1.02	-0.97	-0.67	-0.96
Residual Fuel Oil	-0.02	-0.01	0.05	0.05	0.08	0.05	0.07	0.08	0.02	-0.03	-0.02	0.07	0.02	0.07	0.01
Other Oils (g)	-0.64	-0.49	-0.48	-0.48	-0.49	-0.49	-0.51	-0.58	-0.46	-0.58	-0.64	-0.55	-0.52	-0.52	-0.56
Product Inventory Net Withdrawals	0.06	-0.90	0.00	0.73	0.65	-0.26	0.11	0.41	0.20	-0.66	-0.34	0.31	-0.02	0.23	-0.12
Total Supply	19.50	16.07	18.45	18.72	18.43	20.03	20.30	20.15	20.01	20.51	21.02	20.94	18.19	19.74	20.63
Consumption (million barrels per day)															
Hydrocarbon Gas Liquids	3.37	2.85	3.01	3.68	3.40	3.33	3.09	3.63	3.84	3.35	3.41	3.89	3.23	3.36	3.62
Unfinished Oils	0.18	0.12	0.03	0.03	0.05	0.03	0.01	0.00	0.00	0.00	0.00	0.00	0.09	0.02	0.00
Motor Gasoline	8.51	7.12	8.51	8.06	8.00	9.07	9.27	8.76	8.50	9.21	9.35	8.87	8.05	8.78	8.98
Fuel Ethanol blended into Motor Gasoline	0.85	0.73	0.87	0.85	0.82	0.93	0.93	0.89	0.86	0.94	0.95	0.92	0.82	0.89	0.92
Jet Fuel	1.56	0.69	0.97	1.09	1.13	1.34	1.54	1.52	1.47	1.57	1.72	1.72	1.08	1.38	1.62
Distillate Fuel Oil	4.02	3.49	3.70	3.94	3.97	3.93	3.97	4.13	4.17	4.12	4.10	4.24	3.79	4.00	4.16
Residual Fuel Oil	0.17	0.11	0.32	0.22	0.26	0.25	0.32	0.27	0.27	0.25	0.29	0.28	0.21	0.28	0.27
Other Oils (g)	1.69	1.68	1.92	1.71	1.63	2.08	2.11	1.84	1.76	2.01	2.16	1.93	1.75	1.92	1.97
Total Consumption	19.50	16.07	18.45	18.72	18.45	20.03	20.30	20.15	20.01	20.51	21.02	20.94	18.19	19.74	20.63
Total Petroleum and Other Liquids Net Imports	-0.97	0.11	-0.83	-0.84	-0.07	-0.16	0.70	0.34	0.53	1.18	0.61	-0.20	-0.63	0.20	0.53
End-of-period Inventories (million barrels)															
Commercial Inventory															
Crude Oil (excluding SPR)	483.3	532.7	497.7	485.5	501.9	448.0	427.8	435.7	463.7	466.4	441.8	443.9	485.5	435.7	443.9
Hydrocarbon Gas Liquids	182.9	235.7	298.7	228.2	168.6	195.8	225.7	175.6	137.6	191.6	238.8	200.6	228.2	175.6	200.6
Unfinished Oils	101.9	92.5	81.4	77.6	93.3	93.0	89.0	82.8	93.3	91.1	90.0	83.1	77.6	82.8	83.1
Other HC/Oxygenates	33.4	25.4	24.6	29.7	29.1	27.5	26.7	27.0	29.0	27.8	27.5	27.8	29.7	27.0	27.8
Total Motor Gasoline	261.8	254.5	227.6	243.4	237.6	237.2	218.7	232.8	241.6	246.5	233.8	248.7	243.4	232.8	248.7
Finished Motor Gasoline	22.6	23.5	22.5	25.4	20.3	18.6	21.4	24.3	24.1	23.9	23.1	26.1	25.4	24.3	26.1
Motor Gasoline Blend Comp.	239.2	231.0	205.0	218.0	217.4	218.6	197.3	208.5	217.5	222.6	210.6	222.7	218.0	208.5	222.7
Jet Fuel	39.9	41.6	40.1	38.6	39.0	44.7	43.6	40.4	39.9	40.6	43.0	39.9	38.6	40.4	39.9
Distillate Fuel Oil	126.8	176.9	172.5	161.2	145.5	140.1	130.0	133.6	123.8	129.0	136.2	137.5	161.2	133.6	137.5
Residual Fuel Oil	34.8	39.5	32.1	30.2	30.9	31.1	29.3	31.2	31.2	32.1	30.3	31.8	30.2	31.2	31.8
Other Oils (g)	61.9	59.0	48.3	49.1	55.8	54.1	49.9	52.2	61.3	59.1	49.9	51.3	49.1	52.2	51.3
Total Commercial Inventory	1326.7	1457.7	1423.2	1343.3	1301.7	1271.5	1240.8	1211.3	1221.4	1284.4	1291.4	1264.6	1343.3	1211.3	1264.6
Crude Oil in SPR	635.0	656.0	642.2	638.1	637.8	621.3	621.3	601.3	601.3	601.3	601.3	591.7	638.1	601.3	591.7

(a) Includes lease condensate.

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

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

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

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

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

(g) For net imports and inventories “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; for consumption “Other Oils” also includes renewable fuels except fuel ethanol.

\- = no data available

SPR: Strategic Petroleum Reserve

HC: Hydrocarbons

Notes: EIA completed modeling and analysis for this report on September 2, 2021.

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 - September 2021

	2020				2021				2022				Year		
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	2020	2021	2022
Supply (billion cubic feet per day)															
Total Marketed Production	**102.27**	**96.83**	**97.55**	**98.70**	**97.31**	**100.95**	*100.51*	*100.58*	*101.09*	*102.57*	*104.43*	*105.89*	**98.83**	*99.85*	*103.51*
Alaska	**0.96**	**0.88**	**0.88**	**0.98**	**1.02**	**0.95**	*0.76*	*0.88*	*0.92*	*0.81*	*0.73*	*0.87*	**0.92**	*0.90*	*0.83*
Federal GOM (a)	**2.72**	**2.22**	**1.72**	**1.73**	**2.27**	**2.26**	*1.90*	*2.09*	*2.09*	*2.02*	*1.91*	*1.88*	**2.09**	*2.13*	*1.97*
Lower 48 States (excl GOM)	**98.58**	**93.74**	**94.95**	**95.99**	**94.03**	**97.74**	*97.85*	*97.60*	*98.08*	*99.74*	*101.78*	*103.14*	**95.81**	*96.82*	*100.70*
Total Dry Gas Production	**94.80**	**89.68**	**89.83**	**91.15**	**90.30**	**93.05**	*92.64*	*92.70*	*93.17*	*94.54*	*96.25*	*97.59*	**91.36**	*92.18*	*95.40*
LNG Gross Imports	**0.24**	**0.12**	**0.09**	**0.09**	**0.15**	**0.02**	*0.18*	*0.20*	*0.32*	*0.18*	*0.18*	*0.20*	**0.13**	*0.14*	*0.22*
LNG Gross Exports	**7.92**	**5.52**	**3.91**	**8.78**	**9.27**	**9.81**	*9.41*	*9.83*	*10.47*	*9.73*	*9.41*	*11.00*	**6.53**	*9.58*	*10.15*
Pipeline Gross Imports	**7.60**	**6.08**	**6.39**	**7.27**	**8.68**	**6.80**	*6.80*	*6.85*	*7.39*	*6.36*	*6.38*	*6.72*	**6.84**	*7.28*	*6.71*
Pipeline Gross Exports	**8.15**	**7.17**	**8.09**	**8.21**	**8.31**	**8.55**	*9.37*	*9.52*	*9.34*	*8.66*	*9.38*	*9.38*	**7.91**	*8.94*	*9.19*
Supplemental Gaseous Fuels	**0.19**	**0.17**	**0.15**	**0.18**	**0.18**	**0.15**	*0.17*	*0.17*	*0.17*	*0.17*	*0.17*	*0.18*	**0.17**	*0.17*	*0.17*
Net Inventory Withdrawals	**12.74**	**-12.24**	**-7.68**	**5.36**	**17.19**	**-9.12**	*-7.78*	*4.66*	*15.86*	*-10.79*	*-8.49*	*4.32*	**-0.46**	*1.18*	*0.17*
Total Supply	**99.51**	**71.12**	**76.78**	**87.06**	**98.91**	**72.53**	*73.23*	*85.22*	*97.10*	*72.07*	*75.70*	*88.63*	**83.61**	*82.41*	*83.33*
Balancing Item (b)	**-0.19**	**-0.28**	**0.05**	**-0.98**	**0.28**	**-0.42**	*1.25*	*-0.60*	*-0.33*	*-1.63*	*-0.15*	*-0.83*	**-0.35**	*0.13*	*-0.74*
Total Primary Supply	**99.31**	**70.84**	**76.83**	**86.08**	**99.20**	**72.12**	*74.48*	*84.62*	*96.77*	*70.44*	*75.55*	*87.80*	**83.25**	*82.54*	*82.60*
Consumption (billion cubic feet per day)															
Residential	**22.83**	**8.20**	**3.82**	**16.00**	**25.59**	**7.52**	*3.68*	*16.89*	*25.05*	*7.85*	*3.67*	*16.92*	**12.70**	*13.37*	*13.32*
Commercial	**13.93**	**5.82**	**4.36**	**10.31**	**14.84**	**6.25**	*4.72*	*10.94*	*14.90*	*6.25*	*4.68*	*10.84*	**8.60**	*9.17*	*9.15*
Industrial	**24.65**	**20.62**	**21.15**	**23.83**	**24.05**	**21.77**	*21.91*	*25.10*	*24.95*	*22.66*	*22.41*	*25.22*	**22.56**	*23.21*	*23.81*
Electric Power (c)	**29.55**	**29.05**	**40.10**	**28.19**	**26.65**	**29.14**	*36.67*	*23.87*	*23.61*	*26.19*	*37.05*	*26.61*	**31.74**	*29.09*	*28.40*
Lease and Plant Fuel	**5.17**	**4.90**	**4.93**	**4.99**	**4.92**	**5.10**	*5.08*	*5.09*	*5.11*	*5.19*	*5.28*	*5.35*	**5.00**	*5.05*	*5.23*
Pipeline and Distribution Use	**3.02**	**2.15**	**2.33**	**2.61**	**3.01**	**2.19**	*2.27*	*2.59*	*2.98*	*2.13*	*2.29*	*2.69*	**2.53**	*2.51*	*2.52*
Vehicle Use	**0.16**	**0.10**	**0.13**	**0.13**	**0.14**	**0.15**	*0.15*	*0.15*	*0.16*	*0.16*	*0.16*	*0.16*	**0.13**	*0.15*	*0.16*
Total Consumption	**99.31**	**70.84**	**76.83**	**86.08**	**99.20**	**72.12**	*74.48*	*84.62*	*96.77*	*70.44*	*75.55*	*87.80*	**83.25**	*82.54*	*82.60*
End-of-period Inventories (billion cubic feet)															
Working Gas Inventory	**2,029**	**3,133**	**3,840**	**3,341**	**1,801**	**2,583**	*3,299*	*2,870*	*1,442*	*2,424*	*3,205*	*2,808*	**3,341**	*2,870*	*2,808*
East Region (d)	**385**	**655**	**890**	**763**	**313**	**515**	*808*	*658*	*174*	*452*	*682*	*498*	**763**	*658*	*498*
Midwest Region (d)	**471**	**747**	**1,053**	**918**	**395**	**630**	*970*	*823*	*278*	*537*	*894*	*790*	**918**	*823*	*790*
South Central Region (d)	**857**	**1,221**	**1,313**	**1,155**	**760**	**991**	*1,030*	*979*	*698*	*960*	*1,039*	*970*	**1,155**	*979*	*970*
Mountain Region (d)	**92**	**177**	**235**	**195**	**113**	**175**	*196*	*146*	*93*	*148*	*218*	*201*	**195**	*146*	*201*
Pacific Region (d)	**200**	**308**	**318**	**282**	**197**	**246**	*264*	*233*	*168*	*296*	*342*	*318*	**282**	*233*	*318*
Alaska	**23**	**25**	**31**	**28**	**23**	**27**	*31*	*31*	*31*	*31*	*31*	*31*	**28**	*31*	*31*

(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 September 2, 2021.

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/its-too-late-global-natural-gas-lng-supply-squeeze-sets-stage-for-record-winter-prices

It's Too Late - Global Natural Gas/LNG Supply Squeeze Sets Stage For Record Winter Prices

Thursday, 09/09/2021
Published by: Lindsay Schneider

Global natural gas and LNG prices have spent the summer going from high to higher to the highest on record. The major European indices hit post-2008, and then all-time highs multiple times throughout the summer — even surpassing Asian prices on a handful of days. At the same time, Asian prices have set all-time seasonal records and are now sitting just below the previous single-day high settle from this past January. Usually, as the weather cools heading into fall, so do prices, but that's unlikely this year as the European gas storage inventory is at the lowest level for this time of year than we've seen in recent history, and the time to replenish stocks for the winter is rapidly running out. The incredible bull run for global gas prices has been underpinned by high demand for LNG and the cascading effect of a supply squeeze in Europe, brought on by the triple threat of low domestic production, decreased imports from Russia, and a scarcity of incremental LNG cargoes. Not only is this driving record-high gas prices and increased volatility now, but the low inventory means sustained high prices for the heating season ahead. In today's blog, we take a look at recent global gas price trends and the precarious European storage situation ahead of what is shaping up to be an incredibly bullish winter.

After being decimated by COVID-19 and the subsequent oil price crash in 2020, global gas markets made a startling recovery this year. Prices swung from all-time lows last summer to record highs this year. A confluence of factors led to the bullish reversal in market fundamentals, including weather events and operational issues that disrupted LNG cargoes just as COVID lockdowns were easing. It started with a record-breaking Atlantic hurricane season last year that curtailed U.S. LNG production and interrupted marine traffic in the fall, particularly from the Louisiana facilities (see Such Great Heights). This occurred right around the time when overseas offtakers are typically building up LNG stocks or, in the case of Europe, filling gas storage for the winter ahead. While the U.S. was experiencing LNG production shortfalls from the storms, extended outages were also impacting terminals in Australia and Norway, further reducing global LNG supply.

Then, just as colder-than-average winter weather was boosting heating demand in Europe and Asia, another constraint emerged: prolonged delays for U.S. cargoes transiting the Panama Canal — the fastest, most economical shipping route between the U.S. Gulf Coast and Asia (see Bottleneck Blues). The delays were partially caused by COVID-related restrictions but also were a natural side effect of increased traffic through the canal caused by pent-up demand following months of cargo cancellations from the Gulf Coast last summer. Whether the LNG carriers waited out the delays at the Panama Canal or diverted to the Suez Canal or took the extremely long trip around Africa's Cape of Good Hope, the result was longer voyage times, which, in turn, lowered the overall supply of LNG tankers available to take more cargoes. The vessel shortage likely restrained spot market cargoes even as international gas/LNG prices at the time were the highest they had been in a while. There were simply no extra ships available to carry export cargoes.

All these bullish factors combined to push prices to all-time highs in Asia and to multi-year highs in Europe by early 2021. Figure 1 below shows the three major global gas indices: the Japan-Korea Marker (JKM) representing Asia's LNG benchmark (orange line), the UK National Balancing Point (NBP; yellow line) and Europe's Dutch Title Transfer Facility (TTF; gray line), along with Henry Hub (blue line). As the winter 2020-21 contracts began expiring, prices started to fall but only dropped as low as the high-$5/MMBtu level in both Europe and Asia before rallying again because of overall bullish market conditions. Prices began climbing again in the spring, and by late-June/early-July, prices in Europe briefly traded not only above the highs seen in January but at their highest level since 2008. Prices have kept rising since then, with only brief, minor setbacks along the way, underscoring the relentless crunch for LNG cargoes. In recent weeks, prices in Europe have bested their early-summer highs as well as the previous all-time highs from 2008. In fact, the European gas indices have set a series of fresh highs just in recent days, with rare premiums to JKM. As of yesterday, TTF settled at $19.61/MMBtu, nearly $1/MMBtu above JKM, while NBP surged more than $1/MMBtu above JKM to $19.682/MMBtu.

Although European fundamentals and the precarious storage situation, which we'll get to shortly, are driving most of the price rallies and news headlines, JKM has more than kept pace with TTF and NBP. For most of the summer, in fact, Asian traders have outbid Europe for LNG cargoes at every turn. Global demand for LNG is simply outpacing the supply of available cargoes.

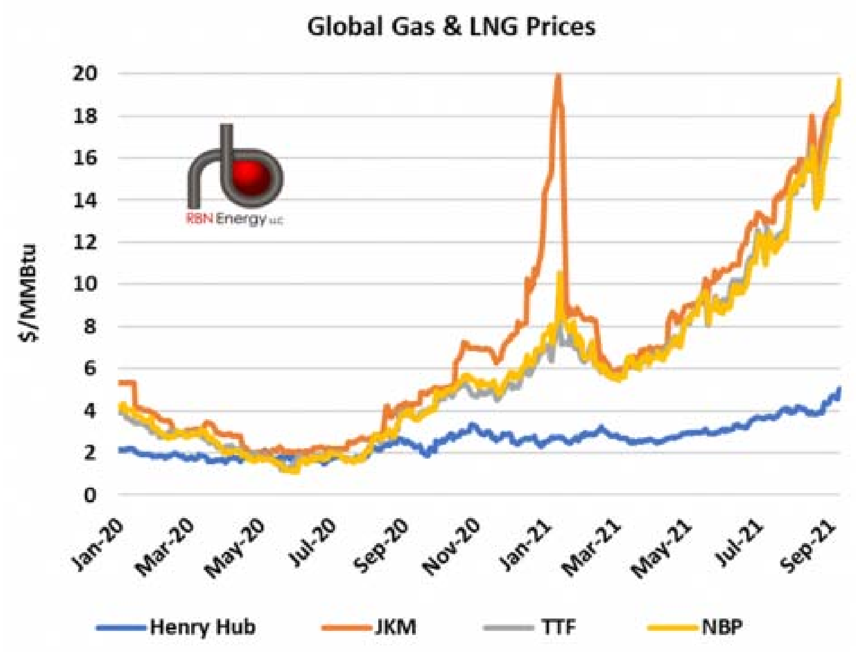


Figure 1. Global Gas & LNG Prices. Source: CME/NYMEX via Bloomberg

While overall higher global demand is supporting prices at these lofty levels, Europe in particular is facing an extreme supply crunch. Unlike Asia, which almost exclusively relies on LNG to meet its gas demand, Europe has a robust gas pipeline grid and a variety of supply sources. These can largely be broken down into three main categories: domestic production, LNG imports, and pipeline imports from Russia. European production has been in a steep decline for more than a decade, both because of declining reserves in existing production fields and the European Union's (EU) environmental regulations. This summer, in addition to the typical and expected decline trends, a number of outages and maintenance events reduced production further, most notably from the Troll gas field in Norway.

Due to its declining production levels, Europe is heavily dependent on natural gas imports — both piped from Russia and via LNG cargoes. Russia supplies the largest share of European gas imports and reliance on Russian gas is increasing as Europe's domestic production falls. Most of the gas in Russia is controlled by state-owned Gazprom, which gives it an enormous influence on the European gas market. Russian gas is piped through a variety of routes, most of which have to pass through Ukraine to reach the EU. The exception is the Opal-Nord Stream route, which pipes Russian gas directly to Germany through the Baltic Sea. Russia strongly prefers this route for gas as it cuts

Ukraine out of the trade equation, giving it even more power and control over gas supplies into Europe. To increase flows along this route, Russia proposed the Nord Stream 2 pipeline, which would double the capacity along the route through the Baltic Sea to 10.6 Bcf/d (110 billion cubic meters, or Bcm/year). However, the project has been incredibly controversial, and, until recently, there was a lot of uncertainty around when and if the pipeline would be completed. While it was heavily favored by Russia and Germany — with the latter negotiating for it to go ahead — the U.S. had been strongly opposed to the expansion for geopolitical reasons. The impasse ended in late July, however, when the U.S. and Germany reached a deal, with the U.S. agreeing to drop the threat of further sanctions on the project, and it now looks likely to go ahead. Pipe laying work was completed earlier this week, and the line now just needs to be tied into the German gas grid. Officially, the pipeline is targeting the start of service before the end of the year, but it could be as early as October.

From the U.S. gas market perspective, the pipeline could create headwinds for its LNG exports in the long term, particularly for export projects still looking to reach final investment decisions (see the latest [LNG Voyager Quarterly] report), as it will decrease the amount of LNG Europe needs to import. In the near term, however, even if Nord Stream 2 starts soon, its likely too little, too late for European storage levels to recover. Europe's imports from Russia are down this year even though the country's production has been strong. This was thought to be a response in opposition to the Nord Stream 2 pipeline and to bolster support for the pipe by showing that it is needed. Russian officials have commented recently that the country is experiencing unusually high domestic demand and needs to fill its own storage. Additionally, a fire at a gas processing plant in early August knocked some production offline. Regardless of Russia's motives, lower pipeline imports from the country are exacerbating Europe's supply shortage.

With supply from all three sources tight and demand strong, Europe has struggled to refill storage this injection season. European natural gas inventory is currently at its lowest level for this time of year since 2013, but at that point storage capacity was much lower than it is now. In percentage terms, storage is currently at its lowest level in more than a decade. As Figure 2 shows, European storage in 2021 (navy blue line) started the year with a surplus compared with 2019 (yellow line) but was rapidly depleted by a cold winter and trended increasingly below 2019 and 2020 (teal line) levels through the spring. By late May, seasonal stocks had dropped below 2018 levels (orange line), the previous three-year minimum (gray area) and the last time the LNG market experienced an extended bull run. In 2018, storage was able to be refilled through the spring, but that has not been the case in 2021.

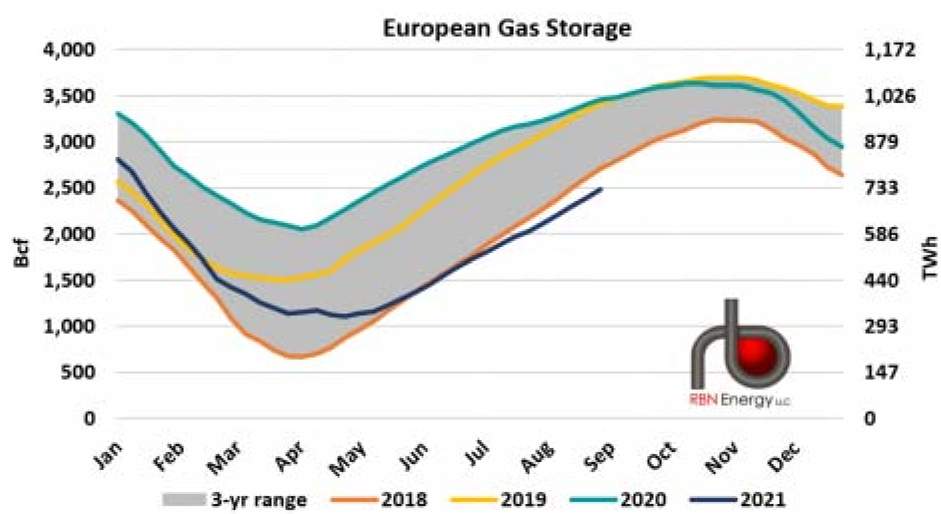


Figure 2. European Gas Storage. Source: RBN LNG Voyager, Bloomberg

The difference this year is that Europe experienced very late-season cold weather that delayed the start of injection season and then slowed the pace of injections once they did start. Then, over the summer, weather flipped, and high temperatures and record-high carbon prices put upward pressure on gas demand for electricity generation. Although the pace of injections has picked up over the summer, the deficit from the three-year minimum is still widening and the window for injections is closing. There are only about eight weeks left in injection season and the size of injections typically begin to taper off as the weather turns cooler. Even if you apply 2018’s very aggressive level of late-season injections to the rest of this season, that would still leave European storage only about 75% full, compared with more than 90% full in the past two years and more than 80% full in 2018. Also, even reaching 75% would be a best-case scenario, considering that injections so far this summer have been below the 2018 pace, and supply shortages appear likely to persist through fall.

The low storage levels have supported prices all summer, and will continue to do so through the winter. The market is currently pricing this in and winter prices are trading above the record highs seen last winter. In addition to a higher baseline of prices for the winter, the low inventory levels also leave the market more exposed to weather-related price spikes and generally more premium prices through the colder months. And that’s not just for Europe either. With the increased reliance on LNG worldwide, gas markets are more connected than ever, and rising tides lift all boats, as they say. The increased competition for limited LNG cargoes means that strength in European prices will equate to higher Asian prices as well. (In an upcoming blog, we’ll take a look at the dynamics that are driving the Asian market.)

With prices soaring currently, U.S. LNG is of course firmly in the money and terminals are likely to operate at full utilization of contracted capacity, or even higher, to produce spot market cargoes whenever possible this winter. Beyond that, the extended and incredibly bullish trend for gas prices has renewed interest in new North American LNG capacity (see You Can Make It If You Try), and will potentially provide enough momentum to push one of the projects to take FID before this bull run is done.

Toni Stern wrote the lyrics, and Carole King wrote the music for "It's Too Late." The song appears as the third song on side one of Carole King's second studio album, *Tapestry.* Released as a single in April 1971, the song went to #1 on the Billboard Hot 100 and Adult Contemporary Tracks Singles charts. It has been certified Gold by the Recording Industry Association of America (RIAA). Toni Stern said she wrote the lyrics to the song in one day, after her love affair with James Taylor had ended. The single won a Grammy Award for Record of the Year in 1972. Personnel on the record were: Carole King (vocals, piano), Curtis Amy (soprano sax), Danny Kortchmar (guitar, conga), Charles Larkey (bass), Joel O'Brien (drums), and Ralph Schuckett (electric piano).

Tapestry was recorded at Studio B at A&M Studios in Hollywood during January 1971. Produced by Lou Adler, the album was released in February 1971. It went to #1 on the Billboard Top 200 Albums chart and has been certified 13x Platinum by the RIAA. It has sold more than 25 million records worldwide and earned four Grammy Awards in 1972. The two singles released from the album both spent five weeks at #1 on the Billboard Hot 100 and Easy Listening Singles charts.

Carole King (Carol Joan Klein) is an American singer-songwriter who has written or co-written 118 charting singles on the Billboard Hot 100 Singles chart. She started as a staff writer at the Brill Building in New York City in 1958, partnering in songwriting with her future husband, Gerry Goffin. She has released 17 studio albums, four live albums, seven compilation albums, one soundtrack album, and 33 singles. She has won four Grammy Awards, a Grammy Lifetime Achievement Award, a Library of Congress Gershwin Prize for Popular Song, and a Kennedy Center Honor. She is a member of the Rock and Roll Hall of Fame with Gerry Goffin, and as a solo artist. King is also a member of the Songwriters Hall of Fame and has a star on the Hollywood Walk of Fame. She has sold more than 75 million records worldwide. King still records and performs occasionally.

Corpus Christi Stage 3

Continued Commercial Momentum Across Platform

~45 mtpa platform ~90% contracted through mid-20s and ~85% longer term

Term LNG sales executed in 2021 with diverse customer base to increase cash flow visibility:

- ✓ Multiple European Utilities
- ✓ Asian Utility
- ✓ Latin American Utility
- ✓ Supermajor
- ✓ North American Producer
- ✓ LNG Marketer

Creditworthy Counterparties

~4.5 mtpa of available long-term contracts to support Stage 3

台灣中油股份有限公司 CPC Corporation, Taiwan

Apache

eog resources

TOURMALINE

Corpus Christi Stage 3 Progress

Competitive Advantages Drive Confidence in 2022 FID

Brownfield Economics

Corpus Christi Stage 3 to leverage significant in-place infrastructure

Tailored Solutions

Stage 3 expected to be underpinned by FOB, DES, and IPM contracts with customers from Europe, Asia, and North America

Bridging Volumes

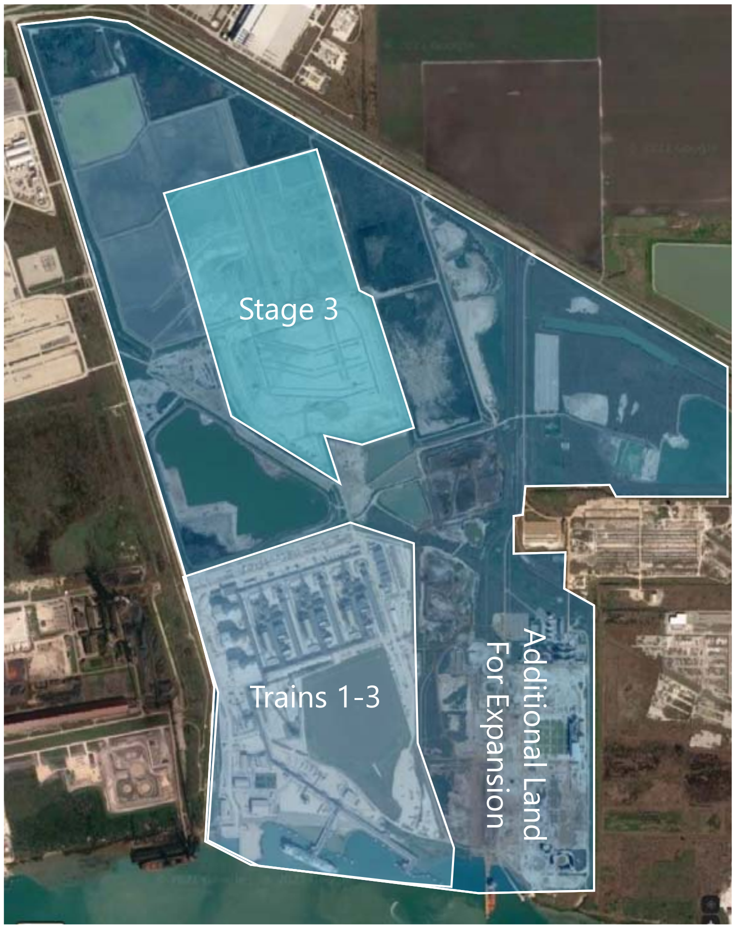
Differentiated platform enables market-leading flexibility for customers to procure early volumes without a condition precedent necessary

ESG Leadership

ESG leadership and action emerging as strategic commercial differentiator, helping secure term LNG sales in 2021

Expect FID of Corpus Christi Stage 3 in 2022 once investment parameters are met

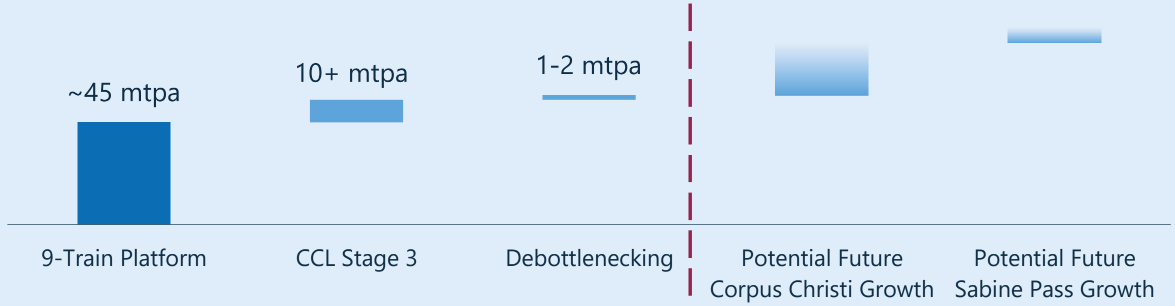
Potential Growth Opportunities at Corpus Christi and Sabine Pass



LNG Platform Growth Strategy

- Corpus Christi Stage 3 is shovel-ready and represents an incremental ~10+ mtpa of liquefaction capacity
- Additional potential expansions at Corpus Christi and Sabine Pass would be designed to leverage shared infrastructure to deliver cost competitive LNG capacity additions
- Significant land position in Corpus Christi and Sabine Pass provides potential development and investment opportunities for further liquefaction capacity expansion beyond Stage 3 at strategically advantaged locations with proximity to pipeline infrastructure and resources

Illustrative Future Growth Potential



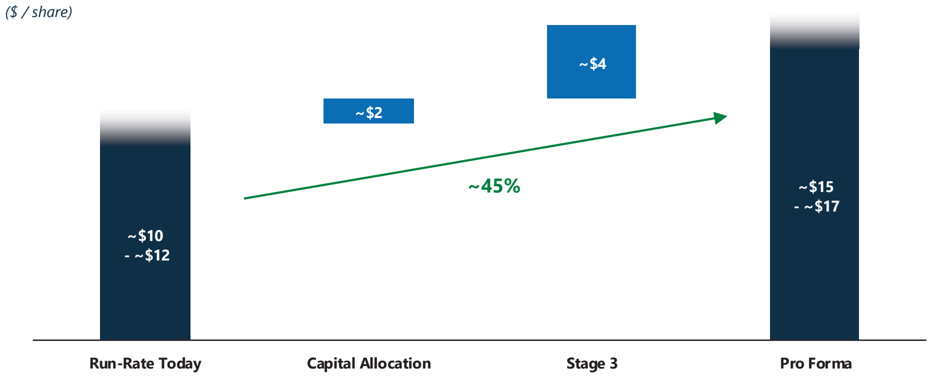
Potential development of significant future brownfield capacity additions

Summary Capital Allocation

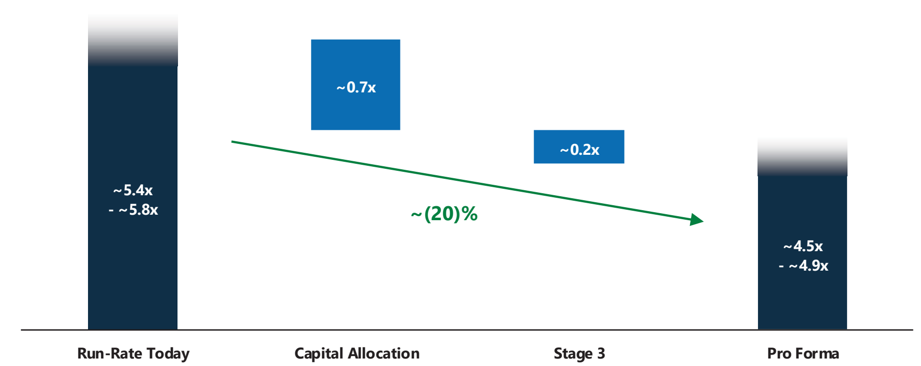
	Status Quo[1]	Capital Return		Growth + Capital Return	
	9 Train Run-Rate	**9 Train Run-Rate**	*% Δ vs. Status Quo*	**9 Trains + CCL Stage 3[2]**	*% Δ vs. Status Quo*
Consolidated Debt	~$31 bn	~$27 bn	*~(10)%*	~$31 bn	–
Consolidated EBITDA	~$5.3 - ~$5.7 bn	~$5.3 - ~$5.7 bn	–	~$6.4 - ~$6.9 bn	*~20%*
Consolidated Leverage	~5.4x - ~5.8x	~4.8x - ~5.0x	*~(10)%*	~4.5x - ~4.9x	*~(20)%*
DCF / Share	~$10 - ~$12	~$11 - ~$13	*~15%*	~$15 - ~$17	*~45%*
Share Count	~255 mm	~245 mm	*~(5)%*	~245 mm	*~(5)%*

Run-Rate DCF / Share

($ / share)



Run-Rate Debt / EBITDA



"All of the Above" Capital Allocation Plan designed to reach ~$16 DCF / share on a run-rate basis

Note: Run rate EBITDA and Distributable Cash Flow per Share ("DCF") figures assume further contracting and CMI sales of $2.00 / MMBtu for the low end of the range and $2.50 / MMBtu for the high end of the range. DCF and Adjusted EBITDA are non-GAAP measures. We have not made any forecast of net income on a run-rate basis, which would be the most directly comparable measure under GAAP, and we are unable to reconcile differences between these run-rate forecasts and net income. See Slide 27 for further detail on run-rate guidance.

(1) Prior to capital allocation realized year-to-date through 2021.

(2) Assumes Stage 3 run-rate achieved ~5 years after FID.

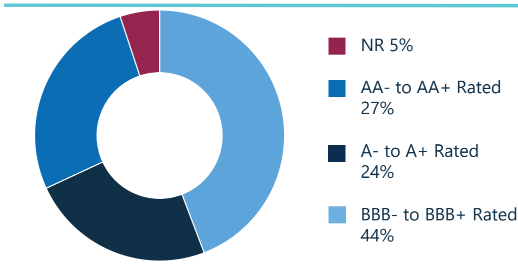
CHENIERE

Underpinned By Long-Term Creditworthy Contracts

Breadth and Depth of Counterparties

- **Over $6 billion of annual fixed-fee, take-or-pay style revenues**[1]
- All customers rated as investment grade by at least two of the three major agencies (S&P, Moody's, Fitch) or deemed investment grade by lenders[2]
- Average portfolio rating of **A- / A3 / A-** by S&P / Moody's / Fitch respectively[2]
- Average remaining life of contracts **~18 years**[2]

External Long-Term Customers[2]



Long-Term Customers

Sabine Pass Liquefaction: Trains 1-6

Shell	Naturgy	KOGAS	GAIL	TotalEnergies	centrica	Vitol	PETRONAS	SPA To Be Determined
(A+ / Aa2 / AA-)	(BBB / Baa2 / BBB)	(AA / Aa2 / AA-)	(NR / Baa3 / BBB-)	(A / A1 / AA-)	(BBB / Baa2 / NR)	(NR / NR / NR)	(A / A2 / BBB+)	(Investment Grade)

Corpus Christi Liquefaction: Trains 1-3

Naturgy	PERTAMINA	endesa	IBERDROLA	woodside	EDF	edp	TRAFIGURA	PetroChina
(BBB / Baa2 / BBB)	(BBB / Baa2 / BBB)	(BBB+ / Baa1 / A-)	(BBB+ / Baa1 / BBB+)	(BBB+ / Baa1 / BBB+)	(BBB+ / A3 / A-)	(BBB / Baa3 / BBB)	(NR / NR / NR)	(A+ / A1 / A+)

Corpus Christi Liquefaction: Stage 3

Apache	eog resources	TOURMALINE OIL CORP.
(BB+ / Ba1 / BB+)	(A- / A3 / NR)	(NR / NR / NR / BBB (high)[3])

Cheniere Marketing (SPAs Assignable to Projects)

台灣中油股份有限公司 CPC Corporation, Taiwan	PGNiG
(AA- / Aa3 / AA)	(NR / Baa2 / BBB+)

Contracted portfolio is foundation of Cheniere's long-term sustainable cash flow profile

Note: Ratings denote S&P, Moody's, Fitch and subject to change, suspension or withdrawal at anytime and are not a recommendation to buy, hold or sell any security.
(1) Includes long-term, mid-term, and short-term SPAs and IPM agreements.
(2) Includes long-term SPAs and IPM agreements.
(3) Represents credit rating from DBRS Morningstar.

Market Dynamics Point to a Tightening LNG Market

LNG capacity additions tapering off as markets continue to expand and legacy supply depletes

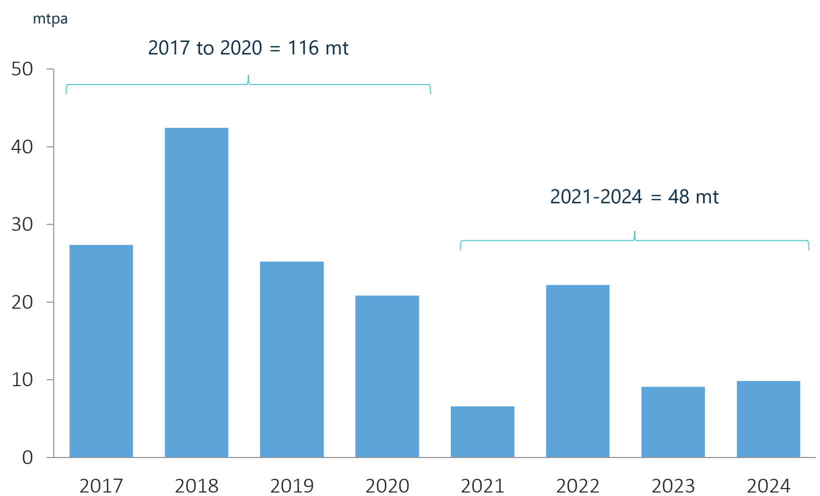
Supply growth has been curtailed, with FIDs on >90 mt of projects delayed or cancelled in 2020

Annual LNG Capacity Additions[1]

Surplus market conditions in 2020 were compounded by COVID-19 pandemic

Rapid market recovery, weather-driven demand and supply constraints have resulted in a swing to a tight market in 2021

Underlying market fundamentals point to **structural market tightness in 2022+ and in the mid-term market**

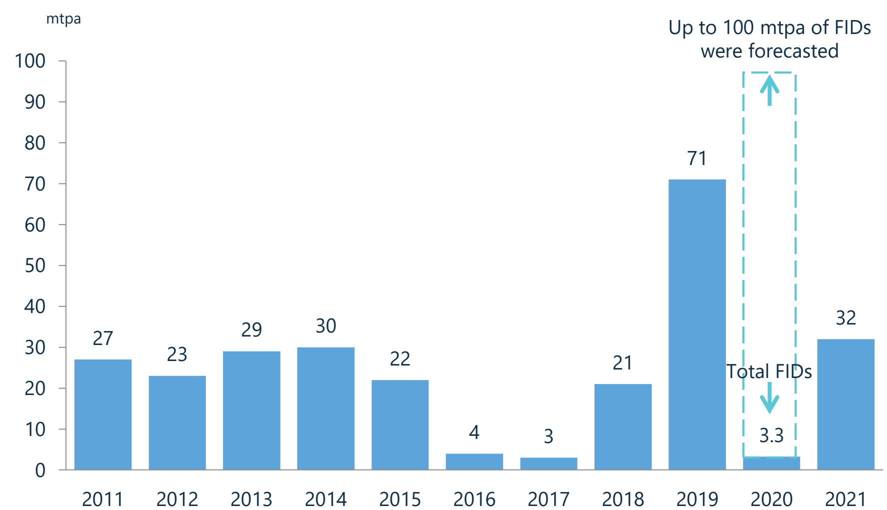


Volume of LNG Project FIDs by Year

~100 mtpa of forecasted LNG supply project FIDs stalled by market conditions in 2020[2]

Few FIDs expected this year beyond Qatar's NFE expansion

Current market conditions favor easier-to-progress expansion projects with bridging volumes, **as buyers seek volume and project certainty**



Sources: Cheniere Research, GIIGNL, Wood Mackenzie for historical figures.

(1) Capacity additions include project debottlenecking.

(2) Next period of rapid supply growth (mid/late 2020's) likely deferred / moderated.

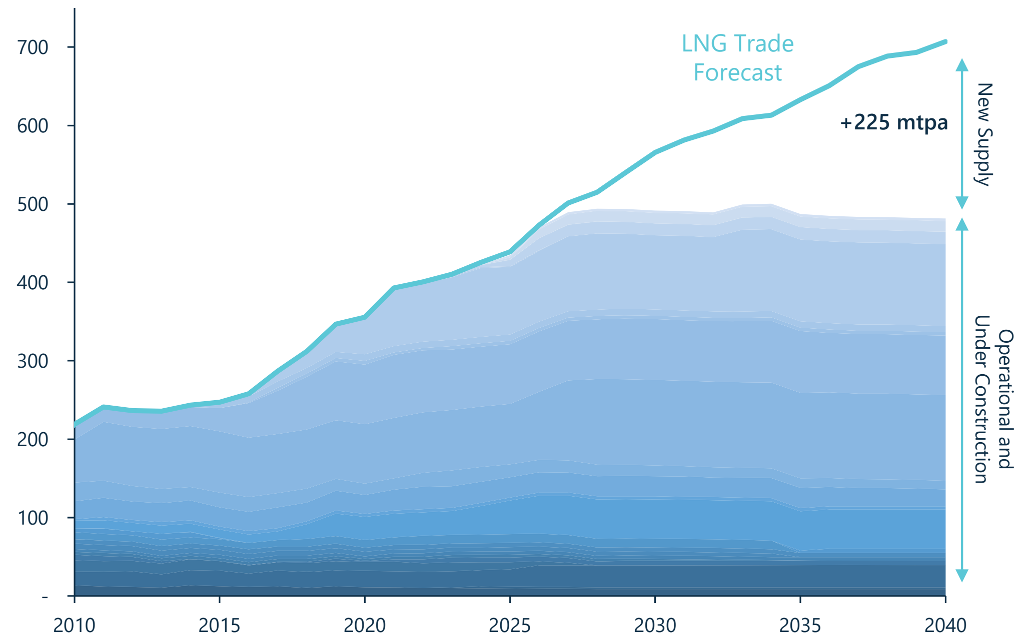
CHENIERE

Market Fundamentals Support LNG Growth for Decades

Driven by growing economies and **demand for secure, affordable and cleaner-burning fuels**

Global LNG Supply Outlook

70 mtpa of incremental LNG supply needed by 2030 and 225 mtpa needed by 2040



Natural Gas Drivers

Displacing Coal and Oil

Meeting the desire of growing economies worldwide to displace less clean-burning fuels with secure, affordable natural gas

Enabling Renewables

A functional role in meeting energy demand and stabilizing energy systems

- Balancing renewables
- Meeting seasonal demand

Climate Scenario Analysis

Incremental LNG supply required to meet growing LNG demand under multiple long-term climate scenarios analyzed

- Natural gas expected to play major role in energy transition
- Resiliency and sustainability of natural gas demand for decades

 Source: Cheniere Research estimates (July 2021), Wood Mackenzie for historical figures. Area chart includes all recent FIDs through February 2021 (up to and including QG NFE).

https://www.spglobal.com/platts/en/market-insights/latest-news/electric-power/063021-pickup-in-commercial-talks-boosts-chenieres-hopes-on-mid-scale-lng-project

- 30 Jun 2021 | 19:39 UTC

Pickup in commercial talks boosts Cheniere's hopes on mid-scale LNG project

HIGHLIGHTS

Progress in needed deals expected over 12-18 months

Exec also address emissions, opportunities, M&A

Author Harry Weber

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.

The comments during a S&P Global Platts Commodities Focus podcast are the most specific the biggest US LNG exporter has been on a time frame for commercializing the up to 11 million mt/year Stage 3 project since the start of the coronavirus pandemic in early 2020.

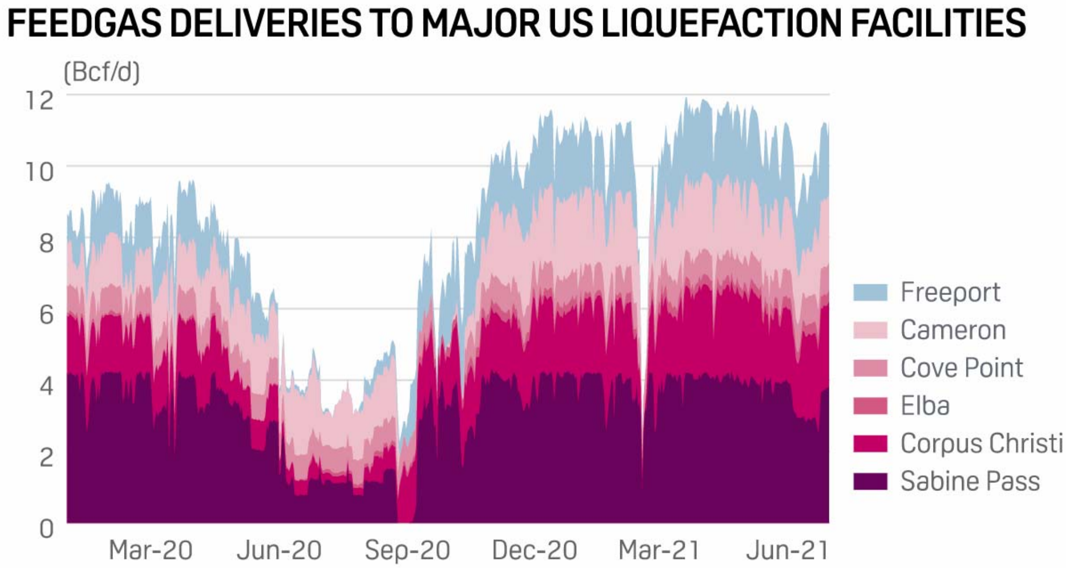
They reflect renewed talks that some operators and developers have been having with commodity traders, utilities and other end-users amid tightening global supplies and the strongest pricing levels for deliveries into Asia and Europe in years.

While Cheniere's time horizon for commercializing Stage 3 is a bit longer than recent estimates from Freeport LNG for its Train 4 expansion, Tellurian for its Driftwood LNG project and NextDecade for its Rio Grande LNG project, it has stuck mostly to the traditional strategy for selling new capacity that served it well for building Sabine Pass Liquefaction in Louisiana and Corpus Christi Liquefaction in Texas.

It also has been focused on securing buyers for excess capacity that it identified from its existing trains and pursuing initiatives to reduce its carbon footprint.

"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."

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."



Source: S&P Global Platts Analytics

Cheniere has not yet made a final investment decision on the mid-scale liquefaction expansion it has proposed to build. It has said that it would sanction the expansion only after signing additional commercial agreements and obtaining adequate financing. Cheniere, which also needs to secure an engineering, procurement, and construction contract for the project, signed agreements in 2019 with US gas producers Apache and EOG Resources to market a combined 1.7 million mt/year of LNG supplies from the Stage 3 expansion

In terms of Cheniere's corporate sustainability and climate-related efforts, the company is pursuing a program to quantify the life-cycle emissions of the LNG cargoes it produces. Cheniere views its role in the energy transition as a leader, given its size and full-service platform. It believes an all-of-the-above strategy that includes employing technologies like carbon capture and underground storage that have had mixed success in other sectors of the US energy industry is the right approach for LNG, Feygin said.

"There will be CCUS projects that are attractive and relatively feasible, and there will be CCUS projects that are science projects and require tremendous achievement in terms of technological advancement and economic improvement," he said. "So, we are of the view that we're not going to let the perfect be the enemy of the good."

Emissions transparency

He said the emissions transparency efforts are "a step on a long-term journey and long-term commitment to not just be the leader on this front for US LNG, where Cheniere of course is the largest exporter, but also for the world."

"It is only a starting point and it is a starting point that we are perfectly positioned to build on with our producer relationships, our relationships with our infrastructure partners and our downstream partners," Feygin said.

He cited a study Cheniere participated in with shipping partner GasLog and others to provide more definitive data on methane emissions from LNG-powered vessels.

Feygin also addressed Cheniere's challenges, opportunities, and views on M&A.

The biggest challenge, he said, is figuring out the right commercial solutions to crack a framework in which most of the supply that will come online in the next five to 10 years is already baked into industry estimates.

"No one is surprising the market with an additional 5 or 10 million tons," Feygin said. "The probability is that supply is actually going to surprise to the downside in the next couple of years."

Upstream and M&A

With that in mind, the growing economies in Asia present the biggest opportunity for Cheniere. It is also optimistic about LNG bunkering and LNG into Europe.

One thing Cheniere does not appear to be interested in anytime soon is a merger, major acquisition or expansion into the upstream, to produce some of the feedgas it uses at its liquefaction facilities.

"We don't see any strategic reason to be in the upstream business," Feygin said.

He said Cheniere also does not currently see any "compelling opportunity that would lead us down the path of M&A," though he added that the company's view is "not for a lack of looking and evaluating."

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

Posted 11am on July 14, 2021

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

Sea change in Asian LNG buyers is also the best validation of the LNG supply gap and big to LNG supply FIDs. 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.

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. LNG markets didn't really react to Total's April 26 declaration of force majeure on its 1.7 bcf/d Mozambique LNG Phase 1. This was an under construction project that was on time to deliver first LNG in 2024. It was in all LNG supply forecasts. There was no timeline given but, on the Apr 29 Q1 call, Total said that it expected any restart decision would be least a year away. If so, we believe that puts any actual construction at least 18 months away. There will be work to do just to get back to where they were when they were forced to stop development work on Phase 1. Surprisingly, markets didn't look the broader implications, which is why we posted our 7-pg Apr 28 blog "*Multiple Brownfield LNG FIDs Now Needed To Fill New LNG Supply Gap From Mozambique Chaos? How About LNG Canada Phase 2?*" [LINK] We highlighted that Mozambique LNG delays were actually 5 bcf/d, not 1.7 bcf/d. And this 5 bcf/d of Mozambique LNG supply was built into most, if not all, LNG supply forecasts. The delay in Total Phase 1 would lead to a commensurate delay in its Mozambique LNG Phase 2 of 1.3 bcf/d. Total Phase 2 was to add 1.3 bcf/d. There was no firm in service date, but it was expected to follow closely behind Phase 1 to maintain services. That would have put it originally in the 2026/2027 period. But if Phase 1 is pushed back at least 2 years, so will the follow on Phase 2, so more likely, it will be at least 2028/2029. The assumption for most, if not all, LNG forecasts was that Phase 2 would follow Phase 1. Exxon Rozuma Phase 1 of 2.0 bcf/d continues to be pushed back in timeline especially following Total Phase 1. Exxon's Mozambique Rozuma Phase 1 LNG will add 2.0 bcf/d and, pre-Covid, was originally expected to be in service in 2025. The project was being delayed and Total's force majeure has added to the delays. Rozuma onshore LNG facilities are right by Total. On June 20, we tweeted [LINK] on the Reuters report "*Exclusive: Galp says it won't invest in Rovuma until Mozambique ensures security*" [LINK]. Galp is one of Exxon's partners in Rozuma. Reuters reported that Galp said they won't invest in Exxon's Rozuma LNG project until the government ensures security, that this may take a while, they won't be considering the project until after Total has reliably resumed work on its Phase 1, which likely puts any Rozuma decision until at least end of 2022 at the earliest. Galp has taken any Rozuma Phase 1 capex out of their new capex plans thru 2025 and will have to take out projects in their capex plan if Rozuma does come back to work. This puts Rozuma more likely 2028 at the earliest as opposed to before the original expectations of before 2025. Pre-pandemic, Exxon's March 6, 2019 Investor Day noted their operated Mozambique Rovuma LNG Phase 1 was to be 2 trains each with 1.0 bcf/d capacity for total initial capacity of 2.0 bf/d with FID expected in 2019 and first LNG deliveries sometime before 2025. LNG forecasts had been assuming Exxon Rozuma would be onstream around 2025. The 2019 FID expectation was later pushed to be expected just before the March 2020 investor day. But the pandemic hit, and on March 21, 2020, we tweeted [LINK] on the Reuters story "*Exclusive: Coronavirus, gas slump put brakes on Exxon's giant Mozambique LNG plan*" [LINK] that noted Exxon was expected to delay the Rovuma FID. There was no timeline, but now, any FID is not expected until late 2022 at the earliest, that would push first LNG likely to at least 2028. What this means is that the Mozambique LNG delays are not 1.7 bcf/d but 5.0 bcf/d of projects that were in all, if not most, LNG supply forecasts. There is much more in our 7-pg blog. But Mozambique is what is driving a much bigger and sooner LNG supply gap starting ~2025 and stronger outlook for LNG prices

One of the reasons why it went under the radar is that major LNG suppliers played stupid on the Mozambique impact. 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".*

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

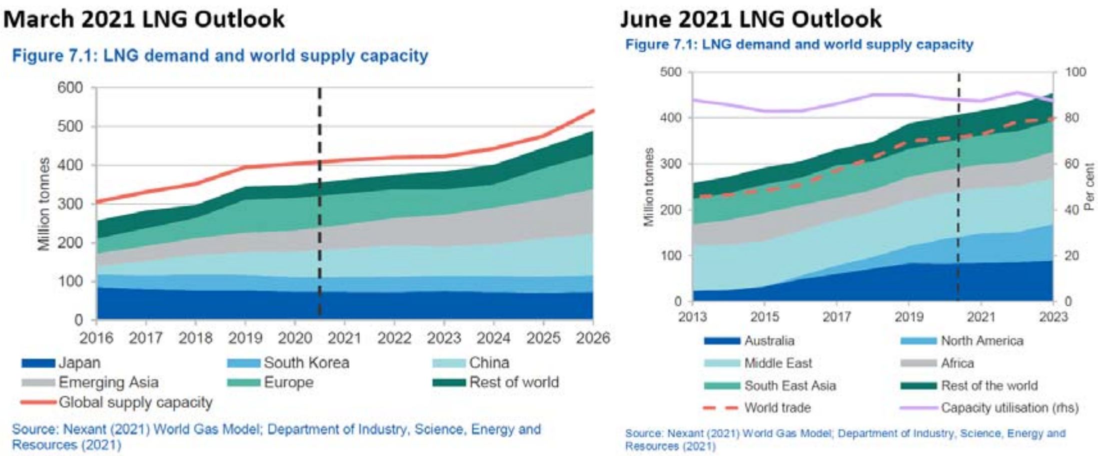
Common theme - new LNG supply is being delayed ie. [Total] Mozambique. Don't forget need capacity>demand due to normal maintenance, etc. Positive for LNG." (ii) Chevron's Gorgon. A big LNG story in H2/20 was the emergence of weld quality issues in the propane heat exchangers at Train 2, which required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

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

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

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

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

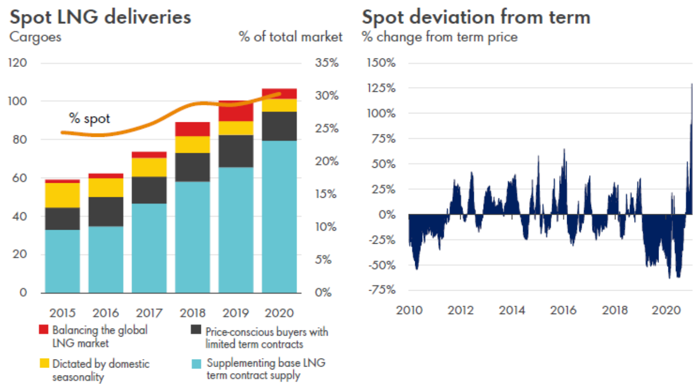


Source: Australia Resources and Energy Quarterly

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

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

Spot LNG deliveries and Spot deviation from term price



Source: Shell LNG Outlook 2021 on Feb 25, 2021

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

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

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

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

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

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

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

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

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

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

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

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

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

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

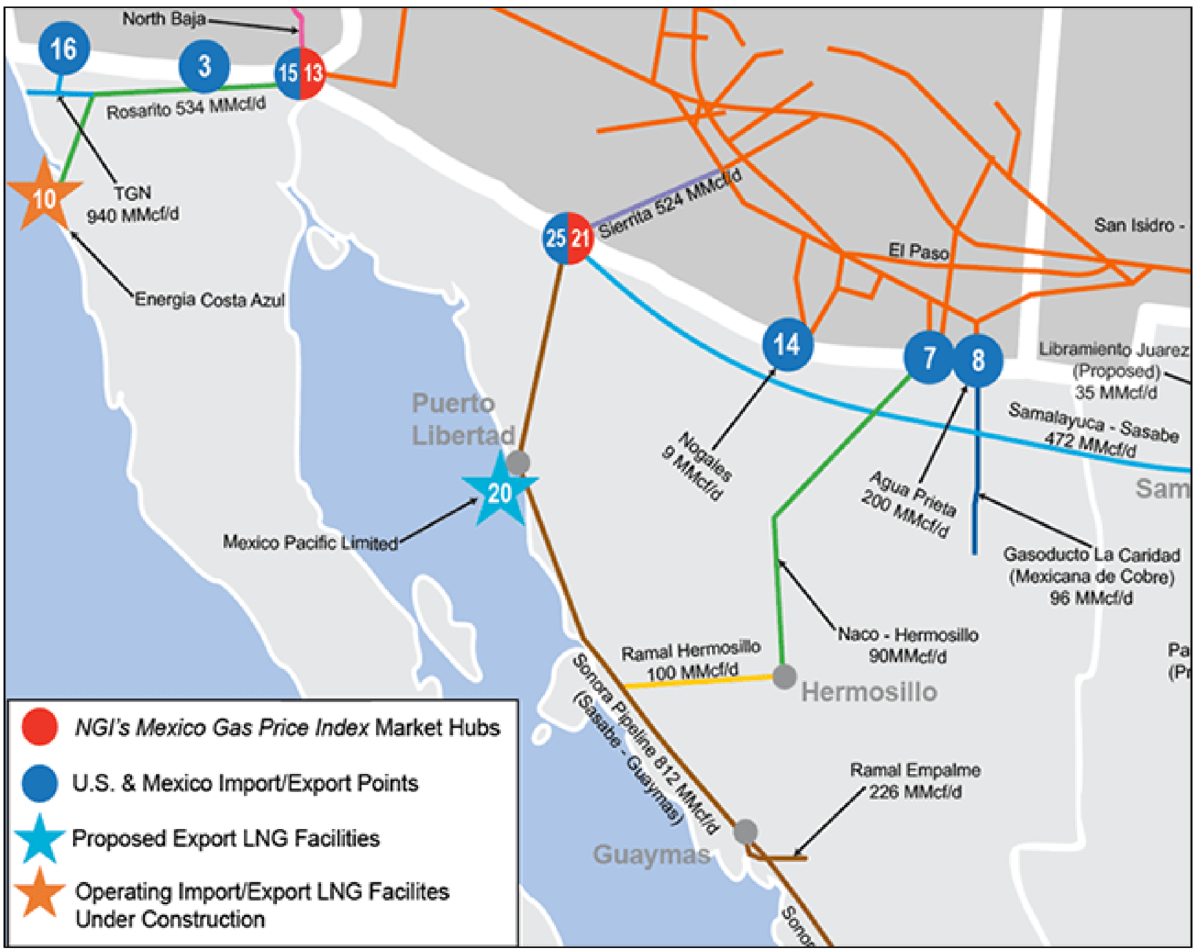
https://www.naturalgasintel.com/lng-buyers-negotiating-22-mmty-from-mexico-pacific-terminal-as-asia-prices-soar/

LNG Buyers Negotiating 22 MMTY from Mexico Pacific Terminal as Asia Prices Soar

BY **ANDREW BAKER**
SEPTEMBER 8, 2021
Share on:TwitterFacebookLinkedIn

Interest from Asian buyers in liquefied natural gas (LNG) exports from Mexico's Pacific Coast has reached a full-blown frenzy amid **soaring natural gas prices and demand**, according to Mexico Pacific Limited LLC (MPL) CEO Doug Shanda.

Mexico Pacific Limited LNG Facility and Nearby Natural Gas Infrastructure



Source: NGI's Map of Mexico's Natural Gas Pipelines, Market Hubs & LNG Facilities 2022 Edition

Shanda spoke with *NGI's Mexico GPI* about the firm's **LNG export terminal** planned for Puerto Libertad in Sonora state.

"We saw a lot of interest at the end of last year," Shanda said, but "this year, it's just been incredible."

Front-month Japan/Korea Marker (JKM) prices, the benchmark for LNG delivered to Asia, settled at $18.650/MMBtu on Wednesday (Sept. 8), compared to $4.914 for the U.S. benchmark Henry Hub.

By allowing shippers of gas produced in the Permian Basin of West Texas to bypass the Panama Canal, MPL will offer “the most competitive price for LNG into Southeast Asia on a landed cost basis,” Shanda said.

To date, he said that 22 million metric tons/year (mmty) of binding offtake capacity is under negotiation for the project, including 14 mmty for which memorandums of understanding (MOU) have been signed.

Another handful of potential offtakers have opted to skip the MOU process and move straight to discussing binding offtake agreements.

Shanda said MPL is aiming to close binding offtake agreements for the first two trains of the project by year-end, and to reach a final investment decision in early 2022.

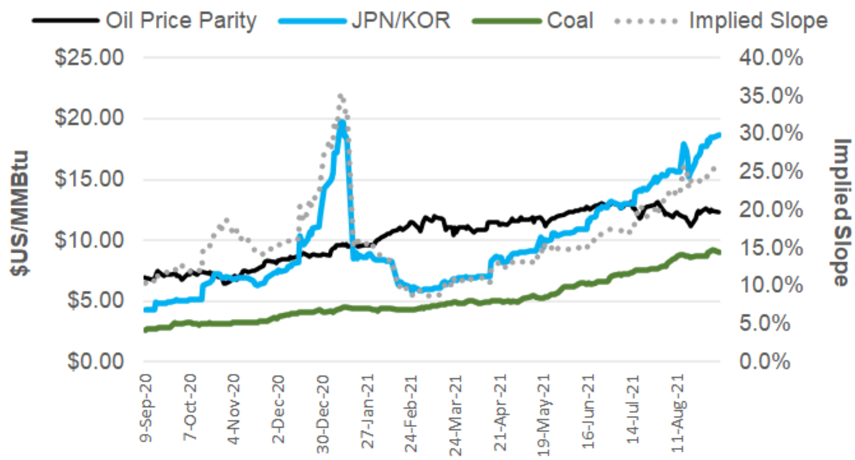
This would keep MPL on track to hit its target of bringing the first two trains, with a combined capacity of 9.4 mmty, online in 2025, “when that supply-demand gap starts to open up,” Shanda said. Once the first two are online, the third is likely to follow quickly, bringing capacity to 14.1 mmty. Longer-term, MPL is eyeing six total trains for a combined 28.2 mmty, Shanda said, noting that the final three trains would be built on the same 300-acre footprint as the first three.

Asia LNG Parity Prices 8-Sep-2021

Current Spot Month Japan/Korea Futures Contract Price (Oct):	**$18.650**
Current Spot Month Brent Crude Oil Futures Price (Nov):	**$72.60**
Current Spot Month Japan Coal Price (Sep):	**$9.05**
Implied Current Japan/Korea Slope to Brent:	**25.7%**

	Oil Price		Oil Parity Price (17.2% Slope)	
Crude Mo.	3 Mo Avg JCC	Brent	3 Mo Avg JCC	Brent
Nov-21	$67.00	$72.60	$11.52	$12.49

Trailing 12M Daily Prompt Japan/Korea Futures



Note: Oil linked parity figures tend to serve as a cap on Asian LNG market prices, while coal prices can help act as a floor.

Source: NGI calculations, ICE, CSI, METI

NGI's LNG INSIGHT

The total size of the site is about 1,100 acres, which “leaves another 800 for us to continue to grow,” he added.

Shanda said that while the pandemic has slowed the regulatory approval process somewhat in Mexico, MPL last month obtained approval from the Comisión Reguladora de Energía (CRE) for modifications to its liquefaction and pipeline transportation permits.

“So…they’re still paying attention to our project, and they’re still approving the things we need to get done,” Shanda said. The last pending regulatory hurdle is a natural gas export permit from CRE, which MPL hopes to obtain within the next few months.

MPL will source its gas from the Waha hub in the heart of the Permian.

“We haven’t had to really seek out places to buy gas, everybody’s been coming to us,” Shanda said.

The Puerto Libertad project will connect to Sempra Energy’s Sonora Pipeline Phase I, which transports gas from the U.S.-Mexico border south of Tuscon, AZ, through Sonora and the northern part of Sinaloa state in Mexico.

The terminal also will connect with Grupo Carso’s Samalayuca-Sásabe pipeline, which also brings U.S. gas ino Mexico.

Only a fraction of the capacity on each of the two pipelines is currently being used by anchor shipper Comisión Federal de Electricidad (CFE), Shanda said, explaining that there are “no gas sinks,” i.e. demand clusters, along the pipeline routes.

CFE is Mexico’s state-owned power company and among the **largest natural gas marketers** in North America.

Shanda said MPL expects to purchase gas from CFE as well as numerous other marketers, explaining that “it’s a really good fit for us with CFE.”

MPL last year awarded front end engineering design work for the project to Technip USA Inc., and engaged Mitsubishi UFJ Financial Group as financial advisor.

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- 21 Apr, 2021

Mexico Pacific is lining up deals for 'black pearl of North American LNG'

Mexico Pacific Ltd. LLC executives embraced the idea of a racehorse coming out of nowhere as a way to describe their proposed LNG project that would export Permian Basin natural gas from Mexico's West Coast.

"'Dark horse' is a good description, but this will be my third time I've been on a dark horse project," MPL President and CEO Douglas Shanda said in an interview.

Shanda is a former Cheniere Energy Inc. executive who also worked several years on the Peru LNG project in South America. "The fundamentals of this project are so strong, and the team is so strong," he said. "I feel good about our opportunity and our odds."

The private developer has been quietly building the commercial support it needs to advance to construction on the project, which would be capable of producing up to 12.9 million tonnes of LNG per year. Executives told S&P Global Market Intelligence in a recent interview that they expect to reach a final investment decision, or FID, on two gas liquefaction trains in late 2021 or early 2022 and to begin exports by 2025.

"We are trending towards FID'ing 8.6 million tonnes, and we do have a third phase of another 4.3 million tonnes that we have permitted," Shanda said. "We're already looking at what comes after that, because right now the commercial interest in our project is so strong."

MPL's reports of commercial progress came as more than a dozen LNG developers in North America compete to advance their projects to construction, following a year marked by a lack of FIDs. Just one LNG project was commercially sanctioned in 2020: Sempra Energy's 2.5-Mt/y Energía Costa Azul terminal, which is also on the West Coast of Mexico, in Baja California.

Other developers, especially those with greenfield projects that would be built from the ground up, have struggled to build the commercial support to get to the construction phase. But some project sponsors in recent months have cited an increasing interest among world LNG buyers in signing long-term supply deals as a source of optimism.

Mexico Pacific Ltd.'s proposed LNG terminal would be capable of producing up to 12.9 million tonnes per year.
Source: Mexico Pacific Ltd. LLC

"Most projects struggle with customers," said MPL Chief Commercial Officer Sarah Bairstow, a veteran of Santos Ltd.'s Gladstone LNG project in Australia "That hasn't been our struggle."

The contestants

Mid-sized projects like MPL and expansion projects of existing terminals have appeared to attract some of the most commercial interest in 2021, according to Jason Feer, head of business intelligence at Poten & Partners.

"We are seeing people give some dark horses more of a look than maybe they were in the past. Mexico Pacific Ltd. has been getting quite a look these days," Feer said in an interview.

"Obviously with the number of projects that we have in the U.S., there is not room for everybody," Feer said. "And the dynamic seems to be that projects that are most competitive are in that 8 [million]-12 million tonne range, or expansion projects — those are the ones that seem to have momentum these days."

One reason that Feer said smaller projects can appeal to buyers is that developers need to contract fewer LNG supplies to secure financing, giving customers greater influence over whether a project advances to construction and removing some of the uncertainty about whether the supplies will be available when buyers need them.

"From a customer perspective, when they sign contracts with projects they need to be certain that these volumes will materialize," Bairstow said. "They don't want to take a punt."

Another key selling point of the MPL project is its proposed location on the Pacific Ocean. This would bring the benefit of a shorter shipping route to Asia compared to facilities on the U.S. Gulf Coast that would enable LNG tankers to avoid the Panama Canal. The project would connect with an existing pipeline system that is underutilized.

Shanda said exporting U.S. gas off the West Coast is "the black pearl of North American LNG."

Backed by the private-equity investor AVAIO Capital, MPL is marketing what it says will be "the lowest North American landed LNG price into Asia."

The race

MPL still needs an export permit from the Mexican government, which executives said they expect will be issued by the end of June. In the meantime, MPL said it is in advanced discussions with buyers serving China, South Korea, and Japan about purchasing supplies under long-term contracts.

To commercially sanction the two trains capable of producing 8.6 Mt/y, the company would need to line up about 6 Mt/y worth of supply deals, according to Shanda. MPL expected to reach that threshold without much trouble. The company said it has about 10 Mt/y worth of preliminary agreements that it is working to convert to sale and purchase agreements, and it is discussing potential deals for some 8 Mt/y worth of additional supplies. The company declined to name the counterparties.

If the anticipated contracts fail to materialize, executives said the company could still move forward with a single 4.3 Mt/y-train by contracting 75% of that capacity.

The company's site in Puerto Libertad, Sonora, about 125 miles south of the Arizona border on the north edge of the Sea of Cortez, has room for expansion. The site covers a total of about 1,100 acres, and the first three phases of the project just require 300 acres.

The company last year tapped Mitsubishi UFJ Financial Group Inc. as its financial advisor. Bechtel Corp. is developing the company's front-end engineering design, the MPL executives said. The executives said they are on track to have an engineering, procurement and construction contract by early November. They expect the signing of binding sales and purchase agreements with customers to follow.

"This project has much more flexibility that allows us to get to FID than most projects have in the world," Shanda said.

https://www.spglobal.com/platts/en/market-insights/latest-news/lng/090921-petronas-warns-customers-of-more-lng-cargo-deferrals-for-winter

- **G | NATURAL GAS**
- 09 Sep 2021 | 02:00 UTC

Petronas warns customers of more LNG cargo deferrals for winter

HIGHLIGHTS

Notifies Japanese offtakers of possible deferrals for Nov-Jan cargoes

Deferments this winter may force end-users into spot trades: Platts Analytics

JKM for October crosses $20/MMBtu on winter supply concerns

Author Hwee Hwee Tan Masanori Odaka

Malaysia's national oil company Petronas has sounded out customers on the possibility of more LNG cargoes being deferred for the winter months from its nine-train LNG complex at Bintulu, Sarawak, traders and end-users told S&P Global Platts.

The potential delays come after Petronas had already requested for deferrals for August LNG cargoes, and could add to tighter demand-supply fundamentals in the Asian LNG market, with a bullish price impact.

Petronas contacted several Japanese LNG importers in the last few weeks cautioning them that cargoes due for delivery in the November-January period could be impacted, although no deferrals have happened yet and no notifications of deferral have been sent out so far, several market participants in Japan said.

Traders said Petronas is contractually obligated to try and make up for the deferrals from its wider LNG supply portfolio and has the ability to widen its own procurement from the market, to try and minimize any impact on customers and uphold its commitment to buyers.

The Malaysian LNG exporter has been able to offset supply issues in the past and the early warnings are meant to seek buyers' understanding during mitigation efforts, as Petronas may still need to exercise contractual flexibilities in its agreements as a last resort, traders said.

LNG exporters are generally able to meet their contractual obligations and minimize the impact on customers, even during periods of high demand and despite tighter margins in a high price environment, to maintain business relationships, market participants said.

"Petronas would like to clarify that there is no supply disruption to our operations at the Petronas LNG Complex in Bintulu, Sarawak," the NOC said in a statement in response to queries, but did not comment on early warnings to its Japanese customers about the possibility of winter deferrals.

"We haven't received any concrete notice [on cargo deferrals] but we are worried that our November and December delivery cargoes may be impacted," one buyer said.

Another offtaker said any cargo deferrals for winter months will be "disappointing" as "JKM [price] is going up and winter peak is approaching."

"If they do this, people will have to cover [their positions], yet it is also unclear whether they will prioritize winter cargo deliveries by contracts, trains or other parameters," the same offtaker said.

Japanese offtakers have said the notifications from Petronas relate to cargoes tied to term supply contracts, implying that there would be a higher dependence on their spot LNG portfolio to make up for any shortfall in term supply.

Market impact

These discussions come after Petronas had requested its Japanese customers to postpone cargo deliveries scheduled for August to September or October, and have raised concerns among Asian LNG importers that are already seeing record-high prices for spot LNG for this time of the year.

The S&P Global Platts JKM for October delivery has soared past $20/MMBtu, and was assessed at $20.038/MMBtu on Sept. 8.

"The potential for cargo deferments this winter could force some end-users into the spot market if the supply is pushed later into next year, as recent memories from last winter will likely lead many to secure cargoes in anticipation of any temperature-driven demand spikes," said Jeffrey Moore, Asia LNG manager at S&P Global Platts Analytics.

Petronas won support from at least three Japanese offtakers to defer delivery of cargoes from August to September or October, Platts reported Sept. 6, but the NOC may find it tougher to get consent to do the same for those scheduled for November to January as buyers and end-users want certainty on winter supplies.

While upstream sources have cited spikes in COVID-19 infections in Sarawak and Sabah that have spread to offshore projects supplying gas to the Bintulu LNG complex, Japanese offtakers said they had also been notified of feed-gas issues due to late production startup at gas fields designed to backfill the project.

https://tass.ru/ekonomika/12352091
SEP 10, 03:24

Germany doubts the start of gas pumping through Nord Stream 2 by October

Klaus Ernst, head of the Bundestag's Economic and Energy Committee, notes that the next steps related to certification may take weeks or even months.

BERLIN, September 10. / TASS correspondent Anton Dolgunov /. Gas via Nord Stream 2 is unlikely to start pumping from the beginning of next month, as reported by the media, since this requires obtaining a few more permits. This opinion was expressed in response to a request from a TASS correspondent by the head of the Bundestag Committee on Economics and Energy Klaus Ernst.

“I would love to see the pipeline go into operation as soon as possible, but I think this date is unrealistic. The next steps related to certification may take weeks or even months. I believe that pumping could start as early as this year, but not on October 1, "said a representative of the Left Party.

On Friday, Gazprom announced that the construction of the Nord Stream 2 gas pipeline was fully completed on the morning of September 10.

Agency Bloomberg reported earlier, citing unnamed sources, that the supply of gas through the first stretch supposedly scheduled to begin on October 1 and December 1 - on both threads.

In response to a request from a TASS correspondent, the timing of the start of operation was not commented on either by the Federal Ministry of Economy or by the regional ministry in Mecklenburg-Vorpommern, where the final point of Nord Stream 2 is located. Both there and there they said that they would not give forecasts, and recommended contacting the operator, Nord Stream 2 AG.

What legal procedures have to be completed

Nord Stream 2 must comply with one of the basic rules by which energy companies operate in the European market. This is the so-called unbundling, or division of companies. The point is that companies that extract resources do not have the right to transport them - these two processes require different firms. If Nord Stream 2 had been completed before May 23, 2019, then this rule would not have affected it.

It was not completed by that time, but billions of dollars in investments had already been made - Nord Stream 2 AG believed that this could formally be considered the completion of the project, but the German regulator - the Federal Network Agency - thought otherwise and did not make exceptions for the project. In his opinion, completion should be understood as the actual completion of the laying and construction of all terminals. Subsequently, the local court sided with the regulator, which means that the unbundling rules are also mandatory for Nord Stream 2. The operator now has the right to file a claim with the Federal Supreme Court, but the company has so far only talked about plans to study the court's decision and did not report on the next steps.

In order to comply with the rules of the EU's third energy package, the operator Nord Stream 2 AG already in June - that is, even before the court's decision - submitted a request to the Federal Network Agency to register an independent transportation operator in Germany. The department, in response to a request from TASS, said that they were still studying the provided package for the presence of all the necessary documents and only after that they would begin to consider the application. "It is still impossible to say whether we will request additional documents and if so, when," they noted. "After that, the department will have four months to prepare a draft decision. Then it will be submitted to the European Commission for evaluation."

In parallel, the certification process is under way at the Mecklenburg-Western Pomerania state level. Here we are already talking about the compliance of the pipeline with technical requirements. The assessment is carried out by the Stralsund Mining Authority. As the TASS correspondent was told in the government of the land, the department has already issued "all the permits necessary for the construction and operation." "There is only a lack of some documents from certified specialists that confirm technical safety. They must be received there before the start of operation," the regional cabinet said. They did not say exactly when they expect to receive these documents from Nord Stream 2 AG.

Election factor and gas demand

It is no secret that the current German Chancellor Angela Merkel has supported Nord Stream 2 in recent years, despite political differences with Russia and the demands of the opposition. She called the project European, not Russian-German, repeatedly pointed to the commercial component, and raised the political aspect on the other hand - Berlin wants to preserve transit through Ukraine in parallel with gas supplies along the bottom of the Baltic Sea. In two weeks, elections to the Bundestag will be held in Germany, as a result of which a new chancellor will appear in the country, and Merkel will leave big politics.

The right to form a coalition will go to the party with the largest number of votes, and the leader of the party list will become the new head of government. Based on current polls, the majority will be recruited by the Social Democrats with a candidate in the person of Olaf Scholz. The Christian Democratic and Christian Social Union with Armin Lashet would be second, and the most zealous opponents of Nord Stream 2, the Greens, would be third. This balance of power is confirmed by several sociological institutions at once.

Both Scholz and Laschet said the pipeline needed to be completed, but in theory it could be stopped in the event of energy security threats. Now we need to wait to see what the next ruling coalition will look like, which will likely have a different view on the project than the current government. Most likely, the "green" will enter the new cabinet, who will once again try to delay the start of operation. The party has already talked about plans to create a climate ministry within the new Cabinet with veto rights over all other government initiatives.

As the German political analyst Alexander Rahr said in an interview with a TASS correspondent, the "greens" can indeed enter the Cabinet, even taking second or third place in the elections, they have experience of working in the government. "They, of course, have a negative attitude towards Russia, but during the coalition negotiations there will be bargaining - who will get which ministry. The Greens will demand for themselves not the post of Minister of Foreign Affairs, but the post of Minister of Finance, and they will also try to create a climate ministry . They will focus on gaining influence on economic and financial projects, "Rahr said.

Germany now needs more natural gas. Germany is on the way to the implementation of a large-scale project for the transition to alternative energy sources - the republic is phasing out nuclear power plants and, in parallel, withdraws from coal energy. The German economy needs blue fuel for a long transition period in order to switch to new sources painlessly for the industry.

Europe Must Better Prepare for Gas Crunch, U.S. Envoy Says
2021-09-10 18:12:24.491 GMT

By Wojciech Moskwa
(Bloomberg) -- Europe isn't doing enough to prepare for a potential gas crunch this winter, especially as U.S. deliveries of LNG can't be increased further, according to the State Department's envoy for energy security.
Amos Hochstein said on Friday that U.S. liquefied natural gas shipments to the continent were running at full capacity, and -- if the winter is harsh -- additional supplies would need to be sent to Europe through its gas pipeline.
"I worry because I don't think we should ever be in a position knowing that if it's a cold winter, there's not enough supply," he told reporters during a visit to Warsaw. Everyone "has to be prepared and to think about this more than I'm seeing currently in Europe."
Hochstein said he's concerned because gas storage in Europe is below the five-year average, which has led to record prices in some markets, and that Russia -- a major source of the continent's energy -- "is coming off an extended period of inexplicably low supply."

--With assistance from Maciej Martewicz.

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To view this story in Bloomberg click here:
https://blinks.bloomberg.com/news/stories/QZ8BN5T0G1L0

Excerpt from http://en.kremlin.ru/events/president/news/66648

News conference following Russian-Belarusian talks

Vladimir Putin and President of Belarus Alexander Lukashenko held a joint news conference at the Kremlin following Russian-Belarusian talks

September 9, 2021 22:15 The Kremlin, Moscow

Vladimir Putin: We need to work gradually. The road maps and these programmes stipulate all this. Consequently, everything will be obvious there. We can see that countries with weaker economies are suffering in the European Union. They could devalue something in a well-known situation, but they are unable to do this because they have no national currency. The euro is a strong currency, and what are they to do? All-out price hikes is the only option fraught with dire social consequences. Therefore we must act very cautiously, analyse the pluses and minuses, the positive aspects of our neighbours and negative examples. We are trying to do this.

You are talking about energy prices. I have said that 1,000 cubic metres cost $650 on the free European market. But the wise-guy members of the European Commission’s previous line-up invented market gas pricing, and the results are here for everyone to see.

And we prefer a different approach. We also stipulate market pricing, and this price is pegged to the crude oil price. No one but market regulates it. But the fluctuations are much less pronounced. But here, someone has failed to pump the required 27 billion cubic metres into underground gas reservoirs, causing a shortage in gas supplies, business activity increased or something else happened, and there you are – gas prices start to exceed the prices of crude oil and petroleum derivatives. So you can see a substantial price hike.

Gazprom does not charge such selling prices under long-term contracts and our pricing principles. Those Europeans who have agreed to sign long-term contracts with us can rub their hands with joy and feel happy because they would otherwise have to pay $650. Gazprom sells gas to Germany for $220; at any rate, this was the case only recently.

Considering rising oil prices considered, this price will still go up, but the process will be more gradual. In reality, Gazprom is interested in this because it also creates a certain safety cushion. There will be no abrupt slump and drop in prices. This is the gist of the matter. Everyone stands to gain from this. Those members of the European Commission who came up with their own ideas have got the desired result.

Shell: “Every LNG Cargo That Could Technically Be Produced In This World Has Been Produced And Has Found A Well Paying Customer”

Posted: September 20, 2017

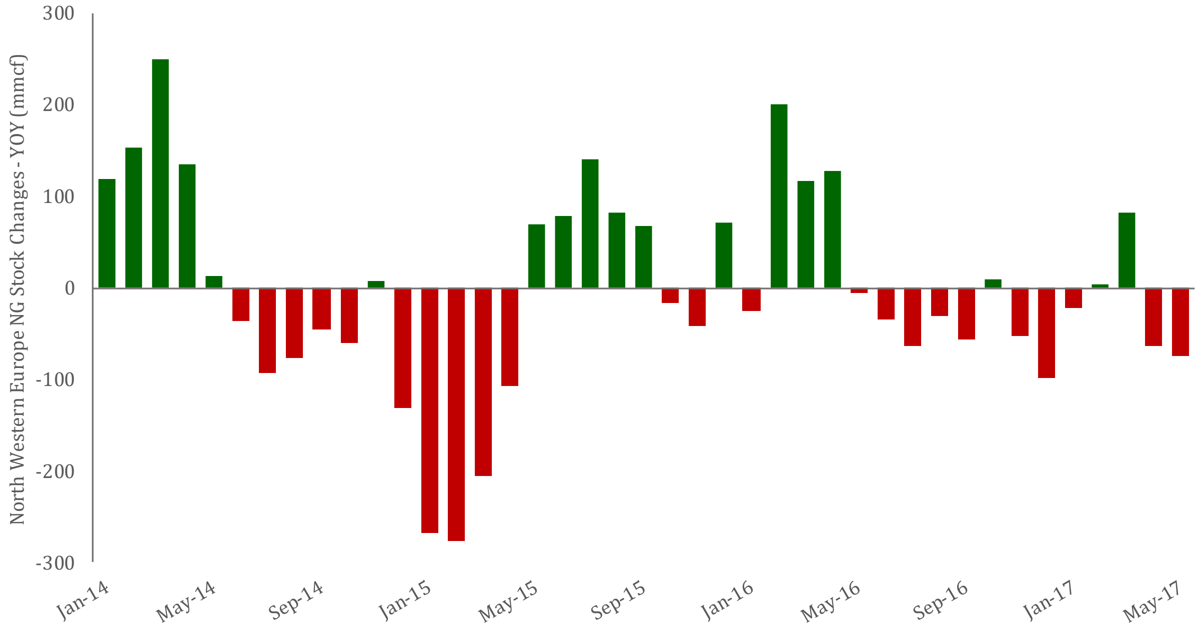
We will be presenting a very bullish outlook for natural gas later today in our webcast for Stream’s 2018 Energy Outlook. The key to our call is that a massive natural gas demand surge has started and will lead to world LNG markets being corrected closer to 2020 than the current conventional wisdom of closer to 2025. One of the reasons we see this happening quickly is we share Shell’s view that global LNG markets, as of mid 2017, are not in an oversupply situation and there is data support (Japan LNG spot prices, NW Europe storage) for this view. Two weeks ago, Shell said “*Actually, over the last 18 months, every LNG cargo that could technically be produced in this world has been produced and has found a well-paying customer”.* Therefore, we have a different starting point than conventional wisdom that says LNG markets are oversupplied in 2017. And if you combine a different starting point with a different view on a massive surge in natural gas demand, then you end up with a much different view of when LNG markets will move to undersupply. We will be posting a blog post today’s webcast on why we see a massive surge in natural gas demand.

A massive surge in natural gas demand has started. Long term readers of Energy Tidbits will likely be surprised by the very bullish natural gas call in this afternoon’s webcast. I was very negative for years, but move to a positive stance a year ago driven by the themes of Floating Storage Gas Regasification Units (FSRUs) and increasing US exports of LNG and to Mexico via pipeline. Those themes are continuing and FSRUs are expanding in their scope. Natural gas has already been on a path of strong demand growth. That path is continuing. But later today, we will be highlighting other major new demand factors that will drive the massive surge in global natural gas demand. This isn’t just an item for investors outside of Canada. Nor is it an item for a couple years down the road. We see these themes impacting Cdn natural gas in 2018. The 2018 Energy Outlook is at 2pm mountain today and can be accessed via[LINK].

Shell’s LNG head Maarten Wetselaar says the LNG market is in balance and all LNG cargos have found well paying customers. Two weeks ago, Shell’s LNG head, Maarten Wetselaar (Integrated Gas & New Energies Director) presented to the Australian financial community at Bloomberg’s Sydney Australia office. The presentation and Q&A in particular was excellent, but the presentation was overlooked because it was only available over the Bloomberg terminal and Shell did not post Wetselaar’s presentation. Bloomberg only posted a small portion of their interview with Wetselaar [LINK]. We prepared a transcript of Wetselaar’s comment on the balanced LNG market. He said “*We have been very pleased to see very strong demand for LNG in the last two years from Asia, particularly from China, but also from new countries that demand LNG in order to make their energy mix go around. There is Pakistan, there is Egypt, and even this year, we see the demand response to the supply increase being very robust so this year we have not seen an oversupply in this product. Actually, over the last 18 months, every LNG cargo that could technically be produced in this world has been produced and has found a well-paying customer. So, this market is in more balance than people perhaps perceive*”.

The key data support to Wetselaar is that NW Europe storage is not seeing surplus LNG cargos looking for a home. In the Q&A, Wetselaar said the data support for his comment that the market is absorbing all of the new LNG supply is to look at NW Europe storage. Wetselaar did not use the description dumping ground, but it is the right term. Webster’s defines “dumping ground” as “*a place to which unwanted people or things are sent*”. He noted that if LNG was in oversupply, there would be surplus LNG cargos looking for a home and these surplus LNG cargos would find their way to NW Europe storage. Shell is not seeing any YoY increase in NW Europe storage. Hence, he is firm in his view that demand was absorbing all the new LNG supply in 2017. We pasted the NW Europe storage data into the below graph and it shows exactly what Wetselaar said – the monthly YoY changes in storage do not show increases in the net storage withdraw/injections, which implies that there isn’t any dumping of surplus LNG cargos in NW Europe storage. We have not been following NW Europe natural gas storage, but now have it on our regular data check list because of Wetselaar’s comments.

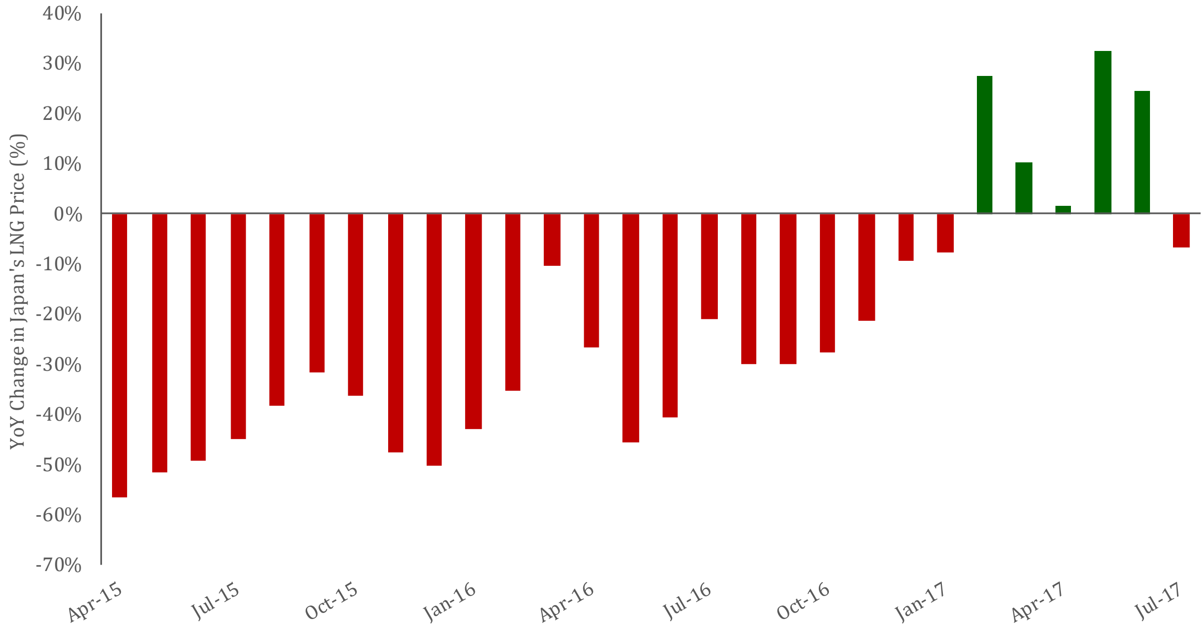
NW Europe YoY Changes In Monthly Storage Net Injections/Withdraw



Source: Bloomberg, Stream Asset Financial

<u>We also believe Japan LNG spot price indicates that the market is absorbing all new LNG supply.</u> We don't disagree that LNG was oversupplied in 2015 and 2016, but, in addition to the NW Europe storage data, we see other data suggesting that all of this new LNG supply is being absorbed by the market. We regularly track Japan LNG spot monthly prices as published by Japan's Ministry of Economy, Trade and Industry and include our graph below showing the YoY change in Japan monthly LNG spot prices. Japan LNG spot prices went down YoY in 2015 and 2016, which was a clear sign there that LNG supply was exceeding demand. But in H1/2017, the Japan LNG spot prices are higher YoY by about 20%. We look at this data and say it is reflective of a LNG market that is balance or at least where the market is absorbing LNG cargos. If LNG markets were still oversupplied like they were in 2015 and 2016, we wouldn't see Japan spot LNG prices up 20% this year?

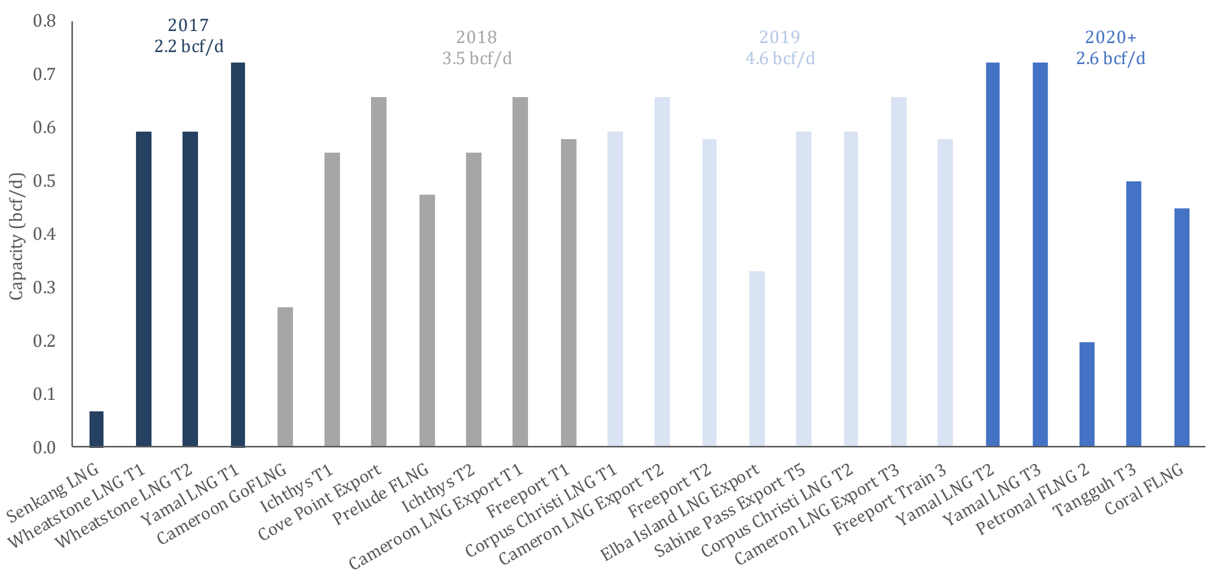
Japan Spot LNG Prices – YoY Monthly Change



Source: Japan Ministry of Economy, Trade and Industry, Stream Asset Financial

<u>The big test is coming in 2018/2019 with 8.1 bcf/d of new LNG supply to come on stream.</u> In our webcast, we will be reviewing factors that should lead to additional LNG demand of 3.5 to 4.5 bcf/d per year more than expected. This additional LNG demand may not all kick in right away but certainly in 2019 and 2020. Please note this is additional demand every year, not just a one-shot boost. Even still, this massive test of increasing demand will be tested in 2018 and 2019 with under construction LNG supply projects expected to add 3.5 bcf/d in 2018 and 4.6 bcf/d in 2019. Then new LNG supply goes down to 2.6 bcf/d in 2020. Inevitably there will be delays to the startup for some of these projects. But if not, it will be a big test. It may well be that the timing for the increased surge in natural gas demand may not line up exactly with the timing of the new LNG supply but it means that any oversupply should be temporary and quickly fixed. Below is our running table of the LNG liquefaction projects that are under construction.

Under Construction LNG Liquefaction Projects



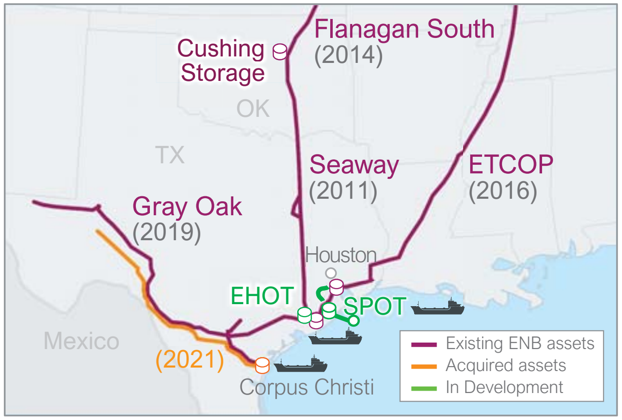
Source: Company Reports, Stream Asset Financial

<u>A better starting point moves LNG to undersupply quicker, especially if combined with a massive surge in natural gas demand.</u> We are highlighting the starting point for LNG markets as it makes a big difference to looking ahead to when LNG moves to undersupply. Conventional wisdom is that LNG is oversupplied in 2017, but we are in the Shell camp that LNG is not oversupplied today because the market is absorbing the increasing LNG supply. We don't see the Japan LNG spot prices and NW Europe storage data suggesting a robust market, but supportive of Shell's view. If you combine a different starting point (LNG is not in oversupply right now) with a different view on a massive surge in natural gas demand, then you end up with a much different view of when LNG markets will move to undersupply. Later today, we will be presenting the reasons for why we see a massive surge in natural gas demand that should lead to increased LNG demand of 3.5 to 4.5 bcf/d per year. US HH gas prices continue to be increasingly linked to global gas prices and this will increase with the under construction 4.6 bcf/d of US LNG capacity to be added thru 2020. We see this as a game changer to natural gas prices in the mid term (2019 to 2024), and why HH gas prices could be ~40% above the post 2019 long dated strips. Cdn gas prices should be dragged up with HH but the tone and valuations to Cdn natural gas should reflect this massive global natural gas demand surge in 2018 and 2019.

Enbridge U.S. Gulf Coast Strategy

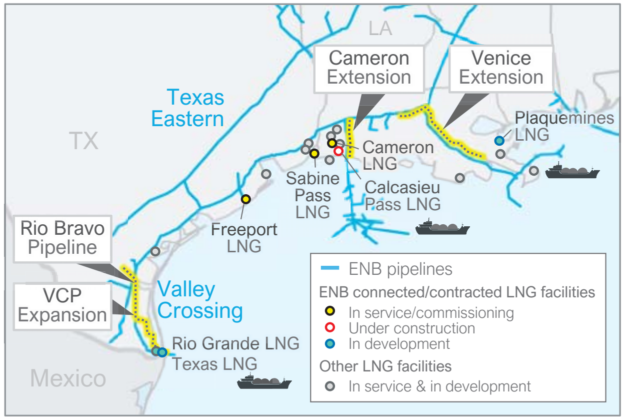
- Strategic & disciplined build out of U.S. Gulf Coast (USGC) energy infrastructure to support North American exports
  - Contracted cash flows aligned with low-risk business model
  - Full-path integrated capabilities connecting long-lived, low-cost supply to global markets
  - Leverage existing assets to deliver capital efficient market optionality
  - Accretion to near and long-term financial outlook
  - Leading ESG approach and carbon emissions profile

Crude Oil Export Strategy



- Heavy and light oil capabilities
- Full path solutions to USGC
- Connected to competitive, long-lived supply

Natural Gas Export Strategy



- Pipelines connected to multiple LNG export facilities
- Full path solutions to USGC
- Connected to competitive, long-lived supply

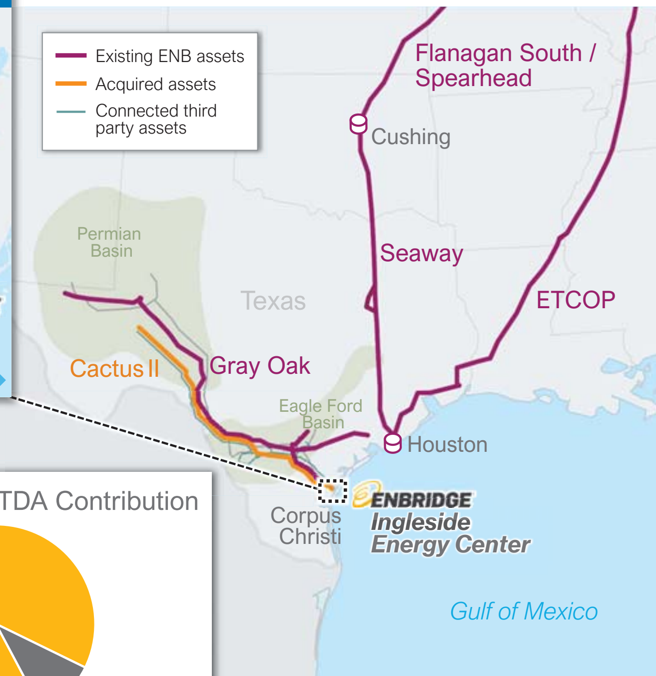
Disciplined execution of strategy to connect sustainably produced N. American energy to global markets

Premier North American Export Platform

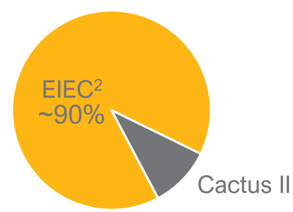
Enbridge Ingleside Energy Center (EIEC)

Storage Capacity	15.3 MMbbls capacity 20.8 MMbbls permitted
Export Capacity	1.6 MMbpd capacity 1.9 MMbpd permitted
Crude Pipeline Connectivity	3.0 MMbpd capacity (Gray Oak, Cactus I, Cactus II, EPIC, Harvest)
Loading Capacity	160,000 bph across 3 berths 45' draft[1] suitable for VLCC
Commercial	Primarily long-term take-or-pay commitments

- Advantaged outer-harbor location avoids inner harbor congestion allowing quicker turnaround times
- Deep draft across multiple berths accommodates a full range of vessel classes, including VLCC
- Connection to all five long-haul pipelines linking low-cost Permian and Eagle Ford supply to Corpus Christi



2022e EBITDA Contribution



Cactus II Pipeline

- 20% equity ownership in the 670 kbpd Permian to Corpus Christi crude pipeline
- Long-term take-or-pay commitments
- Lowest operating costs among Permian long-haul pipelines

Taft Terminal

- 350 thousand bbls storage tank provides critical connectivity to Permian intrastate pipelines and inner harbor locations

Viola Pipeline

- Wholly-owned, 20-inch crude 300 kbpd pipeline provides direct connectivity to Permian and Eagle Ford long-haul pipelines
- Long-term, take-or-pay commitments

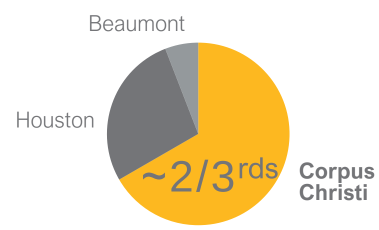
Integrated light crude oil export terminal serving North America's most competitive supply

(1) Draft increasing to 54' upon completion of the Port of Corpus Christi Channel Improvement Project, which is expected to be completed in 2022.
(2) Includes terminal connectivity assets: Taft Terminal and Viola Pipeline

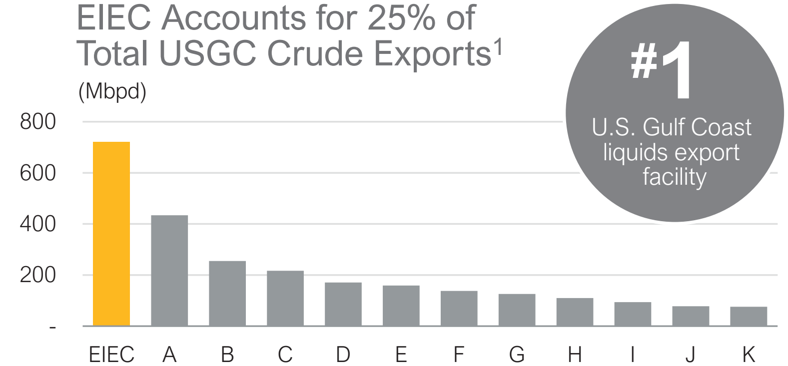
Unparalleled Competitive Position

- State-of-the-art storage and export infrastructure
- Connected to North America's premier & lowest cost crude supply
- Unparalleled connectivity to critical transportation infrastructure
- VLCC capable berths deliver economies of scale
- Loading rates and strategic outer-harbor location ensure the fastest turnaround times
- Best-in-class ESG profile

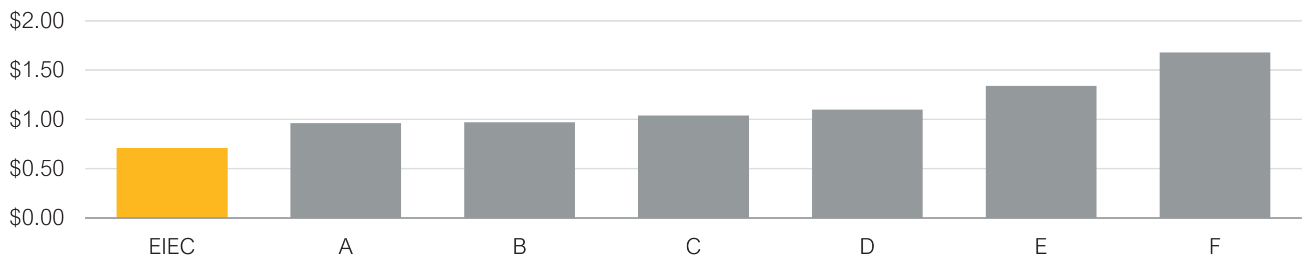
Corpus Christi is the Leading Export Location
(Percent of USGC Crude Exports By Location)



EIEC Accounts for 25% of Total USGC Crude Exports[1]
(Mbpd)



Lowest VLCC Loading Costs for Representative Texas Terminals[2]
Loading Cost ($/bbl)



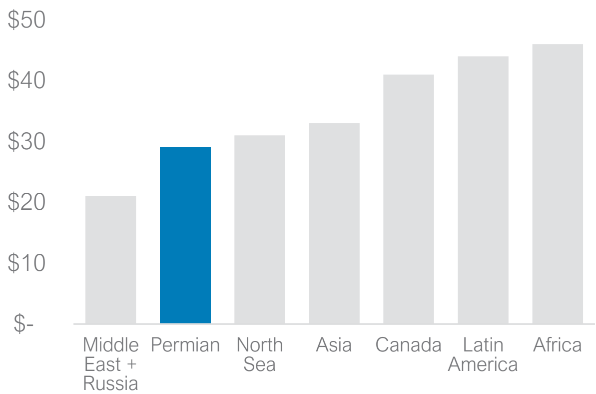
Advantaged location and ~30% lower well-head-to-water cost structure provide a sustainable export advantage

Source: third party data and management estimates
(1) Based on export volumes from 1/1/2020 – 12/31/2020. (2) Cost stack based on the assumption of loading VLCC freight post Port of Corpus Christi dredging.

Light Oil Export Fundamentals

Permian Supply Competitiveness[1]

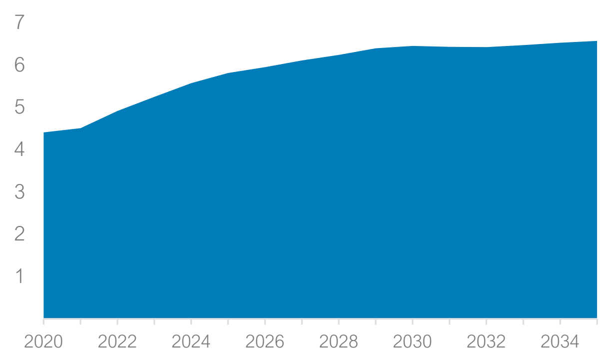
Economic Break Even (WTI Price – $USD/bbl)



- >70 billion barrels of recoverable reserves[2]
- Permian production connected to large domestic and exports markets

Permian Supply Outlook[3]

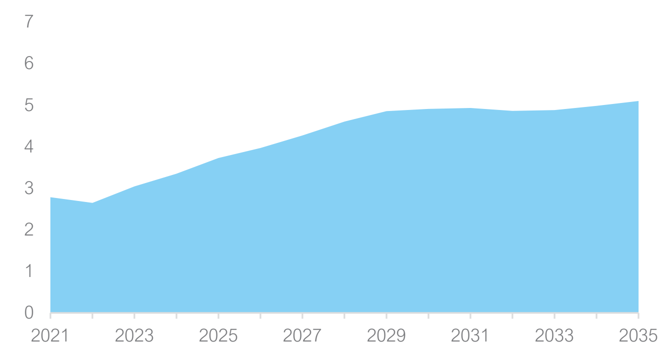
MMbpd



- 2.2 MMbpd of forecasted supply growth through 2035
- Basin underpinned by large and well-capitalized producers, including super-majors

North American Crude Export Outlook[3]

MMbpd



- >2 MMbpd of forecasted exports growth through 2035
- Excess North American light crude oil exported to global markets

Low-cost Permian light oil supply will drive North American exports to global markets

(1) Third party data and Management estimates (2) Based on most recently completed geology-based assessments of undiscovered, technically recoverable reserves performed by the United States Geological Survey
(3) IHS Markit Crude Oil Markets Annual Strategic Workbook (2021)

A Differentiated ESG Approach to Exports

- Plan to reduce 100% of net Scope 1 & 2 facility emissions & contribute to Corporate objective to reduce Scope 3
- Existing and adjacent land can be leveraged to support renewables & low carbon development
- Plan to build up to 60MW of solar power
  - 6MW of terminal self-power requirements
  - Potential to contract excess power to local industry
- Location proximity to industry, renewables and geology suitable to H_2 and CCUS

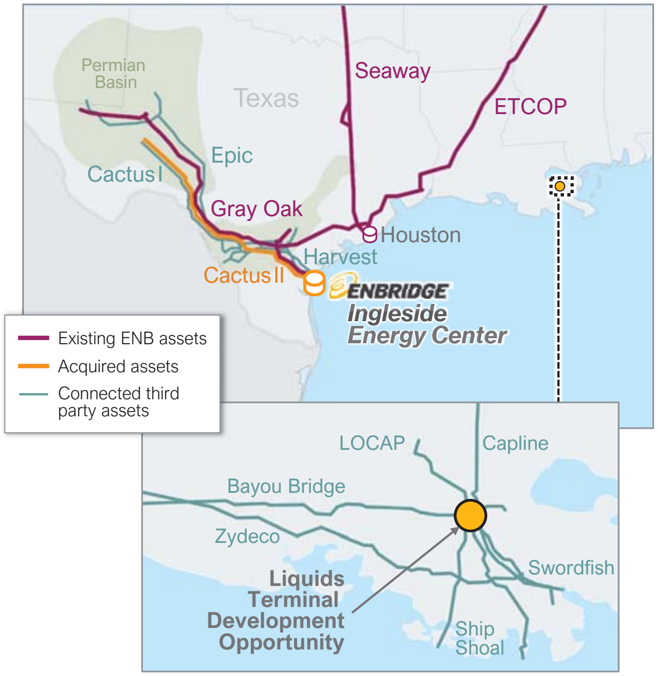
Up to **500 Acres** **of Undeveloped Land within Terminal**

Targeting net-negative emissions profile for EIEC terminal and export facilities;
Aligned with our goal to have Net-Zero emissions by 2050

Embedded Future Organic Growth

Strategy		Opportunity Set
Enbridge Ingleside Energy Center	**Crude Loading and Storage Expansions**	• Suezmax-capable berths to increase export capacity by up to 1 million barrels per day (est. in-service 2023) • Up to 5.5 million barrels of new crude storage capacity (est. phased in-service 2022/2023)
	LPG & NGL Products Expansions	• New and reactivated storage tanks and pipelines to provide an export solution for purity products originating in Corpus Christi and Mont Belvieu • Potential expansion to serve growing export demand for NGL purity products
	Green Fuels	• On-site solar generation facility (up to 60MW) • Potential for utility-scale hydrogen and ammonia production • Location and local offshore geology suitable for CCUS
	St. James Liquids Terminal	• 50% ownership interest[1] in brownfield opportunity to develop of liquids terminal and export capability, leveraging in-place assets

Strategic Locations Support Future Organic Growth



>$1 billion of capital efficient organic growth opportunities with attractive equity returns; Green fuel development potential supports longer term investment

(1) 50% owned by joint development partner

Oil Refiner Phillips 66 May Idle Hurricane-Ravaged Facility
2021-09-10 15:53:08.117 GMT

By Barbara Powell
(Bloomberg) -- Phillips 66 may idle a New Orleans-area refinery that suffered so much damage during Hurricane Ida that repairs may be too costly, according to people familiar with the operation.
Chief Executive Officer Greg Garland is scheduled to visit the Alliance refinery in the suburb of Belle Chasse, Louisiana, next week, said the people, who asked not to be identified because the information isn't public. Company spokesman Bernardo Fallas said there's no operational update or timeline for restarting the facility.
The refinery, which can process more than 250,000 barrels of crude a day, was shut on Aug. 28, the day before Isa slammed into southeast Louisiana with ferocious winds and drenching rains. A 9-foot wall of water punched a hole in the refinery's protective levee and inundated the plant.
The damages may complicate Phillips 66's efforts to find a buyer for an asset it was trying to unload before the storm because of "market conditions and the evolving energy landscape."
Meanwhile, Royal Dutch Shell Plc's refinery and chemical plant north of the city will remain shut for several more weeks so repairs can be performed, people familiar with the operation said. Damages from Ida included wrecked pipes and insulation torn away by the winds.

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https://www.bloomberg.com/news/articles/2020-09-08/mexico-is-cutting-pemex-s-oil-output-forecast-in-latest-setback?sref=f2E6A62x

Mexico Is Cutting Pemex's Oil Output Forecast in Latest Setback

By Amy Stillman and Max De Haldevang
September 8, 2020, 4:17 PM MDT

- Ministry sees output of 1.857 million barrels a day in 2021
- It sees 2021 oil prices at $42.10 a barrel, according to draft

Mexico is cutting its 2021 forecast for oil production at Petroleos Mexicanos by 8.4% as the state producer struggles under a $107 billion debt load and the impact of the deadly coronavirus.

The country's Finance Ministry lowered its preliminary estimate for output next year to 1.857 million barrels a day, down from 2.027 million in an April forecast, according to a draft of next year's budget proposal obtained by Bloomberg News.

Pemex, as the company is also known, has been hit hard by Covid-related deaths among its workers at a time when the oil-market crash only made the ambitions of Mexican President Andres Manuel Lopez Obrador to increase production more difficult.

Even the revised output number looks "optimistic," said Marco Oviedo, Chief Economist for Latin America at Barclays. "It seems that they have not learned," he said, predicting that Pemex will fail to meet the lower target.
The Finance Ministry estimates oil prices will average $42.10 a barrel next year, up from a preliminary forecast of $30 a barrel at the start of April. The numbers are part of a budget proposal that would increase Pemex's spending by just 0.6% next year, to 544.6 billion pesos ($25 billion).

The output goal "takes into account the new demand and price environment, as well as the renewed emphasis on efficiency in the production and supply of fuels by Pemex," according to the document.

Pemex's latest data show that in July it pumped the least oil since October 1979, at 1.595 million barrels a day. Earlier this week, Lopez Obrador said Pemex got it wrong, without providing a new number. Pemex's recent setbacks bode poorly for the leftist government that has placed it at the heart of its economic policy. Mexico's budget depends in part on boosting oil production, a key source of government revenue.

https://www.minenergia.gov.co/en/web/10180/historico-de-noticias?idNoticia=24307344

Gas production in Colombia registered a recovery of 20.3% during July 2021

Minenergy. Bogotá, DC, September 6, 2021. Commercialized gas production in Colombia was 1,122 million cubic feet per day (mcfd) in July 2021, which means a recovery of 20.3% compared to what was registered in the same month of 2020 (932 mpcpd). Compared to June 2021 (1,065 mpcpd), production increased by 5.3%.

The increase in production was due to an increase in gas sold mainly in the Floreña, Floreña Mirador, Pauto Sur (Yopal, Casanare), Cupiagua Sur, Cupiagua Liria (Aguazul, Casanare), Aguas vivas (Sahagún, Córdoba) and Clarinete fields (La Unión, Sucre), due to the increase in gas demand during the month of July and the restoration of production after the impact generated by the blockades in the framework of the National Strike.

During the first seven months of 2021, the average production of commercialized gas in Colombia registered an increase of 6.1%, reaching 1,078 million cubic feet per day (mpcpd) compared to the 1,015 mpcpd reported in the same period of 2020.

Regarding oil production, in July 2021 it was 731,255 barrels a day, a decrease of 0.5% compared to the data reported in July 2020 (734,987 bpd). With respect to the production of last June (694,150 bpd) there was an increase of 5.3%.

The increase in production occurred mainly in the Rubiales (Puerto Gaitán, Meta), Castilla Norte, Chichimene, Chichimene SW (Acacías, Meta), Cohembí (Puerto Asís, Putumayo), Costayaco (Villa Garzón, Putumayo), Andina (Tame, Arauca) and Castilla (Castilla La Nueva, Meta), due to the restoration of production after the lifting of the blockades caused by the National Strike.

In the first seven months of 2021, the average oil production reached 730,138 barrels per day, which shows a reduction of 8.9% compared to the same period in 2020, when there was a production of 801,792 barrels per day.

Finally, during July 2021, the drilling of 3 exploratory wells and 41 development wells began in Colombia, for a total of 18 exploratory wells and 220 development wells so far this year. In addition, during this month 122 kilometers of equivalent 2D seismic were acquired, for a total of 906 kilometers in the year.

Monday, September 6, 2021, Cundinamarca, Bogotá DC, Source: Minenergía

Venezuela central bank reports $5 bln jump in international reserves
2021-09-10 23:58:43.265 GMT

Venezuela central bank reports $5 bln jump in international reserves

Sept. 10 (National Post) -- CARACAS - Venezuela's central bank on Friday published data showing that its international reserves have jumped to a five-year high of nearly $11.3 billion.

The South American nation's reserves rose by $5.1 billion on Wednesday, according to a spreadsheet published on the central bank's website that tracks daily reserve movements.

That increase was removed from the spreadsheet around mid-day but restored by the afternoon.

It was not immediately evident where the funds came from.

The central bank did not reply to a request for comment.

The International Monetary Fund's website shows that Venezuela in August received an allocation of around 3.5 billion Special Drawing Rights, the IMF's unit of exchange that is backed by dollars, euros, yen, sterling and yuan.

Those SDRs were worth $5.08 billion at the SDR exchange rate on Aug. 31. But the IMF says the government of President Nicolas Maduro does not have access to these resources due to a dispute over his legitimacy.

"There remains lack of clarity in the international community regarding the recognition of the de facto government, as a consequence of which the country cannot access SDRs or other IMF resources," an IMF spokesperson said in response to questions.

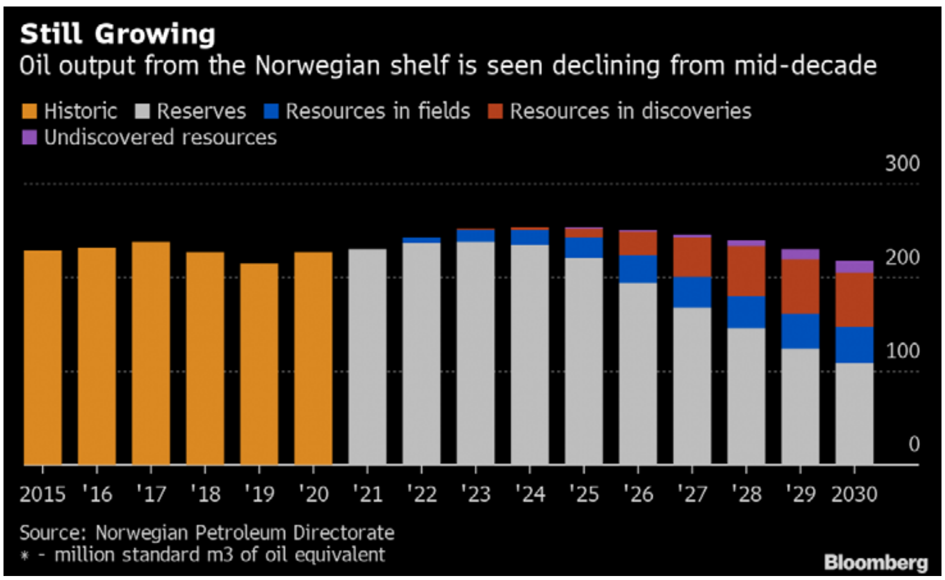
The United States and dozens of other nations in 2019 recognized opposition leader Juan Guaido as the country's legitimate president, as part of a failed effort to push Maduro from power. (Reporting by Mayela Armas, Brian Ellsworth and Deisy Buitrago in Caracas; Additional reporting by Rodrigo Campos in New York; Editing by Daniel Wallis)

-0- Sep/10/2021 23:58 GMT

Norway's Oil Addiction at Stake in Election About Climate Change
2021-09-12 07:00:00.0 GMT

By Lars Erik Taraldsen, Ott Ummelas and Stephen Treloar
(Bloomberg) -- The dilemma Norwegians face in Monday's election is how to reconcile their embrace of electric cars and environmental awareness with the need to wean their oil-rich economy off its key source of wealth.

The release of a landmark United Nations-backed report urging drastic measures to end carbon emissions has thrust climate change to the very heart of the campaign. But it's also apparent that the two biggest parties in the country are still advocates for a $40-billion industry hooked on fossil fuels.

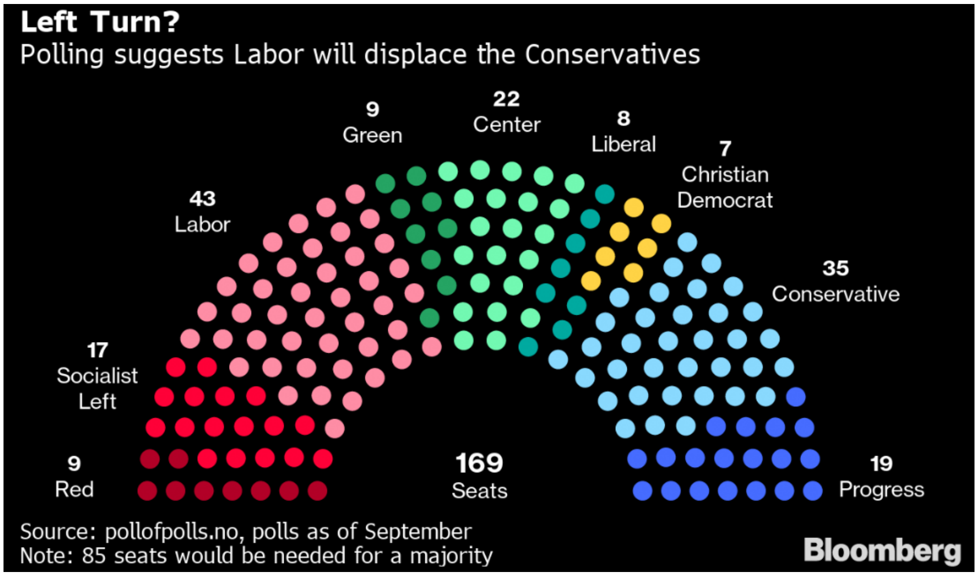


So even if the opposition Labor Party ousts a Conservative-led government, as polls indicate they will, the reality is that change to oil and gas policy can only happen if smaller parties gain enough backing to become kingmakers.

The Socialist Left, which already has experience governing with Labor, enjoy more support than the Greens. Both would call for a halt to new exploration licenses and make it a condition for joining any ruling coalition.

Norway is a key political test ahead of major climate talks set to start Oct. 31 in Glasgow because it will test voters' appetite for real change. Norwegians love their Teslas but they can afford them because the small Scandinavian country got rich on oil and build a $1.4-trillion sovereign wealth fund. The economy hasn't diversified enough to meet the sacrifices needed on climate.

We ranked the likeliest coalition scenarios, and spoke to experts to spell out what it could mean for green policy.



Labor-Center-Socialist Left: End of oil exploration on the table

Labor, headed by millionaire Jonas Gahr Store, is tipped to kick Premier Erna Solberg, known as a political friend of Angela Merkel, out of office after two terms in power. But Labor only enjoys a 3% point lead over Solberg's party, according to Pollofpolls.no, an aggregator of surveys by various pollsters.
So alliances will make the difference. Store, 61, campaigned to reverse tax cuts to finance more welfare for "ordinary" people and a "fair" climate policy. He admits the oil era will soon be over, but he's against ending oil exploration.
He'll be forced to compromise if the Socialist Left, on track to post their strongest results in at least two decades, are his only path to power.
The Center backs the oil industry while the Socialist Left have said radical changes are "realistic."
Will Hares, a senior industry analyst at Bloomberg Intelligence: "While the oil sector will remain core to Norway for many years and we don't expect limitations on development or exploration, new restrictions would still represent an acknowledgment that indefinite oil growth is incompatible with climate goals."

Labor-led Coalition+: Norway to become carbon neutral by 2035

If the parliamentary math force Labor into an even broader coalition, they will have to court the communist Red Party and the Greens -- both of whom are against new exploration and are polling around the 5% mark. Suddenly, Norway reaching carbon neutrality by 2035 becomes viable.
There is a cautionary note though. The last elections showed support for the Green cause fizzled over dismay that the end of oil would hurt people's standards of living. Also, with Store ruling out cooperation with the Greens and baulking at the idea of a support agreement with the Red Party, this is looking

like a very unstable coalition.

Solberg Surprise: A Win for Big Oil

Don’t rule out a Conservative win. In 2017 elections, Solberg came from behind to clinch it. She’s helped by record spending from the sovereign wealth fund, the world’s largest, and has weathered the pandemic better than many. The economy has rebounded swiftly with Nordea Bank raising its 2021 growth forecast for mainland Norway to 3.9%, the fastest pace since 2007.
Some environmentalists have welcomed Solberg’s proposal last month to change how Norway taxes the companies that extract petroleum from fields off its coast, a move that could tighten demands on oil companies and reduce risk of losses for taxpayers.
Anniken Hauglie, head of Norway’s oil lobby and a former Conservative minister: “It goes without saying that there are a number of forces now on the rise that will have major negative consequences for Norway, not just for the industry. This will weaken our ability to meet our climate commitments, but also to contribute to the much-needed transition. Some believe it is possible to separate the oil and gas industry from the green shift. I think that is infinitely naive.”

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"Now the oil price is artificially regulated"

LUKOIL CEO Vagit Alekperov on OPEC + deal, energy transition and taxes

- twenty

Newspaper "Kommersant" №160 from09/07/2021, p. 1

Russian oil workers are preparing to ramp up production as OPEC + parties ease restrictions. President of the company Vagit Alekperov told Kommersant how LUKOIL is preparing for the restoration of production, about the possibility of an energy transition and new projects .

- Over the past few years, LUKOIL has been actively developing foreign projects. Does this mean a change in the focus of the company?

- Russia, within the framework of our confirmed strategy, always remains a priority. At one time, we determined that the country will account for about 80% of investments, and we plan to spend the rest abroad, in regions of strategic interest: the Caspian Sea outside the Russian Federation, West Africa, the Middle East and Mexico. Last year, due to the pandemic, we increased investments in the Russian Federation by 14% and reduced their volume abroad: the distribution was 84% by 16%, that is, the emphasis shifted even more to Russian projects.

- Where did these funds go?

- Increased the drilling program compared to 2019. It must be said that many of our indicators in Russia have reached their maximum: the refining depth at the refinery will be 95% with the launch of a complex for deep processing of oil residues in Nizhny Novgorod, gas utilization this year will be 97%. That is, all projects related to the modernization of oil refineries and gas utilization have been implemented; today we do not have such problems as our colleagues do. And due to this, they were able to direct funds to increase drilling. Drilling volumes will continue to grow, and by 2023 we plan to reach 4 million cubic meters of drilling per year in the Russian Federation.

- Based on what parameters of the OPEC + deal did this drilling forecast come about?

- As of today, the parameters of the agreement have been determined by the end of 2022 and, I hope, will not change.

I would not like to see oil prices above $ 100 per barrel again, as this can stimulate investment in low-profit, ineffective projects and

then again lead to what we have already gone through - the collapse of the market.

The oil price of $ 65-75 per barrel is comfortable for consumers, and the OPEC + countries are aiming to maintain it by regulating volumes.

I think that the OPEC + alliance was created not for a certain period of time, but forever.

It is just that the regulation can be different depending on the situation. So far, September 2022 is the milestone when the restrictions should come to zero. Now the company has stopped up to 90 thousand barrels of production per day, we hope that they will be in demand on the market.

- Does the need to restore production within OPEC + lead to an increase in operating costs?

Why OPEC + kept its production growth plans

- In May 2020, taking into account the OPEC + decision, we stopped more than 8 thousand wells. Of course, this affected the operating costs. We have shut down marginal high-cost and least-efficient wells, so putting them back into operation affects profitability. But it’s not catastrophic, it’s still not drilling new wells or developing new fields, but simply returning to production. In order to stimulate drilling, we have lowered a number of indicators for calculating economic efficiency. These projects are already going through the investment committee, so an incentive is being created for the selection of new investment objects.

- After the return of production to the level before the pandemic, do you expect to increase production further?

- We have potential. The company is provided with effective reserves. The decision to increase drilling in Russia guarantees not only stabilization, but also an increase in production by about 1.5-2% per year after 2022.

- What is the production plan for 2022 now?

- Everything will depend on decisions within the framework of OPEC +. At the last meeting, the ministers of the participating countries agreed on a monthly increase in production by 400 thousand barrels per day.

- Last year, taxes for the oil industry were raised again, including LUKOIL lost benefits for the Y. Yuri Korchagin in the Caspian Sea. Did you manage to agree with the Ministry of Finance on transferring it to additional income tax (AIT)?

- The oil industry has always been overloaded in terms of taxation compared to the rest. The company pays about 50% of taxes on its revenue - many analysts sometimes distort this figure, because our consolidated statements include Litasco (an international oil trading company), which trades a large volume of third-party oil. Let me repeat that the real tax burden of LUKOIL in Russia in the so-called present oil price is about 50%.

Of course, this is high taxation. But at the same time, even such a tax regime makes it possible to form both profit and funds for investment. Now we are discussing with the state the possibility of applying the personal income tax regime at the Korchagin field. This would allow him to be in a profitable zone for many years. The dialogue is proceeding constructively.

- Did you manage to find a compromise with the Ministry of Finance on extra-viscous oils, the benefits for which were canceled?

- We are constantly in dialogue with the government, but so far we have not found a solution. LUKOIL has a special relationship with viscous and extra-viscous oils. The company invested 250 billion rubles. in the arrangement of such deposits. This is the construction of huge factories, complexes for the preparation of steam, which is pumped into these fields. A very complex ecological infrastructure for mining operations.

How LUKOIL tried to get benefits for extra-viscous oil fields

We believe that the future of oil production in Russia is associated with complexly constructed fields, super-viscous reserves, and the sooner we introduce technologies in this area and carry out industrial work, the more reliable the country's raw material base will be in the long term. So I hope that in the future there will be a tax solution for these fields, because they should be effective at an oil price of $ 50–55 per barrel. Then there is an incentive for active investment, the construction of new roadways in order to involve new reserves in development.

- A significant share of Russian production has already been transferred to the AIT. In your opinion, is a full transition possible?

- This approach has shown its effectiveness. Investments and oil production are growing in the fields where the AIT regime is applied. This suggests that both investors and the state are interested in the development of these projects. But there is no ideal tax legislation; it requires constant adjustments. As, for example, you constantly have to modify the damper for gasoline when the external situation and the ruble exchange rate change. But CIT is a more progressive tax than the current traditional tax system.

- Does the fuel damper mechanism also require adjustment?

- Unfortunately, additional adjustment is necessary. With oil prices above $ 70 a barrel, of course, it starts to falter a little.

- Would you support additional damper changes?

- We need to discuss. There has always been a good tradition: the Ministry of Finance, the Ministry of Economy and the government as a whole discussed new tax regimes together with producers, and not separately.

- You say "was."

- Yes, it was. Because, for example, about decisions on viscous oils, on the field. I learned Yuri Korchagin only from the press, they did not even discuss it with us. How can you touch on such a significant segment of the activities of one of the largest companies in Russia and not even inform it? We need to discuss together, look for some parameters. We are all interested in one thing - so that people on the territory of Russia live better and the country's budget is filled.

- Do you expect that taxes on the oil industry may be further increased this year?

- So far there are no such prerequisites, because the price situation for our product is rather unstable. After all, now the oil price is artificially regulated. We understand that due to production restrictions within the OPEC + framework, the current price does not correspond to reality, because a fairly large volume of production has been stopped.

Objectively, the price will become clear after September 2022, when the OPEC + agreement ends. You also need to understand the impact that energy transformation will have on our industry. Because the industry is very dependent on its consumers, and we are interested in making oil prices comfortable for them.

- You touched upon the prospect of energy transformation. Even within the framework of OPEC +, we see disagreements in approaches: Saudi Arabia is striving for high oil prices, and the UAE is interested in quickly monetizing its reserves while they are still in demand. Which concept seems more correct to you: to maintain the price or to extract more?

- I believe that coordination of actions gives the best efficiency. We are responsible for the stable supply of energy resources to the world at an affordable price: we must deliver this product to the point where it is in demand. The OPEC + agreement allows our consumers to be sure that there will not be a sharp rise in prices, because there are reserves to prevent this from happening.

Of course, the agreement led me to give a shutdown command for the first time in over 50 years in the industry. There has never been such a practice at all, neither in the Soviet Union, nor in Russia: we have always had a goal, and we focused our teams on this - to get as much as possible. Therefore, for us, patriots of the industry, it was a very painful transition.

But a balanced position, the compromises that are present within the OPEC + agreement, give confidence that it will remain in effect for many years. There is a dialogue, methods of persuasion and acceptance by one side or another of a common decision, which is aimed at the well-being of the global market as a whole.

- LUKOIL turns 30 this year. In your opinion, will LUKOIL still be an oil company in another 30 years?

- LUKOIL is no longer an oil company, but an energy company. We produce oil, gas, produce and supply petrochemicals, as well as electricity to the southern regions of Russia, provide heat to such major cities as Volgograd, Krasnodar, Rostov-on-Don, Stavropol.

How LUKOIL increased its dividend base and is holding back investments

Whether we remain an energy company, yes, we will. Our strategy for the coming years - and I am convinced that it is correct - is to be a responsible producer, above all of hydrocarbons. At the same time, we have adopted the concept of reducing greenhouse gas emissions by 2030 by 20% in relation to 2017. LUKOIL is adopting a number of investment projects aimed at utilizing CO2, drastically reducing energy consumption through additional investments. The largest project is the conversion of gas processing plants to electric turbines, as well as the utilization of their carbon dioxide emissions.

- Do you plan to rename the company following the example of Western manufacturers? In the European sense, the word "oil" is already a little abusive.

- I will leave this mission to my successor, my hand will not rise.

- The topic of CO2 emissions trading is being actively discussed in Russia. What is LUKOIL's position on this issue? Are you ready to participate in a voluntary system, or perhaps you think that Russia needs a mandatory payment for CO2, like in the EU?

- Each country adopts its own climate strategy. The main locomotive for decisions in this area is Europe, where half a billion people live on a small territory. At the same time, for the United States, for example, the issue is not very relevant, because it is a huge country with vast expanses.

Russia also has a huge potential for CO2 absorption. So we must understand how important it is for the country to levy additional taxes on businesses, taking into account the size of the territory and the colossal forest. How active investments are needed in this area. We must very carefully approach the issue of quotas through a dialogue between business and government, in no case should administrative decisions be applied here. If there is such a trading in quotas, then it should be voluntary.

- The EU introduces a carbon tax, which does not apply to petroleum products yet, but this may change in the future. How does LUKOIL assess the consequences for itself?

- This does not apply to oil products for one reason: in Europe, they are already very seriously taxed. Now the European economy is quite stable, but there is no longer metallurgy, no large machine-building.

We are very closely following the trends in energy transition, but there are questions. Can half a billion people be able to transform so quickly? Will the whole world be able to support Europe's actions? Today, not all countries have even switched to Euro-3 gasoline, and many consumers today ask us for the lowest quality gasoline.

How can you ban the production of cars with hydrocarbon-fueled engines by 2035 (such a proposal was put forward by the European Commission - **"Kommersant"**)? European budgets receive more than € 1 trillion a year through fuel excise taxes. On whom should this burden be laid?

Then we will have to impose an excise tax on electric cars, and there are not so many of them yet. Today we are ready to supply chargers for electric vehicles at all our filling stations, but we have no customers.

- So you don't believe in a fast energy transition?

- I don't really believe. This would be possible if there was a stagnation of population growth in the world, and with it the consumption of energy resources, but consumption is growing, even in spite of energy conservation programs.

- You spoke about the possible sale of your stake in your largest foreign project - West Qurna-2 in Iraq. What is the reason for this?

- We were approached by one of the world's largest companies with a request to consider the acquisition of assets. We turned to the Iraqi government, because without it we have no right to start even negotiations. But they met a categorical refusal. We were told that the Iraqi government is very interested in LUKOIL's work in the country.

Therefore, we continue to negotiate with the Iraqi government on the economics of the West Qurna-2 project and find some understanding. Because the formation at Yamama (one of the two formations in the field **- Kommersant**), where we reach production of 33 thousand barrels per day, showed that this is an absolutely separate complex formation with a high content of hydrogen sulfide, complex permeability, which requires additional work. Both Iraqi experts and officials agreed with this.

- Will the service payment for Yamama be higher than for the main Mishrif formation?

- Yes. Or there will be an average payment. Now I would not like to speak until the end of the negotiation process and on the eve of the elections in October (to the Iraqi parliament - **"Kommersant"**).

- Why, in your opinion, did the wave of large international oil companies leave Iraq?

- Projects in Iraq are service contracts with fairly low payments. Investors do not dispose of the oil produced; everything is sold by the state-owned SOMO company. In addition, oil reserves cannot be put on the balance sheet, and they do not affect the company's capitalization. All large companies have invested a lot of money in Iraq, have returned their invested capital, but in the future they want to participate in projects that would allow them to increase their capitalization, and most importantly, to dispose of the produced oil, since many companies are vertically integrated.

- A reasonable question: why would you stay then?

- So we turned to the Iraqi government, but they did not give permission to us or BP (for the Rumaila field **- Kommersant**). ExxonMobil is suing for quitting. For now, let's wait. I would like to emphasize that LUKOIL has returned all the invested costs in the West Qurna-2 project, we are already talking about the profitability of this project.

- You have drilled several structures in the Caspian Sea. Did you find anything?

- The first well at the Titonskaya structure gave a good flow rate. We have now laid the second well and are already starting exploratory drilling. It is difficult to talk about reserves today, because we still need to drill at least one more well in order to understand the scale of the field we have found.

How LUKOIL raised its capex forecast for 2021

A deposit was also discovered along Khazri. Of course, not of the same scale as the Titonskaya, but it integrates well with it, that is, this field is industrially profitable. This will be developed as one deposit, since the distance between them is small.

The reserves for the previously discovered Severo-Rakushechnoye field have been submitted for approval, which is about 30 million tons. With our infrastructure, it will also be effective. There will be a pipe to the field named after Vladimir Filanovsky. The possible commissioning date is 2028.

Next year we will launch the field named after V. Valery Greifer, in 2024 - the D33 field in the Baltic Sea, in Kaliningrad. We are expanding the Yuzhno-Messoyakhskoye field and fields in Yamal (in the Bolshekhetskaya depression - **"b"**). Large investments are made there to increase gas production.

- If you do not take the Caspian Sea, what new asset in Russia do you see promising?

- We believe that these are our gas projects in Yamal.

- It seemed to me that the economy was not very successful there.

- We have a very constructive relationship with Gazprom. We are currently negotiating, because they are buying our gas from Yamal. If they increase the cost of gas, then we could forcefully launch these fields.

- If you could agree on when could there be an input?

- I think at the end of 2023. We have built a gas pipeline.

- And what about the gas of the North Caspian?

- We talked with Gazprom about the Khvalynskoye field (located on the border of the Russian Federation and Kazakhstan in the Caspian Sea **- Kommersant**). In September, a meeting is to be held on the concept for the development of this asset. You know, we offer Gazprom to become a buyer of gas from this field, but on the territory of Kazakhstan. Because the gas contains a large amount of hydrogen sulfide, and it is, of course, very dangerous to drag it over 300 km to the territory of Russia.

- And what will Gazprom do next with this gas?

- We would clean it up, but it could sell it to both Europe and China through the gas transportation system of Kazakhstan.

- You planned to take an investment decision on a deposit in Cameroon (Etinda), but it was postponed.

- There is an interstate issue in Cameroon - the field is efficient there if the raw materials are supplied to the territory of the neighboring state (Equatorial Guinea **- "Kommersant"**), where a gas liquefaction and drying plant has been built, now there is such a conversation. We hope that there will be a positive decision and then this field will receive good profitability.

- Have you made an investment decision to expand the gas processing plant in Budennovsk?

- Yes, all investment decisions have been made. In the future, we plan to launch a gas chemical complex. We invited Deputy Prime Minister Alexander Novak to launch the project. We hope that the joint trip to Stavrolen will take place at the end of September.

- What measures of state support can be applied for this project?

- We are considering a special investment contract, because this project is very significant for the south of Russia. Of course, the regional authorities also need to resolve the issue of providing water for the implementation of the gas chemical complex.

- You have decided to build a polypropylene production facility at an oil refinery in Nizhny Novgorod. Will there be more petrochemical projects within the refinery?

- Polypropylene in Nizhny Novgorod will be provided with its own resources. Propylene from the new cracker in Perm, in addition to providing for Saratovorgsintez, can be the basis for new petrochemical projects. We are also considering options for partnership in methanol production. We expect to make a decision by the end of the year.

- Will it be based on your gas?

- There, most likely, Gazprom's gas will be used, it is about 2 billion cubic meters per year, but if it gives an opportunity, we can make a swap. Our relations with Gazprom make it possible to look at this issue rather optimistically.

- Are you talking about new construction in ports?

- Yes. We look at sites both in the north and in the south of Russia.

- With what mood did you meet your professional holiday?

- With a good one. Taking this opportunity, on my own behalf and on behalf of the thousands of LUKOIL employees, I would like to congratulate all industry representatives on the Day of Oil, Gas and Fuel Industry Workers, which is traditionally celebrated on the first Sunday of September.

Alekperov Vagit Yusufovich

Private bussiness

Vagit Alekperov was born on September 1, 1950 in Baku. In 1974 he graduated from the Azerbaijan Institute of Oil and Chemistry named after Azizbekov. Since 1968 he worked at the oil fields of Azerbaijan, since 1979 - in Western Siberia. In 1987-1990, he served as the general director of the Kogalymneftegaz Production Association of Glavtyumenneftegaz of the USSR Ministry of Oil and Gas Industry. 1990-1992 - Deputy, then First Deputy Minister of the Oil and Gas Industry of the USSR. In 1992–1993, he headed the LangepasUraiKogalymneft concern (then - LUKOIL). Since 1993 - President of LUKOIL, until 2000 he also headed the board of directors of the company. Owns 28.22% of LUKOIL shares (according to the quotations of the Moscow Exchange on September 6, the package was worth about 1.24 trillion rubles). He was awarded the Russian Orders of Merit for the Fatherland II, III and IV degrees, the Order of Friendship, as well as the Order of the Badge of Honor of the USSR. He is married and has a son.

PJSC "LUKOIL"

Company profile

LUKOIL is one of the largest oil and gas companies in the world, accounting for more than 2% of world oil production and about 1% of proven hydrocarbon reserves, the second largest oil production in the Russian Federation. Created in 1991 on the basis of fields developed in the USSR. LUKOIL currently owns four refineries and two petrochemical plants in Russia, as well as three refineries abroad. The company develops deposits in the Russian Federation and 13 other countries. Proved reserves at the beginning of 2021 amounted to 15.4 billion barrels of oil equivalent according to the SEC classification. LUKOIL's oil production in the six months of 2021 decreased by 6.4% to 39.3 million tons; gas production increased by 7% to 15.85 billion cubic meters. The company's net profit under IFRS amounted to 347 billion rubles. against the loss a year ago, EBITDA grew 2.2 times, to 654.2 billion rubles. LUKOIL's free cash flow grew 3.4 times, up to 276 billion rubles. Top management and members of the board of directors collectively own about 39% of the company's shares. Capitalization as of September 6 - 4.4 trillion rubles.

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

27 JAN, 04:40

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

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

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

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

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

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

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

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

Investments in the further development of Western Siberia

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

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

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

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

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

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

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

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

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

https://www.theglobeandmail.com/business/industry-news/energy-and-resources/article-opec-will-likely-revise-down-optimistic-oil-demand-outlook-next-week/

OPEC will likely revise down ‘optimistic’ oil demand outlook next week, sources say

ALEX LAWLER AND AHMAD GHADDAR
LONDON
REUTERS
PUBLISHED 13 HOURS AGOUPDATED SEPTEMBER 10, 2021

OPEC will likely revise down its 2022 oil demand growth forecast on Monday, two OPEC+ sources said, as the spread of the Delta coronavirus variant puts the speed of a recovery in fuel use in doubt.

On Sept. 1, separate sources said the Organization of the Petroleum Exporting Countries and allies, known as OPEC+, increased its 2022 oil demand forecast to 4.2 million barrels per day (bpd) from 3.28 million bpd previously.

The new figure was seen as optimistic by some in the group, likely prompting revisions, the two OPEC+ sources said. OPEC is scheduled to make its latest supply and demand forecasts public in a report on Monday.

“OPEC may review the figures again for the upcoming monthly report,” one of the sources said, declining to be named.

Governments, companies and traders are closely monitoring the speed that oil demand recovers after crashing in 2020. A slower return could weigh on prices and bolster the view that the impact of pandemic may affect consumption patterns for longer or permanently.

“Recent forecasts for oil demand are looking softer,” said Stephen Brennock of broker PVM in a report. “Growth for the near– to medium-term outlook is being progressively downgraded due to the resurgence of COVID-19, particularly in Asia.”

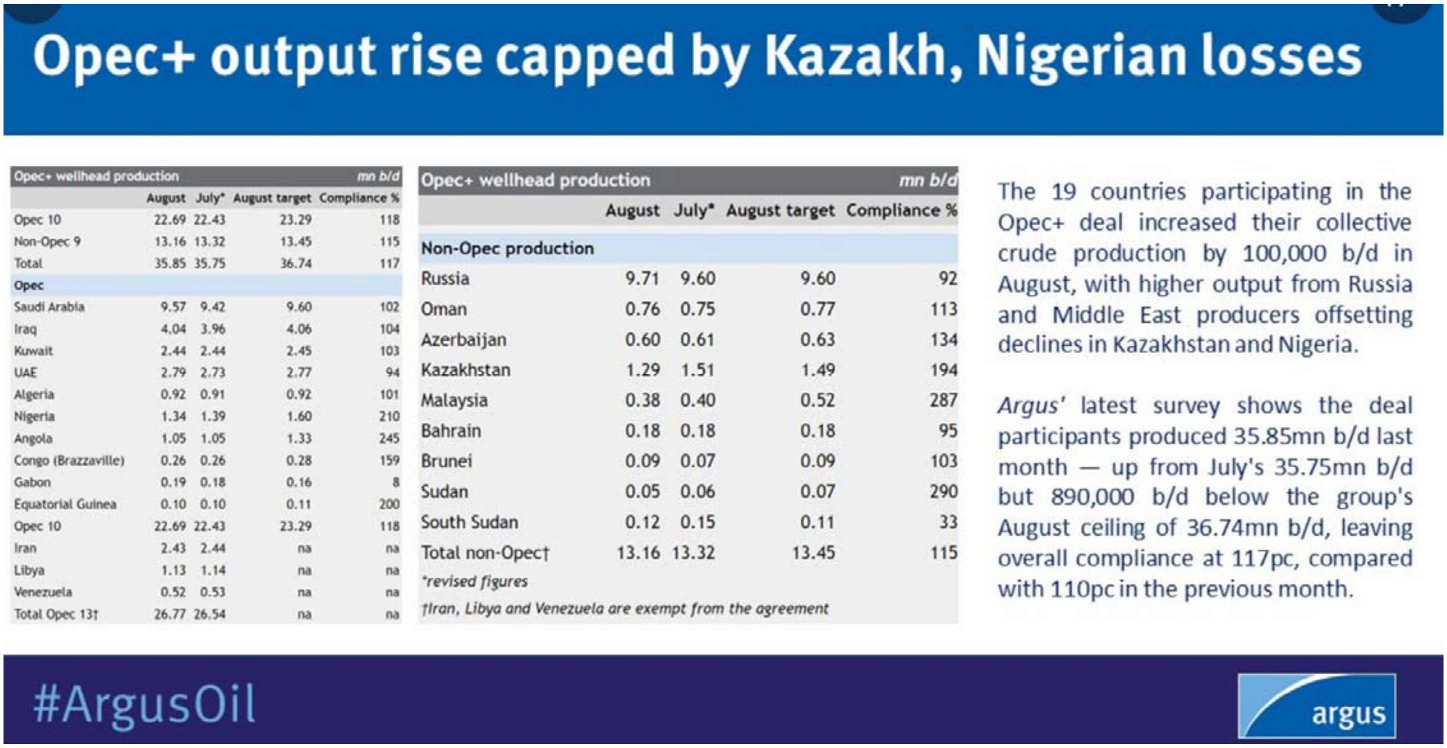
Brennock cited figures from the U.S. government’s forecaster, the Energy Information Administration, which said in its latest outlook on Sept. 8 oil demand would surpass 100 million bpd in the second quarter of 2022.

A month earlier, the EIA expected that milestone to be reached in the fourth quarter of 2021.

OPEC currently has the highest demand growth figures among the three main oil forecasting agencies – itself, the EIA and the International Energy Agency, an adviser to consuming nations which issues its latest monthly report on Tuesday.

In 2021, OPEC expects oil demand to rise by 5.95 million bpd, higher than the IEA figure of 5.3 million bpd and the EIA forecast of 5 million bpd.

For OPEC’s 2021 oil demand growth forecast to be met, world oil demand needs to average 99.82 million bpd in the fourth quarter – almost 1 million bpd higher than the IEA’s fourth-quarter projection.



Opec+ output rise capped by Kazakh, Nigerian losses

Opec+ wellhead production				mn b/d
	August	July*	August target	Compliance %
Opec 10	22.69	22.43	23.29	118
Non-Opec 9	13.16	13.32	13.45	115
Total	35.85	35.75	36.74	117
Opec				
Saudi Arabia	9.57	9.42	9.60	102
Iraq	4.04	3.96	4.06	104
Kuwait	2.44	2.44	2.45	103
UAE	2.79	2.73	2.77	94
Algeria	0.92	0.91	0.92	101
Nigeria	1.34	1.39	1.60	210
Angola	1.05	1.05	1.33	245
Congo (Brazzaville)	0.26	0.26	0.28	159
Gabon	0.19	0.18	0.16	8
Equatorial Guinea	0.10	0.10	0.11	200
Opec 10	22.69	22.43	23.29	118
Iran	2.43	2.44	na	na
Libya	1.13	1.14	na	na
Venezuela	0.52	0.53	na	na
Total Opec 13†	26.77	26.54	na	na

Opec+ wellhead production				mn b/d
	August	July*	August target	Compliance %
Non-Opec production				
Russia	9.71	9.60	9.60	92
Oman	0.76	0.75	0.77	113
Azerbaijan	0.60	0.61	0.63	134
Kazakhstan	1.29	1.51	1.49	194
Malaysia	0.38	0.40	0.52	287
Bahrain	0.18	0.18	0.18	95
Brunei	0.09	0.07	0.09	103
Sudan	0.05	0.06	0.07	290
South Sudan	0.12	0.15	0.11	33
Total non-Opec†	13.16	13.32	13.45	115

**revised figures*

†Iran, Libya and Venezuela are exempt from the agreement

The 19 countries participating in the Opec+ deal increased their collective crude production by 100,000 b/d in August, with higher output from Russia and Middle East producers offsetting declines in Kazakhstan and Nigeria.

Argus' latest survey shows the deal participants produced 35.85mn b/d last month — up from July's 35.75mn b/d but 890,000 b/d below the group's August ceiling of 36.74mn b/d, leaving overall compliance at 117pc, compared with 110pc in the previous month.

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https://www.argusmedia.com/en/news/2252888-opec-output-rise-capped-by-kazakh-nigerian-losses

Opec+ output rise capped by Kazakh, Nigerian losses

Published date: 10 September 2021

The 19 countries participating in the Opec+ deal increased their collective crude production by 100,000 b/d in August, with higher output from Russia and Middle East producers offsetting declines in Kazakhstan and Nigeria.

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Opec+ heavyweights Saudi Arabia and Russia drove last month's increase, raising their respective output by 150,000 b/d and 110,000 b/d. While Riyadh stayed under quota, Moscow exceeded its cap, leaving its spare capacity below 700,000 b/d based on IEA figures from earlier this year. Other notable increases came from Iraq, Opec's second-largest producer, which recorded its highest month-on-month growth since March, up by 80,000 b/d amid a surge in Basrah exports. The UAE added 60,000 b/d.

These rises compensated for operational problems in Nigeria, where output has fallen every month since April. Nigeria shed another 50,000 b/d in August to hit a seven-month low of 1.34mn b/d. *Argus* estimates that loadings of key Nigerian grade Forcados eased to 55,000 b/d last month from 191,000 b/d in July, after a leak prompted Shell to declare force majeure on exports from the Forcados terminal on 16 August.

Maintenance at the Qua Iboe terminal in the second half of August, as well as disruption at the Bonny Light and Brass River terminals, further constrained Nigerian supply. Nigeria saw some improvement by the end of the month and production will be back to the country's Opec+ quota by October at the latest, according to state-owned NNPC's managing director Mele Kyari.

The group's biggest drop in output came from non-Opec Kazakhstan, where maintenance at the Tengiz field drove a 220,000 b/d decline, leaving the country over 200,000 b/d below its 1.49mn b/d August ceiling.

Kakakhstan told the Opec+ Joint Technical Committee (JTC) that it would be 250,000 b/d under its August quota and 170,000 b/d below its September cap to help compensate for past overproduction.

Libya, which remains exempt from the restraint pact, saw a 10,000 b/d drop in output last month after a leak disrupted the operations of state-owned NOC subsidiary Waha Oil. Libyan supply has come under further threat in the past week, with protests intermittently disrupting loadings at three eastern ports — Es Sider, Marsa el-Hariga and Ras Lanuf, which shipped a combined 595,000 b/d in June-August, according to *Argus* tracking. Demonstrator demands range from the dismissal of NOC chairman Mustafa Sanalla to students calling for jobs. Temporary closures are frequent in Libya and can quickly reduce production because of scant storage options. Longer-term blockades — such as last year's eight-month outage — are typically politically led and militarily sustained. Es Sider and Ras Lanuf resumed activity today.

By Ruxandra Iordache

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https://www.spglobal.com/platts/en/market-insights/latest-news/oil/090921-oil-prices-could-hit-200b-without-new-investments-in-upstream-sector-omani-minister

- **COAL | METALS**
- 09 Sep 2021 | 10:24 UTC

Oil prices could hit $200/b without new investments in upstream sector: Omani minister

HIGHLIGHTS

Minister's remarks come in response to IEA's net-zero scenario

IEA's call to end oil and gas investments 'extremely dangerous'

Oil and gas demand will last decades, UAE minister says

-
- Author Dania Saadi

Global oil prices could soar to $200/b if no new investments are made in the oil and gas sector in the short-term, Oman's energy and minerals minister said Sept. 9, in reply to the International Energy Agency's assessment for reaching net-zero emissions by 2050.

The IEA said in a May 18 report that, under an energy scenario needed to put the world on a path to net-zero emissions by 2050, there should be no new oil and gas developments and that global oil demand would collapse by 75%.

"Recommending that we should no longer invest in new oil.... I think that's extremely dangerous," Mohammed al-Rumhy said at a ministerial dialogue on clean energy transitions in the Middle East and North Africa region organized by the IEA.

"My biggest fear, if we stop investing in the fossil fuel industry abruptly, is there will be energy starvation and the price of energy will just shoot [up]. The demand for oil and gas may go down but in the short-term we could see $100/b or $200/b scenario, which although it sounds very attractive today [to producers], it's something that I think many of us, if not all of us, would not like to see happening in the market."

Oman, the biggest Middle Eastern oil producer outside OPEC, is a member of the broader 23-member OPEC+ coalition, which collectively controls about half of the world's oil production capacity and is currently tapering its output restraint agreement to balance the oil markets amid the pandemic.

Race against time

The race to net-zero emissions is a race against time, IEA's executive director Fatih Birol told the ministerial dialogue.

"It's an interesting race. Unless everybody finishes the race, nobody wins the race," Birol said.

"Today 70% of the global GDP of the countries around the world committed themselves to net-zero [by] 2050. The largest consumers are taking these steps and this will have implications for oil demand and therefore for the investments."

The IEA outlined its first roadmap for how the global energy sector can achieve net-zero emissions in the landmark May 18 report, seeing global oil supplies needing to shrink more than 8% annually. Under this scenario, oil demand would never regain its pre-pandemic peak in 2019, shrinking to just 24 million b/d in 2050.

The IEA's advocacy for net-zero emissions was challenged by OPEC, which warned the report could increase oil market volatility and jeopardize needed investment in fossil fuels, the group said in an internal report to its members seen by S&P Global Platts on May 20.

OPEC's most recent long-term oil market forecast, issued in October, projects global demand to rise from pre-pandemic levels of about 100 million b/d to peak at 109.3 million b/d around 2040, before declining to 109.1 million b/d in 2045 and plateauing "over a relatively long period."

Least carbon intensive

Demand for oil and gas will be sustained for decades, Sultan al-Jaber, the UAE's minister of industry and advanced technology and CEO of Abu Dhabi National Oil Co., told the ministerial dialogue. The UAE is OPEC's third biggest producer.

"This region's oil reserves represent the vast majority of the least carbon-intensive barrels available anywhere in the world," Jaber said.

"Even in the most ambitious energy transition scenario, oil and gas will still be needed for many decades to come."

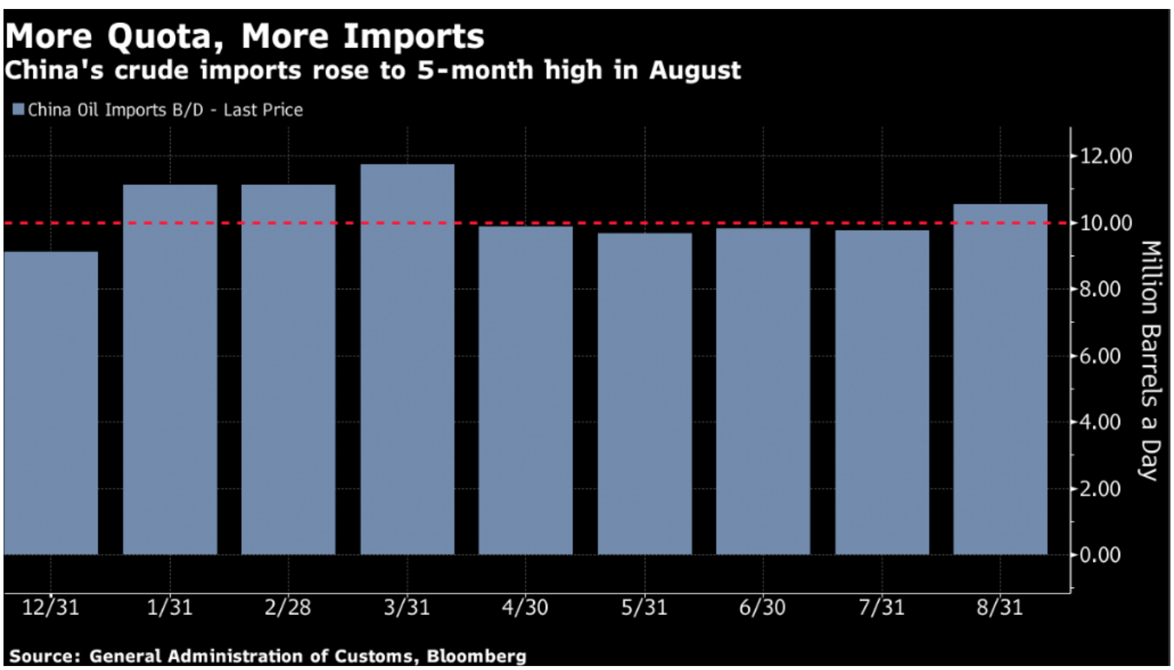
Iraq, OPEC's second biggest producer, is working on a strategy to study the impact of energy transition on its economy and its oil industry, the country's deputy prime minister and finance minister Ali Allawi said at the ministerial dialogue.

"If we have not taken the right precautionary steps and the right moves to broaden and deepen our economies, then I think oil producing countries with large populations and limited financial reserves will face very serious consequences," Allawi said.

"Many of the oil producers do have financial buffers that will allow them to extend the transition phase, countries like Iraq may not have that option. That's why to us it is really an existential issue in the next five years."

China’s Crude Imports Rise to Five-Month High on New Quota
2021-09-07 05:18:50.266 GMT

By Bloomberg News
(Bloomberg) -- China’s overseas crude inflows rose to a five-month high after private refiners were allocated new import quotas and as cargoes that were delayed by a typhoon were finally delivered.
The nation imported 44.53 million metric tons of crude in August, data released Tuesday by the General Administration of Customs showed. That’s equivalent to 10.53 million barrels a day, according to Bloomberg calculations, the most since March. Daily shipments were 9.75 million barrels in July.
Private refiners were able to increase purchases last month after the allocation of additional import quotas in mid-August, while overall inflows were boosted by the delivery of shipments delayed by Typhoon In-Fa in late July, according to Yuntao Liu, an analyst with London-based Energy Aspects Ltd.



Independent refiners were last month granted a third batch of import quotas for 2021 totaling 4.42 million tons, the smallest since China allowed non-state firms to directly import crude. Energy Aspects predicts that processors may get a further 11 million tons of allocations over the rest of the year.

China’s net fuel exports in August, meanwhile, fell to about 800,000 tons, the lowest level since June 2020. Shipments slipped as refiners waited for the allocation of new exports quota, which were eventually granted last month.

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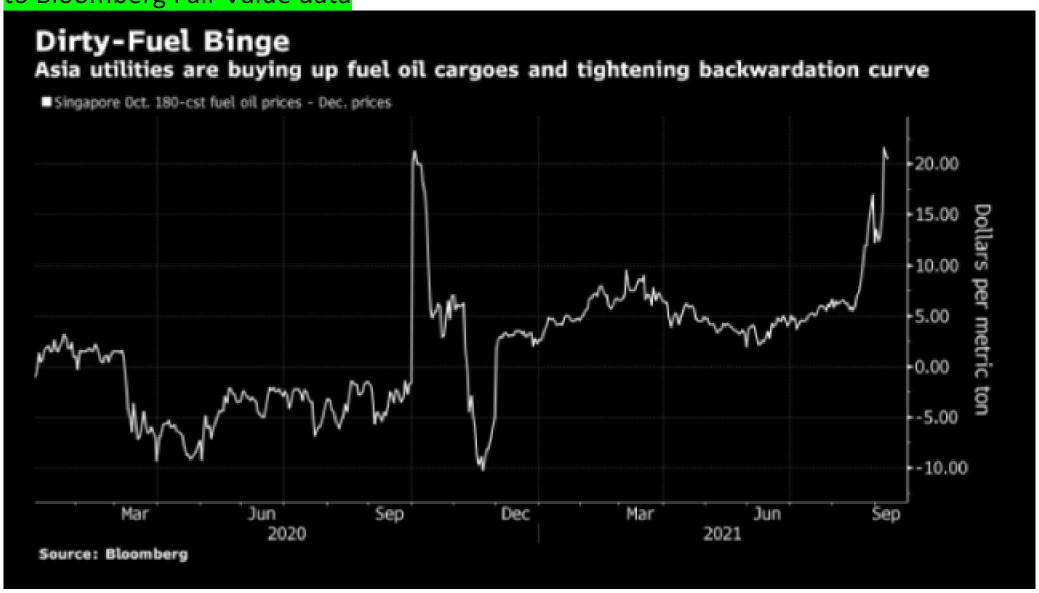
Asia Utilities' Shift to Oil May be Temporary as Prices Rise: FS
2021-09-09 08:15:10.277 GMT

By Ann Koh
(Bloomberg) -- South Asian buyers such as Pakistan and Bangladesh have flocked to purchase fuel oil to replace costlier spot shipments of liquefied natural gas, a phenomenon that my only be a "temporary measure" as the price of the oil product has also started to surge, Fitch Solutions analysts said in a note dated Sept. 8.

* Increased buying by utilities is coming at a time of prolonged refinery outages during the pandemic, reduced heavy crude flows due to OPEC+ production cuts and stronger demand from China, according to Fitch Solutions
* Switch by Pakistan and Bangladesh from LNG is likely to be equivalent to 50,000 to 75,000 barrels a day of fuel oil, according to S&P Global Platts Analytics Services
* NOTE: 180-centistoke grade fuel oil for October delivery is currently trading at a premium of $21 a metric ton to supplies for December, compared with $5 at the start of July, according to Bloomberg Fair Value data



* Still, the surge in spot LNG prices likely has further to go, providing downside risk to near-term demand as buyers seek out cheaper alternatives to manage fuel costs and alleviate pressure: Fitch Solutions
* READ: Sept. 8, Fuel Oil Jumps as Asia Utilities Seek Alternatives to Pricey Gas
* READ: Sept. 8, Asian LNG Prices Cross $20 Mark on Competition With Europe

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Sep 07, 2021 12:39:44

OIL DEMAND MONITOR: Motorists Return as Flying Is Throttled Back

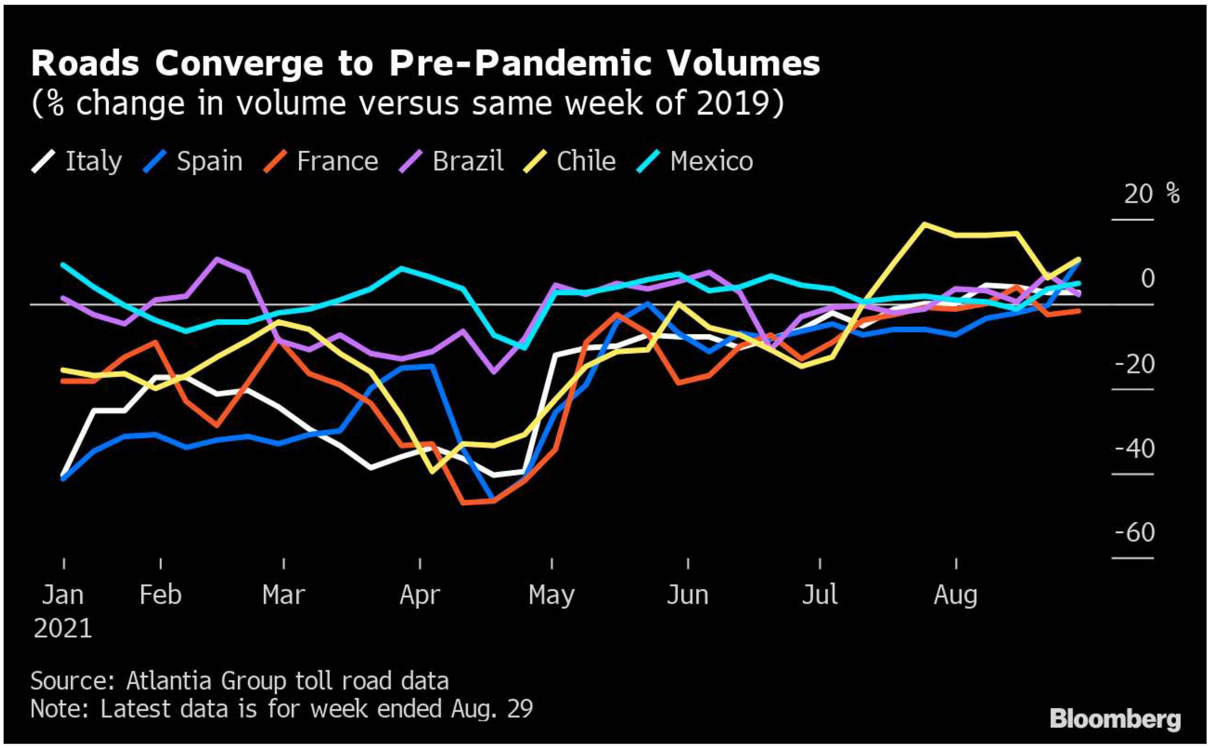
- U.S. airport passenger numbers wind down as summer ends: TSA
- Monday morning traffic in Paris was busiest all year

By Stephen Voss

(Bloomberg) -- More motorists are getting back behind the wheel even as flying begins to stagnate with the end of summer travel across much of the globe and as concern about the coronavirus delta variant lingers on.

Weekly toll road data across three European and three Latin American countries highlight the return to the highways. Kilometers traveled in Italy, Spain, Brazil, Chile and Mexico are all above the equivalent week in 2019, some of them for many weeks in a row, according to Atlantia Group, which operates those roads.

The reading for France was just 1.6% below, compared with a deficit of as much as 47% in early April, Atlantia's traffic measurements show.



Separate government data for the U.S. and U.K. show passenger car miles were between 5% and 2% below pre-pandemic levels, little different to recent weeks, while gasoline demand in those countries was 1% above and 4% below, respectively.

A Bloomberg survey detailing August fuel sales in India showed a third month-on-month gain in gasoline consumption as a roll-back in movement restrictions brings cars back onto the streets of the world's second-most populous nation.

School's In

The resumption of school term time is part of the overall trend since it brings a halt to family holiday air travel and pushes more cars into towns and cities for the morning and afternoon school runs. That was certainly visible in Europe at 8 a.m. local time on Monday, when congestion rose to 13% and 9% above typical 2019 levels in Berlin and Paris, respectively, and only 3% below in London, according to data provided by location technology company TomTom NV. That's the busiest Monday morning so far this year in the French capital.

City road congestion has also been getting stronger in recent weeks in north and south America, though there was a drop at the beginning of this week because of U.S. and Brazilian holidays on

Monday and Tuesday, respectively.

Total oil products demand in the U.S. surged to an all-time record in the week ending Aug. 27, according to estimates from the Energy Information Administration. That's as gasoline demand hums along at pre-Covid levels and jet fuel consumption rose to its highest level since the epidemic began. Importantly, use of less well-known categories of oil-based fuels, including propane and "other" oils used in the petrochemicals industry were also at or near the highest levels in months.

Air Travel

Even with the recent jump in the EIA's jet fuel estimate, other signs are less positive. The average number of passengers passing through U.S. airport security turnstiles is now struggling to exceed 2 million per day, according to daily data from the Transportation Security Administration.

Fourteen of the 20 largest airline markets saw capacity reductions in the past week, according to OAG Aviation. China was a notable exception though, as the number of scheduled seats continues to bounce back from a steep plunge in early August when domestic travel was temporarily restricted to contain the virus.

"China has continually been an outlier in terms of capacity trends through the whole pandemic and this week, capacity has increased by another 6%, with all major carriers adding more seats," John Grant, OAG's chief analyst, said in a note. "You must wonder how many of those will be empty seats, and if those services are both profitable and necessary from an environmental perspective."

The Bloomberg weekly oil-demand monitor uses a range of high-frequency data series to help identify trends that may become clearer later in more comprehensive monthly figures.

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

Measure	Location	% y/y	% vs 2019	% m/m	Freq.	Latest as of Date	Latest Value	Source
Gasoline demand	U.S.	+9	+1.1	-2	w	Aug. 27	9.58m b/d	EIA
Distillates demand	U.S.	+12	+6.2	+21	w	Aug. 27	4.39m b/d	EIA
Jet fuel demand	U.S.	+91	-4.4	+9.4	w	Aug. 27	1.8m b/d	EIA
Total oil products demand	U.S.	+34	+5.5	+7.8	w	Aug. 27	22.8m b/d	EIA
All vehicles miles traveled	U.S.			-3	w	Aug. 29	16.2b miles	DoT
Passenger car VMT	U.S.			-5	w	Aug. 29	n/a	DoT
Truck VMT	U.S.			+9	w	Aug. 29	n/a	DoT

Measure	Location	% y/y	% vs 2019	% m/m	Freq.	Latest as of Date	Latest Value	Source
All motor vehicle use index	U.K.	+7.5	unch	+3.1	d	Aug. 27	100	DfT
Car use	U.K.	+6.5	-2	+4.3	d	Aug. 27	98	DfT
Heavy goods vehicle use	U.K.	+4.1	+1	unch	d	Aug. 27	101	DfT
Gasoline (petrol) avg sales per filling station	U.K.	+7.3	-3.6	+3.2	m	Aug. 29	7,001 liters/d	BEIS
Diesel avg sales per station	U.K.	-0.5	-8.5	+0.3	m	Aug. 29	9,544 liters/d	BEIS
Total road fuels sales per station	U.K.	+2.7	-6.5	+1.5	m	Aug. 29	16,545 liters/d	BEIS
Gasoline	India	+13.6	+4.1	+2.5	2/m	Aug. 1-31	2.43m tons	Bberg
Diesel	India	+16	-9.8	-9.3	2/m	Aug. 1-31	4.95m tons	Bberg
LPG	India	+1.9	-2.4	-1.7	2/m	Aug. 1-31	2.32m tons	Bberg
Jet fuel	India	+42	-45	+20	2/m	Aug. 1-31	350k tons	Bberg
Total Products	India	+7.9	-6.5	+2.9	m	July 2021	16.83m tons	PPAC
Passenger car traffic	Poland	+6	-1	-8.1	w	Sept. 5	24,431	GDDKiA
Heavy goods traffic	Poland	+5	+10	+7.5	w	Sept. 5	4,705	GDDKiA
Toll roads volume	Italy	+8.6	+2.8		w	Aug. 23-29	n/a	Atlantia
Toll roads volume	Spain	+27	+10		w	Aug. 23-29	n/a	Atlantia
Toll roads volume	France	+11	-1.6		w	Aug. 23-29	n/a	Atlantia
Toll roads volume	Brazil	+3.3	+2.1		w	Aug. 23-29	n/a	Atlantia
Toll roads volume	Chile	+73	+10		w	Aug. 23-29	n/a	Atlantia
Toll roads volume	Mexico	+14	+5		w	Aug. 23-29	n/a	Atlantia
All vehicles traffic	Italy	+5.4		+2.1	m	August	n/a	Anas
Heavy vehicle traffic	Italy	+5.5		-18	m	August	n/a	Anas
Gasoline	Portugal	+7.2	-5.2	+12	m	July	94k tons	ENSE
Diesel	Portugal	+3.2	-5.3	+12	m	July	419k tons	ENSE
Jet fuel	Portugal	+110	-49	+31	m	July	85k tons	ENSE
Gasoline	Spain	+13	+3.1		m	July	565k m3	Exolum
Diesel	Spain	+7.5	-4.8		m	July	2341k m3	Exolum
Jet fuel	Spain	+122	-45		m	July	422k m3	Exolum

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

* In DfT U.K. data, the column showing versus 2019 is actually showing the change versus the first week of February 2020, to represent the pre-Covid era. Table shows data for Aug. 27, 2021, rather than holiday-skewed information for Aug. 30.

** In BEIS U.K. data, which is only released once per month, 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.

City congestion:

Measure	Location	% chg vs 2019	% chg m/m	Sept. 6	Aug. 30	Aug. 23	Aug. 16	Aug. 9	Aug. 2	Jul. 26	Jul. 19	Jul. 12	Jul. 5
			(Sept. 6)					Minutes of congestion at 8am local time					
Congestion	Tokyo	-26	+283	28	28	28	11	7	28	28	29	31	36
Congestion	Mumbai	-74	+33	10	5	8	7	7	9	7	9	5	6

Measure	Location	% chg vs 2019	% chg m/m	Sept. 6	Aug. 30	Aug. 23	Aug. 16	Aug. 9	Aug. 2	Jul. 26	Jul. 19	Jul. 12	Jul. 5
Congestion	New York	-100	-100	0	15	16	13	17	16	16	14	18	0
Congestion	Los Angeles	-93	-86	2	29	27	24	17	16	16	18	17	3
Congestion	London	-3	+97	37	1	16	15	19	15	19	25	19	34
Congestion	Rome	-36	+373	31	13	5	2	7	16	22	23	23	35
Congestion	Madrid	-44	+1000	20	6	3	2	2	5	5	8	13	14
Congestion	Paris	+9	+575	49	27	14	9	7	17	16	22	29	39
Congestion	Berlin	+13	+47	38	32	38	29	26	16	14	13	16	16
Congestion	Mexico City	-45	+41	27	24	23	20	19	20	19	20	22	23
Congestion	Sao Paulo	-78	-62	10	30	26	25	25	21	22	22	22	20

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

NOTE: m/m comparisons are Sept. 6 vs Aug. 9. It was a public holiday in the U.S. on Sept. 6 and Brazil on Sept. 7. The U.K. had a holiday Aug. 30. TomTom has been unable to provide Chinese data since late April.

Air Travel:

Measure	Location	% chg y/y	% chg vs 2019	% chg m/m	Freq.	Latest as of Date	Latest Value	Source
Airline passenger throughput	U.S.	+136	-16	-25	d	Sept. 5	1.63m people	TSA
Commercial flights	Worldwide	+36	-22	+0.3	d	Sept. 6	92,573	FlightRadar24
Air traffic (flights)	Europe		-29	+2.1	d	Sept. 6	24,895	Eurocontrol
Seat capacity	Worldwide	+37	-32		w	Sept. 6	78.47m	OAG
Seat cap.	U.S.	+76	-16		w	Sept. 6	18.53m	OAG
Seat cap.	China	-1.4	-5.7		w	Sept. 6	15.15m	OAG
Seat cap.	India	+90	-22		w	Sept. 6	3.11m	OAG
Seat cap.	Spain	+78	-27		w	Sept. 6	2.63m	OAG
Seat cap.	U.K.	+44	-50		w	Sept. 6	1.96m	OAG
Seat cap.	Japan	-9	-54		w	Sept. 6	1.95m	OAG
Seat cap.	Germany	+52	-48		w	Sept. 6	1.80m	OAG
Seat cap.	Brazil	+87	-31		w	Sept. 6	1.78m	OAG
Seat cap.	Mexico	+48	-7.2		w	Sept. 6	1.59m	OAG
Seat cap.	France	+34	-39		w	Sept. 6	1.54m	OAG
Seat cap.	Australia	+34	-75		w	Sept. 6	515k	OAG
Seat cap.	S. Africa	+203	-51		w	Sept. 6	292k	OAG

NOTE: Comparisons versus 2019 are a better measure of a return to normal.

Refineries:

Measure	Location	y/y chg	vs 2019 chg	m/m chg	Latest as of Date	Latest Value	Source
Crude intake	U.S.	+15%	-8.3%	+0.1%	Aug. 27	15.9m b/d	EIA
Utilization	U.S.	+15 ppt	-3.5 ppt	unch	Aug. 27	91.3 %	EIA
Utilization	Gulf Coast U.S.	+19 ppt	-3.2 ppt	-1.2 ppt	Aug. 27	92.4 %	EIA
Utilization	East Coast U.S.	+16 ppt	+16 ppt	-1.2 ppt	Aug. 27	84.7 %	EIA
Utilization	Midwest U.S.	+6.2 ppt	-5.2 ppt	+4.9 ppt	Aug. 27	94.3 %	EIA
Apparent Oil Demand	China	-2.3%		-2.5%	July 2021	13.47m b/d	NBS
Indep. refs run rate	Shandong province, China	-4 ppt	+6 ppt	+3.2 ppt	Sept. 3	71.3 %	SCI99
State refs run rate	East China	unch	-3.1 ppt	-2.8 ppt	Aug. 31	79.5 %	SCI99
State refs run rate	South China	-2 ppt	+4 ppt	-1 ppt	Aug. 31	82 %	SCI99

NOTE: All of the refinery data is weekly, except for SCI99 state refineries, which is twice per month, and the NBS apparent demand, which is usually monthly.

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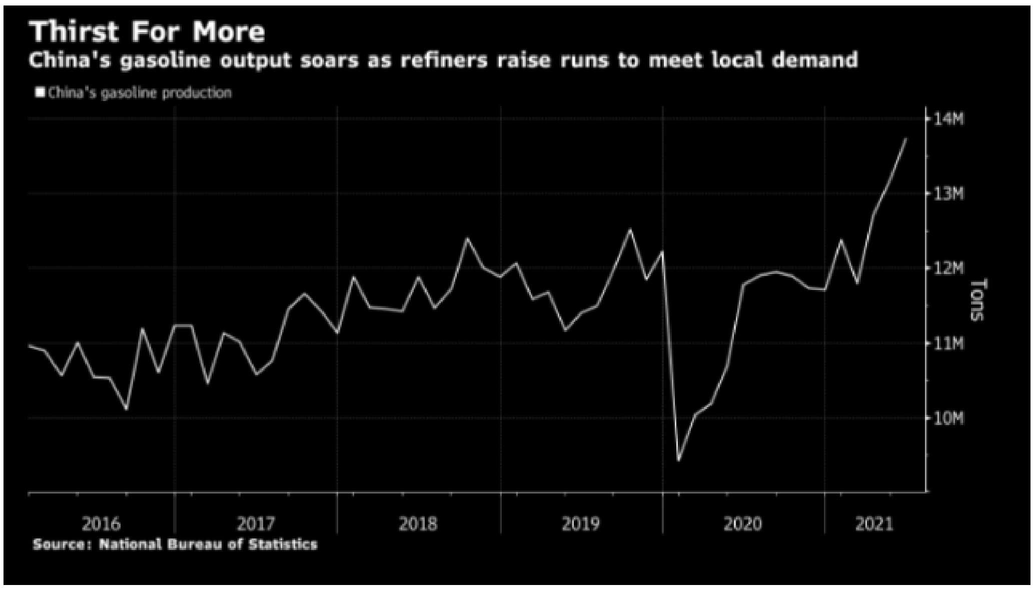
World’s Top Oil Guzzlers Surpass Pre-Pandemic Consumption (2)
2021-09-09 07:20:27.624 GMT

By Bloomberg News
(Bloomberg) -- Some of the world’s biggest economies are seeing oil consumption turn the corner and even surpass pre-pandemic levels as falling Covid-19 infection rates drive a recovery in activity.
Oil demand in China, the world’s top energy consumer, will be 13% higher next quarter than in the same period in 2019 before the pandemic, according to SIA Energy. Indian fuel sales extended a rebound last month, while American consumption of petroleum products just hit a record high. Europe has also just had its best August for gasoline demand in 10 years, IHS Markit said.



The improvement in consumption across major economies is buoying oil prices that have rallied around 40% this year. Against this backdrop, the OPEC+ alliance decided to keep restoring crude supply earlier this month, citing tighter balances into year-end.
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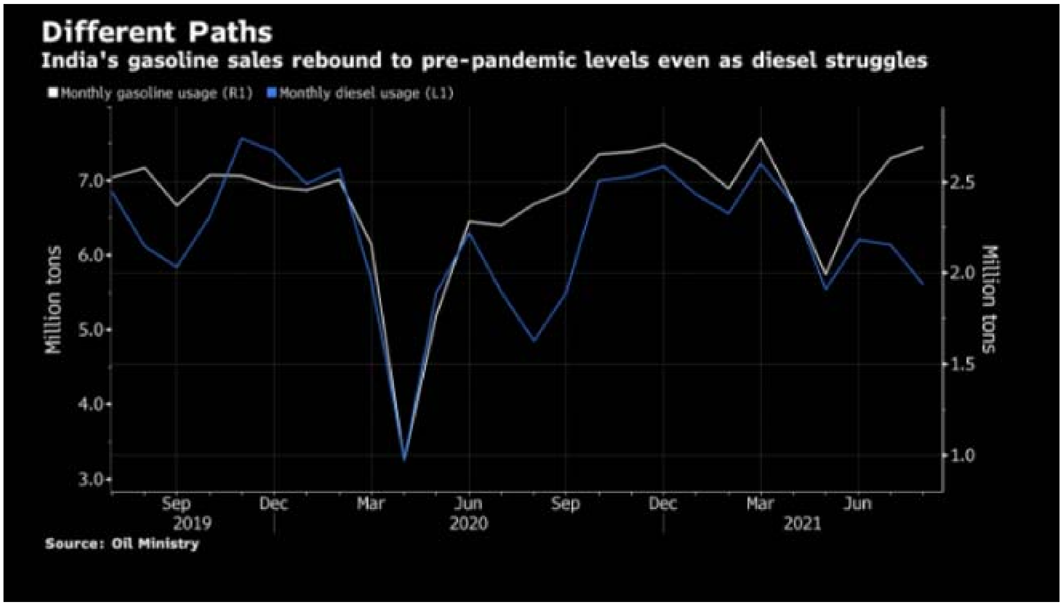
“The worst for Asian fuel demand is over and we see a soft recovery of oil demand in the coming months,” said Sengyick Tee, an analyst at Beijing-based SIA. China’s overall oil consumption will be led by a more than 20% jump in gasoline use next quarter

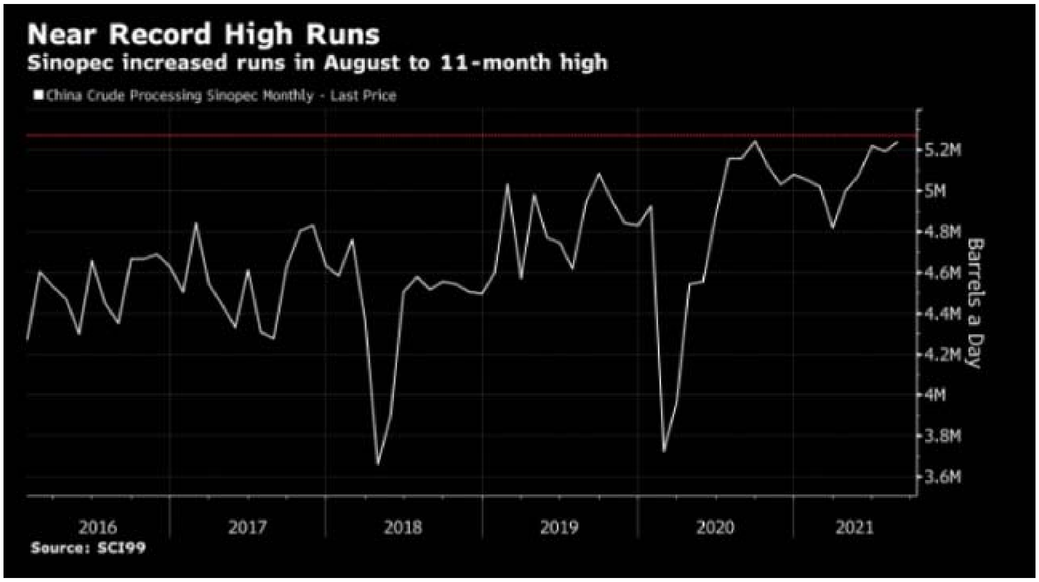
from 2019, he said.
While motor fuel is powering the recovery as people take to the roads after months of lockdown, the situation for other oil products isn't as positive. Jet fuel consumption is still languishing because of the lack of international air travel. Indian diesel use is down due seasonal factors, although SIA Energy sees demand for the fuel in China rising 4% next quarter from 2019.



Trucking and construction activities typically decline in India from June to September because of the monsoon. That weighs on demand for diesel, the country's most popular fuel, before it rises again toward the end of the year amid crop harvesting and festivals.
"Sales volume of petrol has already crossed pre-Covid levels, with diesel likely to reach there in the next two to three months" said Shrikant Madhav Vaidya, chairman of Indian Oil Corp., the country's biggest refiner.

Refining Ramp-Up

Indian processors will have "limited upside potential" for run rate increases this month as they struggle to cope with excess diesel that's been produced from the process of making gasoline, said Senthil Kumaran, head of South Asia oil at industry consultant FGE. A turning point may come around October, with runs potentially rising above 5 million barrels a day by year-end, he said.
Chinese run rates have inched up with state-owned Sinopec refining the most crude in 11 months in August, data from local consultancy SCI99 show. However, activity at private refiners in Shandong province is only just over 70% amid a government-led clampdown on the sector.



Still, with some of Asia's largest economies reporting tens of thousands of virus infections per day, some threats to energy demand remain even as the region races to vaccinate its people. "Resurgence risk is a concern that we have built into our outlook, particularly for populous countries such as India and Indonesia," said Qiaoling Chen, an analyst at energy consultancy firm Wood Mackenzie Ltd. "For now, the worst for Asia oil demand is over, but the downside risks remain."

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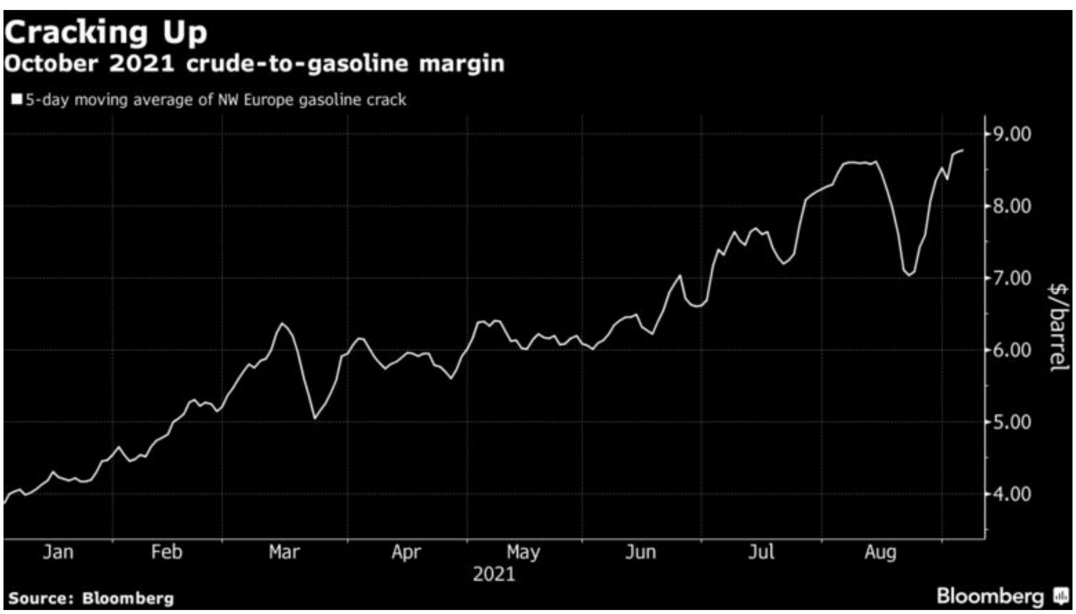
Europeans Hit the Road to Fire Rebound in Continent's Oil Demand

By Alex Longley
September 6, 2021, 6:53 AM MDT

- Gasoline margins stronger as staycations boost driving
- Traffic data point to more car usage; refineries' demand gains

Europe has transformed from an oil-market weakling into a source of strength -- whether it's crude consumption from the continent's refineries, surging traffic data, or rebounding fuel prices.

"August 2021 would be the best month of August since 2011," Hedi Grati, an executive director at IHS Markit, said of the firm's estimate for European gasoline demand. "The ten years in between were all lower."

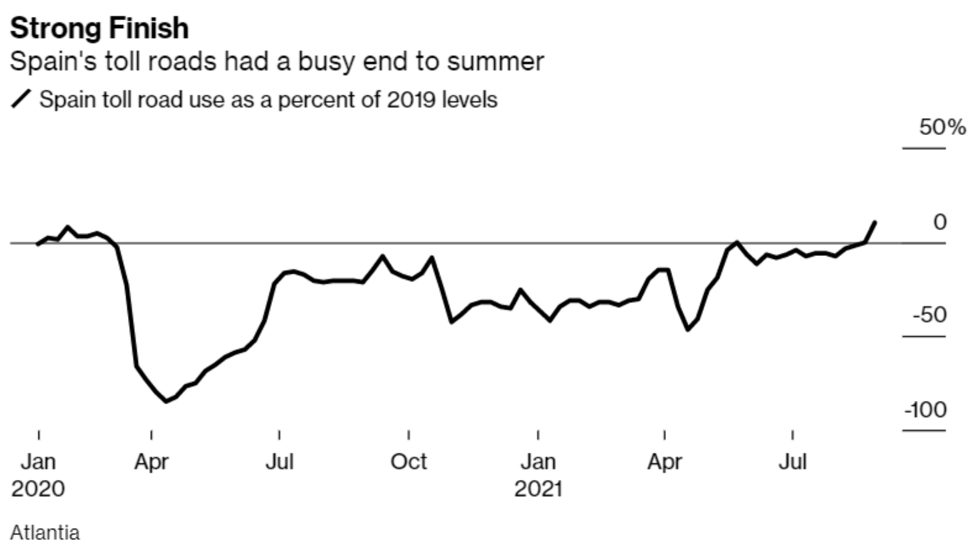


The pickup for the automotive fuel is partly a function of people driving more to take their vacations. It marks a stark change in fortunes for Europe, where months of lockdowns to combat the spread of Covid-19 previously hit the region's oil consumption hard and triggered a major retrenchment within the continent's refining industry. The demand boost appears to be filtering into the wider market, with traders reporting strong demand from local refineries for crude.

Traders measure the strength of petroleum products through what's known as the crack spread: the difference in cost between fuels and the crude from which they are made. For gasoline, that measure is now at about $9 a barrel in northwest Europe for October, more than double where it was in January. Underpinning the demand has been an ongoing shift from diesel to gasoline-powered cars following the VW emissions scandal.

The surge in holiday-season driving that's further firing the rally is visible in traffic data.

Toll-road usage in Spain was up 10% on the equivalent week in 2019 in the most recent data, the strongest week since the pandemic began, according to Atlantia, which operates such roads. The firm's data show that Italian highways were almost 3% busier than 2019, while figures in Poland also reveal busier roads than 2019. In France, highway traffic climbed by more than 6% above 2019 levels in July, toll operator Vinci said. August figures are due later this month.



The strength being observed in Europe is not unique to the continent. With demand in Brazil above 2019 levels and the U.S. close to it, those markets are pulling oil demand higher too, said Giovanni Staunovo, commodity analyst at UBS Group.

Gasoline traders painted a bullish picture of recent European demand, with one saying it was at or above 2019 levels for the holiday period. Another person involved in the gasoline market said they had seen strong interest in components used to make the road fuel. Stockpiles held in independent storage in Amsterdam-Rotterdam-Antwerp are at their lowest since 2016, recent data show.

That strength is filtering into crude markets. Demand from European refiners for light, sweet crude remains very strong. Caspian CPC Blend recently traded at about $1.50 a barrel below Dated Brent, compared with discounts of about $2 a month ago, said traders involved in the market. Most such cargoes for September loading have already been cleared, a faster pace than normal.

Other sweet grades in the Mediterranean and North Sea are also holding well. Traders report that strong demand from European refiners is helping to offset lackluster interest from Asia, with flows curtailed by a relatively high Brent crude price, and a cut in import quotas for China’s teapot refiners.

So-called light, sweet grades -- those that are low in sulfur and less dense -- are easier to turn into gasoline.

While gasoline demand has strengthened, not every oil product is faring so well. Europe’s air traffic is still about 30% below 2019 levels, according to data from Eurocontrol. That’s sapping jet fuel consump[tion. The continent’s August demand for diesel-type fuel -- roughly triple that of gasoline -- is also seen at 4% below the 2019 level by Grati.

“Pent-up demand to some extent is helping, but also lifting of restrictions earlier this year and no additional measures despite rising cases,” Staunovo said.

— With assistance by Jack Wittels, Sherry Su, and Julian Lee

ENERGY MATTERS!

Liberty's mission is to **BETTER HUMAN LIVES.**

Liberty is a **TECHNOLOGY PIONEER** of the shale revolution and has driven enormous improvements in both human well-being and environmental quality.

Liberty management and board are **ALIGNED** with our owners and our communities.

Liberty partners with our customers to deliver **LOW-IMPACT, LOW-COST, RELIABLE ENERGY** (and we're proud of it!).

Liberty sees **THREE GLOBAL ENERGY CHALLENGES:**

- Energy poverty
- Reliable, affordable, clean energy
- Climate change

INTRODUCTION

IT IS SIMPLY NOT POSSIBLE TO DISCUSS THE ENVIRONMENTAL AND SOCIAL IMPACTS OF OUR INDUSTRY WITHOUT CONSIDERING THE ENVIRONMENTAL AND HUMAN IMPACTS OF THE ABSENCE OF OUR INDUSTRY.

As with all complex issues, Liberty strives to learn first, define a thoughtful plan, and then act. Our inaugural Environmental, Social, and Governance (ESG) report is designed to share our journey with you. We go far beyond the narrow focus on our company to look at the bigger picture of the world in which we live and the industry in which we operate. Would the world be better off without fossil fuels? Emphatically "no" is our answer. Because the issues around energy, poverty, and the environment are so important – and so often misunderstood – we will explore and explain them in depth.

Part 1 covers in greater depth the larger issues that form the Energy/Environment/Poverty nexus. This begins with why worldwide clean energy access matters. Since the oil and gas industry began in the second half of the 19th century, global life expectancy has doubled, extreme poverty has plummeted, and human liberty has grown tremendously. The timing here is no coincidence. This progress in the human condition was enabled by the surge in plentiful, affordable energy from oil, gas, and coal.

Unfortunately, many people still lack access to life-enhancing modern energy, which presents the most pressing global energy challenge. Our energy-rich lifestyles have both environmental downsides such as pollutants and climate change, and upsides like forest preservation, reduced need for cropland, and cleaner air.

Part 2 covers the actions Liberty is taking to maximize the benefits of our services and to lead the industry into a new era of technology and stewardship. At Liberty, we view ESG principles as foundational to our business strategy, expanding beyond our four walls to ensure that the work we do benefits our families, our communities, and the world. We passionately work to better the process of bringing hydrocarbons to the surface in a clean, safe, and efficient fashion. It is important to not lose sight of the rich history of progress enabled by the oil and gas industry, and this broader context motivates our team every day.

Liberty's ESG report offers information on critical issues that are important to our business today. Information is provided by Liberty's subject matter experts, approved by our leadership team, and reviewed by the Liberty board of directors. Data in the report covers our 2020 calendar year unless otherwise indicated. The report is prepared in accordance with Sustainability Accounting Standards Board (SASB) standards and uses several other ESG standards to inform our discussion. In developing our report, we have identified opportunities for expanded reporting in subsequent years as we continue to drive improvement.

A MESSAGE FROM CHRIS WRIGHT, CHAIRMAN AND CEO

LIBERTY'S MISSION IS TO BETTER HUMAN LIVES.

The Liberty family, from our field crews to our board of directors, forms a passionate, committed, and engaged team. We strive to enhance our company, families, communities, and the world. Liberty is committed to meeting the challenges of our time. By investing in our people and technology we are helping our customers efficiently produce cleaner oil and gas resources. It is simply not possible to discuss the environmental and social impacts of our industry without considering the environmental and human impacts of the absence of our industry.

Today there is discontent among the public in wealthy nations with oil and gas, and even a growing belief that our industry soon will be, and should be, gone. This report explains why the near-term disappearance of our industry is both highly unlikely and undesirable. Liberty takes great pride in our work, and we strive to explain why in this report.

The big-picture issues are tackled in depth in Part 1 of this report, which gives data-packed summary overviews on energy, energy poverty, climate change, and climate economics. At least a basic understanding of these issues is critical to engaging with today's three global energy challenges: 1) energy poverty, 2) affordable, reliable, clean energy, and 3) climate change.

This report explains why the longer, healthier, opportunity-rich lives in the modern world are simply not possible without oil and gas. Borrowing Thomas Hobbes' words, life for most everyone in history was "nasty, brutish, and short" when liberty was scarce and energy was supplied only by human toil and draught animals. Liberty's mission is to bring modern energy to the fully one-third of humanity that lacks that access today and, therefore, must live far more dangerous and constrained lives than we enjoy.

Part 2 of this report covers Liberty's efforts to better human lives, strengthen our communities, and reduce negative environmental impacts from North American oil and natural gas production. Our efforts on the social front began with the inception of our company. We chose our name, Liberty, because we believe in human liberty: everyone should have the freedom and opportunity to pursue their dreams. This ethos pervades our diverse workforce and hiring policies that focus on where people are headed with their lives far more than where they came from. Liberty provides a home to many of the brave service men and women who have served our country. We also employ dozens of formerly incarcerated people who had a tough start in life, but are now building meaningful careers.

COVID-19 dealt a body blow to Liberty. Our top priority was the health and safety of our team and their families. We were highly effective in suppressing COVID-19 transmission at Liberty even as we worked 24/7 to supply reliable energy and raw materials critical to fighting the global pandemic. We were forced to make our first-ever layoffs in company history. We also had to make significant compensation cuts and, in Liberty fashion, the compensation cuts

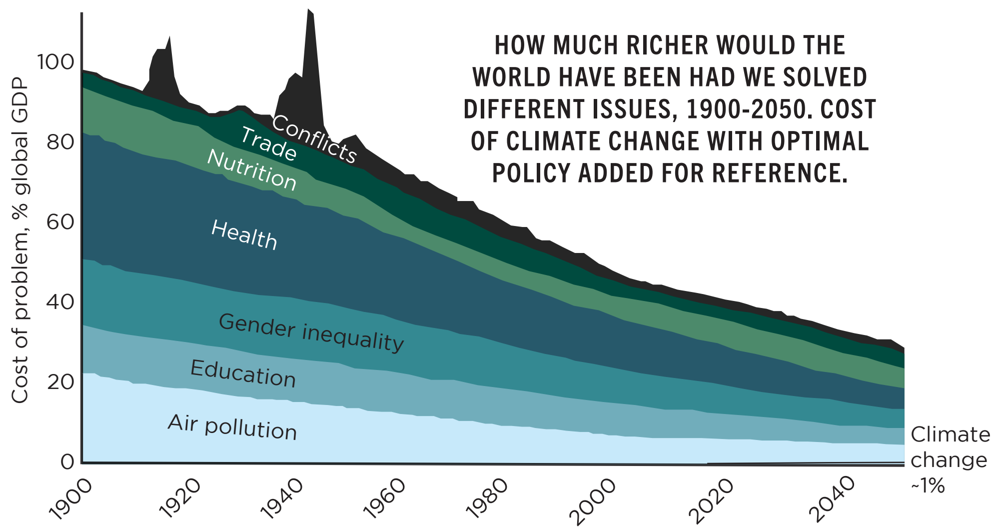


Figure 1.1 Source: Bjorn Lomborg
https://www.sciencedirect.com/science/article/pii/S0040162520304157

were made first and deepest at the executive level. Now as the country has entered a recovery phase, most compensation cuts for the Liberty team are restored and we are hiring again. April 2020 was the toughest professional time of my career. I am proud and humbled to be part of a team that faced adversity with courage, perseverance, and steadfast commitment to Liberty's mission.

Liberty provides over 100 K-12 scholarships to low-income kids through ACE (Alliance for Choice in Education), and we recently launched a Liberty Scholars program at Montana Tech to enable lower income students to get a college engineering education. We have numerous other efforts targeting schools and kid programs, poverty abatement programs, low-income housing (Habitat for Humanity), criminal justice reform and job opportunities for those who had a disadvantaged start in life. Our efforts are all targeted at bettering human lives and growing individual liberty and opportunity.

Liberty is committed to honest, sound, aligned governance that assures management and our board of directors are responsible stewards of our owners' capital. All the Liberty founders are still here fulfilling our dream to build a truly special company. We have always recognized that incentives drive human behavior and that principle guides our corporate governance. We align our financial incentives with our shareholders, and our social and operational practices with the communities in which we operate. Businesses are major players in setting the tone, culture, and character of our society. We behave in ways that our children and neighbors can be proud of for years to come.

This report is long, but necessarily so. It is critical to put Liberty's efforts and our whole industry in proper context. We start in Part 1 by showing how low-cost, reliable energy is an agent of human well-being. The essential role of energy access lifts people out of poverty and reduces the health and environmental stresses that accompany the use of traditional biomass fuels like wood, dung, and agricultural waste. Regrettably, traditional fuels still dominate for roughly one-third of the world's people. The World Health Organization (WHO) estimates that over 2 million premature deaths each year arise from indoor use of traditional biomass fuels, which generate copious particulate matter during combustion. This staggering loss of human potential can and must be eradicated.

WHO estimates there are several million additional deaths from outdoor air pollution, predominantly from the same source: particulate matter, or $PM_{2.5}$, which is one of the world's deadliest pollutants. Transitioning from traditional biomass fuels to modern fuels and using appropriate industrial pollution controls are the keys to reducing outdoor $PM_{2.5}$ concentrations. $PM_{2.5}$, malnutrition, preventable disease, and lack of access to drinking water and basic education collectively account for over 10 million premature deaths per year. Bringing affordable, reliable energy to the world's poor is essential to eradicating these scourges. Even in wealthy nations, rising energy prices pose significant economic and health threats to lower income people.

We see three global energy challenges today: energy poverty; maintaining reliable, affordable, and clean energy; and climate change. There is no reason that we can't master all these challenges. But doing so will require honest assessment, rational evaluation of tradeoffs, continued technology advancement, and the will to get it right. Unfortunately, the first and most urgent issue, energy poverty, afflicts poor countries and lower income residents of the wealthier countries, hence it garners tragically little attention. This is wrong.

The second global energy challenge is maintaining reliable, affordable and clean energy. This issue is starting to garner more attention as power grids become more expensive and less reliable, amply illustrated by the recent serious blackouts in California, Texas, and the U.K.

The third global energy challenge, climate change, has become so politicized and emotionally charged that rational, fact-based decision-making is becoming scarce. Urgent desires to visibly take politically appealing action have often driven up energy prices, made power grids less reliable, and grown energy poverty without making meaningful progress on climate change. Climate change is a long-term challenge requiring broad-based actions with significant technology and system advancements required. Liberty is excited to play a growing role here.

Decisions at Liberty are driven by data, facts, customer preferences, and our commitment to do the right thing. Our efforts on these three big issues that make up the energy/environment/poverty nexus will be no different. Our efforts are both internal to Liberty's operations and in partnership with our customers.

To put the global energy challenges in context, Figure 1.1 shows an economic analysis of the staggering lost economic output resulting from the major afflictions of the world since 1900. Although we have seen over a century of progress, air pollution, disease, malnutrition, etc., still dwarf climate change in urgency. Solving these challenges is intimately tied to raising the poorest third of the world population out of energy poverty. For context, Figure 1.1 overlays, on a like-for-like basis, projections of climate change economic impacts from Nobel Prize winning climate economist, William Nordhaus.

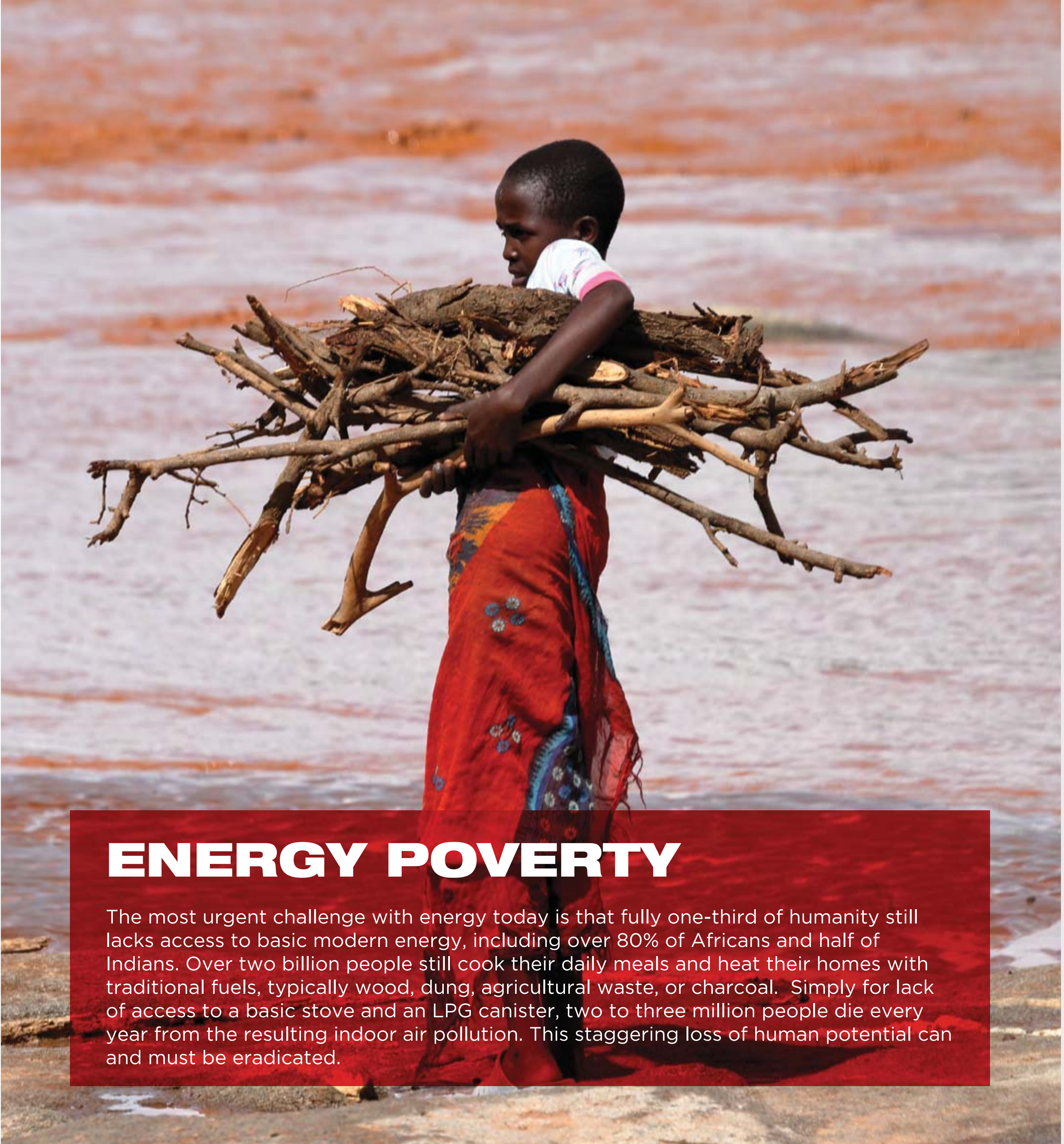
Liberty works in the shale revolution, made possible by innovations in hydraulic fracturing and horizontal drilling. The shale revolution is a major driver of progress for all three global energy challenges. Surging U.S. oil and gas production has reset global oil and gas prices lower, lifting the economic fortunes of everyone, most of all the world's poor. 2020 marked the second straight year that the U.S. produced more total energy than consumed. The last time the U.S. produced more energy than consumed was in the 1950s.

Surging U.S. exports of liquid petroleum gas (LPG) bring this critical fuel to improve the lives of families in dire energy poverty still relying on dirty, life-shortening traditional biomass fuels. On the climate front, surging U.S. natural gas production and plunging natural gas prices brought by the shale revolution have been the largest factors driving down U.S. per capita greenhouse gas (GHG) emissions to their lowest levels in my lifetime! Lower global natural gas prices and surging exports of liquified natural gas (LNG) are globalizing the incremental displacement of coal with cleaner electricity sources like natural gas, solar, and wind.

The broader social, community, governance, environmental, and human flourishing aspects of energy are topics near and dear to our hearts and were significant drivers of why we founded Liberty ten years ago.

TO BETTERING HUMAN LIVES,

CHRIS WRIGHT
CHAIRMAN AND CEO
LIBERTY OILFIELD SERVICES



ENERGY POVERTY

The most urgent challenge with energy today is that fully one-third of humanity still lacks access to basic modern energy, including over 80% of Africans and half of Indians. Over two billion people still cook their daily meals and heat their homes with traditional fuels, typically wood, dung, agricultural waste, or charcoal. Simply for lack of access to a basic stove and an LPG canister, two to three million people die every year from the resulting indoor air pollution. This staggering loss of human potential can and must be eradicated.

In sub-Saharan Africa, an estimated five out of six people (approximately 900 million people) in total lack access to clean cooking resources.

95%

Almost 95% of that subset of the population rely on solid biomass for cooking in the form of fuel wood, charcoal, or dung. The remaining 5% rely on kerosene or coal.

500,000

Household air pollution stemming from inefficient and polluting cooking fuels was linked to nearly 500,000 premature deaths in sub-Saharan Africa in 2018.

2.5 MILLION

Globally, WHO estimates deaths from indoor air pollution at 2.5 million – a figure comparable to the combined death toll of malaria, tuberculosis, and HIV/AIDS in 2018.

WHO estimates there are several million additional deaths from outdoor air pollution from the same source: particulate matter, or $PM_{2.5}$, which is one of the world's deadliest emissions. Transitioning from traditional solid fuels to liquid fuels (or natural gas or electricity) is the key to reducing outdoor $PM_{2.5}$ concentrations just as it is for reducing indoor $PM_{2.5}$ levels. Figure 1.5 shows a global map of outdoor $PM_{2.5}$ pollution. This problem is worst in Africa, south Asia, southeast Asia, and China, the same places where energy poverty drives the indoor air pollution crisis. Wealthy countries have used technology to have both highly energized societies and clean air.

Together $PM_{2.5}$, malnutrition, preventable disease, and lack of access to drinking water and basic education collectively are responsible for over 10 million premature deaths per year. Bringing affordable, reliable energy to the world's poor will be essential to eradicating these scourges.

The good news is that tremendous progress is being made. Energy access is increasing globally as hundreds of millions of people have made the transition from traditional cooking and heating fuels to modern fuels – most commonly to liquid petroleum gas (LPG) – over the last 15 years. The U.S. shale revolution has been simply tremendous in lowering the energy cost bar for low-income families to transition from burning solid biofuels to clean-burning LPG stoves fueled by refillable LPG canisters. The U.S. is now by far the world's largest exporter of LPG (dominantly propane) as well as the source of virtually all the growth in world LPG trade over the last decade. This has brought down LPG prices and significantly grown available supplies. Continuing this trend is essential to bringing everyone clean-burning cooking fuel in the next two decades.

GLOBAL SATELLITE-DERIVED MAP OF $PM_{2.5}$ AVERAGED OVER 2001-2006

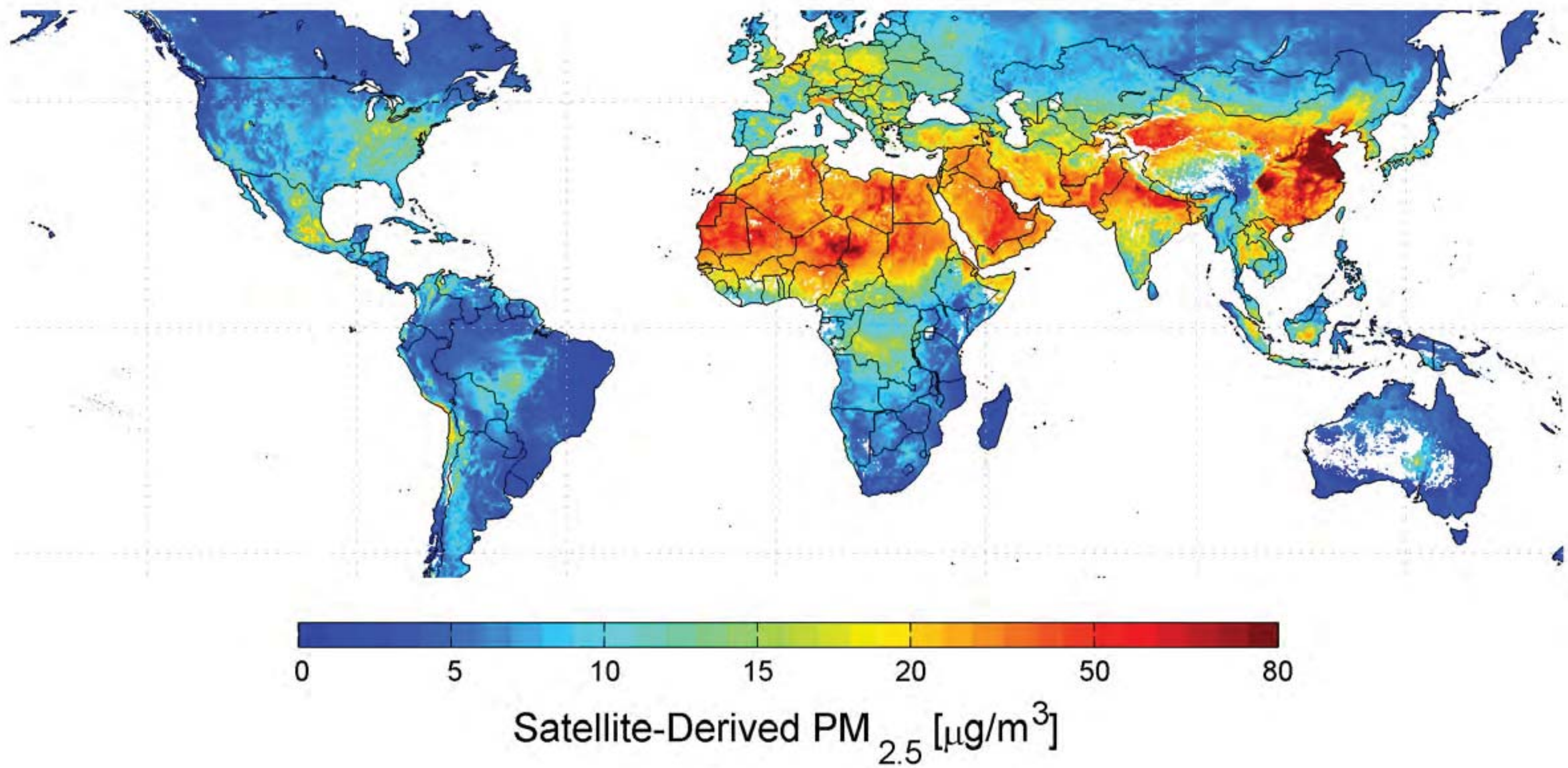


Figure 1.5 Source: Global satellite-derived map of $PM_{2.5}$ averaged over 2001-2006. Credit: Dalhousie University, Aaron van Donkelaar
https://www.nasa.gov/topics/earth/features/health-sapping.html

THE DEVELOPED WORLD TAKES ELECTRICITY ACCESS FOR GRANTED. FOR HUNDREDS OF MILLIONS OF PEOPLE IT IS A LUXURY OR ABSENT.

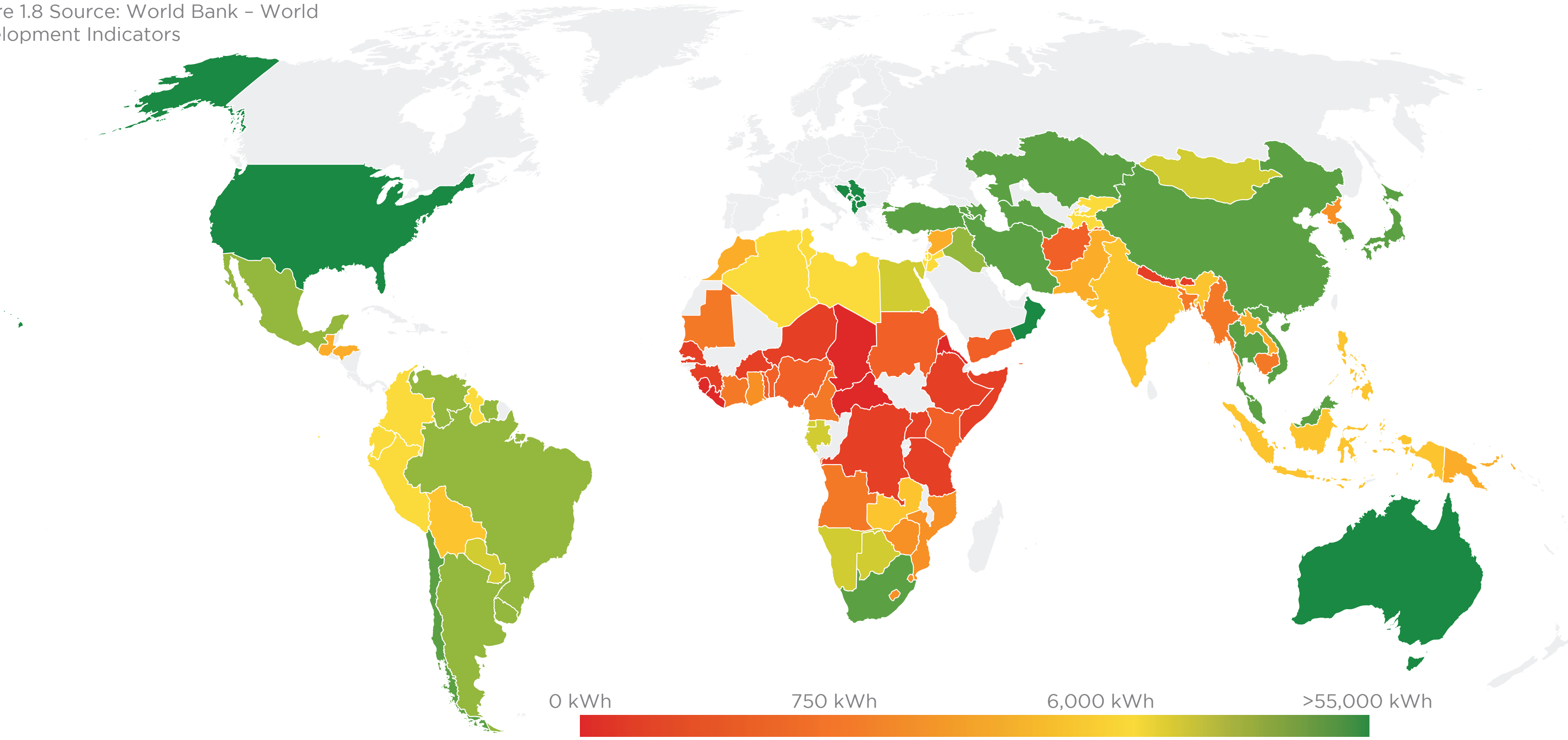
Nearly one billion people have no access to electricity. Another billion have only intermittent – four hours per day – access to modest amounts of electricity. This is enough to power a light bulb or charge a cell phone, but not enough to power a water pump or other machinery necessary to raise their productivity and energize significant increases in productivity and income. One billion people received their first access to electricity in the last 20 years – the large majority from hydrocarbons or hydropower.

Below are side-by-side maps of per capita electricity consumption by country and child malnutrition by country. There is a reason that both maps look quite similar: energy is the prime mover that enables everything else. If you have electricity, your life and that of your family improves beyond recognition.

Continuing the last several decades of unprecedented progress in the human condition requires massive increases in affordable, reliable energy for the world's poorest countries and the poorest citizens in the world's middle income and wealthy nations. While progress continues to be made, there are now growing headwinds due to the heavy-handed actions of the world's wealthy nations in the name of climate change. The World Bank, European Development Bank, and many large commercial banks are now restricting or simply not offering funding for hydrocarbon-fueled power plants, which are the main source of electricity generation globally, and even more so in developing nations.

ELECTRICITY CONSUMPTION kWh PER CAPITA

Figure 1.8 Source: World Bank – World Development Indicators



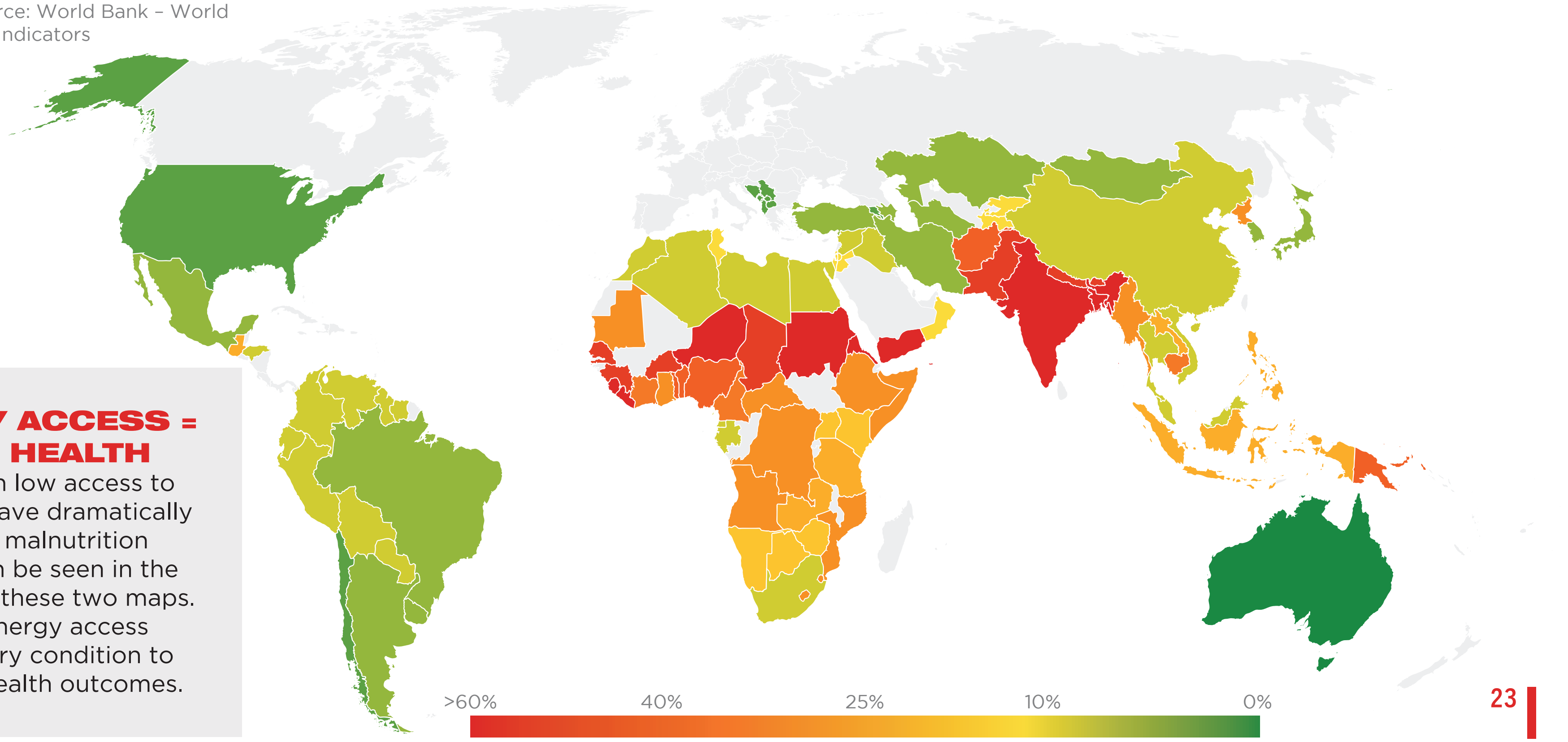
CHANGING WOMEN'S LIVES

- WOMEN IN ENERGY POVERTY SPEND MORE THAN AN HOUR PER DAY GATHERING FUEL WOOD FOR COOKING.
- WOMEN IN ENERGY POVERTY SPEND AN HOUR PER DAY SOURCING WATER FOR DRINKING AND COOKING.

Source: UN report – https://sustainabledevelopment.un.org/content/documents/17489PB12.pdf

PERCENTAGE OF UNDERWEIGHT CHILDREN AT AGE 5

Figure 1.9 Source: World Bank – World Development Indicators



ENERGY ACCESS = BETTER HEALTH

Nations with low access to electricity have dramatically higher child malnutrition rates, as can be seen in the similarity in these two maps. Improved energy access is a necessary condition to improved health outcomes.

The United Nations Human Development Index (HDI) is a good rough proxy for the human condition as it combines life expectancy at birth, years of education received, and per capita gross national product. In 1990 62% of the global population (5.3 billion in 1990) scored "Low" on the HDI. The last three decades have shown tremendous progress as now only 12% of today's larger population (7.6 billion) score "Low" on the HDI. However, 12% is still over 900 million people.

As with child mortality, and virtually any index of human well-being, increasing the HDI requires increased energy consumption. This point is illustrated in the two graphs below. The first graph shows the relationship between energy consumption per capita and HDI across countries, and the second graph shows the changes over the last thirty years for both China and India where rising energy consumption accompanies rising HDI.

ACCESS TO AFFORDABLE ENERGY IS ESSENTIAL FOR HDI IMPROVEMENT

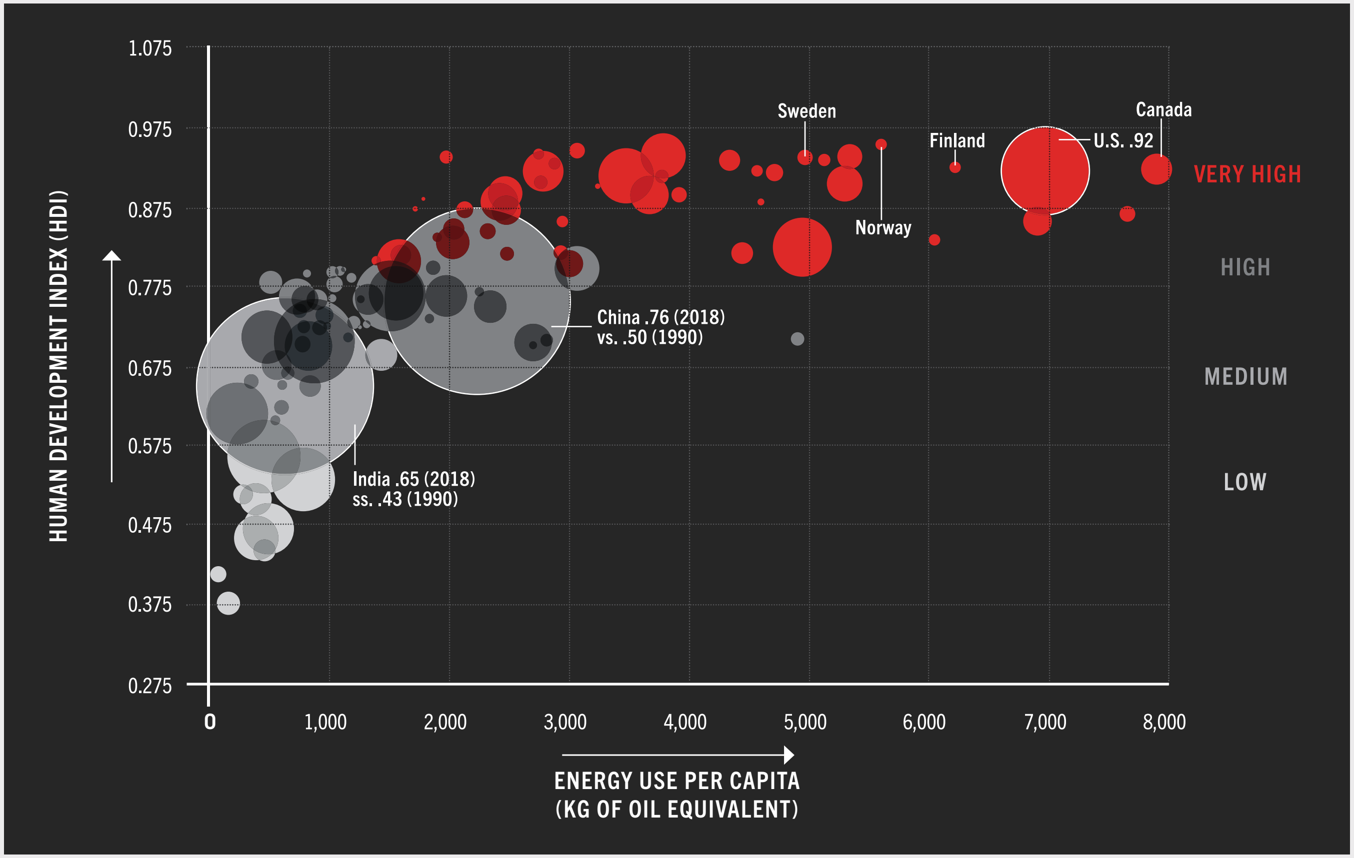


Figure 1.10 Size of Circles Depicts Relative Size of Population | Source: World Bank and United Nations Development Programme 2018

BETWEEN 1990 AND 2018, INDIA AND CHINA HAVE SEEN A 51% AND 52% IMPROVEMENT, RESPECTIVELY, IN HDI

INDIA

- MOVED FROM LOW TO MEDIUM HDI
- MEAN EDUCATION INCREASED 2.2X
- LIFE EXPECTANCY INCREASED 11.5 YEARS
- ENERGY PER CAPITA INCREASED 82%

CHINA

- MOVED FROM LOW TO HIGH HDI
- MEAN EDUCATION INCREASED 1.6X
- LIFE EXPECTANCY INCREASED 7.4 YEARS
- ENERGY PER CAPITA INCREASED 192%

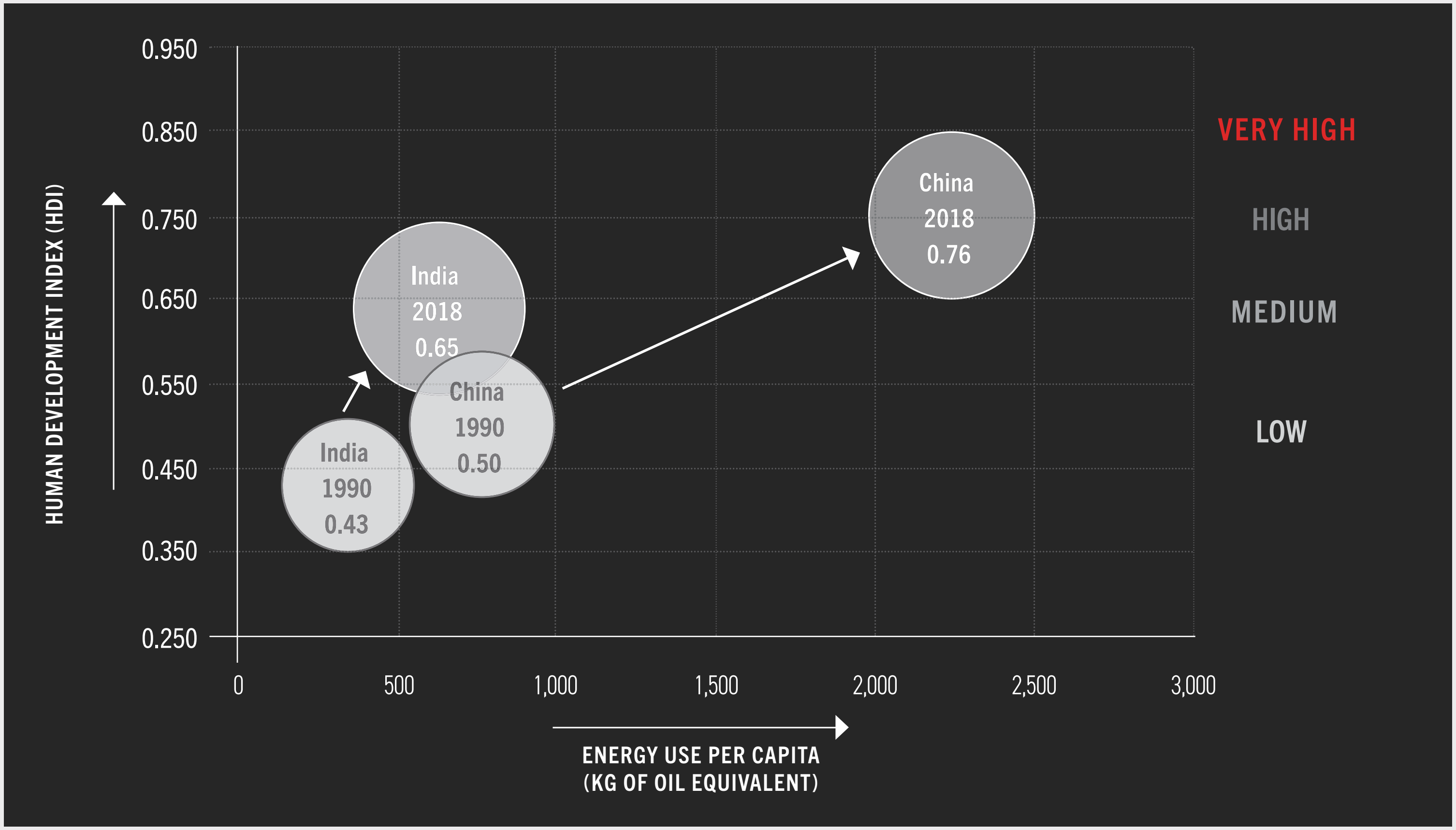


Figure 1.11 Source: World Bank and United Nations Development Programme 2018

https://www.nytimes.com/2021/09/08/business/energy-environment/biden-solar-energy-climate-change.html

From 4% to 45%: Energy Department Lays Out Ambitious Blueprint for Solar Power

By: Ivan Penn
Sept. 8, 2021

The Biden administration on Wednesday released a blueprint showing how the nation could move toward producing almost half of its electricity from the sun by 2050 — a potentially big step toward fighting climate change but one that would require vast upgrades to the electric grid.

There is little historical precedent for expanding solar energy, which contributed less than 4 percent of the country's electricity last year, as quickly as the Energy Department outlined in a new report. To achieve that growth, the country would have to double the amount of solar energy installed every year over the next four years and then double it again by 2030.

Such a large increase, laid out in the report, is in line with what most climate scientists say is needed to stave off the worst effects of global warming. It would require a vast transformation in technology, the energy industry and the way people live.

The report is consistent with climate and energy plans laid out by President Biden during his campaign last year, when he said he wanted to bring net planet-warming emissions from the power sector to zero by 2035. He also wants to add hundreds of offshore wind turbines to the seven currently in American waters. And last month, he announced that he wanted half of all new cars sold to be electric by 2030 in a White House event with executives from three of the nation's largest automakers — a goal that will depend in large part on whether there will be enough places to plug in those cars.

But it is not clear how hard the administration will push to advance solar energy through legislation and regulations. Officials have provided only a broad outline for how they hope to clean up the country's energy system and its cars and trucks. Many details will ultimately be decided by Congress, which is working on a bipartisan infrastructure bill and a much larger Democratic measure that could authorize $3.5 trillion in federal spending.

Still, the Energy Department said its calculations showed that solar panels had fallen so much in cost that they could produce 40 percent of the country's electricity by 2035 — enough to power all American homes — and 45 percent by 2050.

Getting there will mean trillions of dollars in investments by homeowners, businesses and the government. The electric grid — built for hulking coal, natural gas and nuclear power plants — would have to be almost completely remade with the addition of batteries, transmission lines and other technologies that can soak up electricity when the sun is shining and to send it from one corner of the country to another.

While renewable energy has grown fast, it provides about 20 percent of the country's electricity. Natural gas and coal account for about 60 percent. In February, a division of the Energy Department projected that the share of electricity produced by all renewable sources, including solar, wind and hydroelectric dams, would reach 42 percent by 2050 based on current trends and policies.

"That kind of quick acceleration of deployment is only going to happen through smart policy decisions," said Abigail Ross Hopper, the president of the Solar Energy Industries Association. "That's the part where having a goal is important, but having clear steps on how to get there is the issue."

One thing going for the administration is that the cost of solar panels has fallen substantially over the last decade, making them the cheapest source of energy in many parts of the country. The use of solar and wind energy has also grown much faster in recent years than most government and independent analysts had predicted.

"One of the things we're hoping that people see and take from this report is that it is affordable to decarbonize the grid," said Becca Jones-Albertus, director of the Solar Energy Technology Office in the Energy Department. "The grid will remain reliable. We just need to build."

The administration is making the case that the United States needs to act quickly because not doing anything to reduce reliance on fossil fuels also has significant costs, particularly from extreme weather linked to climate change. On Tuesday, on a visit to inspect damage from the intense rainfall caused by the remnants of Hurricane Ida in New Jersey and New York, Mr. Biden said, "The nation and the world are in peril."

Some recent natural disasters have been compounded by weaknesses in the energy system. Ida, for example, dealt a huge blow to the electric grid in Louisiana, where hundreds of thousands of people have been without power for days. Last winter, a storm left much of Texas without electricity for days, too. And in California, utility equipment has ignited several large wildfires, killing scores and destroying thousands of homes and businesses.

Mr. Biden wants to use tax credits to encourage the use of solar power systems and batteries at homes, businesses and utilities. The administration also wants local governments to make it quicker to obtain permits and build solar projects — in some places it can take months to put panels on a single-family house, for example. And officials want to offer various incentives to utility companies to encourage solar-energy use.

Jennifer M. Granholm, Mr. Biden's energy secretary, said part of the administration's strategy would focus on its Clean Electricity Payment Program, which would reward utilities for adding renewable energy to the electric grid, including rooftop solar. Many utility companies have fought against rooftop solar panels because they see a threat to their business and would rather build large solar farms that they own and control.

"Both have to happen, and the utilities will be incentivized to take down the barriers," Ms. Granholm said. "We've got to do a series of things."

Building and installing enough solar panels to generate up to 45 percent of the country's power needs will strain manufacturers and the energy industry, increasing demand for materials like aluminum, silicon, steel and glass. The industry will also need to find and train tens of thousands of workers and quickly. Some labor groups have said that in the rush to quickly build solar farms, developers often hire lower-paid nonunion workers rather than the union members Mr. Biden frequently champions.

Challenges like trade disputes could also complicate the push for solar power. China dominates the supply chain for solar panels, and the administration recently began blocking imports connected with the Xinjiang region of China over concerns about the use of forced labor. While many solar companies say they are working to shift away from materials made in Xinjiang, energy experts say the import ban could slow the construction of solar projects throughout the United States in the short term.

Yet, energy analysts said it would be impossible for Mr. Biden to achieve his climate goals without a big increase in the use of solar energy. "No matter how you slice it, you need solar deployments to double or quadruple in the near term," said Michelle Davis, a principal analyst at Wood Mackenzie, an energy research and consulting firm. "Supply chain constraints are certainly on everyone's mind."

Administration officials pointed to changes being made by state and local officials as an example of how the country could begin to move faster toward renewable energy. Regulators in California, for example, are changing the state's building code to require solar and batteries in new buildings.

Another big area of focus for the administration is greater use of batteries to store energy generated by solar panels and wind turbines for use at night or when the wind is not blowing. The cost of batteries has been falling but remains too high for a rapid shift to renewables and electric cars, according to many analysts.

To some solar industry officials, the Energy Department report ought to help to focus people's minds on what is possible even if lawmakers haven't worked out the details.

"In essence the D.O.E. is saying America needs a ton more solar, not less, and we need it today, not tomorrow," said Bernadette Del Chiaro, executive director of the California Solar and Storage Association, which represents solar developers in the state with by far the largest number of solar installations. "That simple call to action should guide every policymaking decision from city councils to legislatures and regulatory agencies across the country."

Excerpt National Grid ESO “Winter Review and Consultation” June 2021 [LINK]

EMN Case Studies / 4th & 5th November 2020

On the 4th and 5th November 2020, demands were forecast to be **43.2GW** and **43.1GW** respectively (much higher than can be seen from the green bars in the *Winter Outlook Report* chart – Figure 1 in this publication - which assume average weather conditions). Wind generation was also forecast to be at lower-than-expected levels.

Unplanned generation outages were slightly higher than expected for the time of year, but well within the range of variability for this time of year.

Although network reconfiguration and circuit rating enhancements could alleviate some of the active constraints on the system, there remained some generation constrained by circuit outages on the Scottish network. The tightness of margin for 4th and 5th November were consistently forecast from 30th October onwards. EMNs were cancelled on both days ahead of each darkness peak as the contingency requirement moved to zero as we approached real-time operation.

Day ahead prices reached **£132/MWh** on 4 November and **£192/MWh** on 5 November, with comparable intraday prices. Analysis of the underlying basic demand used by the demand forecast models shows that there was no detectable price response in the distributed generation market. This could either be because distributed generators were not expecting to be called upon, and generation was not ready to run, or because in recent days all available generation had been running over the peak, and there was no extra pool of generation to draw on.

Settlement Period	CET/CEST Time	Price (£/MWh)
00 - 01	23 - 00	36.92
01 - 02	00 - 01	36.67
02 - 03	01 - 02	36.95
03 - 04	02 - 03	34.20
04 - 05	03 - 04	28.93
05 - 06	04 - 05	30.97
06 - 07	05 - 06	38.08
07 - 08	06 - 07	43.29
08 - 09	07 - 08	46.33
09 - 10	08 - 09	50.54
10 - 11	09 - 10	50.90
11 - 12	10 - 11	41.10
12 - 13	11 - 12	40.70
13 - 14	12 - 13	40.50
14 - 15	13 - 14	40.58
15 - 16	14 - 15	41.36
16 - 17	15 - 16	43.09
17 - 18	16 - 17	56.00
18 - 19	17 - 18	132.00
19 - 20	18 - 19	99.91
20 - 21	19 - 20	63.00
21 - 22	20 - 21	46.60
22 - 23	21 - 22	37.00
23 - 00	22 - 23	32.44

Table 15. Day ahead auction prices on 04/11/20 from the N2EX dataset

Settlement Period	CET/CEST Time	Price (£/MWh)
00 - 01	23 - 00	43.27
01 - 02	00 - 01	36.42
02 - 03	01 - 02	34.00
03 - 04	02 - 03	31.89
04 - 05	03 - 04	28.09
05 - 06	04 - 05	30.79
06 - 07	05 - 06	34.40
07 - 08	06 - 07	40.96
08 - 09	07 - 08	43.44
09 - 10	08 - 09	50.00
10 - 11	09 - 10	50.36
11 - 12	10 - 11	44.00
12 - 13	11 - 12	39.66
13 - 14	12 - 13	42.80
14 - 15	13 - 14	42.99
15 - 16	14 - 15	42.00
16 - 17	15 - 16	49.75
17 - 18	16 - 17	60.00
18 - 19	17 - 18	192.25
19 - 20	18 - 19	150.00
20 - 21	19 - 20	66.20
21 - 22	20 - 21	45.10
22 - 23	21 - 22	44.90
23 - 00	22 - 23	39.60

Table 16. Day ahead auction prices on 05/11/20 from the N2EX dataset

nationalgridESO

EMN Case Study / 6th December 2020

A third EMN was issued for the darkness peak on Sunday 6th December 2020. Historically, it is highly unusual to have tight margins over a weekend. Like the previous two EMNs, higher than expected demand and low wind were drivers but additionally there was lower Balancing Mechanism generation availability too as some power stations continued to take weekend outages. Lower than average temperatures resulted in demand forecasts of **44GW** and wind generation was at extremely low levels.

Unplanned generation outages were at the high end of normal variability for the time of year, but again, within the range of variability we have seen over the past five years.

No generation was constrained on the GB network, there were minimal exports on the Irish interconnectors and continental interconnectors were importing. The tightness of margin was consistently reported from 1st December onwards, with the impact increasing day on day as the wind forecast was consistently revised downwards. The EMN was cancelled ahead of the darkness peak as the situation improved and contingency margin requirement reduced. The demand outturn was in line with forecasts indicating minimal price response from other distribution connected generators and high Balancing Mechanism prices were setting imbalance prices up to **£720/MWh**.

Day ahead prices peaked at **£350/MWh** on 6 December, and intraday prices at **£380/MWh**. Analysis of the underlying basic data showed no evidence of price response from distributed generators, although increased uncertainty in level of Sunday peak demand, coupled with the effects of the recent lifting of the lockdown may have partially masked this. The demand forecast did not factor in any allowance for price response and was 100MW below the outturn. Any under forecast, however slight, does not give any evidence for demand suppression driven by price.

Settlement Period	CET/CEST Time	Price (£/MWh)
00 - 01	23 - 00	44.55
01 - 02	00 - 01	43.05
02 - 03	01 - 02	42.54
03 - 04	02 - 03	39.57
04 - 05	03 - 04	33.00
05 - 06	04 - 05	31.25
06 - 07	05 - 06	31.98
07 - 08	06 - 07	39.53
08 - 09	07 - 08	34.80
09 - 10	08 - 09	41.86
10 - 11	09 - 10	46.27
11 - 12	10 - 11	50.82
12 - 13	11 - 12	51.62
13 - 14	12 - 13	56.92
14 - 15	13 - 14	56.89
15 - 16	14 - 15	60.82
16 - 17	15 - 16	65.00
17 - 18	16 - 17	189.96
18 - 19	17 - 18	350.00
19 - 20	18 - 19	150.49
20 - 21	19 - 20	77.80
21 - 22	20 - 21	53.68
22 - 23	21 - 22	44.73
23 - 00	22 - 23	42.02

Table 17. Day ahead auction prices on 06/12/20 from the N2EX dataset

nationalgridESO

EMN Case Study / 6th January 2021

A fourth EMN was issued for the darkness peak on Wednesday 6th January 2021. Lower than average temperatures (approx. 2°C) resulted in a high demand forecast of **46.4GW** (including **1.5GW** of customer response demand reduction due to an expected triad) and wind generation was at low levels.

Unplanned generation outages were at the high end of normal variability for the time of year, but again, within the range of variability we have seen over the past five years.

No generation was constrained on the GB network, the Irish interconnectors were partially importing, and the continental interconnectors were fully importing. The tightness of margin was consistently reported from 1st January onwards. The EMN was cancelled ahead of the darkness peak as the situation improved and contingency margin requirements reduced. The demand outturn was in line with forecasts which included approx. **1.5GW** of customer response demand reduction. Analysis of the underlying basic data showed approx. **1.6GW** of customer response demand reduction on 6th January which was close to expected as it was a forecast triad.

Day ahead prices peaked at **£1000/MWh** on 6th January. High Balancing Mechanism prices were setting imbalance prices of up to **£1000/MWh**.

Settlement Period	CET/CEST Time	Price (£/MWh)
00 - 01	23 - 00	46.49
01 - 02	00 - 01	46.41
02 - 03	01 - 02	45.99
03 - 04	02 - 03	42.41
04 - 05	03 - 04	41.55
05 - 06	04 - 05	42.59
06 - 07	05 - 06	48.00
07 - 08	06 - 07	55.03
08 - 09	07 - 08	57.63
09 - 10	08 - 09	75.00
10 - 11	09 - 10	96.60
11 - 12	10 - 11	99.30
12 - 13	11 - 12	97.59
13 - 14	12 - 13	128.47
14 - 15	13 - 14	103.88
15 - 16	14 - 15	90.39
16 - 17	15 - 16	75.00
17 - 18	16 - 17	563.04
18 - 19	17 - 18	1000.04
19 - 20	18 - 19	383.28
20 - 21	19 - 20	156.74
21 - 22	20 - 21	80.30
22 - 23	21 - 22	55.06
23 - 00	22 - 23	51.06

Table 18. Day ahead auction prices on 06/01/21 from the N2EX dataset

nationalgridESO

EMN Case Study / 8th January 2021

A fifth EMN was issued for the darkness peak on Friday 8th January. Lower than average temperatures (approx. 2°C) resulted in a high demand forecast of **46.2GW** and wind generation was at very low levels.

Unplanned generation outages were at the high end of normal variability for the time of year, but again, within the range of variability we have seen over the past five years.

No generation was constrained on the GB network, the Irish interconnectors were partially importing, and the continental interconnectors were fully importing. The tightness of margin was consistently reported from 1st January onwards. The EMN was cancelled ahead of the darkness peak as the situation improved and contingency margin requirements reduced. The demand outturn was in line with forecasts. The demand forecast from Energy Forecasting did not factor in any allowance for price response and was approx. 700MW below the outturn.

Day ahead prices peaked at **£670/MWh** on 8th January. High Balancing Mechanism prices were setting imbalance prices of up to **£4000/MWh**.

A CMN was also issued for 8th January 2021 (as well as the one on 3rd December 2020).

Settlement Period	CET/CEST Time	Price (£/MWh)
00 - 01	23 - 00	56.62
01 - 02	00 - 01	55.52
02 - 03	01 - 02	51.59
03 - 04	02 - 03	48.75
04 - 05	03 - 04	46.98
05 - 06	04 - 05	46.94
06 - 07	05 - 06	52.45
07 - 08	06 - 07	58.56
08 - 09	07 - 08	78.17
09 - 10	08 - 09	89.73
10 - 11	09 - 10	92.94
11 - 12	10 - 11	93.85
12 - 13	11 - 12	93.14
13 - 14	12 - 13	89.77
14 - 15	13 - 14	87.49
15 - 16	14 - 15	84.22
16 - 17	15 - 16	81.74
17 - 18	16 - 17	163.30
18 - 19	17 - 18	670.39
19 - 20	18 - 19	167.31
20 - 21	19 - 20	90.73
21 - 22	20 - 21	75.68
22 - 23	21 - 22	62.11
23 - 00	22 - 23	59.44

Table 19. Day ahead auction prices on 08/01/21 from the N2EX dataset

EMN Case Study / 13th January 2021

A sixth EMN was issued for the darkness peak on Wednesday 13th January. Lower than average temperatures resulted in a demand forecast of **45.4GW** and wind generation was at very low levels.

Unplanned generation outages were at the high end of normal variability for the time of year, but again, within the range of variability we have seen over the past five years.

No generation was constrained on the GB network, the Irish and continental interconnectors were fully importing. The tightness of margin was consistently reported from 8th January onwards. The EMN was cancelled ahead of the darkness peak as the situation improved and contingency margin requirements reduced. The demand outturn was in line with forecasts. The demand forecast from Energy Forecasting did not factor in any allowance for price response.

Day ahead prices peaked at **£1,500/MWh** on 13th January. High Balancing Mechanism prices were setting imbalance prices of up to **£990/MWh**.

Settlement Period	CET/CEST Time	Price (£/MWh)
00 - 01	23 - 00	66.51
01 - 02	00 - 01	65.09
02 - 03	01 - 02	61.58
03 - 04	02 - 03	60.59
04 - 05	03 - 04	59.02
05 - 06	04 - 05	58.09
06 - 07	05 - 06	60.50
07 - 08	06 - 07	66.53
08 - 09	07 - 08	66.53
09 - 10	08 - 09	88.65
10 - 11	09 - 10	142.16
11 - 12	10 - 11	167.70
12 - 13	11 - 12	199.93
13 - 14	12 - 13	195.60
14 - 15	13 - 14	167.28
15 - 16	14 - 15	145.59
16 - 17	15 - 16	103.18
17 - 18	16 - 17	411.61
18 - 19	17 - 18	1499.62
19 - 20	18 - 19	694.54
20 - 21	19 - 20	175.19
21 - 22	20 - 21	99.99
22 - 23	21 - 22	60.52
23 - 00	22 - 23	54.98

Table 20. Day ahead auction prices on 13/01/21 from the N2EX dataset

https://www.bhp.com/news/articles/2021/09/bhp-releases-australian-economic-contribution-figures

BHP releases Australian economic contribution figures

08 September 2021

BHP today released its economic contribution figures for the 2021 financial year, with the company contributing $34.1 billion in economic value to the Australian economy.

The figures form part of BHP's global Economic Contribution Report, to be released in mid-September alongside the company's annual and sustainability reports.

The total contribution to Australia comprises $12.4 billion in tax, royalty and other payments to governments, $11.1 billion of spending with suppliers, $6 billion in dividends and interest, $4.5 billion in employee wages, and $100 million in community investment projects.

BHP President Minerals Australia Edgar Basto said: "The past 18 months have thrown unprecedented challenges at all Australians, and we know many in the community are doing it tough."

"It is through the commitment of our people, and the support of governments, communities, suppliers and traditional owners, that we have been able to keep operating safely through the pandemic. We are grateful for their support and the contribution that our continued operation has been able to make to the broader Australian economy during this time," Mr Basto said.

"We are determined to keep playing our part in supporting regional communities and the national economy through jobs, skills, supplier opportunities and social investments."

BHP Chief Financial Officer David Lamont said: "We are proud of the role we play in Australia's economy through our operations and exports, and we know that will be important to the nation's ongoing recovery."

"BHP will continue to invest in Australian regional jobs, businesses and communities, and we hope our ongoing work with METS sector companies and seven-day payment terms for small, local and Indigenous businesses will create further opportunities, particularly in regional areas."

Notes

All figures are in Australian dollars.

BHP is one of the largest taxpayers in Australia. Over the past decade, BHP has paid $80.3 billion in taxes, royalties and other payments to governments in Australia. In the 2021 financial year, BHP's adjusted effective tax rate in Australia was 41.4 per cent including royalties.

BHP announced a range of initiatives in the 2021 financial year to support regional Australian communities and economies in the response to COVID-19 and in the recovery:

- Pledge to create 2500 apprenticeship and traineeship opportunities over five years through $300 million of investment in the BHP FutureFit Academy.
- Commitment to up to $450 million in contracts with Australian METS companies and advancement of the sector over five years.
- The $30 million Future of Work Program in partnership with the Commonwealth Department of Education, Skills and Employment to create new training opportunities for up to 1000 Australians in regional areas.
- Ongoing delivery of the $50 million Vital Resources Fund established early in the pandemic to support local health services, businesses and community groups.
- Implemented seven-day payment terms for all small, local and Indigenous businesses across Australia.

https://global.toyota/en/newsroom/corporate/35971839.html
Sep. 07, 2021

Livestream of Media briefing & Investors briefing on batteries and carbon neutrality

Investors Briefing (22:00-23:00 in JST)

Chief Technology Officer Masahiko Maeda Presentation

Hello, everyone. My name is Masahiko Maeda, and I am the chief technology officer of Toyota Motor Corporation.

Thank you for taking time out of your busy schedules to join us today.

Today, I would like to talk about Toyota's development and supply of batteries toward achieving carbon neutrality.

First, using industrial products as an example, carbon neutrality means reducing CO_2 emissions to zero throughout the entire life cycle of a product, starting from procurement of raw materials, manufacturing, and transportation to use, recycling, and disposal.

As you all know, the world's concentration of CO_2 has been increasing since the Industrial Revolution.

There is no time to lose when it comes to reducing, in all aspects, the amount of CO_2 emitted by humankind.

For example, according to our calculations, the CO_2 reduction effect of three HEVs is almost equal to that of one BEV.

At the moment, because we can provide HEVs at a comparatively affordable price, in places where the use of renewable energy is to become widespread going forward, electrification using HEVs is among the effective ways of reducing CO_2 emissions.

On the other hand, Toyota believes that the increased use of zero-emissions vehicles, or ZEVs, such as BEVs, and fuel cell electric vehicles, or FCEVs, is important in regions where renewable energy is abundant.

Furthermore, in some regions such as South America, bioethanol has been put to practical use as a response to CO_2 reduction.

As mentioned above, we should focus on how to avoid carbon emissions or on how to reduce them to as close to zero as possible.

Because the options for reducing CO_2 emissions depend on the energy situation at hand, Toyota will continue to try various measures to expand the options for achieving carbon neutrality.

With this in mind, Toyota is preparing a full lineup of electrified vehicles.

We want to provide sustainable and practical products that reduce CO_2 emissions while considering the convenience of our customers in each region.

First of all, please allow me to look back on Toyota's electrified vehicle achievements to date.

Since the introduction of the first-generation Prius in 1997, Toyota has also introduced PHEVs, FCEVs, and BEVs, while also improving performance.

Among such, our cumulative sales of HEVs have now reached as many as 18.1 million units.

Earlier, I mentioned that the CO_2 emissions reduction effect of three HEVs is equivalent to the reduction effect of one BEV, and the 18.1 million HEVs sold to date are equivalent to the CO_2 reduction effect of introducing to the market about 5.5 million BEVs.

The volume of batteries for HEVs that we have produced so far is the same as that of the batteries installed on about 260,000 BEVs.

In other words, we can say that the batteries needed for 260,000 BEVs have been used to achieve the CO_2 emissions reduction effect of 5.5 million BEVs.

In the future, in light of changes in the market, we will also accelerate the introduction of BEVs and PHEVs, leveraging the strengths we have gained through our experience so far. And we will strive to reduce CO_2 emissions by increasing the selection of electrified vehicles we offer and having customers in each region choose us so that we can accelerate the dissemination of electrified vehicles.

The three core technologies that support this full lineup of electrified vehicles are electric motors, batteries, and power control units.

Today, in this context, regarding batteries, I would like to share with you Toyota's unique approach and the competitive edge that we have developed via the mass production of electrified vehicles.

While promoting a full lineup of electrified vehicles, we have also been developing and manufacturing a full lineup of batteries.

For HEVs, our focus is on power output, or in other words, instantaneous power, while, when it comes to PHEVs and BEVs, our focus is on capacity or what can be called "endurance".

As batteries for HEVs, we have been continuously evolving nickel-metal hydride batteries and lithium-ion batteries by taking advantage of their respective characteristics.

Our bipolar nickel-metal hydride battery, which was announced this year and is focused on providing instantaneous power, will be used in an increasing number of vehicles.

For lithium-ion batteries for PHEVs and BEVs, we have been striving to improve both cost and endurance, and we will continue to improve them as we move forward.

We are developing a further advanced new type of lithium-ion battery for introduction in the second half of the 2020s.

From here, I would like to explain something that Toyota values in its development of batteries.

What Toyota values the most is to develop batteries that its customers can use with peace of mind.

Especially, we are focusing on safety, long service life, and high-level quality to produce good, low-cost, and high-performance batteries.

For example, longer service life also affects a vehicle's residual value.

In terms of cruising range, high energy density and high-level performance are also necessary.

We want to make the charging speed faster, but too fast will affect safety.

Therefore, we think it is important to strike a balance between each of these factors to ensure safe use.

This concept has remained unchanged since batteries were installed in the first-generation Prius, and it is the same for the batteries in all of our electrified vehicles.

By applying the technology that we have cultivated through our experience in batteries for HEVs also to the batteries for future BEVs, we believe that we will be able to deliver batteries that can be used with peace of mind.

Now, I would like to introduce three examples of the many efforts required to produce batteries that can be used safely, using lithium-ion batteries as the focus of my explanation.

This is an example of ensuring safety.

It is known that each battery cell shows signs of localized abnormal heat generation during spirited driving or other driving that places a large load on the battery.

By analyzing the phenomena occurring inside the battery and conducting a vast amount of model experiments, we have been able to clarify the effect of driving style on the battery, as well as the mechanism of this effect.

Based on the results, we have been able to detect signs of abnormal local heating of cells through multiple monitoring of voltage, current, and temperature of individual cells, blocks of cells, and the entire battery pack.

The battery is then controlled to prevent abnormal heat generation.

We will maintain our concept of ensuring safety, security, and reliability down to the local areas of each battery even when it comes to BEV systems, and we will continue to refine that concept.

The second example I would like to share with you is our commitment to long service life.

We have applied the technologies that we have cultivated through the development of batteries for HEVs to PHEVs, and the batteries in the C-HR BEV have a greatly higher capacity retention rate after 10 years than the batteries hitherto used in our PHEVs.

Furthermore, for the Toyota bZ4X, which is scheduled to be launched soon, we have set a target of 90 percent endurance performance, which is one of the highest in the world, and we are currently finalizing our development efforts to achieve it.

I would like to introduce some examples of the developments that we are working on to achieve long service life.

From a detailed analysis of the inside of lithium-ion batteries, we know that degraded materials on the surface of the anode have a significant impact on the life of a battery.

To suppress the generation of these degraded materials, we are clarifying the generation mechanism and taking measures in various aspects such as material selection, pack structure, and control system.

Careful implementation of detailed analysis and an accumulation of countermeasures has led to improved endurance performance.

The third example I would like to share with you has to do with our efforts for achieving high-level quality.

If metallic foreign matter enters the battery during the manufacturing process and directly connects the anode and cathode electrically, there is the possibility of failure.

We confirmed the shape, material, and size of foreign matter that enters the manufacturing process and its effect on endurance, and we clarified how such affects batteries.

Based on this, we are being extremely attentive to the size and shape of foreign matter, and we are managing processes in a way that is aimed at preventing the generation or entry of relevant foreign matter.

What I have explained just now are only a few of the things that we are doing, but with this kind of steady and meticulous analysis and with the experience gained from the feedback of 18.1 million units in the market, we aim to continue to deliver batteries that can be used with peace of mind.

Next, I would like to explain the bipolar nickel-metal hydride battery used in the new Aqua announced in July this year.

We co-developed this battery with Toyota Industries Corporation, taking on the challenge of developing a bipolar structure, and we commercialized it as an onboard battery for driving.

Compared to the batteries used in the previous generation of the Aqua, the output density has been doubled, giving the car a powerful acceleration sensation.

As for batteries for next-generation BEVs, the BEV technologies that we have cultivated since our RAV4 EV launched in 1996 and the latest battery and electrified vehicle technologies that we have cultivated through HEVs have been incorporated into the TOYOTA bZ4X and will soon be introduced to the market.

From now, I would like to explain about the batteries of the future.

To popularize BEVs, we would like to reduce costs and provide BEVs at a reasonable price.

To start with, we aim to reduce the costs of batteries themselves by 30 percent or more by developing materials and structures.

Then, for the vehicle, we aim to improve power consumption, which is an indicator of the amount of electricity used per kilometer, by 30 percent, starting with the Toyota bZ4X.

Improved power efficiency leads to reduced battery capacity, which will result in a cost reduction of 30 percent.

Through this integrated development of vehicles and batteries, we aim to reduce the battery cost per vehicle by 50 percent compared to the Toyota bZ4X in the second half of the 2020s.

Please allow me to explain the coming next-generation batteries.

For liquid batteries, we will take on the challenge of material evolution and structural innovation.

We will also aim to commercialize all-solid-state batteries.

As stated, we will develop three types of batteries, and by the second half of the 2020s, we hope to improve the characteristics of each type so that we can provide batteries that can be used with peace of mind.

Next, I would like to explain our initiatives related to all-solid-state batteries.

We are developing all-solid-state batteries to see if we can bring out the joy in such things as high output, long cruising range, and shorter charging times.

In June last year, we built a vehicle equipped with all-solid-state batteries, conducted test runs on a test course, and obtained driving data.

Based on that data, we continued to make improvements, and in August last year, we obtained license plate registration for vehicles equipped with all-solid-state batteries and conducted test drives.

There are some things that we have learned during the development process.

All-solid-state batteries are expected to have higher output because of the fast movement of ions within them.

Therefore, we would like to take advantage of the favorable properties of all-solid-state batteries by also using them in HEVs.

On the other hand, we found that short service life was an issue.

To solve this and other issues, we need to continue development, mainly of solid electrolyte materials.

We feel that having identified an issue has brought us one step closer to commercialization.

The establishment of a battery supply system is also important for the dissemination of BEVs.

With the rapid expansion of electrified vehicles, we are working to build a flexible system that can stably supply the required volume of batteries at the required timing while meeting the needs of various customers in each region around the world.

In pursuit of our battery development concept of achieving batteries that can be used with peace of mind, we will establish the needed technologies by conducting a certain amount of in-house production, and we will cooperate and collaborate with partners who understand and will put into practice our concept. We will also proceed with discussions with new partners in some regions.

We are building a system with our partners that will allow us to incorporate into discussed plans the volume of batteries that we will need in about three years.

Within the Toyota Group, we are also working to shorten the lead time for the start-up of production and to establish a system that is adaptable to change.

This summarizes our development and supply of batteries by 2030.

In development, we will aim to achieve a per-vehicle cost of 50 percent or less compared to now through the integrated development of vehicles and batteries.

In terms of supply, we will respond flexibly to the changing needs of our customers.

For example, we are assuming that we will go beyond the 180 GWh worth of batteries that we are currently considering and will ready 200 GWh worth of batteries or more if the dissemination of BEVs is faster than expected.

The amount of investment in the development of a battery supply system and research and development, as I have just explained, is expected to be approximately 1.5 trillion yen by 2030.

By establishing a system for both development and supply, we will promote the dissemination of electrified vehicles, including BEVs.

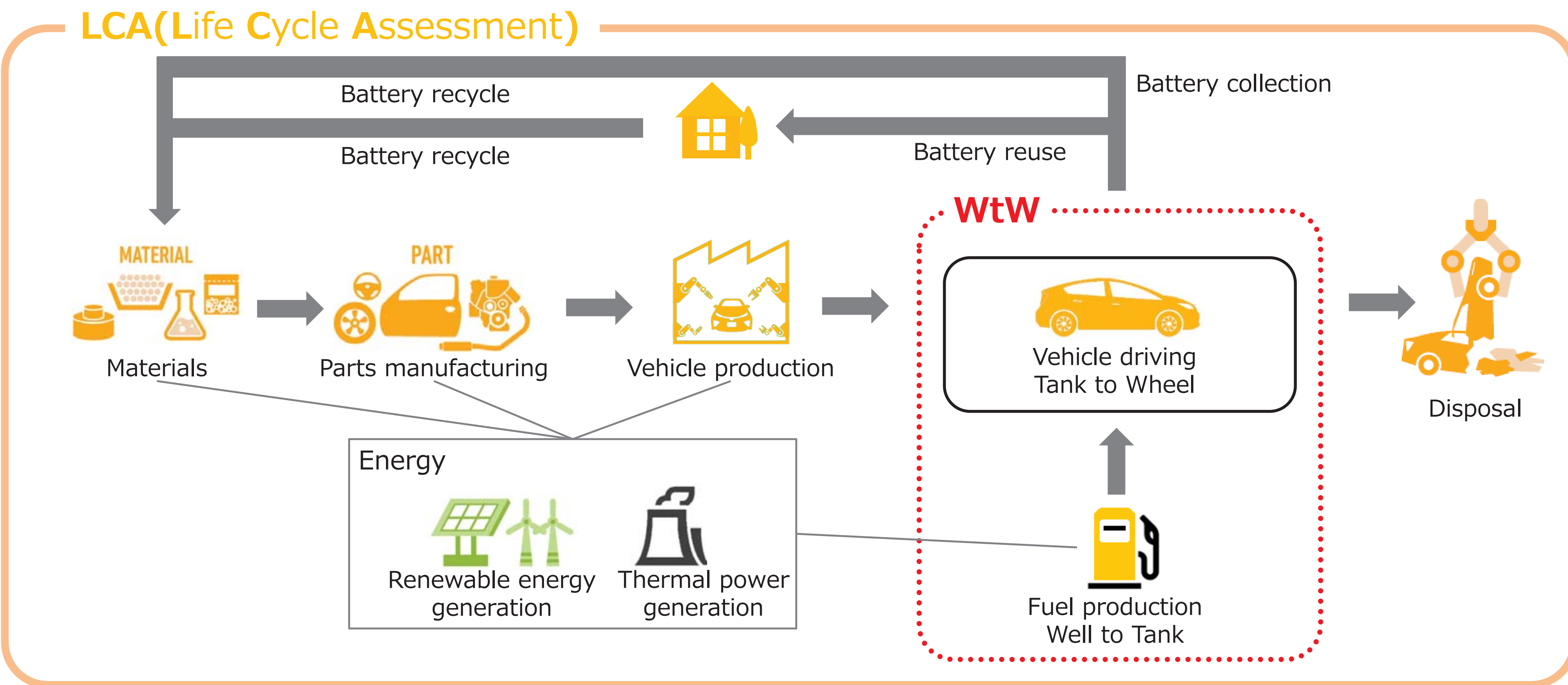
On the way to our goal of achieving carbon neutrality in 2050, the energy situation and infrastructure of each region, as well as the sensibilities and convenience requirements of customers, will continue to change.

When it comes to electrified vehicles, cars and batteries cannot be separated. Toyota, which has been committed to producing batteries within the Toyota Group since 1997 and whose market-introduced HEVs, alone, number 18.1 million units, is an automaker that has been working on battery development as a corporate group, and, into the uncertain future of electrified vehicles as well, it intends to move forward in sure-footed steps.

To adapt to the future sustainably and practically, Toyota would like to contribute to the achievement of carbon neutrality by improving its adaptability to change and its competitiveness, as well as by aiming for the fundamental widespread acceptance of ever-better electrified vehicles.

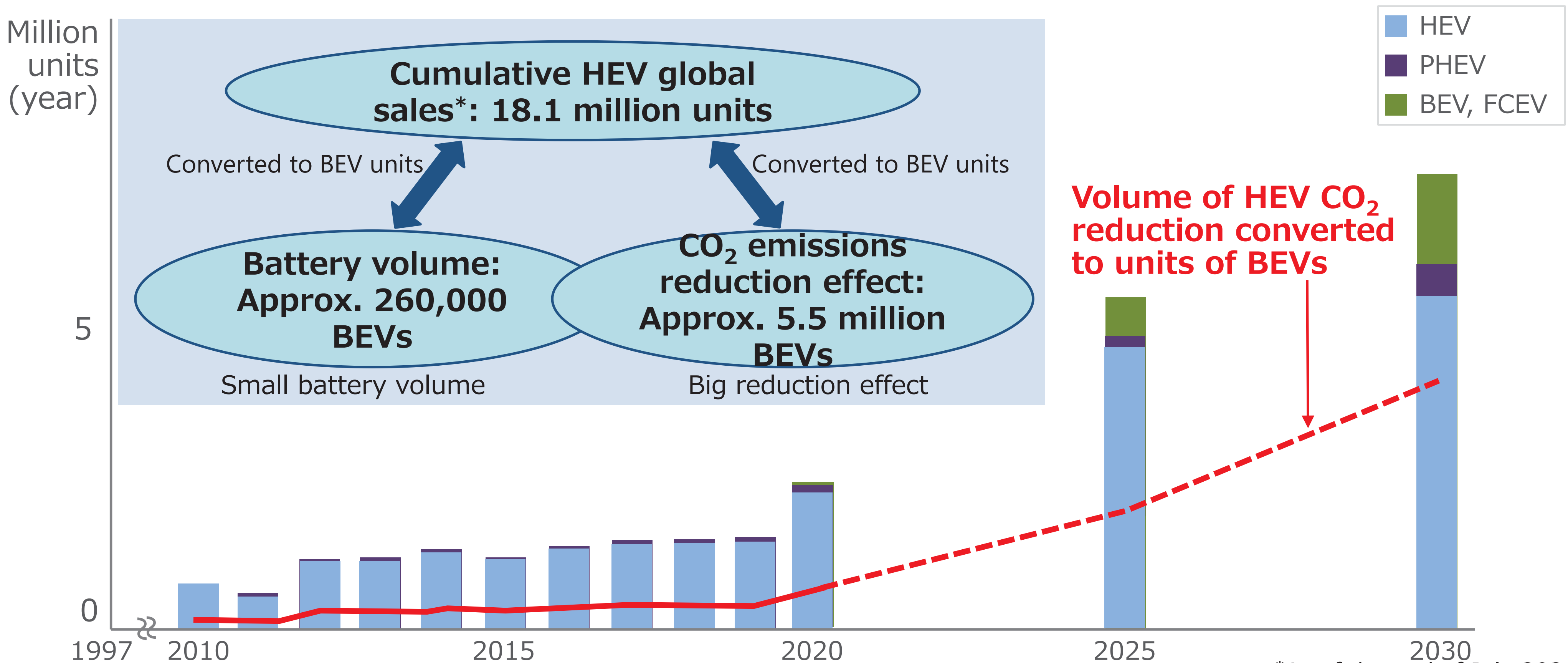
Thank you very much for your attention.

The meaning of carbon neutrality



Carbon neutrality means zero life cycle CO_2 emissions

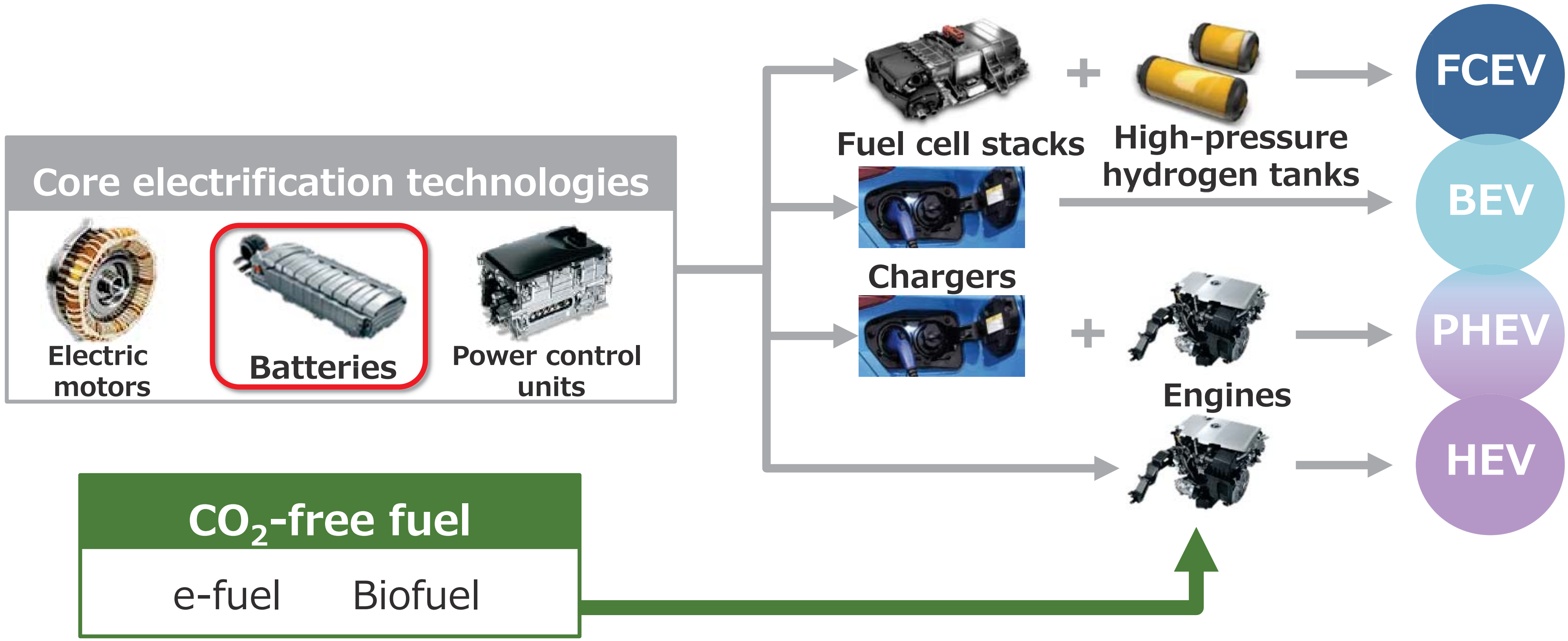
Path toward carbon neutrality: Electrified vehicle global sales



*As of the end of July 2021

- Dissemination of HEVs has efficiently reduced CO_2 emissions with a small volume of batteries.
- Advancing BEV & PHEV technologies for further dissemination

Technologies supporting full lineup of electrified vehicles



Battery development concept

Common to all batteries for HEVs, PHEVs, BEVs, and FCEVs

Security

Safety

Long service life

High level of quality

Aiming to create safe batteries that can be used with peace of mind always and for their entire lifetime, have high resale value, and contribute to the building of a resource-recycling society

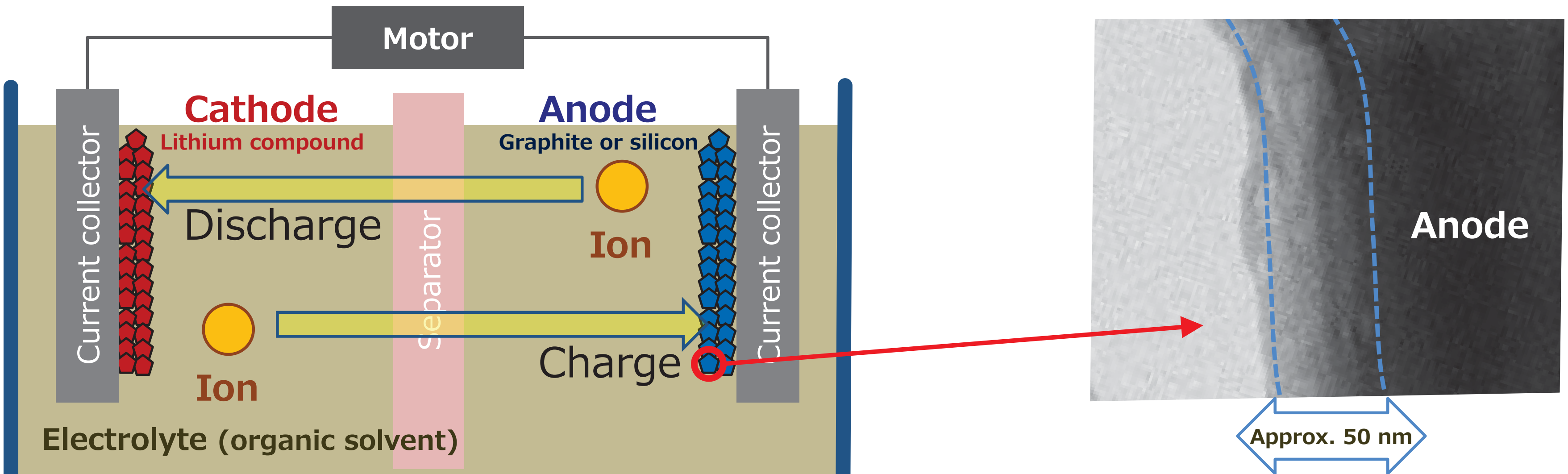
Affordable, high-quality products

High-level performance

Giving electrified vehicles meaning through dissemination
Increasing customer choice

Highly balancing 5 elements to provide reliable batteries

Long service life: Applying HEV-honed technologies to BEVs



Degraded materials containing lithium

Inhibiting formation of degraded materials on anode surfaces

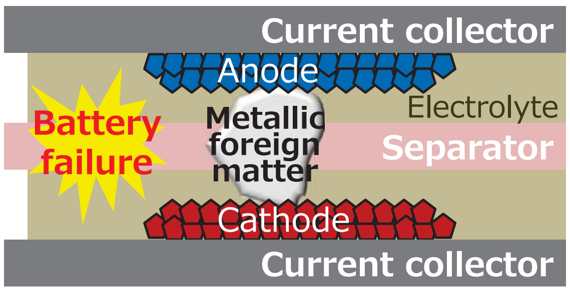
- Appropriate anode surface treatment to prevent degradation
- Design and production technology that prevents moisture contained in battery materials from being introduced into the battery
- Adoption of structure that ensures uniform cooling of battery
- Construction of control system that prevents load from being applied to the entire battery

One key to extending battery life

Suppress degradation in battery materials, pack structure, control systems, etc.

High-level quality: Control of metallic foreign matter

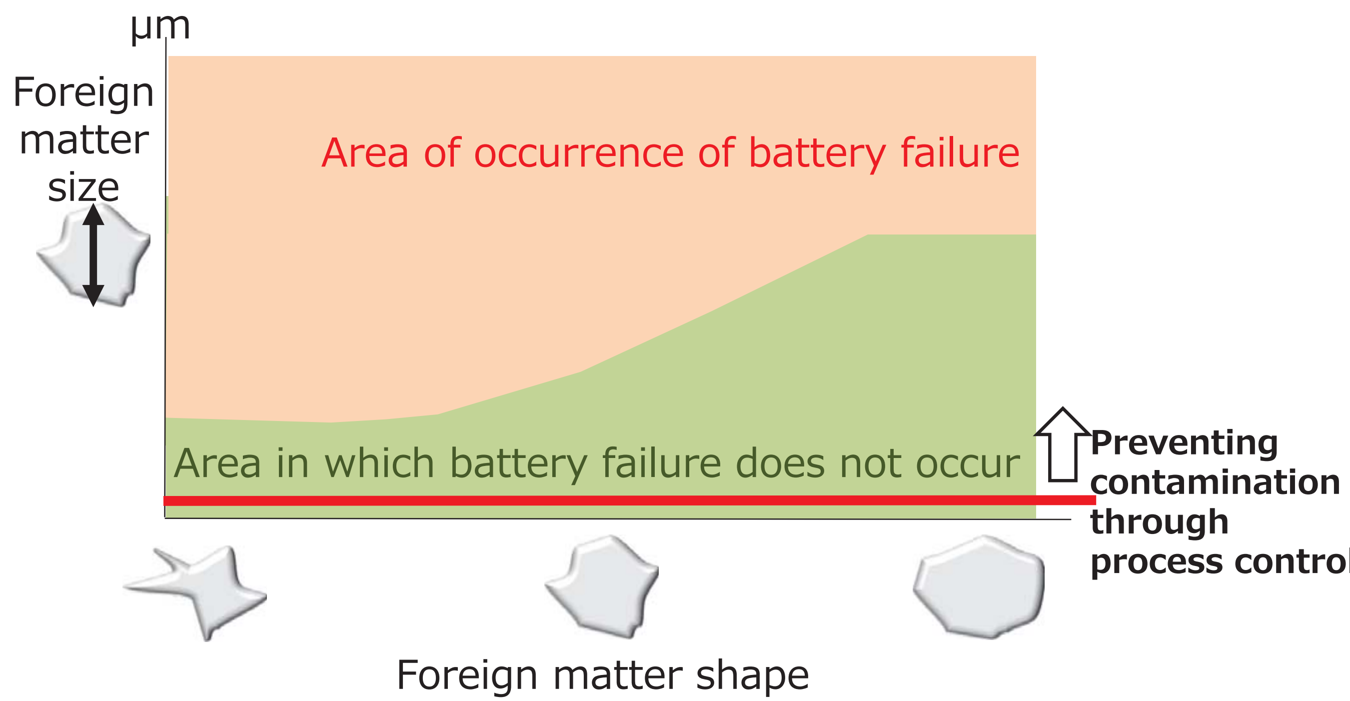
Effect on batteries of metallic foreign matter



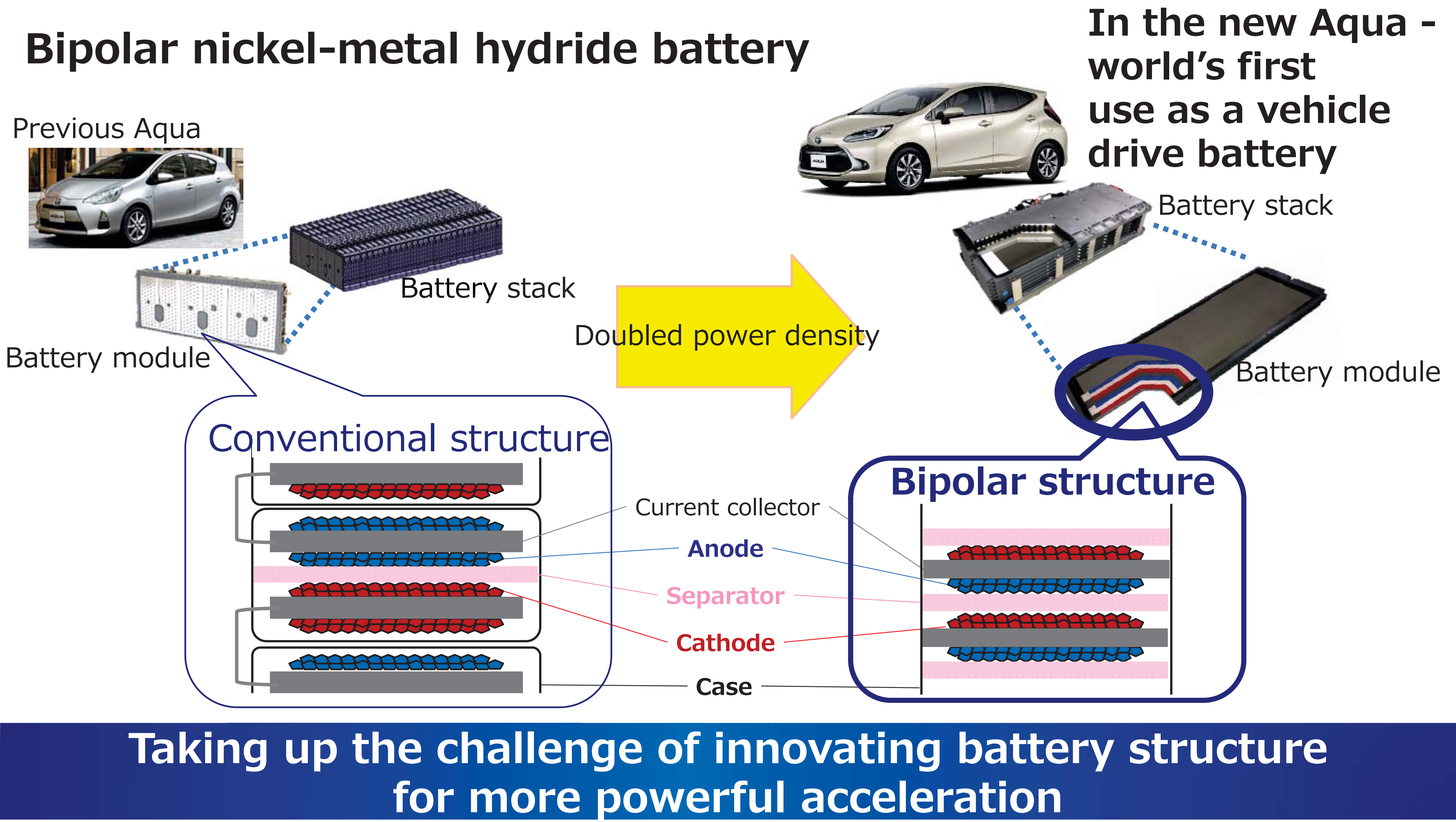
Battery failure due to contact between the anode and cathode

The need to control foreign matter

Effect of size and shape of metallic foreign matter on occurrence of abnormalities



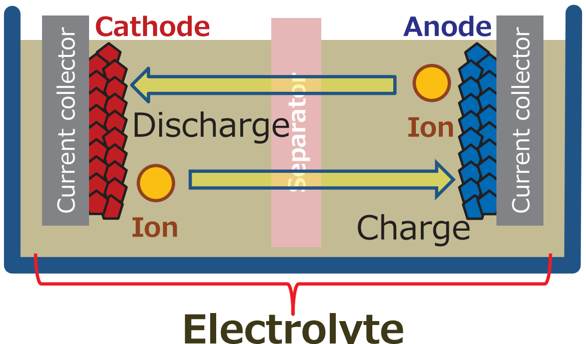
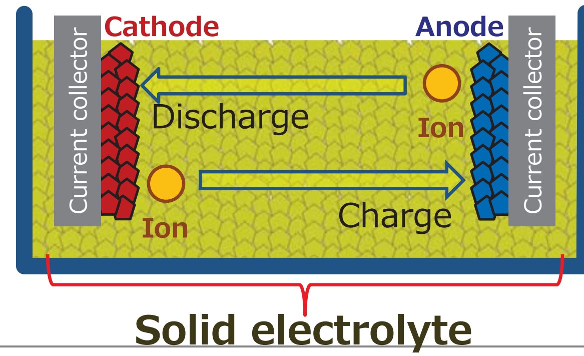
Determining the size and shape of foreign matter that can cause battery abnormalities and controlling the effect of foreign matter


Bipolar nickel-metal hydride battery
Previous Aqua
Battery stack
Battery module
Doubled power density
In the new Aqua - world's first use as a vehicle drive battery
Battery stack
Battery module
Conventional structure
Current collector
Anode
Separator
Cathode
Case
Bipolar structure
Taking up the challenge of innovating battery structure for more powerful acceleration

Next-generation lithium-ion battery

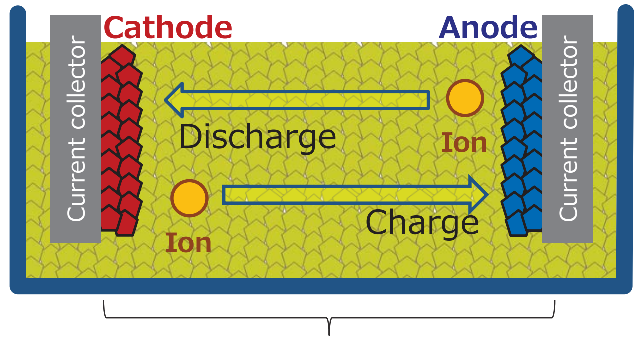
【Aims】

Longer service life	Greater energy density	More compact size	Lower cost

	Evolution in liquid-based battery materials	Innovation in liquid battery structure	All-solid-state batteries
Composition			
Structure	 Prismatic	New structure	 Laminated

Taking on the challenge of developing a wide range of batteries for the second half of the 2020s
Providing BEVs equipped with batteries with improved characteristics that enable driving with peace of mind

Characteristics of all-solid-state batteries



Solid electrolyte

Simple ion movement (fast)

High voltage tolerance

High temperature tolerance

High output

Long cruising range

Shorter charging time

https://www.cnn.com/travel/article/nick-diane-marson-come-from-away-chance-encounters/index.html

CHANCE ENCOUNTERS

The strangers who fell in love when 9/11 diverted their flight

Francesca Street, CNN • Published 8th September 2021

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1/12

Nick and Diane: 20 years ago, Nick Marson and Diane Kirschke were strangers who fell in love when their flight from London to Texas was diverted to Newfoundland, Canada during 9/11. Here they are in Newfoundland on a return trip in 2002.

Courtesy Nick and Diane Marson

(CNN) — Twenty years ago, Nick Marson and Diane Kirschke were strangers on board Continental Airlines flight 5 traveling from London Gatwick to Houston, Texas.

Four hours or so into the flight, the pilot came over the intercom and announced the airplane would be diverting to Newfoundland, Canada.

"There are problems in US airspace," the captain said, giving no further details.

Nick was a British businessman in his 50s who worked in the oil industry. He was heading to Texas for work, and had no idea where Newfoundland was.

"I looked out the window because I thought he might not be telling us the truth, and maybe an engine was on fire," Nick tells CNN Travel today.

At the other end of the aircraft, Diane took in the news. An American divorcee who'd just turned 60, she was returning from visiting her son, who was in the US Air Force and stationed in England.

"I thought, 'Canada, I've never been to Canada. That sounds like an adventure," Diane recalls today.

It was September 11, 2001. Following the terrorist attacks in New York and Washington, the US airspace closed and, under an effort dubbed Operation Yellow Ribbon, more than two hundred commercial aircraft heading to the US diverted to Canada.

Nick and Diane's flight rerouted to Gander -- a rural town with a population of just 10,000, home to an airport whose history as a refueling spot for pre-jet engine aircraft left it with runways to rival far bigger cities.

As Continental 5 approached Newfoundland, Nick saw dozens of planes lined up in rows. He abandoned his suspicion that there was a technical issue.

"We were the 36th plane out of 38 to land -- so clearly not everybody had a problem with their plane," says Nick.

When Continental 5 landed, the captain told passengers there had been terrorist activity in the US and airplanes had flown into the World Trade Center and the Pentagon.

"Even though that sounded horrific, nobody realized how devastating it was until sometime later," says Nick.

In 2001, no one could read the news on their cell phone. No one had Internet on their cell phones. No one had international coverage. Many people didn't have cell phones at all.

Diane recalls being extremely worried about her family in the United States, and fretting that she couldn't reassure them of her own safety.

This state of uncertainty continued for more than 24 hours.

While the airplanes were stuck on the runways, volunteers across Gander and its neighboring towns delivered food and supplies to the jets, and prepared makeshift shelters in schools, colleges and community centers around the region.

Some 7,000 people were about to descend on their community, almost doubling Gander's population.

When the displaced travelers were finally permitted to deplane it was September 12. One aircraft at a time, no luggage allowed, the passengers disembarked.

Nick took this photo of the passengers finally disembarking Continental 5 in Gander, Canada.

Courtesy Nick and Diane Marson

Related content

How 9/11 changed travel forever

When they got through security, they were greeted with smiles and reassurance.

"They were so friendly and open," says Diane of the Gander volunteers. "They just welcomed us. They didn't care who you were, where you came from, how much money was in your wallet, what kind of job you did -- we just needed help, and they were going to take care of us."

Nick was taken to a small shelter in Gambo, about 30 miles outside of Gander. The Society of United Fisherman was the biggest structure in the town, usually reserved for weddings, bingo or town meetings.

Several hours later -- after a detour to a Gander shelter that was full -- Diane ended up there too.

It was at the shelters that the "plane people" -- as the Newfoundlanders called the incomers -- finally saw the horrifying TV footage that had reverberated around the world, and learned the true extent of what had occurred on September 11.

Volunteers had set up phones, and Diane contacted her family to let them know she was safe, and also learned they were all OK.

The "plane people" lined up to collect blankets and supplies. As Diane was handed hers, she commented to herself that it smelled of mothballs.

"Camphor," said a voice behind her.

It was Nick. The two started chatting, first finding humor in the distinctly scented blankets, and then realizing they'd been on the same airplane heading to Texas.

In this unknown -- albeit very friendly -- place, this coincidence seemed like something to hold on to.

"I asked Diane if I could take the cot next to hers. and she said, 'Sure, why not,'" recalls Nick.

Related content

Gander: This Canadian airport sheltered 7,000 people on 9/11

Honorary Newfoundlanders

The next morning, Nick and Diane went out for some fresh air. They needed a break from constantly watching the news.

"It was just too much to sit there and watch those horrible scenes over and over," says Diane.

They were joined at first by another couple, who then fell back. Soon it was just Nick and Diane.

"We're chatting away, and trying to pass the time, enjoying each other's company," recalls Nick.

En route, they stopped at a convenience store to pick up some sodas and trail mix. Nick tried to pay, but Diane beat him to it.

"Well, I had an ulterior motive," says Diane, laughing. She was enjoying Nick's company -- and she figured her paying for their morsels would ensure Nick stuck around.

She thought he was interesting, she recalls, and a real gentleman.

As for Nick, he thought Diane was good-looking and was really enjoying chatting with her.

They had lots to talk about -- both divorced, with adult children, and close to their families. There were cultural differences, but they had shared values.

When they returned to the shelter, they found the cots had been temporarily cleared away and evening entertainment was underway.

The Newfoundland volunteers were initiating the "plane people" into a local tradition known as a Screech-In -- a way of designating visitors "honorary Newfoundlanders."

There are several steps to the process, including drinking a shot of screech and kissing a cod fish.

Screech, explains Nick, tastes like "bad Jamaican rum."

Nick and Diane at the Screech-In ceremony.

Courtesy Nick and Diane Marson

Nick bought Diane a beer and they embraced the ceremony -- kissing the cod and all.

When it was Diane's turn, the master of ceremonies asked her where she was from. She explained she lived in Texas.

The MC then moved on to Nick.

"What part of Texas you from, buddy?" he asked.

"Oh no, I'm from England," explained Nick.

"Well, how does it work?" asked the MC.

Nick was confused.

"How does your marriage work?" clarified the MC, gesturing to Diane.

Nick and Diane explained they weren't married -- it turned out everyone else had figured they were.

The MC, amused, said he was a justice of the peace. "Do you want to be married?" he asked Nick and Diane.

Diane laughed. "Why not?" she said, slightly giddy from the alcohol.

Reflecting on this moment today, Diane says she felt a freedom in being in a place where no one knew her.

"You didn't have to play your usual role," she says. "I wasn't my kid's mom or my grandchildren's grandmother. I wasn't the lady next door. Nobody there knew me. I could be silly if I wanted to."

And for the rest of the evening, Diane's answer kept running through Nick's mind.

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[How a Pan Am flight attendant fell in love with a CIA officer on an airplane]

Where continents collide

Nick took this photo of Diane at a beautiful lookout, Dover Fault.

Courtesy Nick and Diane Marson

The next day, some of the locals took the now-honorary-Newfoundlanders on an outing to a spectacular local lookout, the Dover Fault.

"It's a beautiful outlook, about 200 foot above where the river and the ocean come together," says Diane.

The site was formed when two continents collided millions of years ago, and later separated.

Nick had an early digital camera with him. He'd already snapped a photo of the moment the Continental 5 passengers had disembarked, as well as shots of the shelter with its makeshift beds.

But there was only one picture he really wanted from his detour to Newfoundland -- a photo of Diane.

"I needed a picture to remind me that I hadn't dreamed all this up, these magical days, they actually really happened," he says now.

His camera didn't have a zoom function, so he had to get pretty close to get her in the shot.

"I offered to get out of the way, because I thought he wanted a picture of this beautiful scenic spot," recalls Diane.

"I had no interest in the scenic view," says Nick.

He told her not to move, and that the view he had was perfect.

"I knew then that it was he was interested in me and not the scenery," says Diane. "So that sort of changed the dynamics a little bit."

As they stood admiring the vista, both Diane and Nick considered the unlikeliness of their meeting.

"I had a very settled life," says Diane. "I had a nice little apartment. I had a job that I enjoyed and co-workers and friends."

"Neither one of us got on that plane looking for a romantic encounter," says Nick.

Related content

Girl meets girl at band camp. They fall in love

Saying goodbye

Five days after the planes had landed in Gander, the call came that aircraft were permitted to leave.

Buses rounded up the passengers who'd been scattered across the local towns. One by one, the planes departed.

"We boarded the school bus, and it was raining," recalls Diane. "I was a bit upset because we were leaving these wonderful people -- and I'd gotten to know them and their children, and they'd been so sweet to us -- and I knew I'd never see them again. And I probably wasn't ever going to see Nick again either. So I was very teary."

Nick, sat next to Diane, realized she was welling up. He put his arm around her, and went to kiss on her forehead as a comforting gesture.

"I thought this is my chance," recalls Diane. "So I just grabbed him and gave him a nice big kiss."

On their flight to Texas, Nick and Diane sat next to one another. Nick says they were "canoodling" the whole journey.

Midway through the flight, a flight attendant walked down the aisle, offering hot towels to passengers. When she approached Nick and Diane, she raised an eyebrow.

"Cold towel?" she asked.

Nick stayed in Houston for a few days, checking in with work there. In the evenings, Diane took him out for meals at her favorite restaurants, and before Nick left they exchanged email addresses and telephone numbers.

Then he had to leave.

"It was very difficult flying back to England on my own. That was a real emotional low," says Nick.

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They got a second chance at love in the middle of the Atlantic Ocean

New beginning

Back in their respective home countries, Nick and Diane struggled to come to terms with the fact that they'd fallen for someone in the context of such devastating events.

They kept in regular contact, writing long emails about how they were feeling, and about their lives on opposite sides of the Atlantic.

In October 2001, Nick convinced his office that he had to return to Houston to check on a work project.

"I needed to make sure that Diane was really the person that I remembered, and I hadn't kind of embroidered her a little bit in my mind," he says.

She was -- and the visit clarified in both their minds that they wanted to be together.

A month later, in early November 2001, Nick called Diane from his car.

"I told her I was on my knee," he says.

He proposed.

Overjoyed, Diane said yes.

"We felt that this was destined to be," she says today. "Who could go against fate?"

The two started planning their future together. Diane sold her one bedroom apartment and bought a larger house, and that December, Nick persuaded the company he worked for in England to transfer him to Houston.

In March 2002, Diane introduced Nick to her family for the first time. Diane says they quickly fell for him too -- they say all their loved ones were surprised, but supportive.

After several months of navigating the red tape involved in marrying someone from another country, in September 2002 -- almost exactly a year after they'd met -- Nick and Diane were married at their home in Houston. She took his name, and they became Nick and Diane Marson.

Nick and Diane at the surprise wedding reception thrown for them in Gambo, Newfoundland, in 2002.

Courtesy Nick and Diane Marson

When it came to planning their honeymoon, there was no question about it -- the Marsons were returning to Newfoundland.

The couple were excited to see beautiful sites like the Dover Fault again, but Nick and Diane also wanted to host a small get together to thank the Newfoundlanders for their hospitality the year before. They'd stayed in touch with many of the people they'd met, and felt they owed them so much.

"They could have left us on the plane. They could have even left us in the hangar," says Nick.

"They took us to their hearts and homes," says Diane.

But Nick and Diane underestimated -- once again -- the extent of the Newfoundlanders hospitality.

"We turn up and there's a full blown wedding reception," recalls Nick.

"Complete with a multi-layer wedding cake, gifts, candlelight, the head table had champagne..." adds Diane.

The Mayor of Gambo had even written the two a song. He performed it there and then, singing about how Nick and Diane had met in Newfoundland, fell in love and got married.

Related content

Two strangers, a canceled flight and an unexpected road trip

Sharing their story

During their return trip to Newfoundland in 2002, word spread that two of the "plane people" had fallen in love.

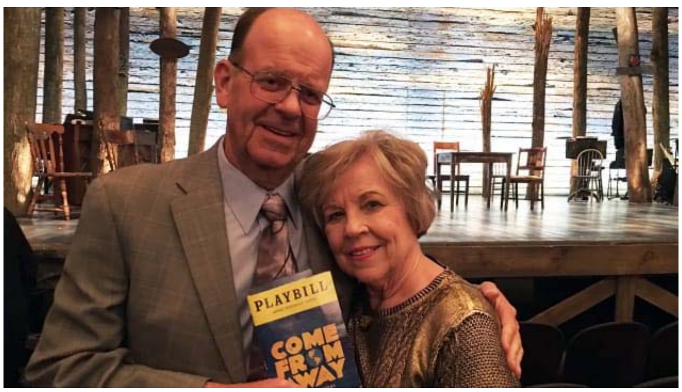
A few media outlets reached out to Nick and Diane, but the couple had no wish to share their story at that stage.

"We were suffering from what's called survivor's guilt," says Nick. "We didn't feel comfortable with what we'd found in the wake of so many disasters."

"Three thousand families had lost someone," says Diane. "And here we'd found happiness."

It wasn't until 2009 that they shared their story, as part of Canadian newscaster Tom Brokaw's documentary about Operation Yellow Ribbon.

A couple years later, on the 10th anniversary of 9/11, Nick and Diane were visiting Gander, and were approached by Irene Sankoff and David Hein, composer-lyricists who explained they'd received a grant from the Canadian government to produce a show about what happened in Newfoundland in the wake of September 11.



Nick and Diane's story is one of the threads in the musical "Come From Away."

Courtesy Nick and Diane Marson

That's how Nick and Diane's story became one of several tales woven into the Tony and Olivier award-winning musical "Come From Away," in which a cast of 12 play several roles, from the Gander residents to the "plane people."

The first time the couple saw the show in Canada in 2013, it was an emotional experience. They couldn't believe how accurately the musical told their story, and how well it evoked the atmosphere in Newfoundland that week.

"It's just a testimony to the generosity, the friendship and the openness of the Newfoundland people," says Diane. "It's a 9/12 story. It's the aftermath of what happened on 9/11. But on 9/12, love reigned."

Since its premier, "Come From Away" has been heralded around the world and now a filmed version of the award-winning show is set to premiere internationally on Apple TV+ on September 10, 2021.

"We've seen the show 118 times," says Nick. "Diane will say it's like we're renewing our vows every time we see it."

"Make the most of every day"

Nick and Diane in August 2021.

Courtesy Nick and Diane Marson

As the world reflects on the 20 years since 9/11, it's also two decades since Nick and Diane first met, and 19 years since their wedding day.

Over the past two decades -- in between watching their love story resonate in theaters across the globe -- the couple have navigated the humorous situations that sometimes arise from their cultural differences, and supported one another through the highs and lows of life.

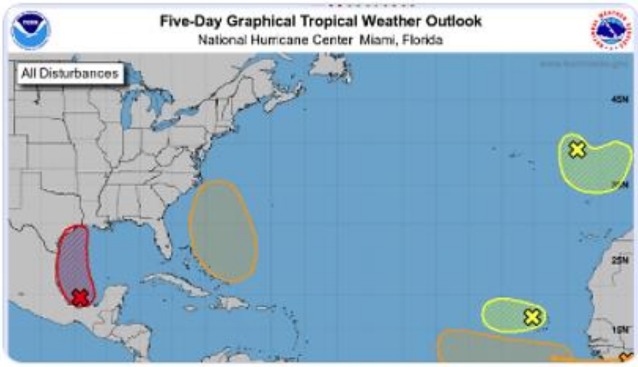
"Even though we had differences of culture and friends, and everything else, there was a kernel of love there -- we knew that we were each looking out for each other," says Diane of their years together so far. "There was a lot of trust between us."

During their five days stranded in Newfoundland, Nick and Diane were forced to live for the day -- it was that mindset led them together and it's a mantra they've stuck with in the years since.

"Make the most of every day, make the most of it," says Diane. "Because who knows how many days anyone has."

Dan Tsubouchi @Energy_Tidbits · 3h

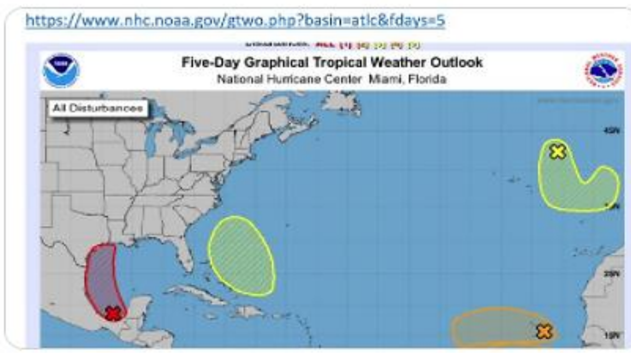
Still 90% chance of disturbance reaching cyclone status in next 48 hrs. @NHC_Atlantic path projection is unchanged, thru deepwater GoM #Oil #NatGas production and then to major Gulf Coast refineries & #LNG export facilities. #OOTT nhc.noaa.gov/gtwo.php?basin...



2

Dan Tsubouchi @Energy_Tidbits · 14h

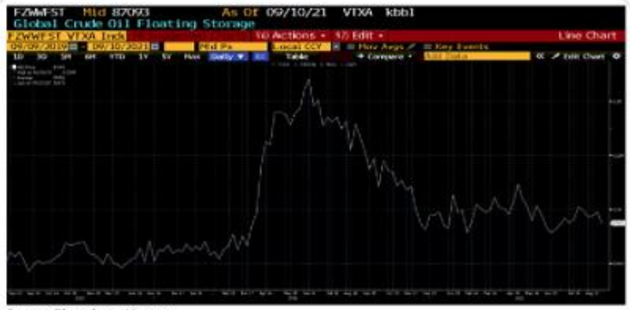
90% chance of disturbance reaching cyclone status in next 48 hrs. @NHC_Atlantic current path projection is thru deepwater GoM #Oil #NatGas production and then to major Gulf Coast refineries & #LNG export. #OOTT
nhc.noaa.gov/gtwo.php?basin...



2 5

Dan Tsubouchi @Energy_Tidbits · 20h

Vortexa floating crude #Oil storage -10.53 mmb WoW to 87.09 mmb at 09/10, vs 97.63 mmb 09/03. 09/07 is still +8.92 mmb vs recent 06/25 trough 78.17 mmb, & +37.85 mmb vs pre-Covid 49.24 mmb 09/19. But -133.41 vs 06/26 peak 220.50 mmb. Thx @Vortexa @TheTerminal #OOTT



Source: Bloomberg, Vortexa

3 4

Dan Tsubouchi @Energy_Tidbits · 21h

Best day for shut-in GoM #NatGas to come back since #HurricaneIda. 12 days since max shut-in, but still shut-in #Oil is 1.12 mmb/d (61.6% of GoM) and 1.35 bcf/d #NatGas (60.67% of GoM). #OOTT

bsee.gov/newsroom/lates...

Date	Total	% of GOM	Total	% of GOM	Total	% of GOM	Total	% of GOM
2021-08-27	89	15.89%	1	9.09%	1,064,849	58.51%	1,088.0	48.79%
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2021-09-08	73	13.04%	4	36.36%	1,399,186	76.88%	1,722.7	77.25%
2021-09-09	71	12.68%	4	36.36%	1,391,865	76.48%	1,722.7	77.25%
2021-09-10	65	11.61%	3	27.27%	1,207,783	66.36%	1,684.7	75.55%
2021-09-11	62	11.07%	2	18.18%	1,121,169	61.60%	1,353.0	60.67%

Note: 09-01 was corrected, originally reported 249 platforms, 1,455,279 b/d, 1.8772 bcf/d shut in

Source BSEE

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

3

Dan Tsubouchi @Energy_Tidbits · Sep 11 ···

So much in great read $LBRT ESG 2020 ie. simply not possible to discuss environmental & social impacts of #Oil #NatGas without considering the environmental & human impacts of the absence of O&G. Thx @Josh_Young $LBRT Anjali Voria. #OOTT #EnergyTransition
libertyfrac.com/wp-content/upl...

Josh Young @Josh_Young_1 · Sep 7

Important reminder of why the oil and gas industry matters and the critical humanitarian problem it addresses. From $LBRT presentation today at the ATB conference @atbfinancial #liberty #humanitarian #ClimateCrisis #oott #natgas #lpg #lng

5 11

Dan Tsubouchi @Energy_Tidbits · Sep 10 ···

"Europe isn't doing enough to prepare for a potential gas crunch this winter" @business @econ1st reporting on comments by new US State Dept energy security advisor @amoshochstein. Did he forget US sanctions was key to keep 5.3 bcfd #NordStream2 from starting up? #NatGas

"I worry because I don't think we should ever be in a position knowing that if it's a cold winter, there's not enough supply," he told reporters during a visit to Warsaw. Everyone "has to be prepared and to think about this more than I'm seeing currently in Europe."

Hochstein said he's concerned because gas storage in Europe is below the five-year average, which has led to record prices in some markets, and that Russia -- a major source of the continent's energy -- "is coming off an extended period of inexplicably low supply."

--With assistance from Maciej Martewicz.

1 3 10

Dan Tsubouchi @Energy_Tidbits · Sep 10

Best day so far for return of shutiin GoM oil, +184,000 b/d vs Thurs, but still shut-in from #HurricaneIda is 1.21 mmb/d #Oil & 1.68 bcf/d #NatGas. More oil back should reflect more deepwater vs shallow water gas. #OOTT bsee.gov/newsroom/lates...

BSEE Gulf of Mexico O&G Activites - Hurriance Ida Response

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Note: 09-01 was corrected, originally reported 249 platforms, 1,465,279 b/d, 1.8772 bcf/d shut in

Source BSEE

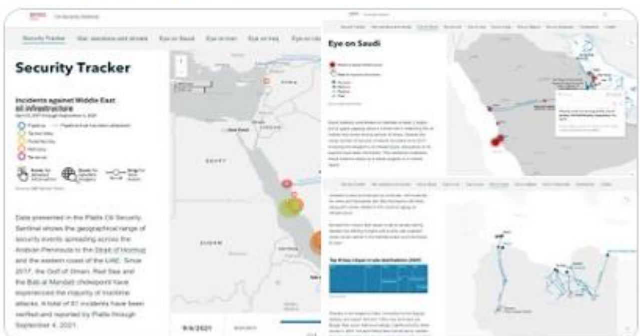
Prepared by SAF Group https://safgroup.ca/news-insights/

2 2

Dan Tsubouchi @Energy_Tidbits · Sep 10

An excellent interactive (can zoom in for detail) reference maps/data from @SPGlobalPlatts "Oil Security Sentinel". Saudi, Libya base maps attached. Also Iraq, Nigeria, VEN, Chokepoints. Definite one to bookmark. Great job @SPGlobalPlatts . #OOTT

spglobal.com/platts/PlattsC...



1 1

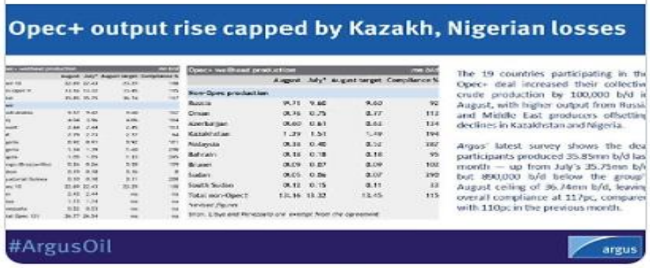
Dan Tsubouchi @Energy_Tidbits · Sep 10

#OPEC+ only +100,000 b/d MoM. Its in total, but well below scheduled +400,000 b/d increase for Aug. Reminds as long as KSA, UAE, KW, RU stay reasonably disciplined, most of remaining OPEC+ seem to have some sort of supply challenge regularly pop up. Thx @ArgusMedia #OOTT #Oil

Argus Media @ArgusMedia · Sep 10

News story: The 19 participants in the #Opec+ deal increased their collective Aug #crudeoil output by 100,000 b/d , with higher output from Russia and Mideast producers offsetting declines in Kazakhstan and Nigeria | #ArgusOil #OOTT

By @RMIordache: okt.to/liS2At



1 4 15

Dan Tsubouchi @Energy_Tidbits · Sep 9

Bullish for #LNG #NatGas "Importantly, higher natural gas and LNG prices are beginning to support an increased level of long-term contracting activity as buyers once again seek out long-term supply agreements"says $BKR @simonelli_l See below SAF 07/14 blog safgroup.ca/news-insights/

1 1 2

Dan Tsubouchi @Energy_Tidbits · Sep 9

For those not near their laptop, EIA weekly #Oil #Gasoline #Distillates inventory data as of Sept 3 just out. Prior to release, WTI was trading $69.69. #OOTT

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

Oil/Products Inventory Sept 3: EIA, Bloomberg Survey Expectations, API

(million barrels)	EIA	Expectations	API
Oil	-1.53	-4.75	-2.88
Gasoline	-7.22	-3.30	-6.41
Distillates	-3.14	-3.50	-3.75
	-11.89	-11.55	-13.04

Note: In addition, there was no change in the SPR for Sept 3 week

Note: Included in the data, Cushing had an injection of 1.92 mmb for Sept 3 week

Source EIA, Bloomberg

Prepared by SAF Group

3

Dan Tsubouchi @Energy_Tidbits · Sep 8

Asian LNG buyers continue shift to long term deal. MexicoPacificLNG CEO on Asian #LNG buyer interest "this year, its been incredible". Follows MPL Apr comment advanced discussion with CN JP KR on long term contracts. Thx @abakerNGI @coreypaul. Fits SAF July 14 blog below. #NatGas

Dan Tsubouchi @Energy_Tidbits · Jul 14

SAF Group blog "Asian LNG Buyers Abruptly Change and Lock in Long Term Supply – Validates Supply Gap, Provides Support For Brownfield LNG FIDs" just posted. Hope it helps in your #LNG #NatGas #LNGSupplyGap #OOTT perspective. ...

1 5 6

Dan Tsubouchi @Energy_Tidbits · Sep 8

#EnergyTransition Not Ready For Prime Time. 16:30 min @GMS_Leadership Sharma no breakthru technology yet for shipping #NetZero, so owners hold capex for new ships & create late 2020s create upcycle in freight. ie like 2020s #Electricity setup & good for #NatGas. Thx @sean_evers

> Gulf Intelligence @gulf_intel · Sep 8
>
> **HALF-TIME TALK**: "Offshore Oil & Gas Vessels are Taking a Sharp Beating!" - Dr. Anil Sharma, President & CEO, @GMS_Leadership
>
> Full Interview here: bit.ly/3l6LLsl
>
> #OOTT #COVID19 #RenewableEnergy #shipping #offshore #netzero #oilandgas #SupplyDemand

2 2

Dan Tsubouchi @Energy_Tidbits · Sep 8

Still only a continued slow return of shut-in GoM #Oil #NatGas production post #HurricaneIda. Still shut-in is 1.40 mmb/d and 1.72 bcf/d. #OOTT

BSEE Gulf of Mexico O&G Activites - Hurriance Ida Response

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Note: 09-01 was corrected, originally reported 249 platforms, 1,455,279 b/d, 1.6772 bcfd shut in

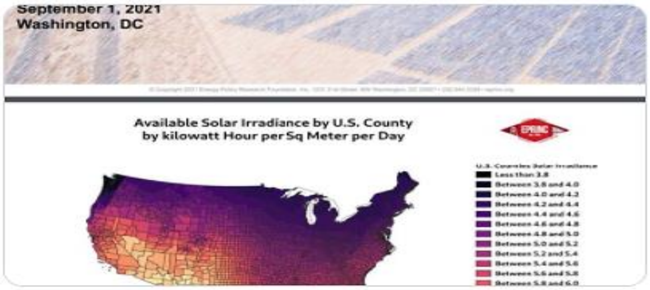
Source BSEE

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

1 3

Dan Tsubouchi @Energy_Tidbits · Sep 8

#Biden wants 1/2 #electricity from #solar, will need no NIMBY stopping big expansion in transmission from solar areas to demand, long duration send out storage for intermittent solar & demand reduction. #NatGas will be needed for longer like being seen in EU now. Thx @EPRINC_DC



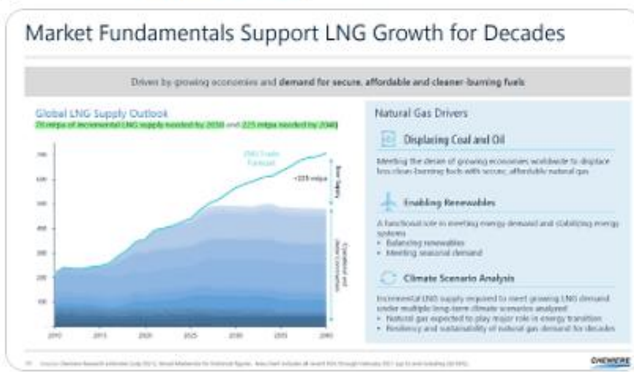
The New York Times @nytimes · Sep 8

Breaking News: The Biden administration will announce a goal of producing almost half the nation's electricity from the sun by 2050, a major shift in energy policy. nyti.ms/3l3e9fw

1 2 4

Dan Tsubouchi @Energy_Tidbits · Sep 8

Bullish #LNG outlook. #Cheniere sees extremely tight LNG supply/demand for next few years & then increasing supply gap. Needs >9 bcf/d of FID now to meet 2020s supply gap, then incremental >20 bcf/d FIDs for 2030s. Big positive for HH & #AECO #NatGas prices.



6 19

Dan Tsubouchi @Energy_Tidbits · Sep 7

Still only continued slow return of shut-in GoM #Oil #NatGas production post #HurricaneIda. Still shut-in is 1.44 mmb/d and 1.84 bcf/d. 20% less evacuated platforms but production return is much less as #Shell's WD-143 transfer station damage keeps multiple fields shut-in #OOTT

BSEE Gulf of Mexico O&G Activites - Hurriance Ida Response

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Note: 09-01 was corrected, originally reported 249 platforms, 1,451,279 b/d, 1.8772 bcf/d shut in

Source BSEE

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

1 2 8

Dan Tsubouchi @Energy_Tidbits · Sep 7

"the future of oil production in Russia is associated with complexly constructed fields, super-viscous reserves" & need tax breaks so can be economic at $50/55 #Oil says #Lukoil CEO. Positive for #Oil in 2020s. #OOTT

Excerpt https://www.kommersant.ru/doc/4975011

"Now the oil price is artificially regulated"

LUKOIL CEO Vagit Alekperov on OPEC + deal, energy transition and taxes

Newspaper "Kommersant" №160 from09/07/2021, p. 1

- **Did you manage to find a compromise with the Ministry of Finance on extra-viscous oils, the benefits for which were canceled?**

- We are constantly in dialogue with the government, but so far we have not found a solution. LUKOIL has a special relationship with viscous and extra-viscous oils. The company invested 250 billion rubles. in the arrangement of such deposits. This is the construction of huge factories, complexes for the preparation of steam, which is pumped into these fields. A very complex ecological infrastructure for mining operations.

We believe that the future of oil production in Russia is associated with complexly constructed fields,

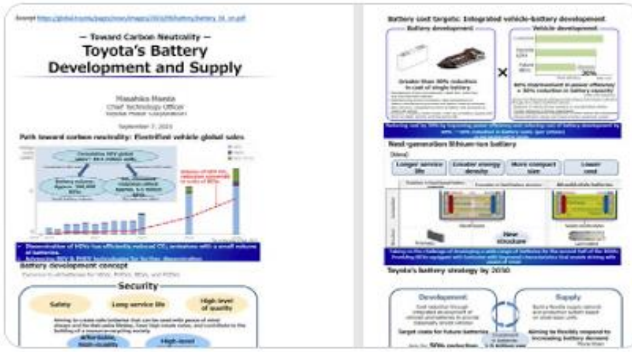
Dan Tsubouchi @Energy_Tidbits · Sep 2

Only half of Russia's #Oil reserves are profitable at $50 says Deputy Energy Minister Sorokin. Fits Jan 27 linked tweet. Bullish for mid/long term oil prices. Detailed comment in SAF Group Jan 27, 2021 Energy Tidbits memo safgroup.ca/news-insights/ #OOTT

2 1 7

Dan Tsubouchi @Energy_Tidbits · Sep 7

Excellent read on #EV battery potential for 2020s. Read script & #Toyota slides for its $13.5b plan to develop own battery supply chain. notes challenges/opportunities for both #HEV & #BEV and also tradeoffs ie. charging too fast impacts safety #OOTT
global.toyota/en/newsroom/co...



1 1 4

Dan Tsubouchi @Energy_Tidbits · Sep 6

Still only a continued slow return of shut-in GoM #Oil #NatGas production post #HurricaneIda. Still shut-in is 1.53 mmb/d and 1.80 bcf/d. #OOTT
bsee.gov/newsroom/lates...

BSEE Gulf of Mexico O&G Activities - Hurriance Ida Response

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2021-09-01	278	49.64%	9	81.80%	1,705,095	93.69%	2,107.0	94.47%
2021-09-02	177	31.61%	6	54.55%	1,702,566	93.55%	2,035.0	91.29%
2021-09-03	133	23.75%	6	54.55%	1,698,557	93.33%	1,990.2	89.25%
2021-09-04	119	21.25%	6	54.55%	1,683,604	92.51%	1,915.4	85.89%
2021-09-05	104	18.57%	5	45.45%	1,607,340	88.32%	1,844.7	82.72%
2021-09-06	99	17.68%	5	45.45%	1,526,409	83.87%	1,801.4	80.78%

Note: 09-01 was corrected, originally reported 249 platforms, 1,455,275 b/d, 1.8772 bcf/d shut in

Source BSEE

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

1 5

Dan Tsubouchi @Energy_Tidbits · Sep 6

Hmm! Record UK power prices & @nationalgriduk grid.iamkate.com shows extremely low #Wind generation. Common factor on 5 winter 20/21 bad power days was low wind. replacing 24/7 baseload coal/nuclear with intermittent wind/solar is expensive. #NatGas #LNG will be needed

> **Dan Tsubouchi** @Energy_Tidbits · Jul 25
>
> Hmmm! Why doesn't UK #NationalGridESO want to call out #Wind as key wildcard for reliable power? Fcast lower reserve for winter 21/22. "reflecting on last winter" say main issue #Coal #CCGT #NatGas plants. Yet common denominator for their 5 winter 20/21 bad power days is wind?
>
> 

2 5

Dan Tsubouchi @Energy_Tidbits · Sep 5

Bigger picture at play here, regardless who owns the pipeline, will bring underwater pipelines under scrutiny. Re this spill, linked fields to this pipeline will inevitably be shut in for longer. Thx @mbieseck for this & other great reporting today on the #Oil spill. #OOTT

> **Michael Biesecker** @mbieseck · Sep 5
>
> BREAKING: Divers identified a sheared-off 1-foot diameter pipeline as the source of a sizable oil spill that appeared after #HurricaneIda. @AP first reported Wed that aerial photos showed a miles-long brown and black oil slick spreading in the Gulf. apnews.com/article/busine...

2 3 5

Dan Tsubouchi @Energy_Tidbits · Sep 5

A picture is worth a thousand words. Sounds like Oun loses his try to oust @NOC_Libya Chair Sanallah. Will this be turning point for budget allocation to #LibyaNOC to get back on track for #Oil growth? #OOTT

> The Libya Observer @Lyobserver · Sep 5
>
> Libyan PM says won't allow administrative hindrances to blockade oil output lyo.ly/21af

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Dan Tsubouchi @Energy_Tidbits · Sep 5

So far, still only a slow return of shut-in GoM production post #HurricaneIda. Still shut-in 1.607 mmb/d #Oil 1.84 bcf/d #NatGas. #OOTT

bsee.gov/newsroom/lates...

BSEE Gulf of Mexico O&G Activites - Hurriance Ida Response

	Platforms Evacuated		Rigs Evacuated		Oil - Shut-In (b/d)		Gas - Shut-In (mmcf/d)	
Date	Total	% of GOM	Total	% of GOM	Total	% of GOM	Total	% of GOM
2021-08-27	89	15.89%	1	9.09%	1,064,849	58.51%	1,088.0	48.79%
2021-08-28	279	49.82%	11	100.00%	1,653,335	90.84%	1,892.7	84.87%
2021-08-29	288	51.43%	11	100.00%	1,740,850	95.65%	2,090.7	93.75%
2021-08-30	288	51.43%	11	100.00%	1,721,809	94.60%	2,087.0	93.57%
2021-08-31	278	49.64%	9	81.82%	1,705,095	93.69%	2,107.0	94.47%
2021-09-01	278	49.64%	9	81.80%	1,705,095	93.69%	2,107.0	94.47%
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Source BSEE

1 6

Dan Tsubouchi @Energy_Tidbits · Sep 5

Our weekly SAF Sept 5, 2021 Energy Tidbits memo was just posted to our SAF Group website. This 53-pg energy research piece expands upon and covers many more items than tweeted this week. See the research section of the SAF website #Oil #OOTT #LNG #NatGas safgroup.ca/news-insights/

SAF GROUP

Energy Tidbits

Sept 5, 2021

Produced by: Dan Tsubouchi

Only Half of Russia's Oil Reserves are Profitable at $50 says Deputy Energy Minister Sorokin

Welcome to new Energy Tidbits memo readers. We are continuing to add new readers to our Energy Tidbits memo, energy blogs and tweets. The focus and concept for the memo was set in 1999 with input from PMs, who were looking for research (both positive and negative items) that helped them shape their investment thesis to the energy space, and not just focusing on daily trading. Our priority was and still is to not just report on events, but also try to interpret and point out implications therefrom. The best example is our review of investor days, conferences and earnings calls focusing on sector developments that are relevant to the sector and not just a specific company results. Our target is to write on 48 to 50 weekends per year and to post by noon mountain time on Sunday.

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